EB-2019-0143

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF a Motion to Review and Vary the Ontario Energy Board's Decision and Order dated April 23, 2019 re. Niagara-on-the-Lake Hydro Inc.'s 2019 Distribution Rate Application (EB-2018-0056).

AND IN THE MATTER OF Rules 8 and 40, 42 and 43 of the *Rules of Practice and Procedur*e of the Ontario Energy Board.

MOTION RECORD OF NIAGARA-ON-THE-LAKE HYDRO INC. FOR A REVIEW OF THE BOARD'S APRIL 23, 2019 DECISION

June 20, 2019

AIRD & BERLIS LLP
Barristers and Solicitors
Brookfield Place
Suite 1800, Box 754
181 Bay Street
Toronto, ON M5J 2T9

David Stevens
Tel (416) 863-1500
Fax (416) 863-1515

dstevens@airdberlis.com

TO: **ONTARIO ENERGY BOARD**
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Tel: (416) 481-1967
Fax (416) 440-7636

AND TO:

ALL INTERVENORS IN EB-2018-0056

INDEX

INDEX

1. Notice of Motion of Niagara-on-the-Lake Hydro Inc. (NOTL Hydro)
2. Supplementary Written Submissions of NOTL Hydro on the Review Motion
3. EB-2018-0056 Decision and Order dated April 11, 2019 (updated April 23, 2019).
4. The record of the EB-2018-0056 proceeding on the issue of OM&A costs, including prefiled evidence, interrogatories and argument.
    i. NOTL Hydro Prefiled evidence, Exhibit 4, Operations, Maintenance & Administration
    ii. NOTL Hydro Additional evidence, Exhibit 4, Operations, Maintenance & Administration
    iii. NOTL Hydro Interrogatory responses re OM&A costs
    iv. NOTL Hydro Supplementary Interrogatory responses re OM&A costs
5. The written submissions in the EB-2018-0056 proceeding on the issue of OM&A costs
    i. NOTL Hydro Argument in Chief
    ii. OEB Staff Submission
    iii. Final Argument of the School Energy Coalition
    iv. Submission of the Vulnerable Energy Consumers Coalition
    v. NOTL Hydro Reply Argument
6. OEB Decisions cited in NOTL Hydro Notice of Motion and Supplementary Written Submissions
    i. EB-2016-0005 Decision on Motion to Review and Vary by the City of Hamilton, March 3, 2016
    ii. EB-2006-0322/0338/0340 Decision with Reasons on Motions to Review the Natural Gas Electricity Interface Review Decision, May 22, 2007
    iii. EB-2016-0105, Thunder Bay Hydro Electricity Distribution Inc., Decision and Order dated September 21, 2017
7. OEB Reports cited in NOTL Hydro Notice of Motion
    i. EB-2010-0379, Report of the Board titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors", December 4, 2013, page 23.

ii. Pacific Economics Group Research, LLC, Productivity and Benchmarking Research In Support Of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board, November 2013, at page 6 (mistakenly identified as page 10 in the Notice of Motion).

TAB 1

EB-2018-0056

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an application by Ni agara-on-the-Lake Hydro Inc. for an order or orders approving electricity distribution rates and other charges commencing as of May 1, 2019.

AND IN THE MATTER OF the Board's Decision and Order dated April 11, 2019 (updated April 23, 2019).

AND IN THE MATTER OF Rules 8 and 40, 42 and 43 of the *Rules of Practice and Procedur*e of the Ontario Energy Board.

NOTICE OF MOTION

Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) will make a motion to the Ontario Energy Board (OEB, or the Board) on a date and at a time to be determined by the Board.

PROPOSED METHOD OF HEARING: NOTL Hydro proposes that the Motion be heard by way of a written hearing.

THE MOTION IS FOR:

1. A review and variance of those portions of the Decision and Order in EB-2018-0056 dated April 11, 2019 (updated April 23, 2019) (referred to herein as the Decision) in which the OEB determined NOTL Hydro's Operating, Maintenance and Administration (OM&A) budget for 2019.

2. An Order approving a revised 2019 OM&A budget of $2,964,765 for NOTL Hydro.

3. An Order that NOTL Hydro satisfies the "threshold test" in Rule 43.01 of the Board's *Rules of Practice and Procedure*.

4. Such further and other Orders as NOTL Hydro may request and the Board approves.

THE GROUNDS FOR THE MOTION ARE:

The proceeding

1. On August 23, 2018, NOTL Hydro filed an application for 2019 distribution rates, to be effective May 1, 2019.

2. NOTL Hydro filed evidence on all aspects of its application, including its proposed 2019 OM&A budget of $2,964,765 for the Test Year (as updated). NOTL Hydro answered interrogatories from the three participants in the proceeding (Board Staff, SEC and VECC) in November 2018 (with follow-up questions in December 2018), and the parties then participated in a Settlement Conference in December 2018.

3. On January 10, 2019, NOTL Hydro filed a (partial) Settlement Proposal with the OEB. The Settlement Proposal indicated that there are six "Unsettled Items", including the OM&A cost forecast for the Test Year.

4. After the Settlement Proposal was filed, the evidentiary record in the proceeding was completed, with the filing of Additional Evidence related to OM&A and other unsettled items, along with interrogatory responses on the Additional Evidence.

5. On the issue of OM&A budget, NOTL Hydro provided a total of 356 pages of prefiled evidence and answered 45 interrogatories.

6. On February 8, 2019, the Board issued its Decision on Partial Settlement Agreement and Procedural Order No. 4, accepting the Settlement Proposal and the rates that result, subject to the adjustments arising from the OEB's decision on the unsettled issues. The Board agreed that no oral hearing was necessary to determine the unsettled issues. The parties filed written argument on the unsettled issues in February and March 2019.

The Decision

7. The Board issued the Decision on April 11, 2019 (with a correction later being issued on April 23, 2019). The Decision addressed each of the unsettled items in the proceeding, including NOTL Hydro's 2019 Test Year OM&A budget.

8. The Board-approved 2019 OM&A budget for NOTL Hydro set out in the Decision is $2,671,367. In making this determination, the Board reduced NOTL Hydro's proposed 2019

OM&A budget by $293,000, to a level that is $168,000 lower than NOTL Hydro's actual OM&A expenditures for 2018.

9. The Decision on NOTL Hydro's 2019 OM&A budget does not consider the actual base components of NOTL Hydro's OM&A costs, nor the utility's most recent actual costs. No explanation is provided as to why the approved budget is reasonable in contrast to these items. Additionally, no recognition was given for the fact that NOTL Hydro's existing and proposed rates are among the lowest of its peers.

10. The Decision determined NOTL Hydro's 2019 OM&A budget by starting with the 2014 Board-approved OM&A budget and then applying adjustments to account for inflation, stretch factor and customer growth for each year up to 2019. Contrary to the evidence and the submissions from NOTL Hydro, the Decision declined to include any adjustment to account for cost pressures arising from kWh delivered and system peak capacity.

11. The Decision also included allowances for costs of some (but not all) new requirements identified as cost drivers by NOTL Hydro. No explanation is provided as to how the items and amounts approved were chosen, nor as to why other new requirements described in evidence and argument were not approved.

12. Finally, the Decision recognized that certain costs that had previously been capitalized should be included the 2019 OM&A budget. However, the Decision declined to treat these items as being notionally included in the 2014 base OM&A budget, meaning that NOTL Hydro was not credited with the impact from inflation and growth on these costs.

The errors in the Decision

13. Rule 40.01 of the Board's *Rules of Practice and Procedure* allows any person to bring a motion requesting the Board to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision.

14. Rule 42.01(a) of the Board's *Rules of Practice and Procedure* requires that a notice of motion shall set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:

    (i) error in fact;

(ii) change in circumstances;

(iii) new facts that have arisen;

(iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time;

15. The OEB has confirmed that this list of grounds is "not an exhaustive list". What is required is that the motion to review must raise a question as to the correctness of the order or decision.[1] The moving party must demonstrate that the findings are contrary to the evidence before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings or something of a similar nature. The moving party must also demonstrate that the alleged error is material and would vary the outcome of the decision.[2]

16. NOTL Hydro respectfully submits that there are several material errors in the Decision on the Test Year OM&A budget. These can be summarized as follows:

    i. The Decision failed to take account of NOTL Hydro's detailed evidence about its forecast OM&A costs for 2019, and about the actual costs required to run the utility in 2018.

    ii. Despite contrary direction from the Pacific Economics Group Research, LLC (PEG) reports to the OEB, the Decision in this case failed to include the impact of the growth in NOTL Hydro's kWh delivered and system peak capacity over the years from 2014 to 2019 when determining a reasonable level of OM&A costs for the Test Year.

    iii. While the Decision properly recognized that NOTL Hydro faces extraordinary costs that will not be accommodated in an OM&A budget that is increased only by inflation and growth, the Decision fails to recognize all such extraordinary cost items and provides no explanation as to the items and amounts excluded.

    iv. While the Decision properly determined that NOTL Hydro should be permitted to include in the Test Year budget certain previously capitalized OM&A costs that were

[1] EB-2016-0005 Decision on Motion to Review and Vary by the City of Hamilton, March 3, 2016, at page 4.
[2] EB-2006-0322/0338/0340 Decision with Reasons on Motions to Review the Natural Gas Electricity Interface Review Decision, May 22, 2007, at page 18.

not included in the base 2014 OM&A budget, it is inconsistent to exclude those costs from the base costs that are adjusted to arrive at the 2019 Test Year budget.

17. Each of the errors raise questions as to the correctness of the Decision, and are material to the outcome of the proceeding. More detail is provided below.

(i) Failure to consider NOTL Hydro's evidence about forecast and actual costs

18. As required by the Board's Filing Requirements For Electricity Distribution Rate Applications, as part of its application NOTL Hydro filed detailed pre-filed evidence about its 2019 OM&A budget. NOTL Hydro provided explanations of the main cost drivers and included breakdowns of the changes in OM&A costs from year to year. NOTL Hydro's Argument in Chief and Reply Argument each highlighted the relevant evidence explaining the elements of the 2019 OM&A budget. As was highlighted in NOTL Hydro's written Argument in Chief, the costs NOTL Hydro is incurring for 2019 are current costs developed as NOTL Hydro has responded to the needs of its customers and are not proposed future costs.

19. NOTL Hydro's evidence and argument also highlighted the utility's most recent actual OM&A expenditures ($2,838,525 for 2018) and asserted that this is the most appropriate starting point to determine a 2019 budget level. NOTL Hydro pointed to a recent Thunder Bay Hydro decision of the OEB where the Board agreed that looking at the most recent OM&A expenditures and adjusting for inflation, growth and stretch factor is an appropriate way to evaluate a forecast Test Year budget.

20. In the "Findings" part of the review of NOTL Hydro's OM&A budget, the Decision did not make any reference to NOTL Hydro's evidence about the components of its OM&A costs, nor to NOTL Hydro's most recent actual expenditures. Instead, the Decision used an "envelope approach to the budget" that adjusted the 2014 OM&A budget for inflation, customer growth and stretch factor, and then made a small number of discrete adjustments. The Decision stated that this envelope approach "helps provide a yardstick that avoids micromanagement of the regulated utility and helps the regulator cope with any asymmetries of information that can be present". Importantly, the Decision does not point to any particular instances of "information asymmetry" in this case. Parties in this case were content to proceed with a written hearing, suggesting that there were no serious concerns about the completeness of the record.

21. The Decision's failure to take account of NOTL Hydro's detailed evidence about its forecast and actual OM&A costs and instead use a "yardstick" calls into question why the OEB's own Filing Guidelines require detailed budget information to be filed and examined. If the OEB requires this information to determine a cost of service application, then it is not correct to ignore the information when making a decision on the application. That is particularly the case when the applicant is relying on the specific evidence filed to support its case.

22. The approach taken in the Decision to set NOTL Hydro's new OM&A budget through a benchmarking exercise rather than evaluate the costs on their own merits is troubling. The stretch factors and elasticity factors found in the PEG reports applied to assess a distributor's costs are meant to be used as a point of comparison in evaluating NOTL Hydro's OM&A and not as the determinant of approved future budgets. Based on the Board's Renewed Regulatory Framework for Electricity (RRFE), a Cost of Service application is meant to determine the "Going In" rates or the rebasing upon which benchmarking is applied for the following four years. The RRFE emphasizes that while actual costs are decoupled from prices during the IR term, that link is restored at the cost of service review. This cannot happen if the cost of service rates are set based on a formulaic basis, starting from prior approved budgets. That approach means that rates are forever decoupled from costs. Under that approach, the determination and approval of actual costs never happens.

23. NOTL Hydro submits that the OEB's Decision on the 2019 OM&A budget is contrary to the evidence filed, and is contrary to policy and previous decisions of the OEB determining OM&A budgets. No explanation is provided as to what, if any, items in the detailed OM&A budget are unreasonable. No explanation is provided as to why it is reasonable for the approved budget to be $168,000 lower than NOTL Hydro's actual OM&A expenditures for 2018.

24. These errors are material, and they render the Decision incorrect.

(ii) Failure to include the impact of growth in NOTL Hydro's kWh delivered and system peak capacity

25. NOTL Hydro's Additional Evidence and argument explain that if the OEB decides to confirm NOTL Hydro's 2019 OM&A budget by reference to the 2014 Board-approved budget, then it is appropriate to adjust the prior budget by several factors, including inflation, customer

growth, stretch factor, load growth and system peak load growth. This is consistent with the approach used by the OEB's expert PEG, which applies five factors to calculate the impact of growth on costs.[3] These factors are customer growth, load growth, system peak growth, increase in distribution lines and acceleration in customer growth. In its Additional Evidence and argument NOTL Hydro used the first three of these items in evaluating the impact of growth on OM&A costs - the latter two items were not used because NOTL Hydro has seen no noticeable change in either the amount of distribution lines or the rate of customer growth.

26. In its determination of the 2019 OM&A budget, the Decision declined to follow the approach proposed by NOTL Hydro. The Decision states "NOTL Hydro also suggested additional load and peak factors as escalators to the 2014 OEB-approved OM&A. However, there is no indication that any increases caused by these factors would not be captured in whole or in part by the customer growth factor."

27. This determination is incorrect. The evidence that increases in load (kWh delivered) and peak load contribute incrementally to a distributor's costs is clear from the reports from PEG, the Board's own expert. While the PEG report found that the number of customers was the dominant cost driver, four other cost drivers were identified as being statistically significant: peak demand, kWh deliveries, circuit km of line and share of customers added over the last 10 years.

28. As explained in the PEG report of November 2013, "PEG developed an econometric model to benchmark distributors' total cost performance. PEG's recommended model finds that there is a statistically significant relationship between a distributor's total costs and five business condition variables: 1) the number of customers served; 2) kWh deliveries; 3) system peak capacity; 4) the average km of distribution over the sample period; and 5) the percent of customers added in the last 10 years."[4] As each of these items is statistically significant, it cannot be said that they are all captured by the customer growth factor.

29. By using only the one variable, the Decision has systematically understated the impact of growth on NOTL Hydro's OM&A. The variables used by PEG are drivers of both OM&A and

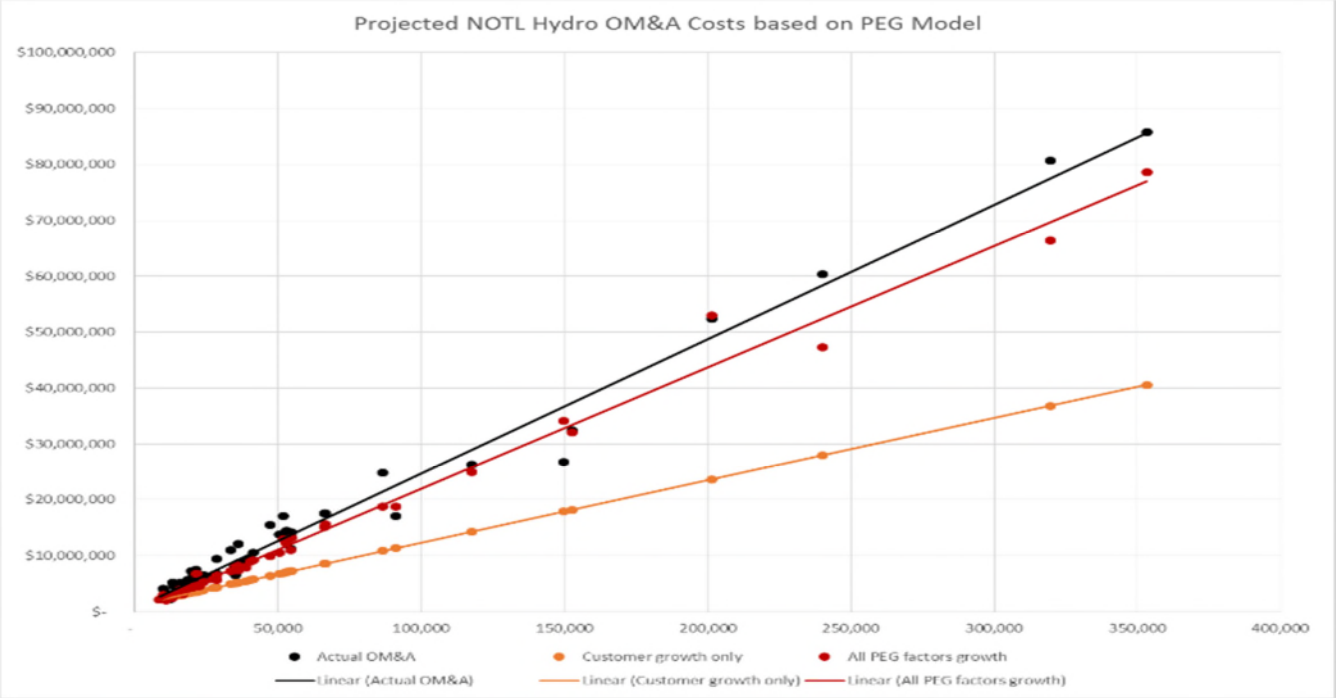
[3]EB-2010-0379, Report of the Board titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors", December 4, 2013, page 23.
[4] Pacific Economics Group Research, LLC, Productivity and Benchmarking Research In Support Of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board, November 2013, at page 10.

capital costs. Factors like system peak growth and load growth increase a utility's operating costs, particularly in the case of a distributor like NOTL Hydro, which has significant transmission assets.

30. The fact that considering only customer growth understates OM&A impacts can be seen by comparing NOTL Hydro to other distributors. In the graph below, NOTL Hydro has extrapolated its OEB-approved 2014 OM&A to calculate what the 2014 OM&A would have been based on the customer counts of the larger Ontario distributors using the PEG model. If the observation in the Decision that only customer growth impacts OM&A expenditures is correct, then NOTL Hydro's extrapolated OM&A should be close to the actual OM&A of the other distributors. However, the results are that, on average, if only the customer count (customer growth factor) is used then NOTL Hydro's extrapolated OM&A is only 55% of the actual OM&A of the other distributors. On the other hand, if the full PEG model (with the five growth factors) is used then NOTL Hydro's extrapolated OM&A is 85% of the actual average OM&A.

31. This analysis is illustrated in the graph below. The black dots and the black trend line are the actual OM&A costs of all larger Ontario distributors sorted by customer count.[5] The orange trend line and orange dots represent what NOTL Hydro's OM&A would be using the customer count of all the other larger Ontario distributors using the PEG formula in the Decision. The red trend line and dots represent what NOTL Hydro's OM&A would be using the PEG formula with all five statistically significant variables. As can be seen, using all five PEG factors leads to an extrapolated NOTL Hydro OM&A amount that is much closer to the actual costs of other distributors, confirming that using all five factors is a much more accurate estimation formula.

[5] All data used was taken from the OEB's 2014 Yearbook of Electricity Distributors (July 31, 2015). Hydro One and Toronto Hydro have been removed as their size has the visual impact of moving all other distributors into the lower left section. Their removal has no impact on the analysis.



32. The difference in NOTL Hydro's 2019 OM&A budget between calculating the needed growth in OM&A using only customer count and using all the statistically significant PEG factors is $129,524. This can be seen in the table below.

	Board Approved 2014	2014	2015	2016	2017	2018	2019
		Actual					Projected
Base OM&A Expense	2,155,262						
Escalator Rates							
Inflation (OEB)		0.00%	1.60%	2.10%	1.90%	1.20%	1.70%
Base Productivity		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Stretch Factor (PEG Group 3)		0.00%	0.30%	0.30%	0.30%	0.30%	0.30%
Sub-Total		0.00%	1.30%	1.80%	1.60%	0.90%	1.40%
Customer Growth (Growth x PEG Elasticity of 0.4485)		0.28%	1.51%	1.40%	0.91%	0.70%	0.87%
		0.28%	2.81%	3.20%	2.51%	1.60%	2.27%
Base OM&A Expense adjusted for Inflation + Customer growth		2,161,224	2,221,889	2,293,029	2,350,478	2,388,019	2,442,148
kWh Growth (Growth x PEG Elasticity of 0.1083)		0.08%	0.26%	0.48%	(0.29%)	0.34%	1.04%
System Peak (Growth x PEG Elasticity of 0.1623)		(1.58%)	1.34%	1.41%	(2.06%)	4.05%	0.41%
		(1.50%)	1.59%	1.89%	(2.35%)	4.40%	1.45%
Additional Base OM&A from kWh and System Peak escalators		(32,290)	698	42,714	(11,115)	91,605	**129,524**
Base OM&A Expense adjusted for inflation/customer growth/load/peak		2,128,934	2,222,588	2,335,743	2,339,363	2,479,624	2,571,673
2014 IFRS Impact - adjusted for escalators	130,784	129,187	134,870	141,736	141,956	150,467	156,053
2014 Board Approved OM&A expenses adjusted for escalators and IFRS impacts		**2,258,120**	**2,357,457**	**2,477,479**	**2,481,319**	**2,630,091**	**2,727,725**

(iii) Failure to include relevant new and increased costs

33. The Decision appropriately acknowledges simply applying escalation factors to NOTL Hydro's 2014 base OM&A budget will not accommodate the costs of new requirements that must be met by the utility and that have arisen since 2014. NOTL Hydro's evidence and argument explained a range of new and increased services whose costs will not be accommodated in an OM&A budget that is increased only by inflation and growth.

34. The Decision recognized some but not all of NOTL Hydro's filed costs for new and increased services. These are provided in the table below:

New / Increased Service	Description	Application	Decision	Variance
IT & Cyber security	This includes the cost of the new IESO service, future audits and consulting on the new framework. The disallowed amount of these costs ($37,394) are the incremental costs with NOTL Hydro's service provider, Skycomp, in order to implement the new IT controls to meet the increased cyber security risks.	$67,394	$30,000	($37,394)
Utilismart	This is a new service NOTL Hydro began implementing in 2018 which will improve the handling of MicroFIT and other renewable generation customers, provide better data to GS>50 customers and assist the new monthly IESO settlement process. GS>50 customers want this data for their own energy use analysis. This cost, as relates to the MicroFIT customers, is being covered by the increase in the MicroFIT charge to $10 a month which is included in Other Revenue and was approved in the Decision. Customers are getting the benefit of the revenue offset from this charge, but NOTL Hydro is not recovering the associated cost because it is not included in the approved OM&A budget.	$56,844	-	($56,844)
Regulatory costs and survey	These items include the increased cost of this application as compared to the 2014 cost of service case (note that the actual costs of his application will be higher than claimed here), the cost of the annual new surveys (customer satisfaction and safety) and the increased cost of charges by the OEB allocated to distributors. All of these are new since 2014.	$36,528	$13,988	($22,540)

Locates	Increased costs arising from Province-wide initiatives to promote the need for customers to request locates.	$36,566	$36,566	-
Health & Safety Consultant	Safety is the top priority at NOTL Hydro. This cost is for a new, part-time position created in 2015 to ensure safety is maintained at the highest standard at NOTL Hydro and that NOTL Hydro is prepared to meet all ESA and Minister of Labour requirements.	$31,367	-	($31,367)
Pole rentals	Increased costs resulting from higher pole rental charges from Bell Canada.	$8,341	$8,341	-
Total		**$237,040**	**$98,435**	**($138,605)**

35. The Decision provides no explanation as to why some of these costs were accepted and others were not. The evidence in this case establishes that the costs for each of the claimed items relates to a new requirement that has arisen since 2014 which must be met by the utility. By the OEB's own reasoning, each of these costs should be included in NOTL Hydro's 2019 OM&A budget. The Decision provides no information or determination supporting any different outcome.

(iv) Failure to include previously capitalized costs in base OM&A costs

36. While the Decision properly determined that NOTL Hydro should be permitted to include in the Test Year budget certain previously capitalized OM&A costs (these costs have been moved to OM&A because of an accounting rules change), it declined to include those costs in the base 2014 OM&A budget that was adjusted to arrive at the 2019 Test Year budget.

37. The Decision on this item is in error. These previously capitalized costs are not new costs. They represent labour costs that were part of the 2014 budget, but were included in capital costs at that time. If the goal of the Decision's budget-setting exercise for 2019 is to inflate the 2014 budget by inflation, growth and stretch factor, then it is proper to use an "apples to apples" comparison, and include all preexisting costs in the 2014 base. The Decision provides no explanation for why a different approach is appropriate. The evidence does not support the Decision on this point.

38. If the Decision had applied the appropriate inflation, growth and stretch factors to the 2014 capitalized labour cost of $130,704, the resulting 2019 OM&A budget would have been increased by $25,269.

The errors are material

39. Each of the errors described above have a material impact on NOTL Hydro's 2019 OM&A budget. This is especially the case when one takes account of the fact that NOTL Hydro's 2019 OM&A budget is the base for each of the next five years, meaning that the impact of the errors will be experienced five times over.

40. The Decision does not specifically deny or question any of NOTL Hydro's OM&A cost forecasts filed in this case. NOTL Hydro submits that had the Decision examined the actual costs and cost forecasts filed, then the requested OM&A budget would have been approved.

41. The table below explains the impact of the other errors in the Decision (taken together these items represent the difference between NOTL Hydro's filing and the OM&A budget approved):

Use of all relevant grown factors in the PEG model	$129,524
Accounting change	25,269
New or increased services	138,605
Total	**$293,398**

42. It is respectfully requested that the Decision be adjusted accordingly, to approve a 2019 Test Year OM&A budget of $2,964,765.

NOTL Hydro satisfies the threshold test

43. Rule 43.01 of the Board's *Rules of Practice and Procedures* states that "In respect of a motion brought under Rule 40.01, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits."

44. Each of the four errors highlighted in this Notice of Motion raises material questions about the correctness of the Decision. Correcting these errors will materially impact the Decision. As such, NOTL Hydro satisfies the Board's threshold test and the Board should proceed to hear the motion on its merits.

THE FOLLOWING DOCUMENTARY EVIDENCE will be used at the hearing of the motion:

1. The EB-2018-0056 Decision and Order dated April 11, 2019 (updated April 23, 2019).

2. The record of this EB-2018-0056 proceeding, including prefiled evidence, interrogatories and argument.

3. OEB reports and decisions, including the RRFE and the Productivity and Benchmarking Research Reports prepared by PEG for the OEB.

4. Written submissions, to be filed.

5. Such further and other documentary evidence as NOTL Hydro may provide and the Board approves.

April 29, 2019

AIRD & BERLIS LLP
Barristers and Solicitors
Brookfield Place
Suite 1800, Box 754
181 Bay Street
Toronto, ON M5J 2T9

David Stevens
Tel (416) 863-1500
Fax (416) 863-1515

dstevens@airdberlis.com

TO: **ONTARIO ENERGY BOARD**
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Tel: (416) 481-1967
Fax (416) 440-7636

AND TO:

ALL INTERVENORS IN EB-2018-0056

TAB 2

EB-2019-0143

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended.

AND IN THE MATTER OF a Motion to Review and Vary the Ontario Energy Board's Decision and Order dated April 23, 2019 re. Niagara-on-the-Lake Hydro Inc.'s 2019 Distribution Rate Application (EB-2018-0056).

AND IN THE MATTER OF Rules 8 and 40, 42 and 43 of the *Rules of Practice and Procedur*e of the Ontario Energy Board.

SUPPLEMENTARY WRITTEN SUBMISSIONS OF NIAGARA-ON-THE-LAKE HYDRO INC.

INTRODUCTION

1. On April 29, 2019, Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) filed a Notice of Motion for a review and variance of those portions of the Decision and Order in EB-2018-0056 dated April 11, 2019 (updated April 23, 2019) (referred to herein as the Decision) in which the OEB determined NOTL Hydro's Operating, Maintenance and Administration (OM&A) budget for 2019.

2. NOTL Hydro's Notice of Motion requested an Order approving a revised 2019 OM&A budget of $2,964,765 for NOTL Hydro. NOTL Hydro also requested an Order that NOTL Hydro satisfies the "threshold test" in Rule 43.01 of the Board's *Rules of Practice and Procedure*.

3. On June 6, 2019, the OEB issued a Notice of Hearing and Procedural Order No. 1 and assigned file number EB-2019-0143 to this Review Motion. The OEB acknowledged receipt of the Notice of Motion and indicated that NOTL Hydro may file any further written submissions in support of the motion by June 20, 2019. Procedural Order No. 1 invited submissions on both the threshold question of whether the matter should be reviewed and on the merits on the motion.

4. NOTL Hydro's Notice of Motion sets out the basis for the relief being requested. NOTL Hydro repeats and relies on the submissions contained in that document.

5. In addition, NOTL Hydro wishes to make brief submissions on two topics, set out below. These Supplementary Submissions should be read in conjunction with the Notice of Motion.

The Threshold Question

6. As set out in the Notice of Motion, NOTL Hydro satisfies the Board's threshold test under the Rule 43 of the *Rules of Practice and Procedure*.

7. At a high level, the Board's Decision failed to consider and take account of the detailed evidence about NOTL Hydro's OM&A costs when determining the 2019 budget. The Decision, which is meant to reflect the outcome of a "cost of service" proceeding, did not actually consider NOTL Hydro's current and forecast OM&A costs. Instead, the Decision applied a "yardstick" approach to set the 2019 budget, starting from the last Board-approved OM&A budget and then making mechanistic adjustments. Virtually no mention was made of the 356 pages of detailed evidence about NOTL Hydro's actual and forecast 2019 OM&A costs. This raises serious questions about the correctness of the Decision.

8. NOTL Hydro's Notice of Motion describes and details four specific errors in the Decision, each of which raise material questions about the correctness of the Decision. The impact of the errors is material to NOTL Hydro, and will have serious negative impacts on its ongoing operations. As such, NOTL Hydro satisfies the Board's threshold test and the Board should consider the motion on its merits.

9. As with all items in this motion, NOTL Hydro reserves the right to reply to submissions from other parties on the threshold question.

The OEB failed to consider the context of NOTL Hydro's requests

10. The Notice of Motion explains the main errors in the Decision. In addition, though, there are important points of context that the OEB failed to consider in the Decision. These contextual items would have supported approval of NOTL Hydro's as-filed 2019 OM&A budget. These contextual items, taken together with the items highlighted in the Notice of Motion, support a determination that the Decision on NOTL Hydro's 2019 OM&A budget includes material errors that should be corrected. Correcting these errors will result in the amended decision requested in this motion.

(a) NOTL Hydro has maintained low rates and only added costs where necessary

11. As a municipally-owned utility serving residents of its community, NOTL Hydro is motivated to keep its rates (and expenditures) as low as reasonably possible while continuing to provide safe, reliable and customer-friendly service. NOTL Hydro's Mission Statement indicates (in part) that "Niagara-on-the-Lake Hydro continuously seeks to provide low cost energy delivery, high reliability and high power quality." This is obtained by seeking a balance between costs, investments, reliability and power quality.[1]

12. NOTL Hydro filed extensive evidence about why it needs its requested 2019 OM&A budget. The "Findings" part of the Decision on this topic does not take issue with any particular OM&A expenses included in NOTL Hydro's evidence. Nowhere is there any determination that forecast OM&A expenses are unnecessary.

13. NOTL Hydro has gone from having one of the highest distribution rates in the province to one of the lowest. In 1994, NOTL Hydro had the 4th highest residential rate of 111 Ontario electric utilities (LDCs) reporting their rates to the Municipal Electric Association. By 2018, NOTL Hydro had the 17th lowest residential rate of 71 LDCs (lowest quartile), the 23rd lowest GS<50 kW rate of 70 LDCs, the 3rd lowest GS>50 kW rate of 70 LDCs and the lowest Large User rate, based on the forecast consumption of the new Large User, of 24 LDCs.[2]

14. As explained in NOTL Hydro's Additional Evidence on OM&A expenses, NOTL Hydro's rates are lower than what would be expected based on the customer density in its service territory.[3] Importantly, NOTL Hydro's distribution rates are lower than others in its region. This will continue to be the case even with NOTL Hydro's 2019 OM&A budget being adjusted as requested in this Motion.[4]

15. Despite the fact that NOTL Hydro highlighted all the points set out above within its Argument in Chief, no mention at all was made of NOTL Hydro's low distribution rates in the Decision.

---

[1] Exhibit 4 – OM&A – Additional Evidence, page 2.
[2] *Ibid.*
[3] Exhibit 4 – OM&A – Additional Evidence, pages 3 and 4.
[4] Argument in Chief, at paras. 25-26 (and the references included therein).

The OEB apparently did not consider this to be relevant context when considering the 2019 OM&A budget.

16. NOTL Hydro submits that the Board's failure to take account of the fact that NOTL Hydro strives to control costs, and has maintained low, predictable overall rates demonstrates the error in the Decision about OM&A budget. It is not sufficient or appropriate to look only at NOTL Hydro's 2019 OM&A forecast in comparison to 2014 Board-approved, as was done in the Decision. The actual components of the budget must be considered (including recent actual spending, as detailed below), and the impacts on overall rates should also be taken into account. Failure to explicitly consider these items results in a Decision that includes material errors, and that should be corrected.

(b) The OEB's failure to take account of actual OM&A expenditures will have negative impacts on customer service

17. NOTL Hydro's evidence explained that its most recent actual OM&A expenditures for 2018 totaled $2,838,525. This, of course, is the best evidence of what NOTL Hydro requires to run its business. The fact that NOTL Hydro has been spending at a level above what was implicitly included in current rates and recovered from customers for OM&A expenses confirms that this expenditure is necessary.

18. The Decision failed to give any weight to NOTL Hydro's most recent actual OM&A expenditures, and did not even mention this important fact in the "Findings" section on OM&A Expense. The "Findings" section of the Decision also made no reference to the Thunder Bay Hydro 2017 rate case decision cited by NOTL Hydro in which the Board had found that the most recent actual expenditures are an appropriate jumping-off point to determine a Test Year budget.[5]

19. The Board's failure to consider NOTL Hydro's most recent actual OM&A expenditures and instead approve a 2019 OM&A budget that is $168,000 lower than NOTL Hydro's actual OM&A expenditures for 2018 is a material error. This error will have negative impacts for NOTL Hydro and its customers.

[5] EB-2016-0105, Thunder Bay Hydro Electricity Distribution Inc., Decision and Order dated September 21, 2017 (page 5).

20. The prefiled evidence explains that NOTL Hydro prides itself on strong customer service.[6] NOTL Hydro serves a relatively high-income area, and its tourism base imposes special demands.

21. Examples of the high level of customer service offered by NOTL Hydro include:
    i. Open office – Any customer can come in between 8:30 am and 4:30 pm any work day. NOTL Hydro must maintain staffing to provide this service level.
    ii. Access to Board and senior management. – Customers have access to NOTL Hydro senior management and its Board of Directors whenever needed and warranted.
    iii. One free disconnection/reconnection – Any customer is entitled to one free disconnection/reconnection per year to allow them to undertake maintenance on their own equipment.
    iv. Off season work – Summer is deliberately avoided when possible for any work that might affect the tourist areas.

22. NOTL Hydro has worked hard to improve and maintain its reliability.[7] NOTL Hydro's customers have indicated that this is the most important priority for them. NOTL Hydro's most recent scorecard posted to the OEB website confirms that the utility continues to exceed all operational effectiveness and customer focus targets. In the most recent customer engagement process, NOTL Hydro's customers confirmed their satisfaction, as indicated in the following comment under the "Reliability" heading in the Customer Engagement report: "[a]ll participating customers commented on how the reliability of the system feels like a dream compared to those customers in a more rural setting. They commented on how happy they are with it."

23. The impact of the Decision, which reduces NOTL Hydro's OM&A budget by $168,000 below current actual expenditures, is that some services currently being provided will have to be discontinued or reduced. The impact will be exacerbated by the fact that NOTL Hydro has

[6] Exhibit 1, Administrative Documents, at pages 60-84; see also NOTL Hydro Business Plan, filed as Appendix 1Y to Exhibit 1, under the headings "Mission", "Values" and "Principles".
[7] Argument in Chief, at para. 19 (and the references included therein).

new cost drivers in 2019 that go beyond its 2018 requirements.[8] NOTL Hydro's customers, whose rates are very competitive with other jurisdictions (even with the relief sought in this Motion), will be negatively impacted by the Board's Decision.

Conclusion

24. For the reasons set out in the Notice of Motion and these Supplementary Written Submissions, NOTL Hydro respectfully requests that the Decision be adjusted to approve a 2019 Test Year OM&A budget of $2,964,765.

25. In the event that there is a finding that the Decision contains errors, but the review panel is not prepared to adjust the OM&A budget as requested, then NOTL Hydro requests that the Board make orders for the errors in the Decision to be corrected through an appropriate process.

June 20, 2019

AIRD & BERLIS LLP
Barristers and Solicitors
Brookfield Place
Suite 1800, Box 754
181 Bay Street
Toronto, ON M5J 2T9

David Stevens
Tel (416) 863-1500
Fax (416) 863-1515

dstevens@airdberlis.com

[8] Exhibit 4 – OM&A –page 17.

TAB 3

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

DECISION AND ORDER

EB-2018-0056

NIAGARA-ON-THE-LAKE HYDRO INC.

Application for electricity distribution rates and other charges

beginning May 1, 2019

BEFORE: **Michael Janigan**
Presiding Member

April 11, 2019

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY 1

2 THE PROCESS 3

3 DECISION ON THE UNSETTLED ISSUES 4

3.1 CAPITAL – UNDERGROUND CONVERSION PROJECT 4

3.2 OM&A EXPENSE 7

3.3 COST OF LONG-TERM DEBT 12

3.4 COST ALLOCATION – INCLUSION/EXCLUSION OF ICM REVENUES IN THE DISTRIBUTION REVENUE 15

3.5 DVAS AND LRAMVA – DISPOSITION PERIOD 16

3.6 TRANSMISSION GROSS LOAD BILLING 17

4 IMPLEMENTATION 20

5 ORDER 21

SCHEDULE A 23

1 INTRODUCTION AND SUMMARY

This is a Decision and Order of the Ontario Energy Board (OEB) on an application filed by Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) to change its electricity distribution rates effective May 1, 2019 (the application). Under the *Ontario Energy Board Act, 1998*, distributors must apply to the OEB to change the rates they charge their customers.

NOTL Hydro provides electricity distribution services to approximately 9,406 residential and commercial customers in the Town of Niagara-on-the-Lake (Town).

NOTL Hydro requested the OEB approve its rates for five years using the Price-Cap Incentive rate-setting (Price-Cap IR) option available under the *"Renewed Regulatory Framework for Electricity Distributors: a Performance Based Approach"*[1], as most recently set out in the *Handbook for Utility Rate Applications.* Under the Price-Cap IR option, rates are determined on a cost of service basis for 2019, and adjusted mechanistically for the next four years through a price cap adjustment based on inflation and the OEB's assessment of NOTL Hydro's efficiency.

NOTL Hydro and intervenors participated in a settlement conference and filed a partial settlement proposal with the OEB on January 10, 2019. On February 8, 2019, the OEB accepted the partial settlement proposal (see Schedule A attached). The following issues were not settled:

- Issue 1.1 Capital: the unsettled issue relates to the prudence of NOTL Hydro's underground conversion project since its last rebasing (impacting 2019 opening rate base) and its proposed test year expenditures for the underground conversion project (impacting 2019 net additions and rate base)
- Issue 1.2 Operations, Maintenance & Administrative Expenses (OM&A)
- Issue 2.1 & 2.2 Revenue Requirement: the unsettled issue relates to the cost of long-term debt regarding the applicable interest rates to one promissory note and two loans from the Town
- Issue 3.2 Cost Allocation: the unsettled issue is whether NOTL Hydro should include the Incremental Capital Module (ICM) revenue in distribution revenue at current rates in the cost allocation model

[1] Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: a Performance Based Approach, October 18, 2012

- Issue 4.2 Deferral and Variance Accounts (DVAs): the appropriate disposition period of Group 2 DVAs and the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)
- Issue 5.3 Transmission Gross Load Billing: the unsettled issue is whether NOTL Hydro should apply the transmission gross load billing for Load Displacement Generators (LDG), with a generator unit rating of 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation

The OEB has made the following findings on the unsettled issues:

- Issue 1.1 Capital: The OEB approves the amount of $335,000 for the Old Town portion of the underground conversion project and general underground capital work. This amount reflects a $125,000 reduction to the amount requested by NOTL Hydro for the Virgil portion of the project.

- Issue 1.2: OM&A Expense: The OEB approves a 2019 OM&A budget envelope of $2,671,367.

- Issue 2.1 & 2.2 Cost of Long-term Debt: The OEB approves the use of the OEB's 2019 deemed long-term debt rate of 4.19% on the promissory note with the Town. The OEB approves the new interest rates applicable to the two Town loans effective April 1, 2019 for inclusion in the NOTL Hydro's cost of debt.

- Issue 3.2 Cost Allocation: The OEB approves the incorporation of ICM revenues into existing distribution revenues for cost allocation purposes.

- Issue 4.2 Disposition Period of Group 2 DVAs and LRAMVA: The OEB approves the clearance of Group 2 DVAs and the LRAMVA over two years with a reduction of $5,000 to the principal balance being recovered to reflect the difference in interest costs.

- Issue 5.3 Transmission Gross Load Billing: The OEB approves NOTL Hydro's proposed transmission charge for the Large Use rate class.

2 THE PROCESS

NOTL Hydro filed its application on August 23, 2018 for 2019 rates. The OEB issued a Notice of Application on September 7, 2018, inviting parties to apply for intervenor status. School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC) applied for and were granted intervenor status and cost eligibility.

The OEB held a community meeting on October 9, 2018 where OEB staff and NOTL Hydro made presentations. A summary of the community meeting was posted on the record of this proceeding. The customers that attended the community meeting asked questions and expressed concerns about a new transformer, bill impacts from rate riders, self-generation, street light revenue reduction and whether the generation from the new large business customer will impact residential rates.

The OEB issued Procedural Order No. 1 on October 10, 2018 with a timetable for a written discovery process, the filing of a proposed issues list and a settlement conference. On December 6, 2018, the OEB issued its Decision on Issues List in which it approved a final issues list that was proposed by OEB staff and agreed upon by the intervenors. A settlement conference was held on December 10 and 11, 2018.

NOTL Hydro, SEC and VECC (the Parties) filed a partial settlement proposal with the OEB on January 10, 2019. OEB staff was not a party to the settlement proposal, but participated in the settlement conference in accordance with the role of OEB staff set out in the OEB's *Practice Direction on Settlement Conferences*. OEB staff filed its submission regarding the partial settlement proposal on January 17, 2019.

On February 8, 2019, the OEB issued a Decision and Procedural Order No. 4 in which it accepted the partial settlement proposal with respect to NOTL Hydro's application. Procedural Order No.4 also set out the dates for a written hearing of the six unsettled issues. All Parties and OEB staff filed written submissions with respect to the unsettled issues.

3 DECISION ON THE UNSETTLED ISSUES

3.1 Capital – Underground Conversion Project

Background

In this application, NOTL Hydro proposed to continue an underground conversion project that was started in 1987. The project consists of continuing conversion of the oldest segment of the existing 4 kV distribution system to underground as well as converting the supply to 27.6 kV. NOTL Hydro stated that the voltage conversion project is to be completed by the end of 2034.

Besides a number of benefits to reliability, safety and the environment, NOTL Hydro referenced a Town by-law which stated that the installation of new overhead plant is prohibited as a means of preserving the heritage nature of the Old Town. In its updated evidence, NOTL Hydro clarified that the Town by-law was a legacy by-law of the NOTL Hydro-Electric Commission that was passed in 1989, and not a by-law of the Town, and that it was adopted as a company policy when NOTL Hydro was incorporated in 2000.

NOTL Hydro further clarified that the spending of $460,000 in the test year, subject to the OEB's determination, is comprised of three parts:

- The underground conversion in Old Town of $215,000
- The Virgil portion of the project along Highway 55 of $125,000 that is not voltage conversion and to be done as part of the region's road widening work
- The general underground work of $120,000 including moving distribution lines for reasons other than voltage conversion; replacing pad-mount transformer or conduit, capital repairs etc.

In its argument-in-chief, NOTL Hydro submitted that its underground voltage conversion program is appropriate and necessary. NOTL Hydro submitted that there should be no issue as to the prudence of amounts already spent, and the forecast costs for 2019 and beyond are appropriate and reasonable.

SEC stated that it does not oppose the program in its entirety. SEC proposed a reduction of $230,000 (50%) to the underground capital budget of $460,000 in 2019. VECC argued that NOTL Hydro misled the OEB and the parties in the 2014 cost of service proceeding on the authority and the breadth of the underground conversion project. VECC submitted that the OEB could disallow portions of the proposed

underground investment but it did not specify the amount to be disallowed. VECC submitted that, alternatively, the OEB could allow the underground conversion project in Old Town only, adjust the proposed OM&A budget to compensate the ratepayers for the higher costs incurred and to be incurred under the existing capital program, and direct NOTL Hydro to develop a comprehensive undergrounding plan for its next cost of service application.

OEB staff submitted that it supports the underground conversion program and general underground work but not the underground work for the Virgil portion of the project. Based on the historical average underspending, as a percentage, and the historical accumulated underspending, OEB staff proposed a reduction of $95,000 to the underground budget in the test year.

With respect to NOTL Hydro's customer engagement regarding the underground conversion project, SEC noted that customers voiced their concerns about the associated costs and that the program should not be done for cosmetic reasons. VECC submitted that customers were not engaged in a meaningful way because NOTL Hydro did not provide comparative costs or a reliability analysis in order for customers to have an informed opinion. OEB staff noted that customers apparently did not object to the Old Town portion of the project.

NOTL Hydro argued, in its reply submission, that it did not knowingly provide incorrect information in its 2014 cost of service application and therefore did not mislead the OEB in that application. NOTL Hydro submitted that the proposed opening rate base (inclusive of underground conversion program) should be approved as filed. With respect to the proposed amount of underground conversion spending proposed for 2019, NOTL Hydro submitted that the entire budgeted amount of $460,000 is needed. However, if the OEB believes that a reduction is necessary, NOTL Hydro agreed with the approach taken by OEB staff which arrived at a reduction of $95,000 in the test year.

Findings

The OEB approves the amount of $335,000 for the underground conversion projects, which includes the Old Town project and general underground capital work. This amount reflects a $125,000 reduction to the amount requested by NOTL Hydro for the entire undergrounding project budget.

The OEB agrees with VECC that this project is a substantial commitment in an expanding capital budget. It requires careful cost benefit analyses for each component and reasonable and insightful evidence of customer engagement.

The NOTL Hydro's substantiation of the Old Town conversion project has been somewhat confused by previous misstatements concerning the effect of an old NOTL Hydro-Electric Commission by-law, and some apparent lack of clarity concerning the extent that the proposed expenditures have met with customer approval. VECC expresses concern that the project may be driven by tourism and aesthetic interests rather than utility service needs.

However, in assessing the complete evidentiary record, the OEB finds that the Old Town project request is reasonable and prudent. The OEB notes that the capital request is part of a project that has been ongoing, and continued in NOTL Hydro's 2014 approved cost of service application. It was also recognized in the distribution system plan.

While customer engagement has not been precise, there also does not appear to be substantial customer opposition to the continuation of the Old Town project as it has been communicated to customers by NOTL Hydro. The OEB agrees with OEB staff that there are benefits to customers that accrue from undergrounding and voltage conversion that include reliability, safety, lower maintenance and environmental enhancement beyond the aesthetic improvements.

The OEB finds that the principal rationale supporting the Virgil project is associated with coordination of the undergrounding with highway repair. However, it does not include voltage conversion, lacks a robust cost/benefit analysis, and may overstate the capital work budget in the test year by not fully recognizing the cost synergies associated with coordination with the proposed roadwork. The project also does not engage a significant urban area. The OEB does not approve the Virgil project's inclusion in NOTL Hydro's 2019 capital budget.

As OEB staff has set out, there has been significant underspending in the capital program since 2014. The Virgil project may still be able to be managed within the capital spending envelope of $335,000 provided in this Decision and Order.

3.2 OM&A Expense

Background

NOTL Hydro proposed a 2019 OM&A budget of $2,974,186 in the application, which was reduced to $2,964,765 after the first round of interrogatories. The proposed budget was 38% higher than NOTL Hydro's OEB-approved budget in 2014. NOTL Hydro's 2014 to 2019 OM&A expenses are set out in Table 1 below:

Table 1 2014-2019 OM&A Expenses ('000)

	2014	2014	2015	2016	2017	2018	2019
	Approved	Actual	Actual	Actual	Actual	Unaudited Actual	Forecast
OM&A	$2,155	$2,208	$2,323	$2,532	$2,595	$2,839	$2,965
						% Increase over 2014 Approved	38%

NOTL Hydro stated that the proposed OM&A budget is necessary to maintain and operate its distribution and transmission assets and distribution business.

In its argument-in-chief, NOTL Hydro used a higher-level approach to evaluate the 2019 OM&A budget. The high-level approach starts with the 2014 approved OM&A budget adjusted for an accounting standard change of $130,784, applying the inflation and growth factors and adding the costs related to the new and increased services to determine the 2019 OM&A budget. NOTL Hydro stated that this approach was used by the OEB in its decision on Thunder Bay Hydro's 2017 rates.[2]

NOTL Hydro stated that a discrete and significant contributor to the OM&A increase is the $130,784 adjustment due to the accounting standard changes. This adjustment is related to the costs of senior management's time that were capitalized under Canadian General Accounting Principles (CGAAP) in the 2014 cost of service application and that are now expensed and included within the 2019 OM&A budget under International Financial Reporting Standards (IFRS). NOTL Hydro stated that the adjustment is needed for an "apples-to-apples" comparison and it was not a new cost in the OM&A budget for the test year.

[2] EB-2016-0105

NOTL Hydro used three of the growth factors out of the five used by Pacific Economics Group (PEG) in the total cost benchmarking to measure the impact of growth on the OM&A expense. These three factors are customer growth, load growth and system peak growth. NOTL Hydro stated that the other two factors (increase in distribution lines and acceleration in customer growth) are not used because NOTL Hydro has seen no noticeable change for these two factors.

All parties, including OEB staff, provided their submissions on this evaluation approach and proposed a reduction to the OM&A budget. SEC proposed a reduction of $374,424 based on its approach of deriving the expected OM&A budget based on the 2014 approved OM&A expense adjusted for the accounting change of $130,784 and applied with the inflation, stretch factors and customer growth. VECC proposed a reduction ranging from $400,000 to $500,000. The reduction of $500,000 appears to be based on the difference between NOTL Hydro's proposed OM&A budget and the OM&A budget derived by VECC using the 2014 approved OM&A adjusted by the Bank of Canada inflation factor and customer growth. OEB staff proposed a reduction of $215,000 mainly consisting of the accounting change adjustment, its related inflation and growth and part of the new and increased services.

SEC accepted the accounting adjustment made to the OEB-approved amounts and stated that that it is appropriate to reflect the changes in capitalizing certain executives' costs due to the transition to IFRS. VECC did not comment on the accounting adjustment.

OEB staff opposed the accounting adjustment of $130,784 and submitted that NOTL Hydro should have identified the $130,784 OM&A increase that was related to the senior management's salaries and benefits during NOTL Hydro's process of changing the capitalization policy and should have presented this item in its 2014 cost of service application. OEB staff noted that the OEB, in its letter[3] issued in 2012, required all electricity distributors to change their capitalization and depreciation policies to be consistent with the OEB's regulatory accounting policies as set out for modified IFRS. One main difference between the capitalization policies under CGAAP and IFRS is that only directly attributable costs are allowed to be capitalized in the capital assets under IFRS. NOTL Hydro stated, in its reply submission, that even assuming that OEB staff is correct that NOTL Hydro should have expensed the costs, the ratepayers have not

[3] The OEB's letter issued on July 17, 2012 to all Electricity Distributors

been harmed since the costs were included in the rate base in the 2014 cost of service application.

Both VECC and SEC commented on the growth factors used by NOTL Hydro to quantify the impact of customer growth on the OM&A expense. OEB staff did not make submissions on the growth factors. VECC used customer growth only to quantify the impact of customer growth on the OM&A budget. SEC opposed the use of load and system peak growth factors to quantify the impact of the growth on OM&A. SEC stated that while load and system peak growth do impact costs, there is no evidence that they materially impact OM&A as opposed to capital costs. SEC submitted that NOTL Hydro's proposal for the inflation and growth adjustment went farther than the OEB's decision[4] for Canadian Niagara Power Inc. NOTL Hydro argued, in the reply submission, that SEC's approach improperly excludes the impact of load growth, which is a significant driver of OM&A costs, especially for a distributor like NOTL Hydro that has transmission assets. NOTL Hydro did not comment on the reason for including the growth factor of system peak.

NOTL Hydro attributed $237,040 of the OM&A increase to the new and increased services over five years. NOTL Hydro submitted that these extraordinary costs should be included in the 2019 OM&A budget because these costs are not accommodated in a budget that simply increases for inflation and growth. In addition, it stated that the OEB has allowed for additional extraordinary expenses in its decision on Innpower Corporation's 2017 rates.[5] Both SEC and VECC proposed not including any additional costs related to the new and increased services. SEC submitted that most of the costs related to the new and increased services should be included in the OM&A budget that is derived for inflation and growth. OEB staff submitted that a reduction of 1.5% out of the 11% proposed OM&A increase due to new and increased services would be appropriate.

SEC, VECC and OEB staff all commented on NOTL Hydro's OM&A costs per customer. All parties noted that the OM&A per customer in 2017 actual, 2018 and 2019 forecast are trending negatively, and submitted that this trend also supports reducing the proposed test year OM&A budget. NOTL Hydro submitted that the actual OM&A cost per customer has never been significantly different from the industry average during any year since 2010 to 2017 when the last actual data is available. Furthermore, it stated

[4] EB-2016-0061
[5] EB-2016-0085

that it has maintained its ranking within cohort three throughout the current incentive rate-setting term.

In its reply submission, NOTL Hydro stated that a key way to evaluate the OM&A budget in the test year is to look at the most recent actual expenditures. NOTL Hydro submitted that applying this approach to the 2018 actual OM&A of $2,838,525 would result in a 2019 OM&A budget very close to the as-filed budget. NOTL Hydro submitted that the OEB approve the as-filed 2019 OM&A budget forecast and it will support continued safe, reliable and responsive service to NOTL Hydro's customers.

Findings

The objective of the OEB's approval of a distribution utility's cost of service application is to provide it with sufficient revenue to safely, reliably, and efficiently operate the utility. The approval of the OM&A budget is a significant component of the regulatory exercise which is intended to achieve both the recognition of prudent proposed expenditures and encourage continuous improvement in utility performance.

NOTL Hydro, OEB staff and intervenors have made submissions as to relevant aspects of NOTL Hydro's performance that support their position as to the quantum of the OM&A budget that should be approved. While the various measurements of performance have been examined, the OEB has not approached the setting of this budget with a view to rewarding NOTL Hydro's past performance achievements as claimed by the applicant, or remedying a perceived decline in performance, as argued by OEB staff and intervenors.

The fixing of the OM&A budget, however, is assisted by reference to accepted parameters measuring sources of cost increases to utility expenses including inflation and customer growth. The development of a guide in the form of an envelope approach to the budget helps provide a yardstick that avoids micromanagement of the regulated utility and helps the regulator cope with any asymmetries of information that can be present. In this application, the OEB has determined to use this guide to assist in evaluating the reasonableness of the NOTL Hydro's request for a 38% increase in OM&A.

In doing so, the OEB has used the 2014 OEB approved OM&A budget and applied escalators including inflation, minus NOTL Hydro's cohort stretch factors ,as well as customer growth factors multiplied by the recommended PEG elasticity factor. The resulting calculations are set out in Table 2 below:

Table 2: 2019 OM&A Budget based on Escalators

	2014 OEB Approved	2014	2015	2016	2017	2018	2019
		ACTUAL					Forecast
Total OM&A	2,155,262						
Customer Growth %		0.62%	3.36%	3.13%	2.02%	1.55%	1.93%
Escalators							
Inflation		0.00%	1.60%	2.10%	1.90%	1.20%	1.70%
Stretch Factor		0.00%	0.30%	0.30%	0.30%	0.30%	0.30%
Customer Growth (Growth x PEG Elasticity of 0.4485)		0.28%	1.51%	1.40%	0.91%	0.70%	0.87%
Total Escalator		**0.28%**	**2.81%**	**3.20%**	**2.51%**	**1.60%**	**2.27%**
Adjusted OM&A - Based on Escalators	**2,155,262**	**2,161,224**	**2,221,889**	**2,293,029**	**2,350,478**	**2,388,019**	**2,442,148**

NOTL Hydro submitted that, for this purpose, any base 2014 OM&A amount should include the cost of capitalized employees by adding $130,784 to the 2014 OEB-approved figure. The OEB declines to depart from the actual OM&A approved number that helped fashion 2014 rates for the purpose of calculating the base amount that must be escalated to derive a final figure.

NOTL Hydro also suggested additional load and peak growth factors as escalators to the 2014 OEB-approved OM&A. However, there is no indication that any increases caused by these factors would not be captured in whole or in part by the customer growth factor.

This envelope must then be adjusted to recognize expenditures that are not simply improvements, updates, or changes to operations driven by management operational decisions or directions. It is expected that the escalation factors noted above should accommodate the costs of such changes. However, there are expenditures in NOTL

Hydro's 2019 budget that recognize new requirements that must be met by the utility that have arisen since 2014. These include new responsibilities as follows:

Cyber Security	$30,000
OEB charges	$9,540
Survey	$13,988
Locates	$36,566
Pole Rental	$8,341
Total	**$98,435**

In addition to these items, the effect of the above noted accounting change of $130,784 should be included in the 2019 OM&A approved amount.

The resulting OM&A envelope for 2019 would project to $2,671,367 comprehending an increase of $516,105 (24%) over the 2014 OEB-approved amount. The OEB finds this amount to be reasonable.

3.3 Cost of Long-term Debt

Background

NOTL Hydro's proposed long-term debt consists of five debt instruments, two from third parties (CIBC and Infrastructure Ontario) and three from the Town. NOTL Hydro's overall proposed rate for long-term debt for 2019 is 3.95%.

The outstanding issues relate to NOTL Hydro's long-term debt regarding the three debt instruments from the Town (two demand loans and a promissory note).

The promissory note with the Town was originally issued in 2000 with an actual interest rate of 7.25%. In 2018, the note was renewed for an additional ten years for the same interest rate. For rate-making purposes, NOTL Hydro has used the 2019 deemed long-term debt rate of 4.13% for the cost of this promissory note. SEC opposed the use of the deemed debt interest rate for the promissory note. SEC proposed that the interest rate should be reduced from 4.13% to 3.48%, which is the rate obtained from a Schedule A bank in December 2018 when NOTL Hydro was finding out the rates for the purpose of the two Town loans. SEC submitted that it is not reasonable for NOTL Hydro to not undertake the due diligence to renew the promissory note. VECC did not comment on the promissory note in its submission. OEB staff submitted that NOTL

Hydro's use of 2019 deemed long-term debt rate for the promissory note with the Town is appropriate.

NOTL Hydro updated the interest rates on two Town loans from 3% to 3.5% after the settlement conference. SEC submitted that it has two major concerns regarding the updated interest rate of 3.5% for the two Town loans as below:

- First, if the OEB accepts both the new rate and effective date, for ratemaking purposes the debt rates built into the test year should not be the 3.5%, but a lower amount reflecting the pro-rated portion of the test year in which the new higher rate is expected to be in place.
- Second, there is no reason that NOTL Hydro should acquiesce to a March 1st effective date. The two loans require a minimum of 90 and 45 day notice respectively. As of the filing of the supplementary interrogatories on January 30th, legal notice had not been given.

VECC took the timing of the update as an issue and stated that the OEB should not make the proposed adjustment until signed loan agreements are proffered. OEB staff submitted that the updated interest rate on the two Town loans is appropriate given the due diligence conducted by NOTL Hydro.

In its reply submission, NOTL Hydro provided a link to the Town council meeting minutes to show that on March 4, 2019, the Town approved proceeding with the new demand loans with an interest rate of 3.5%, effective as of March 1, 2019. NOTL Hydro stated that the Town had provided a notice in a letter on December 19, 2018 regarding the recall for the two Town loans. NOTL Hydro submitted that it does not agree with SEC that the updated rates associated with the demand loans should be pro-rated to reflect only the period when the new rates should be in effect during the 2019 calendar year. However, it stated, that if the OEB were to choose to take this approach, then the proper way is to treat the new rates as being in place for 9 of 12 months, meaning that the effective rate associated with the demand loans is 3.375% (equal to (3%*3 months plus 3.5%*9 months, divided by 12).

The agenda and minutes of the town council of March 11, 2018 available on the website referenced by NOTL Hydro in its reply argument shows that the new loan agreements were approved by the Town council on March 11, 2019, to be effective April 1, 2019.

Findings

The OEB approves the use of the OEB 2019 deemed long term debt rate of 4.19% for the cost of the long term debt associated with the promissory note.

The OEB agrees with the SEC submission that the new interest rates for the loans approved on March 11, 2019 by the Town should be prorated for the purpose of the calculation of the debt rates for the test year. This means that new interest rates on the loans effective on April 1, 2019 will be recognized for a nine month period of the test year. The OEB approves the new interest rates applicable to the two loans as of that date for inclusion in the NOTL Hydro's cost of debt.

SEC has referenced the notice period of 45 days and 90 days provided in the old loan agreements that was required to be given by the town in order to call (i.e. demand payment of) the loans. This was not done by the Town. As of January 30, 2019, as set out in the response to SEC Supp-47, the Town had not called the loans. Instead, the Town and NOTL Hydro embarked on a renegotiation process that culminated in the approval of new loan agreements referenced above.

SEC raises the issue whether it was prudent, and in keeping with its obligation to its ratepayers for NOTL Hydro to agree to new loan interest terms with the town when there was no call on the loans, and thus no urgency to have the new interest rates commence on a date when repayment was not contractually necessary.

The OEB notes that the new loan agreements with the Town continue to have benefit for NOTL Hydro because of the absence of restrictive covenants that might limit the utility's financial flexibility. In addition, NOTL Hydro believed that, if renegotiation was required by the utility, the town might be easier to deal with than another lender. While the appearance of fair dealing between shareholder and the utility is usually best preserved through observance of the provisions of formal arrangements between the parties, the renegotiation of the existing loans without a formal call for payment, was not imprudent on the part of NOTL Hydro. As well, the new interest rates are less than the OEB deemed long-term debt rate. The new loan agreements with the Town are approved for the purpose of the calculation of NOTL Hydro's cost of capital subject to the pro-rating of the new interest rate in the test year as set out previously.

3.4 Cost Allocation – Inclusion/Exclusion of ICM Revenues in the Distribution Revenue

Background

NOTL Hydro proposed to include ICM revenue in its determination of revenue at existing rates for the purpose of cost allocation and the resulting revenue to cost ratios. NOTL Hydro stated that it did so because the project associated with the ICM will be included in 2019 base rates and this approach is a fair way to assess rate impacts derived from its updated revenue requirement.

SEC and OEB staff did not support NOTL Hydro's proposed approach of including the ICM revenue in the existing distribution revenues for the cost allocation. Both SEC and OEB staff acknowledged that NOTL Hydro's approach is a reasonable approach, however, the proposed approach is not consistent with the OEB's existing practice. SEC and OEB staff referenced a number of the OEB's previous decisions[6] to support that the calculation of revenue at existing rates only including the previously approved base distribution rates. SEC submitted that NOTL Hydro's proposed approach reduces the bill impacts for residential customers at the expense of other classes of customers. OEB staff noted that an ICM is analogous to the smart meter funding adder, where smart meter funding adder revenue was not included as part of distribution revenue in determination of revenue to cost ratios, and it would be appropriate to apply the same treatment to ICMs.

VECC supported NOTL Hydro's proposed approach. VECC stated that the proposed approach is reasonable because the ICM is a mechanism similar to the capital expenditures in a cost of service rate application and it is logical to include the ICM revenues since customers are currently paying the ICM rate riders as part of the cost of their distribution service.

NOTL Hydro submitted, in its reply submission, that consistency with treatment of ICMs in OEB's previous applications is not a sufficient reason to deny NOTL Hydro's

[6] OEB Staff referenced to the OEB's decisions for Innpower Corporation's 2017 rates EB-2016-0085, Wellington North Power's 2016 rates EB-2015-0110, Alectra Utilities – Powerstream rate zone's 2016 rates EB-2015-0003, Festival Hydro's 2015 rates EB-2014-0073, Oakville Hydro's 2014 rates EB-2013-0159 and Hydro Hawkesbury's 2014 rates EB-2013-0139. SEC also referenced to three additional OEB's decisions: Toronto Hydro's 2015 rates EB-2014-0116, Centre Wellington Hydro's 2013 rates EB-2012-0113 and Kingston Hydro's 2016 rates EB-2015-0083.

proposal. It also stated that NOTL Hydro is not unduly favoring one customer class over another.

Findings

The OEB approves the incorporation of ICM revenues into existing distribution revenues for cost allocation purposes. The OEB notes that this has not been the practice to date, but accords with the reality that ICM revenues form part of the development of rates based on capital spending requirements. As such, these revenues emanate from a process that is similar to the OEB approval of such expenditures upon rebasing. The difference is simply that such spending arises within the Incentive Rate Mechanism (IRM) period. The ICM revenues should thus be considered part of the utility's revenue requirement and incorporated into the cost allocation model.

3.5 DVAs and LRAMVA – Disposition Period

Background

NOTL Hydro stated, in its argument-in-chief, that due to an error outside its control, the impact of the DVA rate riders communicated to NOTL Hydro's customers at the open house was incorrectly stated to be negligible, when in fact it has a significant impact. As a result, NOTL Hydro proposed the disposition of the Group 2 DVAs and LRAMVA over a two-year period instead of a one-year period in order to reduce the bill impacts. In addition, NOTL Hydro submitted that both the Group 2 DVAs (mainly Account 1508 Deferred IFRS costs and Accounts 1518 and 1548 Retail Settlement Variance Accounts) and the LRAMVA were aggregated over multiple years so there should be no inherent requirement to have them repaid in one year rather than over two or more years.

SEC and VECC did not support the proposed two-year disposition period. Both parties stated that there is no need to mitigate or smooth the bills when the NOTL Hydro's proposed bill impact is less than 10%, and the 10% is usually the threshold that the OEB uses for a bill mitigation. SEC submitted that the OEB should reject NOTL Hydro's proposal, unless NOTL Hydro is willing to forego the collection of interest on the additional year's balance. VECC understood that the one-year disposition period is a strict criteria set by the OEB and submitted that there is no reason for NOTL Hydro to depart from the one-year default recovery period for the Group 2 DVAs and LRAMVA

balances. However, VECC acknowledged that the two-year recovery period does have merit from a rate smoothing perspective.

OEB staff supported the two-year disposition period and submitted that NOTL Hydro has provided adequate explanation for the two-year disposition request, especially given that NOTL Hydro communicated negligible bill impacts from the rate riders to its customers in the open houses.

NOTL Hydro, in its reply submission, stated that the proposed approach is in the interests of ratepayers, and proposed to forego the additional $5,000 interest on the additional year of recovery.

Findings

The OEB approves the clearance of Group 2 DVAs and the LRAMVA over two years with a reduction of $5,000 to the principal balance being recovered to reflect the difference in interest costs.

3.6 Transmission Gross Load Billing

Background

NOTL Hydro is seeking the OEB's approval to have the Retail Transmission Rate – Line and Transformation Connection Service Rates for LDG, with a generator unit rating of 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation, applied on a gross load billing basis. This is consistent with how the Independent Electricity System Operator (IESO) bills NOTL Hydro for Line Connection and Transformation Connection Services as Hydro One applies gross loading billing on such terms. NOTL Hydro proposed to use the same wording as is used in the 2019 tariffs and rates for Entegrus Powerlines Inc. (Entegrus).[7]

SEC submitted that it is unsure what the OEB's expectation is at this time for distributors applying for gross load billing. However, it acknowledged that the proposed approach has merit. VECC submitted that NOTL Hydro's proposal to use gross load billing should be accepted by the OEB subject to some suggested wording changes. VECC stated that it is appropriate for NOTL Hydro to establish its billing determinants

[7] EB-2018-0024

for Line and Transformation Connection Services using the same approach as the IESO uses for billing these services to NOTL Hydro.

OEB staff submitted that the wording in Entegrus' tariffs is not adequate to support the same wording in NOTL Hydro's tariff without further considerations. OEB staff submitted that NOTL Hydro should follow a more recent OEB decision[8] for Enwin Utilities (Enwin)' 2018 rates which stated that the OEB may review this matter further on a generic basis and provide information in due course.

NOTL Hydro, in its reply submission, stated that the OEB's plan to review the matter on a generic basis is not adequate reason to refrain from approving NOTL Hydro's proposal in this proceeding. NOTL Hydro submitted that it is not appropriate for the other customers to pay costs caused by a Large Use customer class where such costs can be directed to the Large Use class. The fact that NOTL Hydro has not applied this transmission gross load billing before now is because there has been no customer causing upstream gross load billing costs. NOTL Hydro submitted that approving its current proposal will not impair the OEB's ability to look at the question of transmission gross load billing on a generic basis at a later time. If the OEB directs an approach that is different from what is in place for NOTL Hydro, it can implement that different approach at that time.

Findings

The OEB approves NOTL Hydro's proposed transmission charge for the Large Use rate class. In doing so the OEB notes the following:

1. All parties did not object to the proposal on the basis of accepted principles of cost allocation and rate design.
2. The proposal prevents a potential subsidy to the NOTL Hydro's Large Use customer that will be solely served by a proposed combined heat power plant to be installed by this customer. Hydro One's practice of "gross load billing" will otherwise fail to recognize that only one customer will benefit from the generation from the plant. This same result might obtain for future LDG customers without adoption of the proposed transmission charge.

[8] EB-2017-0037

3. The NOTL Hydro's proposal is consistent with the billing for Line and Connection and Transformation Services by the IESO.

4. The proposal was developed by NOTL Hydro in consultation with the Large Use customer that will be served by the above-noted plant.

OEB staff have submitted that the issue of the proposed transmission charge should be governed by the determination of the OEB in the recent Enwin decision.[9] In that decision, the OEB declined to approve Enwin's proposed change of approach to its current determination of transmission gross load billing, suggesting that the OEB may review this matter in a generic proceeding.

The OEB notes that the Enwin decision arose in the context of an IRM application. IRM applications are designed to be mechanistic and provide relief through the application of a regulatory framework that has already been established in a preceding rate rebasing. In this application, NOTL Hydro is seeking relief in its 2019 cost of service application. In such application, the setting of rates must be determined on the basis of the reasonableness of the incurrence of utility expenses and the correct allocation of those expenses in rates. Consistency across utilities in the approach to rate design is a desirable goal, but the OEB agrees with NOTL Hydro that approval of its proposal should not impair OEB consideration of this issue on a generic basis in the future, if the regulator chooses to do so.

The OEB agrees with VECC's submission that the definition of "renewable energy" for the purpose of the NOTL proposed transmission charge should be the same as that used in the 2019 Uniform Transmission Rates (UTR) and that gross load billing be applicable only to generation capacity installed after October 30, 1998, consistent with the UTR.

[9] EB-2017-0037

4 IMPLEMENTATION

NOTL Hydro shall include the cost consequences of the partial settlement proposal, updated to incorporate the findings in this Decision and Order on the unsettled issues, in its calculation of its revenue requirement for recovery from customers.

The OEB expects NOTL Hydro to file detailed supporting material showing the impact of this Decision and Order on the overall revenue requirement, the allocation of revenues between classes and the derivation of base rates.

SEC and VECC are eligible for cost awards in this proceeding. The OEB has made provision in this Decision and Order for these intervenors to file their cost claims. The OEB will issue its cost awards decision after the following steps are completed.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. NOTL Hydro Inc. shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision and Order, no later than April 18, 2019. NOTL Hydro Inc. shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.
2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to NOTL Hydro Inc., no later than April 25, 2019.
3. NOTL Hydro Inc. shall file with the OEB and forward to intervenors, responses to any comments on its draft Rate Order no later than May 2, 2019.
4. Intervenors shall submit their cost claims no later than April 25, 2019.
5. NOTL Hydro Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs May 2, 2019.
6. Intervenors shall file with the OEB and forward to NOTL Hydro Inc. any responses to any objections for cost claims no later than May 9, 2019.
7. NOTL Hydro Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

All filings to the OEB must quote the file number, EB-2018-0056, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at https://pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb.ca/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a USB memory stick in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Registrar at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Tina Li at Tina.Li@oeb.ca and OEB Counsel, Ljuba Djurdjevic at Ljuba.Djurdjevic@oeb.ca.

ADDRESS

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

E-mail: boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto April 11, 2019

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

SETTLEMENT PROPOSAL

FILED ON JANUARY 10, 2019

DECISION AND ORDER

NIAGARA-ON-THE-LAKE HYDRO INC.

EB-2018-0056

APRIL 11, 2019

SETTLEMENT PROPOSAL

Niagara-on-the-Lake Hydro Inc.

2019 Cost of Service Distribution Rates Proceeding

January 10, 2019

TABLE OF CONTENTS

ISSUE		DESCRIPTION
		Preamble
		Overview
		The Settled and Unsettled Items
1		Rate Base
2		Distribution System Plan and capital expenditures
3		Operating Costs
4		Cost of Capital
5		Load Forecast and Other Revenue
6		Revenue Sufficiency/Deficiency
7		Cost Allocation
8		Rate Design
9		Deferral and Variance Accounts
10		Other
	a	Is the proposed microFIT rate appropriate?
	b	Are the proposed changes to the Specific Service Charges appropriate?
	c	Is the proposed transmission gross load billing appropriate?
	d	Is the proposed distribution standby charge appropriate?

Appendices

Appendix “A”	Approved Issues List and Table of Concordance
Appendix “B”	NOTL Hydro 2019 Revenue Requirement Work Form 20190110
Appendix “C”	NOTL Hydro 2019 Filing Requirements Chapter 2 Appendices 20190110 & NOTL Hydro 2019 Filing Requirements Chapter2 Appendix 2C 20190110
Appendix “D”	NOTL Hydro 2019 Load Forecast Wholesale 20190110
Appendix “E”	NOTL Hydro 2019 Tariff Schedule and Bill Impact Model 20190110
Appendix “F”	NOTL Hydro 2019 DVA Continuity Schedule CoS 20190110
Appendix “G”	NOTL Hydro 2019 Cost Allocation Model RUN3 20190110
Appendix “H”	Cost Allocation
Appendix “H”	Impacts of including ICM in revenue at existing rates
Appendix “I”	Draft Accounting Order for Specified Customer Revenue Variance Account
Appendix “J”	CONFIDENTIAL - Name of Large Use Customer for the Specified Customer Revenue Variance Account

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board (the "OEB" or the "Board") in connection with the Application of Niagara-on-the-Lake Hydro Inc. (NOTL Hydro), for an order or orders approving changes to the distribution rates that NOTL Hydro charges for electricity distribution and other charges to be effective May 1, 2019.

On September 7, 2018, the OEB issued its Notice of Application in this proceeding. In Procedural Order No. 1, dated October 10, 2018, the Board established the process to address the application, up to and including a Settlement Conference and presentation of any Settlement Proposal.

A Settlement Conference was held on December 10 and 11, 2018, and discussions continued after that time. Karen Wianecki acted as facilitator for the Settlement Conference. This Settlement Proposal arises from the Settlement Conference.

NOTL Hydro and the following intervenors, as well as Ontario Energy Board technical staff (OEB Staff), participated in the Settlement Conference:

School Energy Coalition (SEC)
Vulnerable Energy Consumers Coalition (VECC)

The intervenors listed above participated in the Settlement Conference and subsequent discussions. Any reference to "the Parties" in this Settlement Proposal is intended to refer to NOTL Hydro and the intervenors listed above.

OEB Staff is not a Party to the Settlement Proposal. Although it is not a Party to the Settlement Proposal, once the Settlement Proposal is filed, OEB Staff will file a submission commenting on two aspects of the settlement: whether the settlement represents an acceptable outcome from a public interest perspective, and whether the accompanying explanation and rationale is adequate to support the settlement. Also, as noted in the Practice Direction on Settlement Conferences, OEB Staff who participated in the Settlement Conference are bound by the same confidentiality and privilege rules that apply to the Parties to the proceeding.

All items in NOTL Hydro's Application and pre-filed evidence were addressed by the Parties during the Settlement Conference. These matters have been considered under the topic headings included in this Settlement Proposal. These topic headings address the key items required for NOTL Hydro's 2019 rates to be approved, and include all items set out in the Board-approved Issues List in this proceeding (see Appendix "A" for the OEB approved list of issues and sub-issues, as well as a Table of Concordance showing where each of the issues on the Issues List is addressed in this Settlement Proposal). As set out herein, the Parties have reached complete agreement on all but six items in this Application (the Settled Items). The remaining six items have not been resolved, and the

Parties propose that each of them be determined by the Board (the "Unsettled Items). No other issues or proposals were addressed by the Parties during the Settlement Conference or are addressed in this Settlement Proposal.

Where in this Settlement Proposal, the Parties "accept" the evidence of NOTL Hydro, or the Parties "agree" to a revised term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

This document is called a "Settlement Proposal" because it is a proposal by the Parties to the Board to settle 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 is binding and enforceable in accordance with its terms. As set forth below, this Settlement Proposal 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 *Ontario Energy Board Act*, *1998*, the Board has exclusive jurisdiction with respect to the interpretation or enforcement of the terms hereof.

Best efforts have been made to identify all of the evidence that relates to each Settled Item. The identification and listing of the evidence that relates to each settled issue is provided to assist the Board. The supporting evidence for each Settled Item is identified individually by reference to its exhibit or interrogatory number in an abbreviated format.

The evidence in support of the Settlement Proposal also includes the Appendices to this document. The Parties acknowledge that the Appendices were prepared by NOTL Hydro. While the intervenors have reviewed the Appendices, the intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

The Settlement Proposal describes the agreements reached on the Settled Items. The Settlement Proposal provides a direct link between each Settled Item and the supporting evidence in the record to date and/or the additional evidence attached to hereto. In this regard, the Parties are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the Settled Items and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the Settled Items.

None of the Parties can withdraw from the Settlement Proposal except in accordance with Rule 30 of the *Ontario Energy Board Rules of Practice and Procedure*. Further, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions Parties might take with respect to the same issue in future proceedings, whether for NOTL Hydro or other applicants.

The Parties acknowledge that all data, documents or information provided and any discussions, including negotiations, admissions, concessions, offers and counter-offers occurring during the course of the Settlement Conference (settlement information), including subsequent related discussions, are privileged and confidential and without prejudice in accordance with (and subject to the exceptions set out in) the Board's *Practice Direction on Settlement Conferences* (see pages 5-6 of the OEB's *Practice Direction on Settlement Conferences*, as revised October 28, 2016).

It is fundamental to the agreement of the Parties that none of the provisions of this Settlement Proposal are severable. If the Board does not accept the provisions of the Settlement Proposal in their entirety, there is no Settlement Proposal (unless the Parties agree that any portion of the Settlement Proposal that the Board does accept may continue as a valid Settlement Proposal).

In the event that the OEB 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 must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the OEB.

OVERVIEW

The Parties are pleased to advise the OEB that they have reached an agreement with respect to most issues in this proceeding (the Settled Items). This agreement on the Settled Items is subject to any updates that will be required to reflect and implement the Board's decisions on the Unsettled Items (which are described below).

In reaching this Settlement Proposal, the Parties have been guided by the Filing Requirements for 2019 rates, incorporation of all applicable laws and the Approved Issues List (found at Appendix "A"). If accepted, this Settlement Proposal will support approval of most aspects of NOTL Hydro May 1, 2019 rates – final rates will be prepared after the Unsettled Items are determined.

A summary of the changes in NOTL Hydro's revenue requirement resulting from answers to Interrogatories (as summarized in response to Staff Interrogatory #1) and from this Settlement Proposal as compared to NOTL Hydro's filing is provided in Table 1 below.

The outstanding items (the Unsettled Items) are the following:

(i) Rate Base and capital expenditures, specifically the underground conversion program/projects (replacing older overhead distribution lines with a higher voltage underground system);

(ii) OM&A cost forecast of $2,964,765 for the Test Year;

(iii) the cost of NOTL Hydro's long-term debt;

(iv) Cost Allocation and Rate Design, specifically, the proposal to include previous ICM rate rider in revenue at current rates for the purposes of determining the appropriate R/C ratios, which have an impact on rate design;

(v) whether NOTL Hydro's proposal for gross load billing should be approved; and

(vi) disposition period of agreed upon Group 2 deferral and variance account balances.

NOTL plans to file updated evidence on a number of unsettled issues, and the Parties agree that Intervenors and Board Staff be permitted the opportunity to ask interrogatories to file on that evidence. As a result, the Parties agree that the Board should defer any request for submissions and/or consideration of which unsettled issues should be heard in writing, and for which issues the OEB should hold an oral hearing, until responses to those interrogatories have been provided.

Table 1. Summary of Changes in Revenue Requirement

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 1,771,030	5.77%	$ 30,698,011	$ 28,964,816	$ 2,172,361	$ 1,157,365	$ 109,828	$ 2,974,186	$ 6,047,363	$ 502,939	$ 5,544,424	$ 50,401
3-STAFF-36	Updated Load Forecast tab 10.1 to reflect CDM impact of 3,770,854 consistent with tab 10	$ 1,770,796	5.77%	$ 30,693,964	$ 28,910,864	$ 2,168,315	$ 1,157,365	$ 109,775	$ 2,974,186	$ 6,047,077	$ 502,939	$ 5,544,138	$ 53,904
	Change	-$ 233	0.00%	-$ 4,046	-$ 53,952	-$ 4,046	$ -	-$ 53	$ -	-$ 286	$ -	-$ 286	$ 3,503
2-STAFF-23	Updated Other Revenue for the assumption of 100 Bell Canada poles 100 x $43.63	$ 1,770,796	5.77%	$ 30,693,964	$ 28,910,864	$ 2,168,315	$ 1,157,365	$ 109,775	$ 2,974,186	$ 6,047,077	$ 507,302	$ 5,539,775	$ 49,541
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,363	-$ 4,363	-$ 4,363
2-STAFF-46	Updated Other Revenue to reconcile Share Services mark-up in Appendix 2-N to Other Revenue Appendix 2-H	$ 1,770,796	5.77%	$ 30,693,964	$ 28,910,864	$ 2,168,315	$ 1,157,365	$ 109,775	$ 2,974,186	$ 6,047,077	$ 507,793	$ 5,539,284	$ 49,050
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 491	-$ 491	-$ 491
2-STAFF-23	Updated Pole Attachment expense (account 5095) to reflect assumption of 100 Bell Canada poles 100 x $43.63	$ 1,770,777	5.77%	$ 30,693,637	$ 28,906,501	$ 2,167,988	$ 1,157,365	$ 109,771	$ 2,969,823	$ 6,042,691	$ 507,793	$ 5,534,898	$ 44,664
	Change	-$ 19	0.00%	-$ 327	-$ 4,363	-$ 327	$ -	-$ 4	-$ 4,363	-$ 4,386	$ -	-$ 4,386	-$ 4,386
4-STAFF-47	Reduced Intervenor cost estimate from $75,000 to $50,000 based on 2 intervenors in this case vs. an estimate of 3 in the original submission	$ 1,770,756	5.77%	$ 30,693,262	$ 28,901,501	$ 2,167,613	$ 1,157,365	$ 109,766	$ 2,964,823	$ 6,037,664	$ 507,793	$ 5,529,872	$ 39,638
	Change	-$ 22	0.00%	-$ 375	-$ 5,000	-$ 375	$ -	-$ 5	-$ 5,000	-$ 5,027	$ -	-$ 5,027	-$ 5,027
Updated Information	Moved the disposal of the T1 transformer fron 2019 test year to 2018 bridge year	$ 1,764,473	5.77%	$ 30,584,366	$ 28,901,501	$ 2,167,613	$ 1,150,110	$ 100,905	$ 2,964,823	$ 6,015,265	$ 507,793	$ 5,507,473	$ 17,239
	Change	-$ 6,282	0.00%	-$ 108,896	$ -	$ -	-$ 7,255	-$ 8,861	$ -	-$ 22,399	$ -	-$ 22,399	-$ 22,399
2-STAFF-13 2-VECC-14	Updated Appendix 2-BA to include actual disposals year to date and forecast disposals for the remainder of the year	$ 1,762,622	5.77%	$ 30,552,276	$ 28,901,501	$ 2,167,613	$ 1,146,311	$ 99,119	$ 2,964,823	$ 6,007,829	$ 507,793	$ 5,500,037	$ 9,803
	Change	-$ 1,851	0.00%	-$ 32,090	$ -	$ -	-$ 3,799	-$ 1,786	$ -	-$ 7,436	$ -	-$ 7,436	-$ 7,436
Updated Information	Updated Leap amount based on revised Service Revenue Requirement	$ 1,762,622	5.77%	$ 30,552,272	$ 28,901,444	$ 2,167,608	$ 1,146,311	$ 99,119	$ 2,964,765	$ 6,007,771	$ 507,793	$ 5,499,979	$ 9,745
	Change	-$ 0	0.00%	-$ 4	-$ 58	-$ 4	$ -	-$ 0	-$ 58	-$ 58	$ -	-$ 58	-$ 58
4-STAFF-49	Updated PILs model to move Building & Fixture additions from CCA class 47 (8%) to CCA class 1b (6%)	$ 1,762,622	5.77%	$ 30,552,272	$ 28,901,444	$ 2,167,608	$ 1,146,311	$ 99,553	$ 2,964,765	$ 6,008,205	$ 507,793	$ 5,500,413	$ 10,178
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ 434	$ -	$ 434	$ -	$ 434	$ 434
Settlement Proposal	Update 2018 capital spend to mosre recent capital forecast for 2018	$ 1,761,984	5.77%	$ 30,541,220	$ 28,901,444	$ 2,167,608	$ 1,128,766	$ 96,495	$ 2,964,765	$ 5,986,964	$ 499,484	$ 5,487,480	-$ 2,754
	Change	-$ 638	0.00%	-$ 11,051	$ -	$ -	-$ 17,545	-$ 3,058	$ -	-$ 21,241	-$ 8,309	-$ 12,932	-$ 12,932
Settlement Proposal	Add 2 GS<50 customers to the 2019 customer count	$ 1,762,015	5.77%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 96,502	$ 2,964,765	$ 5,987,003	$ 499,496	$ 5,487,507	-$ 5,449
	Change	$ 31	0.00%	$ 541	$ 7,208	$ 541	$ -	$ 7	$ -	$ 38	$ 12	$ 26	-$ 2,696
Settlement Proposal	Update OEB Cost of Capital Parameters to 2019 values	$ 1,764,336	5.78%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 95,621	$ 2,964,765	$ 5,988,443	$ 499,496	$ 5,488,947	-$ 4,009
	Change	$ 2,321	0.01%	$ -	$ -	$ -	$ -	-$ 881	$ -	$ 1,440	$ -	$ 1,440	$ 1,440
Settlement Proposal	Update Retail Service Charges EB-2015-0304	$ 1,764,336	5.78%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 95,621	$ 2,964,765	$ 5,988,443	$ 506,635	$ 5,481,808	-$ 11,148
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,139	-$ 7,139	-$ 7,139
Settlement Proposal	Remove collection of account changes	$ 1,764,336	5.78%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 95,621	$ 2,964,765	$ 5,988,443	$ 482,447	$ 5,505,995	$ 13,039
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 24,188	$ 24,188	$ 24,188
Settlement Proposal	Reduce loss factor for Large Use Customer from 1.0373 to 1.0045	$ 1,764,252	5.78%	$ 30,540,302	$ 28,889,192	$ 2,166,689	$ 1,128,766	$ 95,602	$ 2,964,765	$ 5,988,340	$ 482,447	$ 5,505,892	$ 12,936
	Change	-$ 84	0.00%	-$ 1,460	-$ 19,460	-$ 1,460	$ -	-$ 19	$ -	-$ 103	$ -	-$ 103	-$ 103
Settlement Proposal	Update interest rate on 2015 loans from the Town from 3.0% to 3.5%	$ 1,807,009	5.92%	$ 30,540,302	$ 28,889,192	$ 2,166,689	$ 1,128,766	$ 95,602	$ 2,964,765	$ 6,031,096	$ 482,447	$ 5,548,649	$ 55,693
	Change	$ 42,756	0.14%	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,756	$ -	$ 42,756	$ 42,756
Settlement Proposal	Add an additional 2 GS<50 customers to the 2019 customer count	$ 1,807,040	5.92%	$ 30,540,840	$ 28,896,373	$ 2,167,228	$ 1,128,766	$ 95,609	$ 2,964,765	$ 6,031,135	$ 482,447	$ 5,548,687	$ 54,901
	Change	$ 32	0.00%	$ 539	$ 7,182	$ 539	$ -	$ 7	$ -	$ 39	$ -	$ 39	-$ 791

NOTL Hydro has prepared the Appendices and Tables to this Settlement Proposal on the following basis: (a) any updates to NOTL Hydro's filing arising from the answers to interrogatories have been reflected in the relevant materials; (b) all impacts from the Settlement Proposal have been reflected in the relevant materials; and (c) the Unsettled Items have been reflected on an as-filed basis (including the impact of updated evidence related to the cost of long-term debt and the proposal to clear the LRAMVA and Group 2 Accounts over two years). The updated RRWF is provided at Appendix "B".

The proposed Bill Impacts that will result from this Settlement Proposal are set out Appendix "E".

Proposed tariffs are included in Appendix "E". The Total Revenue and Base Revenue Requirement agreed to as part of this Settlement Proposal for the Test Year are $6,031,135 and $5,548,687 respectively. This translates into a Grossed-up Revenue Deficiency of $54,901.

Details of the settlement on the Settled Items, along with a description of the Unsettled Items, are set out in the balance of this document.

THE SETTLED AND UNSETTLED ITEMS

1. Rate Base - Is the rate base element of the revenue requirement reasonable and has it been appropriately determined in accordance with OEB policies and practices?

With the exception of the unsettled issue described below, the parties are in agreement that the 2019 Base of $30,540,840, which has been updated to take account of NOTL Hydro's most recent capital expenditure forecast for 2018, is reasonable.

The unsettled issue related to the prudence of NOTL Hydro's underground conversion project/program since its last rebasing (impacting opening 2019 Opening Rate Base) and its proposed test year expenditures for underground conversion program, described in section 2 (impacting 2019 net additions and Closing Rate Base).

The Parties agree that NOTL Hydro will file updated evidence on the issue of the prudence of its underground conversion project/program spending. The Parties further agree that Intervenors and Board Staff be permitted the opportunity to ask interrogatories to file on any updated evidence on this unsettled issue.

Working Capital, as part of this calculation, been updated to reflect:

a) the revised customer forecast forming part of this Settlement Proposal (see Item 5); and

b) the impact on Cost of Power resulting from the update to the loss factors applicable to the Large User rate (see Item 8).

The Parties accept the evidence of NOTL Hydro that the rate base calculations, after making the adjustment to the working capital and the in-service additions for 2019, as detailed in this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices. Table 4 below outlines NOTL Hydro's Rate Base calculation. An updated fixed asset continuity schedule has been included in Appendix "B" as well as a live version being filed on RESS.

Table 2. – Summary of Cost of Power

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Electricity Projections	$23,015,166	($47,890)	$22,967,276	($3,672)	$22,963,605
Wholesale Market Service	$832,836	($1,783)	$831,053	($2,274)	$828,779
Transmission Network	$1,521,236	($3,214)	$1,518,022	$826	$1,518,848
Transmission Connection	$451,219	($916)	$450,303	$212	$450,515
Rural Rate Assistance	$69,403	($149)	$69,254	($189)	$69,065
IESO Smart Meter Entity	$65,815	$ -	$65,815	$27	$65,842
Total Cost of Power	$25,955,675	($53,952)	$25,901,724	($5,070)	$25,896,653

Table 3. – Summary of Working Capital

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Controllable Expenses	$3,009,141	($9,421)	$2,999,720	$ -	$2,999,720
Cost of Power	$25,955,675	($53,952)	$25,901,724	($5,070)	$25,896,653
Working Capital Base	$28,964,816	($63,372)	$28,901,444	($5,070)	$28,896,373
Working Capital Rate %	7.50%	0.00%	7.50%	0.00%	7.50%
Working Capital Allowance	$2,172,361	($4,753)	$2,167,608	($380)	$2,167,228

Subject to the determination of the Unsettled Item related to the underground conversion program (see Item 2, below), the Parties have agreed that the 2019 Test Year capital additions of $5,848,590 are reasonable.

The Parties accept the evidence of NOTL Hydro that the Net Depreciation is correctly determined from the above is $1,128,766. Continuity Schedules are provided at Appendix "B".

Table 4. Summary of Rate Base

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Gross Fixed Assets (average)	$56,132,843	($961,368)	$55,171,475	($20,788)	$55,150,687
Accumulated Depreciation (average)	($27,607,193)	$820,382	($26,786,811)	$9,737	($26,777,075)
Net Fixed Assets (average)	$28,525,650	($140,986)	$28,384,663	($11,051)	$28,373,612
Allowance for Working Capital	$2,172,361	($4,753)	$2,167,608	($380)	$2,167,228
Total Rate Base	$30,698,011	($145,739)	$30,552,272	($11,432)	$30,540,840

Evidence: The evidence in relation to this issue includes the following:

Exhibit 2	Rate Base
I.2.STAFF.10-30	Staff Interrogatories #10-30
I.2.SEC.13-24	SEC Interrogatories #13-24
I.2.VECC 3-14	VECC Interrogatories #3-14
Supplementary Responses	Supplementary Responses to Staff 25 and 27 and VECC 8

2. <u>Distribution System Plan and capital expenditures</u> - Are NOTL Hydro's proposed capital expenditures appropriate and have the trade-offs with the proposed level of Operating Cost been given adequate consideration?

Subject to one Unsettled Item described below, for the purposes of settlement the Parties accept the evidence of NOTL Hydro that the level of planned capital expenditures, as summarized in Table 5 below, and the rationale for planning and pacing choices are appropriate to maintain system reliability, service quality objectives and the reliable and safe operations of the distribution system, is appropriate.

Similar to the unsettled issue discussed in section 2, there no agreement on NOTL Hydro's proposed underground conversion projects in the Olde Towne and Virgil areas of the service territory. The forecast capital cost for these projects in 2019 is $460,000 (see Distribution System Plan, filed at Exhibit 2, at pages 35 and 55 – 58). The Parties agree that all issues about the underground conversion projects should be determined by the Board.

The Parties agree that NOTL Hydro will file updated evidence on the issue of the reasonableness of its proposed underground conversion project/program Test Year expenditures. The Parties further agree that Intervenors and Board Staff be permitted the opportunity to ask interrogatories to file on any updated evidence on this unsettled issue.

The Parties acknowledge that NOTL Hydro retains the full discretion to manage its capital spending in the Test Year and beyond in accordance with the actual operating conditions it experiences in any year.

Table 5. Planned Capital Expenditures

	Initial Application	Interrogatories	Settlement Proposal
System Access	$835,500	$835,500	$835,500
System Renewal	$1,097,000	$1,097,000	$1,097,000
System Service	$3,832,340	$3,832,340	$3,832,340

General Plant	$83,750	$83,750	$83,750
Total Assets	**$5,848,590**	**$5,848,590**	**$5,848,590**

Evidence: The evidence in relation to this issue includes the following:

Exhibit 2	Rate Base
I.2.STAFF.10-30	Staff Interrogatories #10-30
I.2.SEC.13-24	SEC Interrogatories #13-24
I.2.VECC 3-14	VECC Interrogatories #3-14
Supplementary Responses	Supplementary Responses to Staff 25 and 27 and VECC 8

3. Operating Costs

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties agree that the 2019 Test Year operating expenses related to Depreciation/Amortization, Property Taxes and PILs are reasonable. There is no agreement on the forecast OM&A expenses for the 2019 Test Year.

Table 6. Summary of Operating Costs

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
OM+A Expenses	$2,974,186	($9,421)	$2,964,765	$ -	$2,964,765
Depreciation/Amortization	$1,157,365	($11,054)	$1,146,311	($17,545)	$1,128,766
Property taxes	$34,955	$ -	$34,955	$ -	$34,955
Income taxes (grossed up)	$109,828	($10,275)	$99,553	($3,944)	$95,609
Other expense	$ -	$ -	$ -	$ -	$ -
Total Operating Costs	$4,276,333	($30,750)	$4,245,584	($21,489)	$4,224,095

OM&A

NOTL Hydro's 2019 Test Year OM&A forecast is $2,964,765. There is no agreement on this portion of NOTL Hydro's operating costs. The Parties agree that all issues about the OM&A expenses should be determined by the Board.

Depreciation

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties accept that NOTL Hydro has correctly calculated

depreciation. Accounting for NOTL Hydro's most recent capital expenditure forecast for 2018, the depreciation amount is $1,128,766.

Table 7. Summary of Change in Depreciation

		Depreciation Expense				
OEB Class	OEB Account	Initial Application	Adjustments	Interrogatory Response	Adjustments	Settlement Proposal
1611	Computer Software	67,001	-	67,001	876	67,877
1815	Transformer Station Equipment - Normally Primary Above 50kV	190,683	(7,255)	183,428	2,255	185,682
1820	Transformer Station Equipment - Normally Primary Below 50kV	-	-	-	-	-
1825	Storage Battery Equipment	22,117	-	22,117	-	22,117
1830	Poles, Towers & Fixtures	122,877	(2,698)	120,179	(571)	119,608
1835	Overhead Conductors & Devices	91,281	(595)	90,686	2,355	93,041
1840	Underground Conduit	76,029	-	76,029	(819)	75,210
1845	Underground Conductors & Devices	196,571	-	196,571	(4,248)	192,324
1850	Line Transformers	162,827	(506)	162,322	(301)	162,021
1855	Services	107,184	-	107,184	(5,851)	101,333
1860	Meters	149,180	-	149,180	(721)	148,460
1908	Buildings & Fixtures	20,723	-	20,723	(13)	20,710
1915	Office Furniture & Equipment	6,186	-	6,186	-	6,186
1920	Computer Equipment - Hardware	15,074	-	15,074	(1,667)	13,407
1940	Tools, Shop & Garage Equipment	10,979	-	10,979	1,142	12,121
1955	Communications Equipment	336	-	336	-	336
1980	System Supervisor Equipment	45,791	-	45,791	(9,983)	35,809
1995	Contributions & Grants - Credit	(127,476)	-	(127,476)	-	(127,476)
	Total	**1,157,365**	**(11,054)**	**1,146,311**	**(17,545)**	**1,128,766**

Property Taxes and PILs

The Parties accept NOTL Hydro's forecast of property taxes for the Test Year, as set out above in Table 6.

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, Parties accept that NOTL Hydro has correctly calculated PILs in the amount of $95,609.

The live PILs workform has been filed on the Board's website.

Table 8. PILs Summary

Particulars	Initital Application	Interrogatories	Settlement Proposal
Determination of Taxable Income			
Utility net income before taxes	$1,105,128	$1,099,882	$1,097,027
Adjustments required to arrive at taxable utility income	($800,512)	($823,764)	($831,847)
Taxable income	$304,617	$276,118	$265,180
Calculation of Utility income Taxes			
Income taxes	$80,723	$73,171	$70,273
Total taxes	$80,723	$73,171	$70,273
Gross-up of Income Taxes	$29,104	$26,381	$25,336
Grossed-up Income Taxes	$109,828	$99,553	$95,609
PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$109,828	$99,553	$95,609
Other tax Credits	$ -	$ -	$ -
Tax Rates			
Federal tax (%)	15.00%	15.00%	15.00%
Provincial tax (%)	11.50%	11.50%	11.50%
Total tax rate (%)	26.50%	26.50%	26.50%

Evidence: The evidence in relation to this issue includes the following:

Exhibit 4	Operations, Maintenance & Administration
I.4.STAFF.39-54	Staff Interrogatories #39-54
I.2.SEC.27-30	SEC Interrogatories #27-30
I.2.VECC.24-36	VECC Interrogatories #24-36
Supplementary Responses	Supplementary Responses to Staff 42 and VECC 29 and SEC Supplementary 2

4. Cost of Capital

NOTL Hydro's filing uses the OEB approved deemed capital structure of 4% short term debt, 56% long term debt and 40% equity.

The Parties have agreed that the return on equity (ROE) applicable to NOTL Hydro's cost of capital will be updated to the Board's approved rate for 2019 cost of service applications (8.98%). This item is also subject to any updates that are required to reflect the Board's decisions on the Unsettled Items.

The Parties have agreed that the rate for short-term debt will be updated to the Board's approved rate for 2019 cost of service applications (2.82%). This item is also subject to any updates that are required to reflect the Board's decisions on the Unsettled Items.

There is no agreement on NOTL Hydro's cost of long-term debt. The parties agree that all issues related to this item will be determined by the Board.

Concurrently with this filing of this Settlement Proposal NOTL Hydro has indicated to Parties it will be filing updated evidence about its cost of long-term debt, applying: (i) an updated notional rate associated with a promissory note with the Town of NOTL to reflect the Board's approved long-term debt rate for 2019 cost of service applications (4.13%); and (ii) a proposed increased interest rate on two loans from the Town of NOTL from 3.0% to 3.5%.

While there is no agreement on these items, or even on the appropriateness of NOTL Hydro filing the updated evidence, the Settlement Proposal has been updated to reflect the impact of the updated evidence about long-term debt in the tables, appendices and schedules associated with this Settlement Proposal. Table 9 shows the impact of NOTL Hydro's updated evidence about long-term debt, and Table 10 shows the overall updated Cost of Capital

The Parties further agree that it is appropriate that intervenors and Board Staff be permitted the opportunity to ask interrogatories on the updated evidence or to object to the appropriateness of the filing of the updated evidence, in whole or in part.

Table 9 – Long Term Debt

Initial Application								
Description	**Lender**	**Affiliated or Third-Party Debt?**	**Fixed or Variable-Rate?**	**Start Date**	**Term (years)**	**Principal ($)**	**Rate (%) (Note 2)**	**Calculated Interest ($)**
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.16%	$ 87,308.82
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 30,601.68
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.00%	$ 58,641.19
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.00%	$ 42,912.05
						$ 6,624,865	**3.71%**	**$ 245,474.55**

Interrogatory Responses								
Description	**Lender**	**Affiliated or Third-Party Debt?**	**Fixed or Variable-Rate?**	**Start Date**	**Term (years)**	**Principal ($)**	**Rate (%) (Note 2)**	**Calculated Interest ($)**
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.16%	$ 87,308.82
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 30,601.68
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.00%	$ 58,641.19
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.00%	$ 42,912.05
						$ 6,624,865	**3.71%**	**$ 245,474.55**

Updated Evidence								
Description	**Lender**	**Affiliated or Third-Party Debt?**	**Fixed or Variable-Rate?**	**Start Date**	**Term (years)**	**Principal ($)**	**Rate (%) (Note 2)**	**Calculated Interest ($)**
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.13%	$ 86,679.19
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 30,601.68
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.50%	$ 68,414.72
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.50%	$ 50,064.06
						$ 6,624,865	**3.95%**	**$ 261,770.46**

Table 10 – Cost of Capital, including LT Debt

Initial Application				
Particulars	**Capitalization Ratio**		**Cost Rate**	**Return**
Debt				
Long-term Debt	56.00%	$17,190,886	3.71%	$637,782
Short-term Debt	4.00%	$1,227,920	2.29%	$28,119
Total Debt	60.00%	$18,418,806	3.62%	$665,901
Equity				
Common Equity	40.00%	$12,279,204	9.00%	$1,105,128
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,279,204	9.00%	$1,105,128
Total	100.00%	$30,698,011	5.77%	$1,771,030

Interrogatory Responses				
Particulars	**Capitalization Ratio**		**Cost Rate**	**Return**
Debt				
Long-term Debt	56.00%	$17,109,272	3.71%	$634,754
Short-term Debt	4.00%	$1,222,091	2.29%	$27,986
Total Debt	60.00%	$18,331,363	3.62%	$662,740
Equity				
Common Equity	40.00%	$12,220,909	9.00%	$1,099,882
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,220,909	9.00%	$1,099,882
Total	100.00%	$30,552,272	5.77%	$1,762,622

Updated Evidence				
Particulars	**Capitalization Ratio**		**Cost Rate**	**Return**
Debt				
Long-term Debt	56.00%	$17,102,569	3.95%	$675,551
Short-term Debt	4.00%	$1,221,612	2.82%	$34,449
Total Debt	60.00%	$18,324,181	3.87%	$710,001
Equity				
Common Equity	40.00%	$12,216,121	8.98%	$1,097,008
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,216,121	8.98%	$1,097,008
Total	100.00%	$28,384,663	5.92%	$1,807,009

Evidence: The evidence in relation to this issue includes the following:

Exhibit 5	Cost of Capital
I.5.STAFF.55-56	Staff Interrogatories #55-56
I.5. SEC.31-32	SEC Interrogatories #31-32
I.5.VECC.37	VECC Interrogatory #37
Exhibit 5 Additional Evidence	Additional Evidence re. Cost of Long-Term Debt

5. Load Forecast and Other Revenue

Customer Forecast

The Parties have agreed the 2019 customer count as filed should be increased by 4 GS < 50 kW customers and that with this change it is a reasonable forecast of customer count for use in setting rates. This takes account of additional information provided by NOTL Hydro in response to VECC clarification question #50-part c.

Table 11. Customer Forecast

Class	Initial Application	Settlement Proposal
Residential	8,152	8,152
GS<50	1,338	1,342
GS>50 (50 to 4999)	131	131
Large Use	1	1
Street Light (connections)	2,187	2,187
Unmetered Scattered Load	26	26

Load Forecast

The Parties have agreed with NOTL Hydro's as-filed load forecast updated for an additional 4 GS<50 kW customers as reflected in Table 11. Table 12 below, provides the agreed 2019 CDM Adjusted Forecast which includes the 2016 and 2017 actual verified results. NOTL Hydro agrees that any future calculations for LRAM or CDM will exclude the impact of the CHP generation unit expected to be operated by the Large Use customer.

Table 12 – CDM Adjusted Load Forecast (kWh) for 2019

Customers or Connections					
Customer Class Name	**Initial Application**	**Adjustments**	**Interrogatory Responses**	**Adjustments**	**Settlement Proposal**
Residential	8,152	0	8,152	0	8,152
GS<50	1,338	0	1,338	4	1,342
GS>50	131	0	131	0	131
Unmetered	26	0	26	0	26
Streetlights	2,187	0	2,187	0	2,187
Large User	1	0	1	0	1
TOTAL	**11,835**	**0**	**11,835**	**4**	**11,839**

Consumption (kWh)					
Customer Class Name	**Initial Application**	**Adjustments**	**Interrogatory Responses**	**Adjustments**	**Settlement Proposal**
Residential	73,998,981	(100,283)	73,898,698	0	73,898,698
GS<50	41,877,513	(139,557)	41,737,956	127,721	41,865,678
GS>50	82,705,771	(237,722)	82,468,049	0	82,468,049
Unmetered	251,508	0	251,508	0	251,508
Streetlights	886,616	0	886,616	0	886,616
Large User	23,308,825	0	23,308,825	0	23,308,825
TOTAL	**223,029,214**	**(477,562)**	**222,551,653**	**127,721**	**222,679,374**

Consumption (kW)

	Actual				
Customer Class Name	**Initial Application**	**Adjustments**	**Interrogatory Responses**	**Adjustments**	**Settlement Proposal**
Residential	0	0	0	0	0
GS<50	0	0	0	0	0
GS>50	212,896	(612)	212,284	0	212,284
Unmetered	0	0	0	0	0
Streetlights	2,475	0	2,475	0	2,475
Large User	60,000	0	60,000	0	60,000
TOTAL	**275,370**	**(612)**	**274,758**	**0**	**274,758**

Table 13 – LRAMVA Thresholds

	2017	2018	2019	Total for 2019
Amount used for CDM threshold for LRAMVA (2019)	3,447,680.00	1,524,390.03	1,045,247.50	6,017,317.53

Other Revenue

The Parties have agreed that Other Revenue as filed is appropriate subject to the following adjustments:

- A reduction in forecast Other Revenue of $24,188 to reflect the expected implementation of the OEB's determination in the Review of Customer Service Rules (EB-2017-0183) that distributors will no longer be permitted to use Collection of Account charges as of May 1, 2019.

- An increase in Retail Service Charges by $7,139 to reflect the expected implementation of the OEB's Energy Retailer Service Charges report (EB-2015-0304).

- Increase in Standard Supply Service – Administrative charge of $12 due an increase of 4 GS<50 customers in the Test Year.

The fourth change relates to the updated capital forecast for 2018 as described in Item 1. The reduction in the estimate for Contributed Capital results in a $8,309 decrease forecast Other Revenue in 2019.

Table 14 below shows NOTL Hydro's updated Other Revenues, as agreed by the parties.

For further discussion of the Service Charges, and the MicroFit Charge, see Item 10, below.

Table 14. Other Revenues and Revenue Offsets

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Specific Service Charges	$87,551	$491	$88,042	($24,188)	$63,854
Late Payment Charges	$54,284	$ -	$54,284	$ -	$54,284
Other Distribution Revenue	$310,170	$4,363	$314,533	($1,158)	$313,375
Other Income and Deductions	$50,934	$ -	$50,934	$ -	$50,934
Total Revenue Offsets	$502,939	$4,854	$507,793	($25,345)	$482,447

Change in Other Distribution Revenue	
Retail Service Charges	$7,139
Deferred Revenue	($8,309)
SSS Admin	$12
Total Change	($1,158)

Evidence: The evidence in relation to this issue includes the following:

Exhibit 3	Load and Other Revenue Forecast
I.3.STAFF.31-38	Staff Interrogatories #31-38
I.3.SEC.25-26	SEC Interrogatories #25-26
I.3.VECC.15-23	VECC Interrogatories #15-23
Supplementary Responses	Responses to VECC Supplementary #50 – 54

6. Revenue Sufficiency/Deficiency

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties accept the evidence of NOTL Hydro that it has calculated the revenue deficiency of $54,901 in accordance with the Board's policies and practices and the agreed elements of the Settlement Proposal discussed herein.

The RRWF is included as Appendix "B" and a live version of the RRWF is on the Board's RESS as part of this Settlement Proposal which incorporates the changes agreed to herein.

Table 15 – Summary of Revenue Sufficiency/Deficiency

Particulars	Initial Application		Interrogatory Responses		Settlement Proposal	
	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		$50,401		$10,178		$54,901
Distribution Revenue	$5,494,023	$5,494,023	$5,490,234	$5,490,234	$5,493,786	$5,493,786
Other Operating Revenue	$502,939	$502,939	$507,793	$507,793	$482,447	$482,447
Offsets - net						
Total Revenue	$5,996,962	$6,047,363	$5,998,027	$6,008,205	$5,976,234	$6,031,135
Operating Expenses	$4,166,506	$4,166,506	$4,146,031	$4,146,031	$4,128,486	$4,128,486
Deemed Interest Expense	$665,901	$665,901	$662,740	$662,740	$710,013	$710,013
Total Cost and Expenses	$4,832,407	$4,832,407	$4,808,771	$4,808,771	$4,838,499	$4,838,499
Utility Income Before Income Taxes	$1,164,555	$1,214,956	$1,189,256	$1,199,434	$1,137,735	$1,192,636
Tax Adjustments to Accounting Income per 2013	($800,512)	($800,512)	($823,764)	($823,764)	($831,847)	($831,847)
Taxable Income	$364,043	$414,445	$365,492	$375,670	$305,887	$360,789
Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax on Taxable Income	$96,471	$109,828	$96,855	$99,553	$81,060	$95,609
Income Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -
Utility Net Income	$1,068,083	$1,105,128	$1,092,401	($5,247)	$1,056,674	$1,146,902
Utility Rate Base	$30,698,011	$30,698,011	$30,552,272	$30,552,272	$30,540,840	$30,540,840
Deemed Equity Portion of Rate Base	$12,279,204	$12,279,204	$12,220,909	$12,220,909	$12,216,336	$12,216,336
Income/(Equity Portion of Rate Base)	8.70%	9.00%	8.94%	-0.04%	8.65%	9.39%
Target Return - Equity on Rate Base	9.00%	9.00%	9.00%	9.00%	8.98%	8.98%
Deficiency/Sufficiency in Return on Equity	-0.30%	0.00%	-0.06%	-9.04%	-0.33%	0.41%
Indicated Rate of Return	5.65%	5.77%	5.74%	2.15%	5.78%	6.08%
Requested Rate of Return on Rate Base	5.77%	5.77%	5.77%	5.77%	5.92%	5.92%
Deficiency/Sufficiency in Rate of Return	-0.12%	0.00%	-0.02%	-3.62%	-0.13%	0.16%
Target Return on Equity	$1,105,128	$1,105,128	$1,099,882	$1,099,882	$1,097,027	$1,097,027
Revenue Deficiency/(Sufficiency	$37,045	$ -	$7,481	($1,105,128)	$40,353	$49,875
Gross Revenue Deficiency/(Sufficiency)	$50,401		$10,178		$54,901	

Evidence: The evidence in relation to this issue includes the following:

Exhibit 6 Revenue Requirement

7. Cost Allocation

Subject to the amendments from NOTL Hydro's filing described below, as well as any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties agree the cost allocation methodology and the allocations reflect OEB policies and are appropriate.

NOTL Hydro's determination of revenue at existing rates for cost allocation purposes includes the impact of the ICM revenue because the project associated with the ICM will be included in 2019 base rates. NOTL Hydro believes that this approach is a fair way to assess rate impacts from its updated revenue requirement. Intervenors are not aware of

any other LDC who in its rebasing application after an ICM has applied ICM riders to base rates for the revenue at existing rates calculation. There is no agreement on whether this approach is appropriate. The issue will be determined by the Board. Appendix “H” to this Settlement Proposal shows the impact of including the ICM revenue in distribution revenue at current rates.

NOTL Hydro has agreed to remove the direct allocation to its Large User Customer of the distribution line that will serve its Large User customer and other customers, and instead allocate the costs of that asset to all customers on the same basis as the allocation of costs associated with other like assets. NOTL Hydro has also agreed to update its 4 NCP value for the Large Use Customer as set out in response to VECC clarification question #59.

An updated cost allocation model has been included as Appendix “G” and has been filed on the OEB’s RESS system as part of this Settlement Proposal which incorporates the changes agreed to herein.

Table 16. Summary of Cost Allocation

	Total	1 Residential	2 GS <50	3 GS >50kW	6 Large User	7 Street Light	9 Unmetered Scattered Load
Distribution Revenue at Existing Rates	$5,492,956	$2,923,268	$1,177,925	$977,428	$124,034	$281,952	$8,350
Miscellaneous Revenue (mi)	$482,447	$304,702	$86,364	$63,375	$10,313	$16,937	$756
	Miscellaneous Revenue Input equals Output						
Total Revenue at Existing Rates	$5,975,403	$3,227,970	$1,264,289	$1,040,803	$134,347	$298,889	$9,106
Factor required to recover deficiency (1 + D)	1.0101						
Distribution Revenue at Status Quo Rates	$5,548,649	$2,952,907	$1,189,868	$987,338	$125,291	$284,810	$8,434
Miscellaneous Revenue (mi)	$482,447	$304,702	$86,364	$63,375	$10,313	$16,937	$756
Total Revenue at Status Quo Rates	$6,031,096	$3,257,609	$1,276,232	$1,050,713	$135,605	$301,747	$9,190
Expenses							
Distribution Costs (di)	$931,637	$565,651	$178,720	$123,290	$28,285	$34,341	$1,350
Customer Related Costs (cu)	$862,631	$630,126	$122,984	$81,045	$627	$26,547	$1,301
General and Administration (ad)	$1,205,452	$796,213	$205,208	$140,899	$20,756	$40,609	$1,768
Depreciation and Amortization (dep)	$1,128,766	$633,630	$235,486	$191,020	$37,388	$29,951	$1,290
PILs (INPUT)	$95,602	$50,346	$20,657	$17,708	$4,055	$2,719	$118
Interest	$710,001	$373,903	$153,410	$131,509	$30,111	$20,190	$877
Total Expenses	$4,934,088	$3,049,870	$916,465	$685,470	$121,223	$154,356	$6,704
Direct Allocation	$0	$0	$0	$0	$0	$0	$0
Allocated Net Income (NI)	$1,097,008	$577,709	$237,031	$203,192	$46,525	$31,195	$1,356
Revenue Requirement (includes NI)	$6,031,096	$3,627,579	$1,153,496	$888,662	$167,748	$185,551	$8,060
	Revenue Requirement Input equals Output						
Rate Base Calculation							
Net Assets							
Distribution Plant - Gross	$60,395,904	$34,454,054	$12,448,909	$9,572,474	$1,882,192	$1,958,626	$79,649
General Plant - Gross	$7,196,876	$4,038,108	$1,490,532	$1,196,458	$254,026	$208,778	$8,975
Accumulated Depreciation	($26,777,075)	($15,258,743)	($5,568,307)	($4,164,732)	($769,240)	($978,483)	($37,570)
Capital Contribution	($12,442,094)	($8,230,189)	($2,256,303)	($1,382,338)	($176,235)	($381,059)	($15,969)
Total Net Plant	$28,373,612	$15,003,230	$6,114,831	$5,221,862	$1,190,742	$807,862	$35,085
Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
Cost of Power (COP)	$25,889,472	$8,628,863	$4,858,359	$9,566,379	$2,703,848	$102,848	$29,175
OM&A Expenses	$2,999,720	$1,991,991	$506,911	$345,234	$49,669	$101,497	$4,418
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$28,889,192***	***$10,620,853***	***$5,365,270***	***$9,911,613***	***$2,753,517***	***$204,345***	***$33,594***
Working Capital	$2,166,689	$796,564	$402,395	$743,371	$206,514	$15,326	$2,520
Total Rate Base	$30,540,302	$15,799,794	$6,517,227	$5,965,233	$1,397,256	$823,187	$37,604
	Rate Base Input equals Output						
Equity Component of Rate Base	$12,216,121	$6,319,918	$2,606,891	$2,386,093	$558,902	$329,275	$15,042
Net Income on Allocated Assets	$1,097,008	$207,739	$359,767	$365,243	$14,382	$147,391	$2,486
Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
Net Income	$1,097,008	$207,739	$359,767	$365,243	$14,382	$147,391	$2,486
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	100.00%	89.80%	110.64%	118.24%	80.84%	162.62%	114.03%
EXISTING REVENUE MINUS ALLOCATED COSTS	($55,693)	($399,609)	$110,793	$152,141	($33,401)	$113,337	$1,046
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($369,970)	$122,736	$162,051	($32,143)	$116,196	$1,130
RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	3.29%	13.80%	15.31%	2.57%	44.76%	16.53%

Evidence: The evidence in relation to this issue includes the following:

Exhibit 7	Cost Allocation
I.7.STAFF.57-63	Staff Interrogatories #57-63
I.7.VECC.38-44	VECC Interrogatories #38-44
Supplementary Responses	Responses to Staff Supplementary #8 and VECC Supplementary #55-59

8. Rate Design

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties accept the Proposed Tariff and the Parties accept the evidence of NOTL Hydro that it has calculated the Bill Impacts correctly and accept that such impacts are acceptable.

NOTL Hydro has agreed to treat the split between fixed and variable charges for the streetlighting and USL rate classes in the same manner as the GS >50 rate class. With that change, the Parties accept the evidence of NOTL Hydro that all elements of the rate design, including fixed-variable splits and revenue to cost ratios, have been appropriately determined, taking account of OEB policies and practices.

NOTL Hydro has updated the loss factor associated with the Large Use customer class. NOTL Hydro's filing did not include any separate loss factor for this customer class. After having reviewed the applicable loss factor for similar customer classes with other distributors, NOTL Hydro has proposed to update the applicable Tariffs to include the following:

Total Loss Factor – Secondary Metered Customer < 5,000 kW 1.0373 [no change]
Total Loss Factor – Secondary Metered Customer > 5,000 kW 1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW 1.0275 [no change]
Total Loss Factor – Primary Metered Customer > 5,000 kW 1.0045

The only impact on rates from the proposed change will be through the calculation of Cost of Power for the purpose of determining the Working Capital Allowance. This impact (an approximate $1,500 reduction in rate base) is shown in Item 1, above. The Parties accept this change. In agreeing to the Large Use rate, the Parties accept and rely on the evidence of NOTL Hydro that it has consulted with its Large Use customer, and that such customer is amenable to the proposed new Large Use rate.

For discussion of the proposed Standby Charges and the proposed Transmission Gross Load Billing Charge, see Item 10, below.

A copy of the Proposed Tariff is included at Appendix "E". The Proposed Tariff reflects the items described in this Settlement Proposal, including those related to the unsettled items.

Table 17 – Summary of Distribution Rates

Customer Class	Customer and Load Forecast				Distribution Rates	
	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Monthly Service Charge	Volumetric Rate
Residential	kWh	8,152	73,898,698	-	$ 30.47	$ - /kWh
GS<50	kWh	1,342	41,865,678	-	$ 39.41	$ 0.0133 /kWh
GS>50	kW	131	82,468,049	212,284	$ 281.65	$ 2.6169 /kW
Unmetered	kWh	26	251,508	-	$ 21.20	$ 0.0072 /kWh
Streetlights	kW	2,187	886,616	2,475	$ 7.85	$ 7.3887 /kW
Large User	kW	1	23,308,825	60,000	$ 2,829.49	$ 2.6169 /kW

Table 18 - Table Revenue to Cost Ratios

Name of Customer Class	Proposed Revenue-to-Cost Ratio		Policy Range
	Test Year	Price Cap IR Period	
	2019	2020 - 2023	
1 Residential	**90.58%**	**91.09%**	85 - 115
2 GS<50	110.64%	110.64%	80 - 120
3 GS>50	118.24%	118.24%	80 - 120
4 Unmetered	114.03%	114.03%	80 - 120
5 Streetlights	**130.00%**	**120.00%**	80 - 120
6 Large User	100.00%	100.00%	85 - 115

Table 19 – Summary of Fixed Variable Splits

Customer Class	Customer and Load Forecast							Fixed / Variable Splits	
	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable
Residential	kWh	8,152	73,898,698	-	$ 2,980,917	$ 2,980,917	$ -	100.00%	0.00%
GS<50	kWh	1,342	41,865,678	-	$ 1,190,494	$ 634,501	$ 555,993	53.30%	46.70%
GS>50	kW	131	82,468,049	212,284	$ 987,196	$ 442,754	$ 544,442	44.85%	55.15%
Unmetered	kWh	26	251,508	-	$ 8,433	$ 6,614	$ 1,819	78.43%	21.57%
Streetlights	kW	2,187	886,616	2,475	$ 224,278	$ 205,993	$ 18,285	91.85%	8.15%
Large User	kW	1	23,308,825	60,000	$ 157,369	$ 33,954	$ 123,415	21.58%	78.42%

RTSRs

The Parties accept the evidence of NOTL Hydro that it has calculated the RTSRs correctly and agree that they are acceptable.

Table 20 - Proposed RTSRs

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.									
Rate Class	**Rate Description**	**Unit**	**Adjusted RTSR-Network**	**Loss Adjusted Billed kWh**	**Billed kW**	**Billed Amount**	**Billed Amount %**	**Current Wholesale Billing**	**Proposed RTSR-Network**
Residential	RTSR - Network	kWh	0.0068	73,708,854		501,767	37.8%	501,767	**0.0068**
General Service Less Than 50 kW	RTSR - Network	kWh	0.0062	42,276,847		263,475	19.8%	263,475	**0.0062**
General Service 50 to 4,999 kW	RTSR - Network	kW	2.5322		122,962	311,361	23.4%	311,361	**2.5322**
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.7367		89,640	245,314	18.5%	245,314	**2.7367**
Unmetered Scattered Load	RTSR - Network	kWh	0.0062	260,263		1,622	0.1%	1,622	**0.0062**
Street Lighting	RTSR - Network	kW	1.9093		2,400	4,583	0.3%	4,583	**1.9093**
The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.									
Rate Class	**Rate Description**	**Unit**	**Adjusted RTSR-Connection**	**Loss Adjusted Billed kWh**	**Billed kW**	**Billed Amount**	**Billed Amount %**	**Current Wholesale Billing**	**Proposed RTSR-Connection**
Residential	RTSR - Connection	kWh	0.0016	73,708,854		118,331	32.2%	118,331	**0.0016**
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0016	42,276,847		67,871	18.4%	67,871	**0.0016**
General Service 50 to 4,999 kW	RTSR - Connection	kW	0.5327		122,962	65,503	17.8%	65,503	**0.5327**
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW	1.2812		89,640	114,846	31.2%	114,846	**1.2812**
Unmetered Scattered Load	RTSR - Connection	kWh	0.0016	260,263		418	0.1%	418	**0.0016**
Street Lighting	RTSR - Connection	kW	0.4118		2,400	989	0.3%	989	**0.4118**

LRAMVA

NOTL Hydro is only seeking clearance of the LRAMVA for 2016 and 2017. The Parties accept that NOTL Hydro has determined the LRAMVA appropriately. The Parties agree the results are acceptable. Table 20 provides a history of LRAMVA actuals versus forecast from 2011 to 2017 and the amounts to be recovered from each rate class.

Table 21 - LRAMVA

Description	**LRAMVA Previously Claimed**	**Residential**	**GS<50 kW**	**Street Lighting**	**Unmetered Scattered Load**	**General Service 50 - 4,999 kW**	**Total**
		kWh	kWh	kW	kWh	kW	
2011 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2012 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2013 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2014 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2015 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2016 Actuals		$22,353.60	$30,305.37	$31,223.24	$0.00	$24,738.05	$108,620.26
2016 Forecast		($4,979.74)	($14,033.57)	$0.00	$0.00	($2,379.45)	($21,392.76)
Amount Cleared							
2017 Actuals		$25,384.05	$36,341.80	$31,743.35	$0.00	$35,082.11	$128,551.31
2017 Forecast		($3,550.37)	($14,279.77)	$0.00	$0.00	($2,419.08)	($20,249.23)
Amount Cleared							
2018 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2018 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2019 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2019 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2020 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2020 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
Carrying Charges		$1,438.19	$1,398.16	$2,346.80	$0.00	$1,995.69	$7,178.85
Total LRAMVA Balance		**$40,646**	**$39,732**	**$65,313**	**$0**	**$57,017**	**$202,708**

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design
I.8.STAFF.64-65	Staff Interrogatories #64-65
I.8.SEC.33	SEC Interrogatories #33

9. Deferral and Variance Accounts

Clearance of Group 1 and Group 2 Accounts

The Parties agree to the clearance of NOTL Hydro's Deferral and Variance accounts as-filed, with one exception. The change from the filing is that the parties have agreed, in the context of the overall partial settlement, that NOTL Hydro will not clear the OEB Cost Assessment Variance Account, because the balance in that account ($16,762) does not meet the relevant materiality threshold.

The Parties also agree that the Group 1 balances are disposed of on an interim basis consistent with Board policy and that the Group 2 balances are settled on a final basis.

The Parties agree that the recovery period for all Group 1 deferral and variance account rate riders will be 1 year.

There is no agreement on the disposition period of Group 2 deferral and variance accounts and the LRAMVA. Concurrently with this filing of this Settlement Proposal NOTL Hydro has indicated to Parties it will be filing updated evidence proposing to clear the accounts over a 2-year period (the original prefiled evidence had proposed a one-year clearance period). The table below sets out the relative impacts of clearance over 1 or 2 years. The Parties agree that the Board should determine this item. The Parties further agree that it is appropriate that intervenors and Board Staff be permitted the opportunity to ask interrogatories on the updated evidence or to object to the appropriateness of the updated evidence

Table 22 – LRAMVA and Group 2 Deferral and Variance Accounts

LRAM	Rate Rider 1 Year	Rate Rider 2 Years	Variance	Bill Impact
Residential	$ 0.42	$ 0.21	$ 0.21	$ 0.21
GS<50	$ 0.0010	$ 0.0005	$ 0.0005	$ 1.00
GS>50	$ 0.2686	$ 0.1343	$ 0.1343	$ 18.13
Steet Lights	$ 26.3920	$ 13.1960	$ 13.1960	$ 382.68
Unmetered	$ -	$ -	$ -	$ -
Large User	$ -	$ -	$ -	$ -

Group 2	Rate Rider 1 Year	Rate Rider 2 Years	Variance	Bill Impact
Residential	$ 0.80	$ 0.40	$ 0.40	$ 0.40
GS<50	$ 0.0011	$ 0.0005	$ 0.0006	$ 1.10
GS>50	$ 0.4104	$ 0.2052	$ 0.2052	$ 27.70
Steet Lights	$ 0.3785	$ 0.1893	$ 0.1893	$ 5.49
Unmetered	$ 0.0011	$ 0.0005	$ 0.0006	$ 0.41
Large User	$ 0.4104	$ 0.2052	$ 0.2052	$ 1,026.00

Table 23 - Deferral/Variance Account Balances and Rate Riders

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

Please indicate the Rate Rider Recovery Period (in months) | 12

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL	kWh	73,898,698	-$ 44,565	- 0.0006
GENERAL SERVICE LESS THAN 50 KW	kWh	41,865,678	-$ 23,992	- 0.0006
GENERAL SERVICE 50 TO 4,999 KW	kW	212,284	-$ 46,247	- 0.2179
STREET LIGHTING	kW	2,475	-$ 497	- 0.2009
UNMETERED	kWh	251,508	-$ 141	- 0.0006
LARGE USER	kW	60,000	-$ 13,071	- 0.2179
Total			**-$ 128,514**	

Rate Rider Calculation for RSVA - Power - Global Adjustment

Please indicate the Rate Rider Recovery Period (in months) | 12

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL	kWh	1,777,899	-$ 3,221	- 0.0018
GENERAL SERVICE LESS THAN 50 KW	kWh	6,392,462	-$ 11,580	- 0.0018
GENERAL SERVICE 50 TO 4,999 KW	kWh	76,481,342	-$ 138,544	- 0.0018
STREET LIGHTING	kWh	779,154	-$ 1,411	- 0.0018
UNMETERED	kWh	-	$ -	-
LARGE USER	kWh	23,308,825	-$ 42,223	- 0.0018
Total			**-$ 196,979**	

Rate Rider Calculation for Group 2 Accounts

Please indicate the Rate Rider Recovery Period (in months) | 24

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL	# of Customers	8,152	$ 78,073	$ 0.40
GENERAL SERVICE LESS THAN 50 KW	kWh	41,865,678	$ 44,230	$ 0.0005
GENERAL SERVICE 50 TO 4,999 KW	kW	212,284	$ 87,126	$ 0.2052
STREET LIGHTING	kW	2,475	$ 937	$ 0.1893
UNMETERED	kWh	251,508	$ 266	$ 0.0005
LARGE USER	kW	60,000	$ 24,625	$ 0.2052
Total			**$ 235,257**	

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in months) | 24

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account 1568 Balance	Rate Rider for Account 1568
RESIDENTIAL	# of Customers	8,152	$ 40,646	0.21
GENERAL SERVICE LESS THAN 50 KW	kWh	41,865,678	$ 39,732	0.0005
GENERAL SERVICE 50 TO 4,999 KW	kW	212,284	$ 57,017	0.1343
STREET LIGHTING	kW	2,475	$ 65,313	13.1960
UNMETERED	kWh	251,508	$ -	-
LARGE USER	kW	60,000	$ -	-
Total			**$ 202,708**	

Specified Customer Revenue Variance Account

The Parties agree to the creation of a Specified Customer Revenue Variance Account that will record the difference between forecast and actual revenues solely from the Large Use customer forecast in NOTL Hydro's application. As explained in the prefiled evidence, the reason for the account is that the load forecast for the one customer that will be included in the Large Use Customer Class is uncertain, and it is quite large relative to NOTL Hydro's total load. The Parties agree that it is appropriate that neither the distributor nor customers bear the benefit or burden of currently unknown variances in the large customer's load, and that a variance account is appropriate. The name of the large customer is set out in Appendix "J" to the Settlement Proposal. The Parties agree that it would be appropriate for Appendix "J" to be filed confidentially with the OEB, pursuant to the OEB's Practice Direction on Confidential Filings.

The account will record the annual difference between forecast revenues from this customer versus the actual revenues from the customer at the current or adjacent location (including any standby charges), regardless of the number of accounts it has, and the rate class(es) they ultimately may end up within The Parties agree that the new account will be cleared annually via a rate rider which will be in effect for one year by allocating the balance of the variance account across customer classes based on customer class revenue. Within each customer class it will be allocated across customers based on kwh.. The Parties agree that the clearance of the account will include the Large Use customer class. A draft updated Accounting Order for the Specified Customer Revenue Variance Account is attached as Appendix "I".

Retail Service Cost Variance Account

Consistent with the expected outcome from the EB-2015-0304 Report of the Ontario Energy Board on Energy Retailer Service Charges, issued on November 29, 2018, the Parties agree that NOTL Hydro will discontinue its Retail Service Cost Variance Account as of May 1, 2019.

E*vidence:* The evidence in relation to this issue includes the following:

Exhibit 9	Deferral and Variance Accounts
I.9.STAFF.66-74	Staff Interrogatories #66-74
I.9.SEC.34	SEC Interrogatory #34
I.9.VECC.47-49	VECC Interrogatories #47-49
Supplementary Responses	Supplementary Responses to Staff #67 and 71
Exhibit 9 Additional Evidence	Additional Evidence re. Group 2 and LRAM Rate Riders

10. Other

(a) Is the proposed microFIT rate appropriate?

The Parties agree that the proposed MicroFIT monthly service charge of $10.00 is appropriate.

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design
I.8.VECC.46	VECC Interrogatory #46

(b) Are the proposed changes to the Specific Service Charges appropriate?

The Parties agree with the Service Charges proposed in NOTL Hydro's application, with two changes.

First, the Retail Service Charges will be updated to reflect expected updates in the EB-2015-0304 Report of the Ontario Energy Board on Energy Retailer Service Charges, issued on November 29, 2018.

Second, NOTL Hydro will update its approved Service Charges (effective May 1, 2019) to reflect the expected changes resulting from the OEB's Review of Customer Service Rules (EB-2017-0183). NOTL Hydro will remove the Collection of Account, Install/Remove load control device – during regular business hours, and Install/Remove load control device – after regular business hours charges, and will change the name of the "Disconnect/Reconnect" Charge to "Reconnection" and will ensure that its late payment charge is reflected as 1.5% per month (effective annual rate 19.56% per annum or 0.04896% compounded daily).

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design
I.8.VECC.46	VECC Interrogatory #46

(c) Is the proposed transmission gross load billing appropriate?

There is no agreement on this item. The Parties agree that the Board should determine all issues related to this item.

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design (Additional Evidence)

(d) Is the proposed distribution standby charge appropriate?

NOTL and VECC accept NOTL Hydro's proposal for a Distribution Standby Charge as set out in the Additional Rate Design Evidence (Exhibit 8), with one change. The change is that the minimum level to which the Distribution Standby Charge will apply is 500kW. As set out in response to SEC Supplementary Interrogatory #3, NOTL Hydro's evidence is that there is one customer who will be immediately impacted by the Distribution Standby Charge, and that customer supports the proposed charge. SEC takes no position on this issue.

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design (Additional Evidence)
I.8.SEC.46	SEC Interrogatory #33
Supplementary Responses	SEC Supplementary Interrogatory #3

Appendix "A"- Approved Issues List and Table of Concordance

Approved Issues List
EB-2018-0056
Niagara-on-the-Lake Hydro Inc.

1. PLANNING

1.1 Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- customer feedback and preferences
- productivity
- benchmarking of costs
- reliability and service quality
- impact on distribution rates
- trade-offs with OM&A spending
- government-mandated obligations, and
- the objectives of the Applicant and its customers

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- customer feedback and preferences
- productivity
- benchmarking of costs
- reliability and service quality
- impact on distribution rates
- trade-offs with capital spending
- government-mandated obligations, and
- the objectives of the Applicant and its customers.

2. REVENUE REQUIREMENT

2.1 Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

2.2 Has the Revenue Requirement been accurately determined based on these elements?

3. LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?

3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?

3.3 Are the applicant's proposals for rate design appropriate?
3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?
3.5 Are the proposed Retail Transmission Service Rates appropriate?

4. ACCOUNTING

4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?
4.2 Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, the continuation of existing accounts, and the request for a new revenue variance account for the Large User customer appropriate?

5. OTHER

5.1 Is the proposed microFIT rate appropriate?

5.2 Are the proposed changes to the Specific Service Charges appropriate?

5.3 Is the proposed transmission gross load billing appropriate?

5.4 Is the proposed distribution standby charge appropriate?

Concordance Table between Issues List and Settlement Proposal

Issue from Issues List	Where this is addressed in the Settlement Proposal
1.1 Capital Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to: ➢ customer feedback and preferences ➢ productivity ➢ benchmarking of costs ➢ reliability and service quality ➢ impact on distribution rates ➢ trade-offs with OM&A spending ➢ government-mandated obligations, and ➢ the objectives of the Applicant and its customers	Item 1 – Rate Base Item 2 – Distribution System Plan and capital expenditures
1.2 OM&A Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to: ➢ customer feedback and preferences ➢ productivity ➢ benchmarking of costs ➢ reliability and service quality ➢ impact on distribution rates ➢ trade-offs with capital spending ➢ government-mandated obligations, and ➢ the objectives of the Applicant and its customers.	Item 3 – Operating Costs
2.1 Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices? **2.2** Has the Revenue Requirement been accurately determined based on these elements?	Item 1 – Rate Base Item 2 – Distribution System Plan and capital expenditures Item 3 – Operating Costs Item 4 – Cost of Capital Item 5 – Load Forecast and Other Revenue Item 6 – Revenue Deficiency/Sufficiency

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?	Item 5 – Load Forecast and Other Revenue
3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?	Item 7 – Cost Allocation
3.3 Are the applicant's proposals for rate design appropriate?	Item 8 – Rate Design
3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?	Item 8 – Rate Design
3.5 Are the proposed Retail Transmission Service Rates appropriate?	Item 8 – Rate Design
4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?	Throughout
4.2 Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, the continuation of existing accounts, and the request for a new revenue variance account for the Large User customer appropriate?	Item 9 – Deferral and Variance Accounts
5.1 Is the proposed microFIT rate appropriate?	Item 10(a) – Other
5.2 Are the proposed changes to the Specific Service Charges appropriate?	Item 10(b) – Other
5.3 Is the proposed transmission gross load billing appropriate?	Item 10 (c) – Other
5.4 Is the proposed distribution standby charges appropriate?	Item 10(d) - Other

Appendix "B" - NOTL Hydro 2019 Revenue Requirement Work Form 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix "C"- NOTL Hydro 2019 Filing Requirements Chapter 2 Appendices 20190110 & NOTL Hydro 2019 Filing Requirements Chapter 2 Appendix 2C 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “D” - NOTL Hydro 2019 Load Forecast Wholesale 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “E”- NOTL Hydro 2019 Tariff Schedule and Bill Impact Model 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “F”- NOTL Hydro 2019 DVA Continuity Schedule CoS 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “G” - NOTL Hydro 2019 Cost Allocation Model RUN3 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix "H" - Impact of Including ICM in Distribution Revenue at Existing Rates

2019 Rates with ICM included in Revenue at Existing Rates

	Distribution Rates		Revenue less Transformer Ownership			
Customer Class	Monthly Service Charge	Volumetric Rate	Monthly Service Charge	Volumetric Revenues	Tranformer Allowance	Revenue less Transformer Ownership
Residential	$ 30.47	$ - /kWh	$ 2,980,834	$ -	$ -	$ 2,980,834
GS<50	$ 39.41	$ 0.0133 /kWh	$ 634,501	$ 556,814	$ -	$ 1,191,315
GS>50	$ 281.65	$ 2.6169 /kW	$ 442,754	$ 555,525	$ 11,086	$ 987,193
Unmetered	$ 21.20	$ 0.0072 /kWh	$ 6,614	$ 1,811	$ -	$ 8,425
Streetlights	$ 7.85	$ 7.3887 /kW	$ 205,993	$ 18,285	$ -	$ 224,279
Large User	$ 2,829.49	$ 2.6169 /kW	$ 33,954	$ 157,014	$ 33,600	$ 157,368
			$ 4,304,651	**$ 1,289,449**	**$ 44,686**	**$ 5,549,413**

2019 Rates with ICM excluded from Revenue at Existing Rates

	Distribution Rates		Revenue less Transformer Ownership			
Customer Class	Monthly Service Charge	Volumetric Rate	Monthly Service Charge	Volumetric Revenues	Tranformer Allowance	Revenue less Transformer Ownership
Residential	$ 30.97	$ - /kWh	$ 3,029,749	$ -	$ -	$ 3,029,749
GS<50	$ 39.41	$ 0.0131 /kWh	$ 634,501	$ 548,440	$ -	$ 1,182,941
GS>50	$ 281.65	$ 2.4248 /kW	$ 442,754	$ 514,745	$ 11,086	$ 957,499
Unmetered	$ 21.20	$ 0.0080 /kWh	$ 6,614	$ 2,012	$ -	$ 8,626
Streetlights	$ 7.85	$ 7.3887 /kW	$ 205,993	$ 18,285	$ -	$ 224,279
Large User	$ 3,790.12	$ 2.4248 /kW	$ 45,481	$ 145,488	$ 33,600	$ 190,969
			$ 4,365,093	**$ 1,228,971**	**$ 44,686**	**$ 5,594,064**

Appendix "I" -
Draft Accounting Order for Specified Customer Revenue Variance Account

Niagara-on-the-Lake Hydro Inc.

DRAFT ACCOUNTING ORDER

Specified Customer Revenue Variance Account

The Specified Customer Revenue Variance Account is established with respect to a Specified Customer that is initially classified in the Large User rate class in NOTL Hydro's 2019 cost of service rate application. This variance account remains applicable irrespective of the Specified Customer's rate classification(s), or if they have multiple accounts at the current or adjacent location.

On a monthly basis the demand revenue from the Specified Customer will be reviewed and any variance from a demand of 5,000 kW will result in a journal entry in the account. Demand revenue will include any standby revenue billed due to the Specified User's behind-the-meter generation displacing demand revenue. The amount recorded will be the difference between actual revenue collected from the Specified Customer and the amount of revenue forecasted to be collected for that period, based on the approved fixed and variable rates in effect during that period

If the demand exceeds 5,000 kW then the entry is:

Dr. 4305 Regulatory Debit

Cr. 1508- sub-account Specified Customer Revenue Variance Account

If the demand is lower than 5,000 kW then the entry is:

Dr. 1508 – sub-account Specified Customer Revenue Variance Account
Cr. 4310 Regulatory Credit

Following the audit of the account's year-end balance, NOTL Hydro will request disposition of the account via a rate rider which will be in effect for one year. A rate rider will be determined for all customer classes including the Specified Customer who is currently forecasted in Large User class.

Assuming the variance account has a credit balance, the monthly recording of the billing of the rate rider will be:

Dr. 1508-sub-account Specified Customer Revenue Variance Account
Cr. 4305 Regulatory Debit

Dr. 4080 Distribution Revenue

Cr. 1100 Customer Accounts Receivable

If the variance account has a debit balance, the entries would be:

Dr. 4310 Regulatory Credit
Cr. 1508-sub-account Specified Customer Revenue Variance Account
Dr. 1100 Customer Accounts Receivable
Cr. 4080 Distribution Revenue

Following the audit of the year in which the last month of the rate rider was billed, any remaining balance in the variance account will be included in the balance requested for disposition in a future period. The rate rider will be determined by allocating the balance of the variance account across customer classes based on customer class revenue. Within each customer class it will be allocated across customers based on kwh.

Appendix "J" - CONFIDENTIAL

Name of Large Use Customer for the Specified Customer Revenue Variance Account

The customer’s name is

34870543.1

TAB 4

TAB i



Exhibit 4

Operations, Maintenance & Administration

Table of Contents

2.4.1 Overview of Cost Trends 4
2.4.1.1 Overview of Operating Expenses 4
2.4.2 Summary and Cost Driver Tables 9
2.4.2.1 Cost Driver Tables 9
2.4.2.2 OM&A Variance Analysis 14
2.4.2.3 OM&A per Customer 18
2.4.3 Program Delivery Costs with Variance Analysis 21
2.4.3.0 Program Variance Analysis 22
2.4.3.1 Workforce Planning and Employee Compensation 24
2.4.3.2 Shared Services and Corporate Cost Allocation 30
2.4.3.3 Purchases of Non-Affiliate Services 33
2.4.3.4 One-time Costs 36
2.4.3.5 Regulatory Costs 36
2.4.3.6 Low Income Energy Assistance Programs 39
2.4.3.7 Charitable and Political Donations 41
2.4.4 Depreciation, Amortization & Depletion 42
2.4.4.1 Depreciation Rates and Methodology 42
2.4.4.2 Depreciation Expense 48
2.4.4.3 Asset Retirement Obligations 49
2.4.4.4 Half Year Rule 49
2.4.4.5 Depreciation/Amortization Policy 49
2.4.4.6 Components 50
2.4.4.7 Regulatory Accounting Changes for Depreciation Expense 50
2.4.5 Taxes or Payments In Lieu of Taxes (PILs) and Property Taxes 51
2.4.5.1 Overview of PILs 51
2.4.5.2 Latest Filed Tax Return, Tax Assessments and Correspondence 53
2.4.5.3 Calculation of Tax Credits 54
2.4.5.4 Other Additions and Deductions 54
2.4.5.5 Non-recoverable and Disallowed Expenses (OEB Ref 2.4.5.1) 56
2.4.5.6 Integrity Checklist 57
2.4.6 Conservation and Demand Side Management 58
2.4.6.1 Overview of CDM 58
2.4.6.2 Lost Revenue Adjustment Mechanism (OEB Ref 2.4.6.1) 58

2.4.6.3 Disposition of the LRAMVA....58

Appendix 61

List of Appendices....61

2.4.1 Overview of Cost Trends

2.4.1.1 Overview of Operating Expenses

Operations, Maintenance and Administration (OM&A) expenses included in the calculation of Niagara-on-the-Lake Hydro Inc.'s (NOTL Hydro's) revenue requirement are those determined to be reasonable in amount and necessary for and related to the provision of utility service or in some way a benefit to customers.

In this Exhibit, the operating costs consist of the required expenditures necessary to maintain and operate NOTL Hydro's distribution system and transmission station assets, the costs associated with metering, billing, collecting from its customers, the costs associated with ensuring all stakeholders safety (public and employees) and costs to maintain the distribution business service quality and reliability standards set by the regulating bodies.

By way of this 2019 Cost of Service rate application, NOTL Hydro is proposing an OM&A amount of $2,974,186 for the 2019 Test Year.

Table 4.1: OM&A 2014-2019

	Board Approved	2014	2015	2016	2017	2018	2019
Operations	$532,044	$491,400	$548,540	$654,295	$673,867	$679,413	$715,973
Maintenance	$416,132	$412,259	$451,578	$476,273	$414,737	$473,074	$449,790
Billing and Collecting	$534,260	$559,556	$601,150	$547,188	$573,154	$597,617	$632,867
Community Relations	$17,800	$578	$758	$9,700	$4,161	$12,765	$11,485
Administrative and General	$655,026	$744,411	$721,094	$844,735	$929,202	$1,141,995	$1,164,070
Total	**$2,155,262**	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
%Change (year over year)		2.5%	5.2%	9.0%	2.5%	11.9%	2.4%

As shown in Table 4.2 below, NOTL Hydro's increase in OM&A spending from its 2014 Cost of Service to the 2019 Test Year is $818,923 or 38% over the 5 years.

Table 4.2: 2014 Board Approved vs. 2019 Test Year OM&A

	Board Approved	2019	Change
Operations	$532,044	$715,973	$183,929
Maintenance	$416,132	$449,790	$33,658
Billing and Collecting	$534,260	$632,867	$98,608
Community Relations	$17,800	$11,485	-$6,315
Administrative and General	$655,026	$1,164,070	$509,044
Total	**$2,155,262**	**$2,974,186**	**$818,923**
%Change (year over year)			38.0%

The 38% increase in OM&A is the result of a combination of inflation, growth and increasing complexity of operations.

Inflation is estimated to be 7% from 2014-2019 using the inflation factors provided each year by the OEB and less the productivity factor of 0.30%. NOTL Hydro has had a PEG rating of 3 in each of these years. For 2019 we have used the average inflation over the past four years as the best estimate.

Table 4.3: Inflation less productivity 2015-2019

Year	2015	2016	2017	2018	2019	Total
Inflation	1.30%	1.80%	1.60%	0.90%	1.40%	7.00%

Growth can be measured in a number of ways. An increase in customers increases operating costs as there are more customers to have service installed, to be billed monthly and to be responded to. During the 2014-2019 period NOTL Hydro increased its customer service staff by one new full-time customer service representative. The increase in customers also leads to an increase in load, increasing demand on NOTL Hydro assets which requires maintenance be increased accordingly. During the 2014-2019 period NOTL Hydro will have installed two new transformers at its transmission station to manage the increasing load and to ensure redundancy of supply. Finally, an increase in assets (net book value) requires increased maintenance. During the 2014-2019 period NOTL Hydro added one new lineman.

Table 4.4: NOTL Hydro Growth Indicators

Measure	2014	2019	% Increase
# Customers	8,574	9,649	12.5%
Load (MWh)	189,356	223,061	17.8%
Assets ($000's)	23,501	30,657	30.5%
Average			20.3%

NOTL Hydro is attributing 20.3% of its increase in OM&A to growth factors note above.

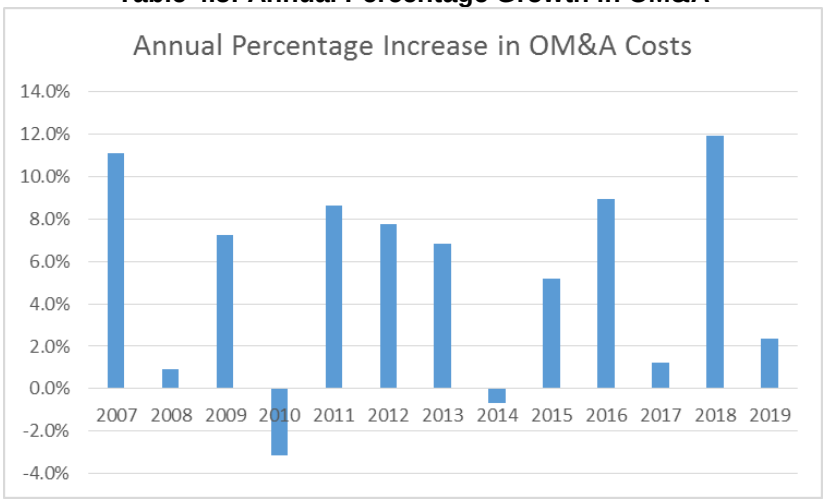
Some of the increase in OM&A is the result of changes in operations or the regulatory environment that increase both revenues and expenses. Just looking at expenses in isolation does not give the full story. Some examples in the case of NOTL Hydro include:

- Pole rental costs are forecast to increase $13.3 thousand from 2017 to 2019 due to the increase in the province-wide pole rental rate. NOTL Hydro has forecast an increase in pole rental revenue of $70 thousand which serves to reduce rates.
- The net increase in the Utilismart service is $29.4 thousand. Some of this will be recovered by the requested increase in the monthly MicroFIT charge which will generate around $8 thousand per year. The rest is increased services to our large customers who will be able to access the data.

Together, these two items represent a $42.7 or 2% increase in OM&A costs.

One of the challenges with OM&A in a smaller LDC is the "lumpiness" of the change. Some years, like 2018, may have several drivers of expense increases while other years, such as 2017 and the 2019 forecast, the changes are quite small. This can be seen in the table below. A longer time horizon yields a different analysis. For instance, from 2006-2019 the average annual increase in OM&A expenses is 5.3%. From 2014-2019 the average annual increase is 5.9%. This would indicate that the higher increases in 2014-2019 is a matter of "timing" and that 3% of the increase from 2014-2019 (5.9% - 5.3% * 5 years = 3%) is a matter of looking at the costs over a short time horizon.

Table 4.5: Annual Percentage Growth in OM&A



The remaining driver of increases in OM&A costs is the increasing complexity of providing electricity distribution services in Ontario. Some of these complexities include:

- Increased expectations by customers. NOTL Hydro introduced its Outage Management System in 2015 so that it can respond to outages without relying solely on customer calls. Like many LDCs, we now have stories of restoring power before a customer is even aware the power is out.
- Net metering. These are much more time consuming to service than a regular customer or a standalone generator due to the complexity of the calculations. NOTL Hydro now has seven net metering customers across all major customer classes (residential, GS<50 kW and GS>50 kW).
- Increased renewable generation. Excluding net metering, these have grown from 117 in 2014 to 153 in 2018; a 31% increase. Renewable generation is increasing costs in another way as NOTL Hydro adapts its asset base and operations in expectation of much more renewable generation in the future.
- Increased regulatory reporting. The volume and complexity of the RRR and other ad hoc reporting to the OEB has grown substantially from 2014 to 2018.
- Increased labour costs. While the inflation estimate above was 7% the cost of labour at NOTL Hydro has gone up a minimum of 11.8% due to the agreements with unionized staff.
- No winter disconnections. This lead to more write-offs. This is somewhat heightened in Niagara-on-the-Lake as there are Niagara College student tenants whose terms end before the end of the disconnect ban. This also leads to increased costs as more phone calls and other efforts to obtain payments must be undertaken.
- Increased Ministry of Energy programs. New programs such as the OESP and the Affordability Fund all require resources to implement and manage from the context of integrating them within the LDC.

A breakdown of the 2014-2019 increase in OM&A costs would therefore be:

Table 4.6: Breakdown of Increase in OM&A (2014-2019)

Cause	Percentage
Inflation	7%
Growth	20%
Expenses with offsetting revenue	2%
“Timing”	3%
Increase in requirements	6%
Total	**38%**

On a per customer basis the trend in OM&A is as shown in the table below:

Table 4.7: OM&A per Customer

	2014	2015	2016	2017	2018	2019
OM&A	$2,208,203	$2,323,119	$2,532,191	$2,595,121	$2,904,865	$2,974,186
Customers	8,574	8,860	9,134	9,321	9,469	9,649
OM&A per Customer	$ 258	$ 262	$ 277	$ 278	$ 307	$ 308

OM&A per customer is expected to rise 19% between 2014 and 2019. This is consistent with the calculation above as the increase in OM&A per customer is the non-growth increase (inflation, offsetting revenues, requirements, etc.) above.

2.4.2 Summary and Cost Driver Tables

2.4.2.1 Cost Driver Tables

The table below provides a summary of NOTL Hydro's Operations, Maintenance and Administrative ("OM&A") costs as required by the OEB's filing guidelines. This is consistent with Appendix 2-JA.

Table 4.8: Summary of Recoverable OM&A Expenses

Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
	Board Approved	2014	2015	2016	2017	2018	2019
Operations	$532,044	$491,400	$548,540	$654,295	$673,867	$679,413	$715,973
Maintenance	$416,132	$412,259	$451,578	$476,273	$414,737	$473,074	$449,790
SubTotal	**$948,177**	**$903,658**	**$1,000,118**	**$1,130,568**	**$1,088,604**	**$1,152,487**	**$1,165,763**
%Change (year over year)		-4.7%	10.7%	13.0%	-3.7%	1.9%	7.1%
%Change (Test Year vs Last Rebasing Year - Actual)						21.5%	29.0%
Billing and Collecting	$534,260	$559,556	$601,150	$547,188	$573,154	$597,617	$632,867
Community Relations	$17,800	$578	$758	$9,700	$4,161	$12,765	$11,485
Administrative and General+LEAP	$655,026	$744,411	$721,094	$844,735	$929,202	$1,141,995	$1,164,070
SubTotal	**$1,207,085**	**$1,304,545**	**$1,323,001**	**$1,401,623**	**$1,506,517**	**$1,752,377**	**$1,808,422**
%Change (year over year)		-39.5%	1.4%	5.9%	7.5%	25.0%	20.0%
%Change (Test Year vs Last Rebasing Year - Actual)						-18.7%	38.6%
Total	**$2,155,262**	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
%Change (year over year)			5.2%	9.0%	2.5%	11.9%	2.4%

	Board Approved	2014	2015	2016	2017	2018	2019
Operations	$532,044	$491,400	$548,540	$654,295	$673,867	$679,413	$715,973
Maintenance	$416,132	$412,259	$451,578	$476,273	$414,737	$473,074	$449,790
Billing and Collecting	$534,260	$559,556	$601,150	$547,188	$573,154	$597,617	$632,867
Community Relations	$17,800	$578	$758	$9,700	$4,161	$12,765	$11,485
Administrative and General	$655,026	$744,411	$721,094	$844,735	$929,202	$1,141,995	$1,164,070
Total	**$2,155,262**	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
%Change (year over year)		2.5%	5.2%	9.0%	2.5%	11.9%	2.4%

Table 4.9: Summary of Recoverable OM&A Expenses

	Board Approved	2014	Variance	2015	Variance	2016	Variance	2017	Variance	2018	Variance	2019	Variance
Operations	$532,044	$491,400	$40,645	$548,540	$57,140	$654,295	$105,755	$673,867	$19,573	$679,413	$5,546	$715,973	$36,560
Maintenance	$416,132	$412,259	$3,874	$451,578	$39,319	$476,273	$24,695	$414,737	-$61,537	$473,074	$58,338	$449,790	-$23,284
Billing and Collecting	$534,260	$559,556	-$25,296	$601,150	$41,594	$547,188	-$53,962	$573,154	$25,966	$597,617	$24,463	$632,867	$35,250
Community Relations	$17,800	$578	$17,222	$758	$180	$9,700	$8,942	$4,161	-$5,539	$12,765	$8,604	$11,485	-$1,280
Administrative and General	$655,026	$744,411	-$89,385	$721,094	-$23,317	$844,735	$123,641	$929,202	$84,467	$1,141,995	$212,793	$1,164,070	$22,075
Total OM&A Expenses	$2,155,262	$2,208,203	-$52,941	$2,323,119	$114,916	$2,532,191	$209,072	$2,595,121	$62,930	$2,904,865	$309,744	$2,974,186	$69,321
Adjustments for Total non-recoverable items													
Total Recoverable OM&A Expenses	$2,155,262	$2,208,203	-$52,941	$2,323,119	$114,916	$2,532,191	$209,072	$2,595,121	$62,930	$2,904,865	$309,744	$2,974,186	$69,321
Variance from previous year				$114,916		$209,072		$62,930		$309,744		$69,321	
Percent change (year over year)				5.20%		9.00%		2.49%		11.94%		2.67%	
Percent Change: Test year vs. Most Current Actual								20.41%					
Simple average of % variance for all years													6.26%
Compound Annual Growth Rate for all years													6.1%
Compound Growth Rate (2014 vs. 2017 Actuals)								5.53%					

In accordance with the OEB's minimum filing requirements, the table below outlines the key drivers of OM&A costs over the 2014 to 2019 period.

Table 4.10: Recoverable OM&A Cost Driver Table (Appendix 2-JB)

Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Opening Balance	$2,155,262	$2,208,203	$2,323,119	$2,532,191	$2,595,121	$2,904,865
Continuous Cost Increases						
Wage increase		$42,767	$69,517	$71,121	$42,850	$43,707
Inflation		$11,287	$17,696	$17,315	$9,046	$20,721
New staff			$31,780	$67,541	$42,000	
Locate costs		$26,000				
Cyber security				$25,000	$5,000	
Utilismart contract				$25,000		
CHEC		$22,300	$4,700			
Variable Costs						
Capitalized labour		-$82,845	$56,124	$19,736	$73,129	$1,316
Transformer St. Mtce		$15,000	$13,000	-$36,000	$46,000	-$25,000
Tree trimming		$23,500	$0	-$40,000	$45,000	
Underground services		$30,000	-$17,000			
One-time Costs						
Regulatory costs	$52,941	-$42,353				$46,198
Severance		$42,000	-$42,000			
Micro-grid study			$100,000	-$100,000		
Temporary staff		$30,490	-$11,942	-$18,548	$25,000	
Other		-$3,230	-$12,803	$31,765	$21,719	-$17,621
Decrease in OM&A offseting increase						
Closing Balance	$2,208,203	$2,323,119	$2,532,191	$2,595,121	$2,904,865	$2,974,186
OM&A Summay Integrity Check	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
Difference	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Cost Drivers

The cost drivers have been organized into three categories: those that have a continuous impact on costs, those that vary from year to year so could have a positive or negative impact on costs (though can still be going up over time) and those that are of a one-time nature.

Continuous Cost Increases

Wage Increases – NOTL Hydro is a unionized company. Non-management staff are members of IBEW Local 636 and their wages are subject to the union agreements. There are two agreements; one for line and engineering staff and one for office workers. However, the agreements are kept identical other than specific provisions that apply to one group or the other. The five-year time period of this analysis is covered by two collective agreements; 2013-2016 and 2016-2020. The following are the annual wage increases built into the agreements:

Table 4.11: Annual Wage Increases under Union Contract

	2014	2015	2016	2017	2018	2019
Annual Wage Increase	2.8%	2.8%	2.1%	2.1%	2.0%	2.0%

Management staff receive the same wage increase as unionized staff but they also receive a bonus of 10-15% of pay based on a combination of personal and company performance. Management staff may also receive a wage adjustment to keep their wages competitive or to reflect the changes in their responsibilities. Changes in personnel may also affect the pay for a given management position. The annual increases will therefore often be higher overall than the contract increase.

Inflation – Inflation has been calculated at the OEB PEG performance rate for all non-labour costs.

New staff – In 2016 and 2017 NOTL Hydro hired a new Customer Service Representative and a new Lineman due to the overall growth in the company business.

Locate Costs – The costs of locates has risen with increased growth and activity. The increase in 2015 was the most significant.

Cyber security – Cyber security is a growing and significant threat to LDCs such as NOTL Hydro. The risks include loss of private customer or employee information, third party access to system controls and general business disruptions. The OEB has recognized Cyber Security a significant concern and developed reporting and monitoring responsibilities. In 2017, NOTL Hydro conducted a Cyber Security audit as a best practice. The cost of this, the resulting increase in costs as findings were corrected and new processes implemented and the new requirements of the OEB mean ongoing new costs.

Utilismart – In 2017, NOTL Hydro signed a new contract with Utilismart for new services relating to the capture and presentation of meter data from large customers and generators. This will assist NOTL Hydro in meeting its reporting requirements and will allow us to provide a better service to the large customers by given them access to this data with the Utilismart tools.

CHEC - In 2015, NOTL Hydro joined CHEC (Cornerstone Hydro Electric Concepts Inc.) at a cost of around $25k per year. NOTL Hydro has found this membership beneficial with cost savings in certain areas (surveys, the CHEC model for this application) and with the operational knowledge from working with other similar sized LDCs closely. NOTL Hydro is not a member of the EDA (Electricity Distributors Association).

Variable Cost Increases

Capitalized Labour - Line, engineering and management staff will work on capital projects at various times. The cost of these services is capitalized. Depending on the amount of capital work in any given year the cost capitalized will vary; as will inversely the amount charged to OM&A. While NOTL Hydro tries to keep the amount of capital work consistent it will vary each year depending on the nature of the planned capital work that year, the customer capital work required and the amount of general service work.

Transformer Station Maintenance – NOTL Hydro owns two transmission stations. The cost of required maintenance at these stations will vary from year to year depending on the nature of the work to be done. There is a large increase in 2018 due to the repairs needed on the tap changer of the old 25 MVA transformer.

Tree Trimming – NOTL Hydro uses a three year rotation to trim the trees along its primary lines. This service is contracted to local Niagara companies and used to be done on an annual or biannual basis. In 2017, the section being maintained was smaller than in previous years so the cost was significantly lower. Going forward, NOTL Hydro has awarded a three year contract so the annual costs should be more stable.

Underground Services – NOTL Hydro does not have the equipment or training for underground electrical services so it contracts these to local suppliers. The amount of service work required will vary from year to year depending on customer needs and any power issues. This service work is awarded separately from the annual capital work through which overhead 4 kV lines are converted to underground 27.6 kV lines.

One-Time Cost Increases

Regulatory Costs – The costs of the cost of service rate application process are incurred once every five years. This amount represents one-fifth of total costs incurred as it is recognized that for rate setting purposes these costs will be amortized over five years.

Severance – In 2015, NOTL Hydro let go a management employee and incurred a $42k severance cost. There is a corresponding reduction in costs in 2016.

Microgrid Study – In 2016, NOTL Hydro conducted its own study on the potential for creating micro grids within Niagara-on-the-Lake. The conclusion was that they were not feasible at this time. There is a corresponding reduction in costs in 2017.

Temporary Staff – In 2015 and 2016, NOTL Hydro had temporary staff (college and university students) providing assistance to the front office, line crew and CDM staff. With the hiring of new staff in 2016 and 2017 this temporary assistance was no longer required. In 2018, one of the finance staff went on maternity leave. The replacement, hired through an agency, will cost an additional $25k for each six-month period.

2.4.2.2 OM&A Variance Analysis

Table 4.12: 2014 Board Approved vs. 2014 Actual

	Board Approved	2014	$ Change	% Change
Operations	$532,044	$491,400	-$40,645	-7.6%
Maintenance	$416,132	$412,259	-$3,874	-0.9%
Billing and Collecting	$534,260	$559,556	$25,296	4.7%
Community Relations	$17,800	$578	-$17,222	-96.8%
Administrative and General	$655,026	$744,411	$89,385	13.6%
Total	**$2,155,262**	**$2,208,203**	**$52,941**	2.5%

Overall, OM&A was 2.5% higher in 2014 than the proposed spend approved by the OEB and used to set rates. Operations was lower by $41k or 7.6%. Operations costs will vary from year to year depending on the amount of capital work to be performed by line staff. Maintenance costs were lower by $4k or 0.9% so were basically at the same level as approved by the OEB. Billing

and Collecting was higher by $25k or 4.7% due to higher than normal write-offs; primarily from cleaning up the outstanding cheque balances. Community Relations was lower by $17k or 97% as this budget was largely unspent. General and Administrative costs were $89k or 13.6% higher than Board approved primarily due to costs related to the 2014 cost of service rate application.

Table 4.13: 2014 Actual vs. 2015 Actual

	2014	2015	$ Change	% Change
Operations	$491,400	$548,540	$57,140	11.6%
Maintenance	$412,259	$451,578	$39,319	9.5%
Billing and Collecting	$559,556	$601,150	$41,594	7.4%
Community Relations	$578	$758	$180	31.1%
Administrative and General	$744,411	$721,094	-$23,317	-3.1%
Total	**$2,208,203**	**$2,323,119**	**$114,916**	5.2%

Overall, OM&A was higher in 2015 than in 2014 by 5.2%. Operations costs were higher by $57k due to an increase in locate costs by $26k and an increase in GIS system costs of $16k as the provider billed for both 2014 and 2015 in 2015. Maintenance costs were higher by $39k primarily due to internal and external costs related to fixing an outage on a main underground line. Billing and Collecting costs were $42k higher due to severance pay when the previous Manager of this department was replaced. General and Administrative costs were $23k or 3.1% lower than 2014 as costs related to the 2014 cost of service rate application were no longer being incurred.

Table 4.14: 2015 Actual vs. 2016 Actual

	2015	2016	$ Change	% Change
Operations	$548,540	$654,295	$105,755	19.3%
Maintenance	$451,578	$476,273	$24,695	5.5%
Billing and Collecting	$601,150	$547,188	-$53,962	-9.0%
Community Relations	$758	$9,700	$8,942	1180.3%
Administrative and General	$721,094	$844,735	$123,641	17.1%
Total	**$2,323,119**	**$2,532,191**	**$209,072**	9.0%

Overall, OM&A was higher in 2016 than in 2015 by 9.0%. Operations was higher by $106k or 19.3%. $50k of this was increased labour due to less time spent on capital projects by internal staff; this varies from year to year depending on the nature of the capital projects and customer service requirements. The remainder of the increase was a one-time study on the potential use of micro-grids to reduce customer costs; some of these costs were also booked to administration.

As this study was a one-time event, was fully expensed and not in a rebasing year, the cost of the study has been fully absorbed by the shareholder. Maintenance was up $25k or 5.5% due to higher transmission station maintenance. Billing and Collecting was down $54k or 9.0% as 2015 had the $42k severance payment. In addition, lower labour costs due to a maternity leave were offset by higher bad debt expenses from an illegal grow-op. General and Administration costs were higher due the micro-study referred to above and the cost of the retirement and then hiring a new VP Finance.

Table 4.15: 2016 Actual vs. 2017 Actual Year

	2016	2017	$ Change	% Change
Operations	$654,295	$673,867	$19,573	3.0%
Maintenance	$476,273	$414,737	-$61,537	-12.9%
Billing and Collecting	$547,188	$573,154	$25,966	4.7%
Community Relations	$9,700	$4,161	-$5,539	-57.1%
Administrative and General	$844,735	$929,202	$84,467	10.0%
Total	**$2,532,191**	**$2,595,121**	**$62,930**	2.5%

Overall, OM&A was higher in 2017 than in 2016 by 2.5%. Operations costs were largely unchanged with 3% or $20k growth. Maintenance was down $62k due to lower station maintenance, this will vary from year to year based on needs, and the tree trimming contract which was $40k lower in 2017 due to it being the easiest section of a three year rotation. Billing and Collecting was up 4.7% or $26k with the cost of a new Customer Service Representative being somewhat offset by bad debt expense which was down $47k. Administrative and General Costs were up 10% or $84k due to a cyber security audit and increased IT costs related to cyber security.

Table 4.16: 2017 Actual vs. 2018 Bridge Year

	2017	2018	$ Change	% Change
Operations	$673,867	$679,413	$5,546	0.8%
Maintenance	$414,737	$473,074	$58,338	14.1%
Billing and Collecting	$573,154	$597,617	$24,463	4.3%
Community Relations	$4,161	$12,765	$8,604	206.8%
Administrative and General	$929,202	$1,141,995	$212,793	22.9%
Total	**$2,595,121**	**$2,904,865**	**$309,744**	11.9%

Overall, OM&A is expected to be higher in the 2018 Bridge Year than in 2017 by 11.9%. Operations costs are forecast to be flat. The transfer of the cost of the VP Operations to Administration is being offset by an increase in labour as less allocation to capital work is expected. This is not a change in accounting policy but a change in work practice. Maintenance is up by $58k or 14.1% as the annual tree trimming budget returned to its normal level and the additional costs incurred to fix the tap changer on the T2 transformer at NOTL station. Billing and Collecting is up by $24k or 4.3% due to additional services to be supplied by Utilismart which will allow NOTL Hydro to improve the electricity usage information being supplied to its larger customers and generators. Administration is up by $213k or 22.9% due to the additional cost of the VP Operations and increased staffing costs from maternity coverages.

Table 4.17: 2018 Bridge Year vs. 2019 Test Year

	2018	2019	$ Change	% Change
Operations	$679,413	$715,973	$36,560	5.4%
Maintenance	$473,074	$449,790	-$23,284	-4.9%
Billing and Collecting	$597,617	$632,867	$35,250	5.9%
Community Relations	$12,765	$11,485	-$1,280	-10.0%
Administrative and General	$1,141,995	$1,164,070	$22,075	1.9%
Total	**$2,904,865**	**$2,974,186**	**$69,321**	2.4%

Overall, OM&A is expected to be higher in the 2019 Test Year than in the 2018 Bridge Year by 2.4%. Operations is up by $37k or 5.4% primarily due to higher pole rental fees to be paid to Bell. Billing and collecting is up by $35k or 5.9% due to increased meter reading costs with more interval meters and the use of Utilismart. Administration is up by $22k or 1.9% due to the increase in regulatory costs.

2.4.2.3 OM&A per Customer

The OEB's Appendix 2-L Recoverable OM&A Cost per Customer and per FTE calculates the cost per customer per full time employee. This information is shown in the table below and covers the 2014 to 2019 period:

Table 4.18: Recoverable OM&A Cost per Customer and per FTE

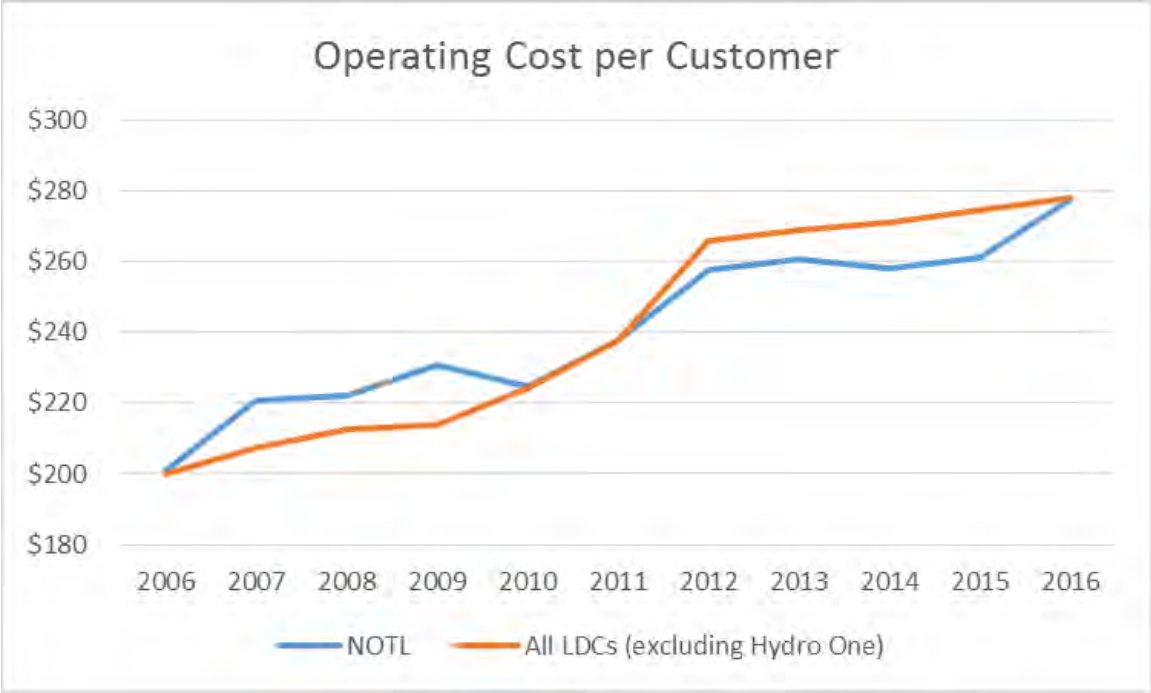
	2014 Board Approved	2014	2015	2016	2017	2018	2019
Reporting Basis							
OM&A Costs							
O&M	$ 1,500,236	$ 1,463,792	$ 1,602,025	$ 1,687,456	$ 1,665,919	$ 1,762,870	$ 1,810,116
Admin Expenses	$ 655,026	$ 744,411	$ 721,094	$ 844,735	$ 929,202	$ 1,141,995	$ 1,164,070
Total Recoverable OM&A	$ 2,155,262	$ 2,208,203	$ 2,323,119	$ 2,532,191	$ 2,595,121	$ 2,904,865	$ 2,974,186
Number of Customers [2,4]	8,522	8,574	8,860	9,134	9,321	9,469	9,649
Number of FTEs [3,4]	19.10	16.03	17.45	17.48	17.60	18.08	18.00
Customers/FTEs	446.18	534.95	507.80	522.49	529.66	523.61	536.06
OM&A cost per customer							
O&M per customer	176	171	181	185	179	186	188
Admin per customer	77	87	81	92	100	121	121
Total OM&A per customer	253	258	262	277	278	307	308
OM&A cost per FTE							
O&M per FTE	78,546	91,329	91,819	96,531	94,663	97,486	100,562
Admin per FTE	34,295	46,446	41,329	48,323	52,800	63,152	64,671
Total OM&A per FTE	112,841	137,775	133,148	144,854	147,463	160,638	165,233

The OM&A costs per customer in the Test Year have increased 22% since the 2014 Board Approved costs and 19% compared to the 2014 actual results. Half of this increase can be attributed to inflation. The remainder of the increase can be attributed to the increased investment in the NOTL Hydro system (new transformers, automated switches and reclosures, asset management systems, etc.) that create additional operating costs as well as increased demands on LDCs (growing renewable distributed generation, net metering, new provincial tariffs, more customer communications and incremental regulatory requirements); all of which increase costs.

According to the OEB's published 2016 Yearbook, the total cost per customer provincial average was $431. However, if Hydro One is removed from this calculation the provincial average becomes $278. NOTL Hydro's total cost per customer average was $278.

A comparison of cost per customer between NOTL Hydro and the average of the other LDCs, excluding Hydro One, is below:

Chart 4.19: Operating Cost per Customer



Total cost per customer is calculated as:

$$= \frac{\text{Operating Expenses}}{\text{Average Number of Customers}}$$

OM&A costs per FTE have increased 46% over 2014 Board approved costs ($112,841) and 20% over 2014 actual results ($137,775) to a forecast $165,233 in 2019. The Board approved FTE of 19.1 was reduced by 2.8 FTE in the actual 2014 due to a combination of layoffs, retirements and long term disabilities. The trend since 2014 has been increasing OM&A per FTE as NOTL Hydro has used outsourcing and productivity to improve performance.

Some examples of outsourcing and cost-sharing over the past five years have included:

- Bill printing has been outsourced to ERTH.
- The costs of the customer satisfaction and safety surveys are being shared with other CHEC members in order to keep the actual cost increases lower than if NOTL Hydro acted alone.
- The outage management system is being managed by Savage Data.

- All the changes that have been required in the customer billing systems to accommodate the changing requirements of the Ministry of Energy have been implemented in co-operation with other UCS members in order to keep the overall cost increase down.

All these examples serve to increase the OM&A per FTE.

2.4.3 Program Delivery Costs with Variance Analysis

Program Description

In its simplest expression, the job of a local distribution company in Ontario is to keep the lights on and bill its customers on behalf of the full electricity system. NOTL Hydro therefore defines its programs in a manner largely consistent with the breakdown of the OEB in the analysis above:

Operations – Keeping the lights on.

Customer Service – Billing the customer.

Administration – Overall management and administrative support for Operations and Customer Service.

Operations Overview

Operations includes functions classified as both Operations and Maintenance under the OEB record keeping. At NOTL Hydro this includes the line department (staff of 4), the line supervisor and the engineering department (staff of 3). It also includes some key services that are outsourced including tree trimming, transmission station maintenance, some engineering and SCADA management, the control centre, underground service and capital work, some metering and some overhead line service and capital work. In addition to the above outsourced services, key work performed by these departments include outage management, metering, new customer connections, renewable generation connections, system maintenance, capital work, GIS system maintenance, system design, disconnections and customer trouble calls. Considerable time is also spent on safety training and equipment maintenance to ensure the above functions are conducted in a safe and efficient manner.

Customer Service Overview

The Customer service department has a staff of four including one Manager and three Customer Service Representatives. Key activities managed by the department include billing, collecting, customer calls, customer visits at the office and rates management in the CIS system. This department also bills and collects for water and wastewater though that time is charged to the Town of Niagara-on-the-Lake which reduces the overall cost to NOTL Hydro.

Administration

Administration includes the finance department (staff of 2), conservation (staff of 1) and the executive (staff of 3). The conservation manager also manages information technology so his time is charged accordingly. There is no human resources department or staff. Key activities managed by Administration include all finance functions (financial reporting, cash management, treasury, accounts payable, payroll), regulatory requirements, legal, human resources, information technology, conservation, stakeholder relations, reporting to the Board and overall management.

2.4.3.0 Program Variance Analysis

Table 4.20: OM&A Cost by Program

	Board Approved	2014	2015	2016	2017	2018	2019	2019 vs. Board Approved	2019 vs. 2017
Operations	$948,177	$903,658	$1,000,118	$1,130,568	$1,088,604	$1,152,487	$1,165,763	$217,586	$77,160
		-4.7%	10.7%	13.0%	-3.7%	5.9%	1.2%	22.9%	7.1%
							5.2%		
Customer Service	$534,260	$559,556	$601,150	$547,188	$573,154	$597,617	$632,867	$98,608	$59,714
		4.7%	7.4%	-9.0%	4.7%	4.3%	5.9%	18.5%	10.4%
							2.5%		
Administrative and General	$672,826	$744,989	$721,851	$854,435	$933,363	$1,154,760	$1,175,555	$502,729	$242,192
		10.7%	-3.1%	18.4%	9.2%	23.7%	1.8%	74.7%	25.9%
							9.6%		
Total	**$2,155,262**	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**	**$818,923**	**$379,065**
%Change (year over year)		2.5%	5.2%	9.0%	2.5%	11.9%	2.4%	38.0%	17.6%

A more detailed analysis can be seen in Appendix 2-JC.

Operations has grown at an annual rate of 5.2%. Key factors driving this growth in expenses have been the increase in staffing of 14% with the addition of a new lineman in 2017, increased service requirements with customer growth, reduced capital work due to the increase in service requirements and increased maintenance at the transmission stations. Operations costs would have shown faster growth but for the transfer of the VP Operations costs to Administration.

Material drivers in the change in Operations costs include:

Table 4.21: Operations Program Costs Drivers

Cost	Variance since Board Approved 2014	Variance since 2017	Explanation
Distribution sub-stations	$53,690	$18,984	Increased maintenance at the 2 transmission stations due to age, increased activity and service requirements. Most of this work is contracted to third parties due to need for transmission voltage expertise.
Overhead	$192,432	$69,673	All non-capital service work on overhead lines increasing due to wage increases, increased traffic in Town and shift in focus on customer service from capital work.
Engineering	-$45,671	-$62,067	Transfer of most of non-dedicated VP Operations time to Administration.

Customer service has grown at an annual rate of 2.5%; largely in line with wage increases. NOTL Hydro has been able to minimize the cost increases of this program through continued use of UCS to provide the CIS system maintenance, outsourced bill printing and tight controls over bad debts which were high in 2014.

Material drivers in the change in Customer Service costs include:

Table 4.22: Customer Service Program Costs Drivers

Cost	Variance since Board Approved 2014	Variance since 2017	Explanation
Customer Service	$96,605	$57,499	Includes mailing, billing and collections. Increased due to increased number of customers and resulting increase in staff, increased wages and recent signing of services with Utilismart to provide improved data access to our large customers and generators.

Administration has grown at an annual rate of 8.8%. Key factors driving this growth in expenses have been the increase in regulatory costs with the expected cost of this rate application, the inclusion of much of the costs of the VP Operations, an increase in staffing in finance and regulatory to handle the increased requirements, increased costs relating to cyber security and increased wages with a new executive team.

Material drivers in the change in Administration costs include:

Table 4.23: Administration Program Costs Drivers

Cost	Variance since Board Approved 2014	Variance since 2017	Explanation
Executive salaries and professional services	$296,103	$161,609	Increased due to addition of VP Operations to Administration, new staff in all three executive roles and less time charged to capital due to focus on other responsibilities.
IT, software, communications	$67,273	$10,986	Increased due to increased cyber-security demands that required new contract with IT provider and more time dedicated by internal staff.

2.4.3.1 Workforce Planning and Employee Compensation

Overview

NOTL Hydro's overall compensation philosophy for all employees is designed to be competitive and equitable in order to attract and retain qualified personnel. The compensation package includes a base wage and benefits package as well as a bonus for certain management personnel. As NOTL Hydro states in the Principles on its website:

> "*We should hire the best employees possible and have the best working environment. Motivated and intelligent employees will always provide the best service and, in the long run, at the lowest cost."*

Staffing and Compensation

The number of employees is based on the computation of the number of full-time equivalent (FTE) positions throughout each of the years. A position that was added in a particular calendar year is counted as a portion of an FTE in that calendar year based on the start date of the position.

The salaries and wages amounts include all salaries and wages paid, inclusive of overtime, vacations, holidays, sick leave, bereavement leave, and bonuses. The benefits amount include the employer's portion of statutory benefits (CPP, EI and EHT), employer contributions to OMERS and WSIB and NOTL Hydro's costs for providing extended health care, dental, long-term disability and life insurance for its employees.

The table below details NOTL Hydro's employee compensation (Appendix 2-K).

Table 4.24: Employee Compensation

	Last Rebasing Year (2014 Board Approved)	Last Rebasing Year (2014 Actuals)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	6	5	5	5	6	6	6
Non-Management (union and non-union)	13	10	11	12	12	12	12
Total	19	15	16	17	18	18	18
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 611,906	$ 538,997	$ 530,811	$ 574,605	$ 564,591	$ 652,445	$ 665,494
Non-Management (union and non-union)	$ 874,309	$ 794,717	$ 849,769	$ 841,184	$ 964,936	$ 976,380	$ 995,910
Total	$ 1,486,214	$ 1,333,714	$ 1,380,580	$ 1,415,789	$ 1,529,527	$ 1,628,826	$ 1,661,404
Total Benefits (Current + Accrued)							
Management (including executive)	$ 130,289	$ 123,542	$ 99,963	$ 135,696	$ 131,592	$ 148,231	$ 150,442
Non-Management (union and non-union)	$ 197,428	$ 182,156	$ 160,029	$ 198,649	$ 224,903	$ 227,360	$ 230,565
Total	$ 327,717	$ 305,698	$ 259,992	$ 334,345	$ 356,495	$ 375,592	$ 381,007
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 742,195	$ 662,540	$ 630,774	$ 710,301	$ 696,183	$ 800,676	$ 815,936
Non-Management (union and non-union)	$ 1,071,737	$ 976,873	$ 1,009,798	$ 1,039,833	$ 1,189,839	$ 1,203,741	$ 1,226,475
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411

Compensation – Union

NOTL Hydro is a unionized company. Non-management staff are members of IBEW Local 636 and their wages are subject to the union agreements. There are two agreements; one for line and engineering staff and one for office workers. However, the agreements are kept identical other than specific provisions that apply to one group or the other. The five year time period of this analysis is covered by two collective agreements: 2013-2016 and 2016-2020. The following are the annual wage increases built into the agreements:

Table 4.25: Annual Wage Increases under Union Contract

	2014	2015	2016	2017	2018	2019
Annual Wage Increase	2.8%	2.8%	2.1%	2.1%	2.0%	2.0%

Compensation - Management

Management staff receive the same wage increase as unionized staff but they also receive a bonus of 10-15% of pay based on a combination of personal and company performance. Management staff may also receive a wage adjustment to keep their wages competitive or to reflect the changes in their responsibilities. Changes in personnel may also affect the pay for a given management position. The annual increases will therefore often be higher overall than the contract increase.

Annual Variances

Table 4.26: Total Compensation

	Board Approved	Actual	Actual	Actual	Actual	Bridge Year	Test Year
	2014	2014	2015	2016	2017	2018	2019
Total Compensation	1,813,931	1,639,412	1,640,572	1,750,134	1,886,022	2,004,417	2,042,411
Variance		-9.6%	0.1%	6.7%	7.8%	6.3%	1.9%

Board Approved 2014 – Actual 2014 – The actual cost in 2014 was much lower due to a reduction in the expected headcount of three. The President retired and was not replaced until July of 2014. An office clerk also retired and was not replaced. During the first six months there was a part-time caretaker President. One of the Engineer Technologists was laid off and the position was not brought back. The CDM Manager went on long-term disability leave.

Actual 2014 – Actual 2015 – Little change in cost. A $47k increase in salaries and wages was offset by a $46k decrease in benefit costs. The 3.5% increase in salaries and wages was made up of the 2.8% increase in wages under the Union contract plus having the President role filled for the full year. The decrease in benefits was primarily in health benefits due to changes in usage.

Actual 2015 - Actual 2016 – Total cost was up 6.7% or $90k due to the 2.1% increase in wages under the Union contracts and a $75k increase in benefits costs which was primarily health and OMERS.

Actual 2016 – Actual 2017 – Total cost was up 7.8% or $136k due to the 2.1% increase in wages under the Union contracts, the hiring of two new staff (Customer Service Representative and Lineman), one of the Lineman moving from being an Apprentice to being a Journeyman Lineman, the transitioning to new VP Finance and VP Operations with overlap and an increase in benefits of $20k.

Actual 2017- Bridge Year 2018 – Total cost is expected to rise 6.3% due to the 2.0% increase in wages under the Union contract, one month overlap and then the replacement of a maternity leave with a higher priced contract staff, a full year with the new VP Operations and an increase in benefits of $20k.

Bridge Year 2018 – Test Year 2019- Total cost is expected to rise 1.9% which is in line with the Union contract increase of 2%.

Benefit Program Costs

A detailed summary of benefit program costs are presented below in the table below:

Table 4.27: Benefit Expenses

	Board Approved	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Benefit	**2014**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
CPP		42,244	39,721	40,143	47,975	48,673	48,719
EI		23,696	17,435	22,676	21,886	28,878	29,456
OMERS		130,254	137,003	147,576	157,433	167,699	172,102
Life Insurance		4,922	2,187	7,126	6,036	7,454	7,603
Health and Dental		53,738	12,868	62,872	62,586	68,541	68,569
WSIB		12,395	7,806	10,748	14,380	14,270	14,426
Employee Health Tax		24,375	28,383	29,000	30,808	22,497	22,552
EAP service		1,018	1,189	1,529	816	1,784	1,784
Long Term Disability		13,056	13,400	12,675	14,575	15,797	15,797
Total	$327,717	$305,698	$259,992	$334,345	$356,495	$375,592	$381,007
Variance		-6.7%	-15.0%	28.6%	6.6%	5.4%	1.4%
Variance (2014-2019)							24.6%

Total company benefits have increase 24.6% from 2014 to 2019. The biggest benefit is OMERS which accounts for 45% of all benefits. OMERS has increased by 32% over this time period and has therefore accounted for most of the benefit cost increase. Benefits are expensed on an accrual basis.

Pension

The employees of NOTL Hydro participate in the OMERS retirement plan. Therefore, the pension benefits provided to the employees of NOTL Hydro are consistent with the pension benefits provided to employees of other LDCs. The cost of OMERS is based on the earnings of the employee (see table below) so as salaries and wages increase then so does the cost of OMERS. Pensions are accounted for on an accrual basis based on OMERS rates. As part of OMERS, NOTL Hydro does not have the data or requirement for pension accounting.

Table 4.28: OMERS Rate Increases (2014 to 2018)

Year	YMPE	Contribution on Earnings up to WMPE	Contribution on Earnings above YMPE
2014	$52,500	9.00%	14.60%
2015	$53,600	9.00%	14.60%
2016	$54,900	9.00%	14.60%
2017	$55,300	9.00%	14.60%
2018	$55,900	9.00%	14.60%

Benefits

A comprehensive and competitive benefits package exists which includes health and dental insurance, life insurance, long-term disability, vacation and leave policies. The plans are designed to address the health and well-being of employees.

Employee Staffing Levels (annual average)

Table 4.29: Employee Staffing Levels

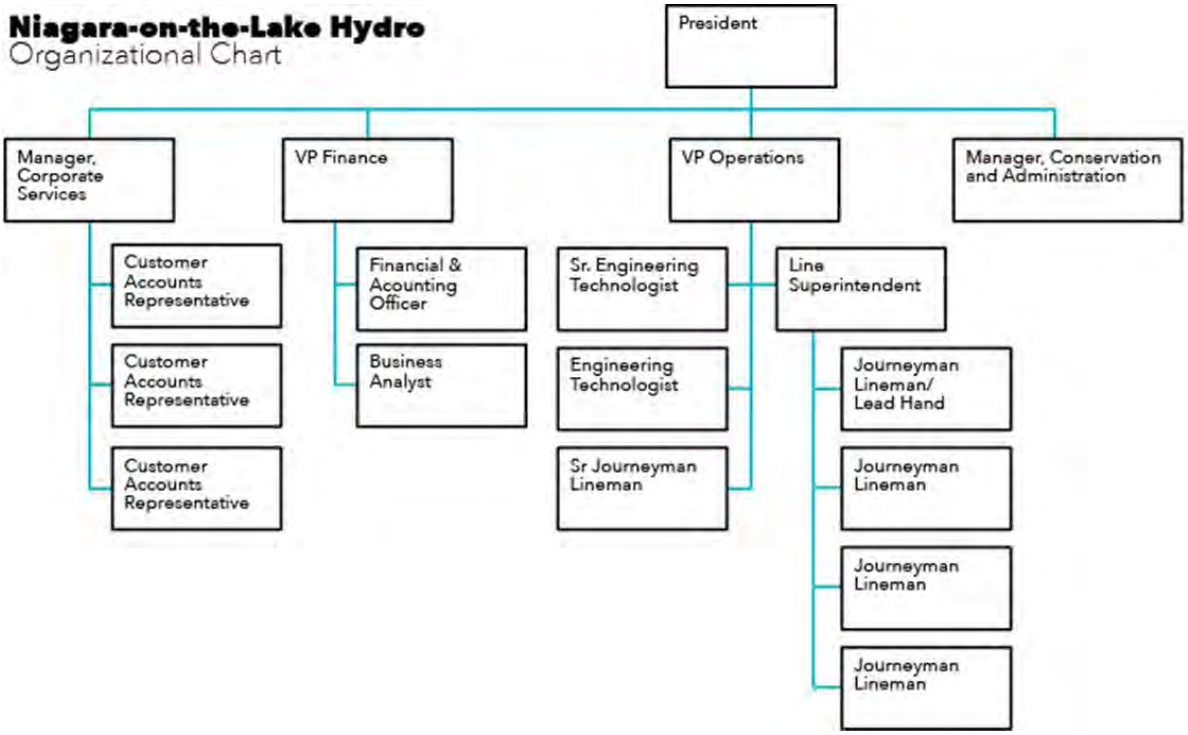
	Board Approved	Actual	Actual	Actual	Actual	Bridge Year	Test Year
	2014	2014	2015	2016	2017	2018	2019
Executive	3.00	3.00	3.00	3.05	3.04	3.00	3.00
Management	3.00	2.58	2.00	2.00	2.60	3.00	3.00
Union	12.00	9.26	9.85	9.59	10.97	11.50	11.50
Non-union	1.00	1.19	2.60	2.84	0.98	0.58	0.50
Total	19.00	16.03	17.45	17.48	17.60	18.08	18.00

Changes in Staff Levels

From 2013 and 2014 there was a drop in staff of three. The President retired and was not replaced until July of 2014. An office clerk also retired and was not replaced. During the first six months there was a part-time caretaker President. One of the Engineer Technologists was laid off and the position was not brought back. The CDM Manager went on long-term disability leave.

In 2015 and 2016 there were various temporary staff that resulted in an increase in average staff of 1.5. In 2016 and 2017 two new staff were hired on a permanent basis which brought the staffing level to 18. No new staff are currently contemplated but this will be reviewed periodically based on growth and needs.

Table 4.30: NOTL Hydro's Current Structure (effective January 1st 2018)



2.4.3.2 Shared Services and Corporate Cost Allocation

NOTL Hydro has two affiliates; Niagara-on-the-Lake Energy Inc. (NOTL Energy) and Energy Services Niagara Inc. (ESNI).

NOTL Energy is a holding company that has no active operations or revenue. Its only expenses are those it directly incurs as a corporate entity: corporate insurance and auditor charges for the preparation of the annual tax return.

ESNI is a subsidiary of NOTL Energy and a sister company to NOTL Hydro. The non-regulated activities of NOTL Energy are conducted within ESNI. During the period from 2014-2019 these have included: a water heater rental business, water billing services on behalf of the Town of Niagara-on-the-Lake and solar generation. ESNI has no direct employees so all services supplied by NOTL Hydro staff are billed to ESNI on a cost plus basis.

The following is a breakdown of the services supplied to ESNI by year (Appendix 2-N):

Table 4.31: Services to ESNI (2014-2019)

Year: 2014

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	% Allocation
From	To			$	$	
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service-Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$89,478.97	$74,791.81	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$2,229.83	$1,880.76	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable, Account Reconcilations, Payroll	Cost-Base	$2,993.78	$2,496.64	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$37,441.89	$34,038.08	# of bills printed/cancelled * proportion related to water bills* cost of bill print plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance	Cost-Base	$6,129.81	$5,572.55	0.0483% on mtce of building, property taxes, property insurance plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00	2 members x $250 + 2 @ $100 per meeting

Year: 2015

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	Allocation
From	To			$	$	
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service-Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$78,748.12	$65,755.40	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$385.97	$321.64	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$813.71	$679.75	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$38,403.77	$34,912.52	# of bills printed/cancelled * proportion related to water bills* cost of bill print plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Verifying meter installs, water reads/billing for water # meters installs	Cost-Base	$28,716.66	$24,190.30	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$7,462.07	$6,783.70	0.0543% on mtce of building, property taxes, property insurance plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00	2 members x $250 + 2 @ $100 per meeting

1

Year: 2016

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	Allocation
From	To			$	$	
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service-Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$82,471.07	$69,251.08	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$921.18	$767.61	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$753.98	$628.31	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$41,844.14	$38,040.13	# of bills printed/cancelled * proportion related to water bills* cost of bill print plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Verifying meter installs, water reads/contractor charges # meters installs	Cost-Base	$14,013.00	$12,573.76	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$7,595.49	$6,904.99	0.0543% on mtce of building, property taxes, property insurance plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00	2 members x $250 + 2 @ $100 per meeting

2

Year: 2017

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	Allocation
From	To			$	$	
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service-Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$81,313.67	$68,029.88	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Payable Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$147.14	$122.61	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll/Solar Panel- Engineering Consulting	Cost-Base	$7,358.83	$6,132.68	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$43,059.47	$39,144.97	# of bills printed/cancelled * proportion related to water bills* cost of bill print plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Contractor charges for #Meter Installed	Cost-Base	$17,435.20	$15,850.19	Service Cost is marked up as follows: Labour 20%, Truck 10%, Material 10%, Contractor 10% Accounts Paybale Misc 10%
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$4,815.75	$4,377.95	0.0337% on mtce of building, property taxes, property insurance plus 10% mark-up
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00	2 members x $250 + 2 @ $100 per meeting

3

Year: **2018**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service- Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$82,716.98	$69,200.81
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$0.00	$0.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll/Solar Panel- Engineering Consulting	Cost-Base	$3,501.20	$2,917.66
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$43,593.92	$39,630.84
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Contractor charges for #Meter Installed	Cost-Base	$12,078.00	$10,980.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$6,516.63	$5,924.21
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00

1

Year: **2019**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service- Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$85,676.13	$71,666.78
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$0.00	$0.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll/Solar Panel- Engineering Consulting	Cost-Base	$2,103.03	$1,752.53
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$44,117.04	$40,106.40
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Contractor charges for #Meter Installed	Cost-Base	$12,078.00	$10,980.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$6,516.63	$5,924.21
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00

2

The following table provides a comparison of shared services between the OEB approved 2014, the actual 2017 and the test year 2019:

Table 4.32: Services to ESNI Comparisons

Service	2014 OEB Approved	2017 Actual	2019 Proposed
Water heaters rental support	$4,200	$7,505	$2,103
Water and waste water billing	$110,500	$141,808	$141,871
Administration	$5,800	$4,816	$6,517
Board of Directors	-	$8,400	$8,400
Total	**$120,500**	**$162,530**	**$158,891**

The water heater support business was sold in 2014. Some administrative services are still being provided to the purchaser but these are declining over time.

The water and wastewater billing services have increased over time with the growth in the number of customers. Beginning in 2015, the Town of Niagara-on-the-Lake began installing transmitters to remotely read the water readers in a manner similar to electric smart meters. This initially increased the costs being charged for this service but as the transition problems are being resolved and the benefits of the remote reading realized, the costs are expected to decline.

Administration is an allocation of overhead including premises, insurance and other similar charges.

Two of the Board members are on the Board of ESNI. Technically they are paid by ESNI but as ESNI has no employees and no payroll system the costs flow through NOTL Hydro.

2.4.3.3 Purchases of Non-Affiliate Services

NOTL Hydro purchases equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. In making purchase decisions, NOTL Hydro also considers the “total acquisition cost” (i.e. value for money) rather than the lowest bid, and this includes, but limited to such factors as repairs, staff training, compatibility, warranty, trade-in values, recycling and safe environmental disposal.

Vendors are screened to ensure knowledge, reputation, and the capability to meet NOTL Hydro's needs. The procurement of goods and/or services for NOTL Hydro is carried out with highest of ethical standards and consideration to the public nature of the expenditures. NOTL Hydro has a Purchasing and Procurement Policy that the company adheres to and a copy of this policy is contained in the Appendix.

All substantial purchases of goods and services must be approved by the Board of Directors of NOTL Hydro as presented in the annual Operating and Capital budgets. Formal Board of Director's approval of the annual Operating and Capital budgets constitutes financial approval to proceed with the procurement process. Budget amendments, capital expenditures not yet approved in the budget or special expenditures must be supported by a Resolution by the Board of Directors. The Resolution shall specify the purpose of the expenditure and the funding source.

All payments for goods and services over $50,000 require the signature of a Board member. The only exceptions are what are considered non-controllable, regular expenditures such as taxes, interest and payments on debt, IESO invoices and payments to the Town of Niagara-on-the-Lake in the regular course of business (primarily collections on water invoices).

When goods or services are tendered, a Tender/Request for Proposal or a Request for Quote will be issued to a minimum of three vendors, if availability permits.

A copy of NOTL Hydro's purchasing policy has been attached as Appendix 4F.

NOTL Hydro's 2017 Vendor list over the materiality threshold of $50,000 is presented below:

Table 4.33: Products and Services from Non Affiliates 2017

Supplier	**Service**
Alectra Utilities Corporation	SCADA operator and Load transfer
Anixter Power Solutions Canada Inc	Distribution equipment supplies
Burman Energy	CDM Services
Canada Post Corporation	Postage
Claimsecure Inc	Benefits provider
Hy-Line Utility Solutions Inc	Line services
Jubb Utility Supply Ltd	Tools
KPMG LLP	Auditor
LaPrairie Inc.	Distribution equipment supplies
Niagara Peninsula Energy Inc	Load transfer
Peninsula Video & Sound Inc	Locates
Raven Engineering Inc	Engineering Services
Sensus Canada Inc	Meters
Siemens Transformers Canada Inc	Transformers
Skycomp Solutions Inc	IT support
Stella-Jones Inc	Wood poles
Utility Collaborative Services	CIS system
Wiens Underground Electric Inc	Underground services

2.4.3.4 One-time Costs

The only noteworthy one-time cost included in the 2019 test year OM&A is the regulatory cost of this application. NOTL Hydro is proposing to spread this cost over the five years of the application period.

One-time costs included in historical years include the $42k severance paid in 2015 and the micro-grid study of $100k in 2016.

The material capital expenditures that would be considered one-time are the installation of the 50 MVA transformer installed in NOTL station in 2015 for $2.6 million and the planned 83 MVA transformer to be installed in York station in 2019 for $3.5 million.

2.4.3.5 Regulatory Costs

The table below shows NOTL Hydro's regulatory costs for 2014-2017, 2018 Bridge Year and 2019 Test Year. All regulatory costs listed in this table are tracked in account 5655 – Regulatory Expenses. NOTL Hydro uses sub-accounts to track OEB Assessments, Cost Awards from the OEB and the costs associated with NOTL Hydro's rate applications (i.e.; annual IRM's filings and cost of service rate applications).

Table 4.34: Breakdown of Regulatory Costs

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year Board Approved	2014	2015	2016	2017	2018	2019
1	OEB Annual Assessment	5655		On-Going	$ 30,300	$ 28,850	$ 29,681	$ 32,729	$ 30,300	$ 30,300	$ 39,840
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going		$ 373	$ 505	$ 20			
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 1,900	$ 514	$ 4,109	$ 637	$ 1,000	$ -	
4	Expert Witness costs for regulatory matters	5655									
5	Legal costs for regulatory matters	5655		One-Time	$ 20,000	$ 1,071					
6	Consultants' costs for regulatory matters	5655		One-Time			$ 2,000	$ 1,650		$ -	$ 2,000
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going						$ 1,190	$ 1,113
8	Operating expenses associated with other resources allocated to regulatory matters	5655		One-Time		$ 740	$ 9,445	$ 2,366	$ 14,661	$ 5,334	$ 5,398
9	Other regulatory agency fees or assessments	5655									
10	Any other costs for regulatory matters (please define) Annual Registration Fee + COS	5655		One-Time	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800	$ 38,800
11	Intervenor costs	5630		One-Time			$ 4,495	$ 1,504		$ 59	
12	Sub-total - Ongoing Costs		$ -		$ 32,200	$ 29,737	$ 34,295	$ 33,386	$ 31,300	$ 31,490	$ 40,953
13	Sub-total - One-time Costs		$ -		$ 20,800	$ 2,611	$ 16,740	$ 6,320	$ 15,461	$ 6,192	$ 46,198
14	Total		$ -		$ 53,000	$ 32,348	$ 51,035	$ 39,706	$ 46,761	$ 37,682	$ 87,151

In the table above NOTL Hydro has shown the amortized cost of this application as amortized over 5 years commencing in 2019. It is recognized that under IFRS all the regulatory costs related to this application will be booked in 2018 and 2019.

NOTL Hydro has also updated Chapter 2 Appendix 2-M with the breakout of actual and forecasted costs incurred in preparing and submitting NOTL Hydro's 2019 Cost of Service rate application

as well as reaching a Decision and Order from the Board. The table below summarizes these costs:

Table 4.35: Overview of Regulatory Costs for 2019 Cost of Service Application

Cost of Service Cost Components

Application - Consulting (TESI)	$10,000.00
Application - Consulting (CGE)	$13,500.00
Application - Auditor	$10,000.00
Applicaton - Legal	$5,000.00
Interogatories - Consulting	$7,500.00
Interogatories - Auditor	$2,500.00
Interogatories - Legal	$5,000.00
Settlement - Consulting	$5,000.00
Settlement - Legal Review	$15,000.00
Presentation Day	
OEB Customer Session	$10,000.00
Public Notice	$1,500.00
Oral Hearings	$30,000.00
Intervenor Costs	$75,000.00
Incremental	
Rate Order	$0.00
Total Cost of Service Filing costs	$190,000.00

NOTL Hydro recognizes that the actual costs for the subcategories of regulatory costs set our above will likely be different from forecast, depending on how the case proceeds. Other considerations include:

- TESI is Tandem Energy Services Inc. who has assisted NOTL Hydro in developing this cost of service application
- CGE is CGC Educational Communications who acted as an independent observer at the public information sessions NOTL Hydro hosted in 2018, had private discussions with a number of customers and reviewed the results of the survey undertaken at these sessions. Their report is included in this application.
- Interrogatory, settlement and hearing costs have been estimated based on other rate applications.

NOTL Hydro proposes that costs directly associated with the Cost of Service application are amortized over a period of 5 years. $190,000 allocated over five years is $38,000 per year. The balance of $38,800 above includes the $800 in annual registration fees.

2.4.3.6 Low Income Energy Assistance Programs

NOTL Hydro has included $7,100 for the expense for the Low Income Assistance Program (LEAP) under Deductions Donation Expense (USoA #6205). This amount $7,267 for LEAP funding which is based on the Board's determination that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000 should be included in the utility's costs. These funds are fully dedicated to providing financial assistance. NOTL Hydro also provides an annual payment of $1,000 to assist Reach Out Niagara to assist in covering out of pocket expenses, primarily insurance. The volunteers who operate Reach Out Niagara are not compensated.

NOTL Hydro has partnered with Reach Out Niagara in Niagara-on-the-Lake to assist in programs intended to provide emergency relief to eligible low-income customers who may be experiencing difficulty paying current arrears. Reach Out Niagara was specifically created to administer the LEAP funds as there was no agency located in Niagara-on-the-Lake who was able and willing to take on this service.

NOTL Hydro has included the projected LEAP funding of $7,267 in its 2019 Revenue Requirement.

Table 4.36: Charitable Contributions (2014-2019)

Charitable Donations

2014

Vendor	GL Number	Description	Amount
			$0.00
Total			$0.00

2015

Vendor	GL Number	Description	Amount
Reach Out Niagara	10-6205-0000-00	LEAP Administrator	$1,000.00
Reach Out Niagara	10-6205-1000-00	LEAP Administrator	$5,520.00
Reach Out Niagara	10-6205-1000-00	LEAP Administrator	$5,693.85
			$0.00
Total			$12,213.85

2016

Vendor	GL Number	Description	Amount
Reach Out Niagara	10-6205-0000-00	LEAP Administrator	$1,000.00
Reach Out Niagara	10-6205-1000-00	LEAP Administrator	$5,693.85
			$0.00
Total			$6,693.85

2017

Vendor	GL Number	Description	Amount
Reach Out Niagara	10-6205-0000-00	LEAP Administrator	$1,000.00
Reach Out Niagara	10-6205-1000-00	LEAP Administrator	$5,693.85
			$0.00
Total			$6,693.85

2018

Vendor	GL Number	Description	Amount
Reach Out Niagara	10-6205-0000-00	LEAP Administrator	$1,000.00
Reach Out Niagara	10-6205-1000-00	LEAP Administrator	$5,693.85
United Way	10-6205-2000-00	United Way Donation	$4,169.11
			$0.00
Total			$10,862.96

2019

Vendor	GL Number	Description	Amount
Reach Out Niagara	10-6205-0000-00	LEAP Administrator	$1,000.00
Reach Out Niagara	10-6205-1000-00	LEAP Administrator	$7,100.16
United Way	10-6205-2000-00	United Way Donation	$4,169.11
			$0.00
Total			$12,269.27

2.4.3.7 Charitable and Political Donations

NOTL Hydro does not contribute to political causes.

NOTL Hydro does make some charitable donations. In addition to the LEAP funding, as described in section 2.4.3.6, NOTL Hydro matches employee contributions to United Way. NOTL Hydro received an award from United Way in 2018 for it employee participation in the program. For the purposes of this application, the donations to the United Way have been removed from the OM&A in the 2019 test year.

NOTL Hydro confirms that, other than LEAP, no donation amounts have been included for recovery.

2.4.4 Depreciation, Amortization & Depletion

2.4.4.1 Depreciation Rates and Methodology

In accordance with the July 17, 2012 letter from the Board on Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies, NOTL Hydro adopted the Kinectrics proposed useful lives and componentization as of January 1, 2013. At this time the life span of the assets were adjusted to comply with the depreciation changes.

For the fiscal year 2013, NOTL Hydro completed a conversion of the company's fixed asset module which supported the revised average useful lives for all asset categories based on historical evidence and is within the typical useful life bands outlined in the Kinectrics Report "Asset Depreciation Study for the Ontario Energy Board" with exception of the categories for the PCB Shed and Remote Scada. The service lives for the PCB shed and Remote SCADA of 30 years and 10 years respectively were approved in NOTL Hydro's 2014 Cost of Service Application.

NOTL Hydro undertook a comprehensive review of assets that is summarized below and is also found in Appendix 4E - IFRS Policies.

Significant components of PP&E are separately accounted under IFRS. Each significant component and related estimated useful life are used for purposes of computing depreciation expense under IFRS.

Overhead system

Four components identified – Poles, OH Conductors/Switches, Transformers and OH Secondary Cable.

The company currently has only wood poles and has determined that there are no components of the pole that are material in dollar value or have a significantly different useful life. Therefore, the company has concluded that there is only one component comprised of the fully dressed wood pole. This component includes the standoff brackets and guy wires which are considered immaterial.

In terms of useful life, the Kinectrics report gave a range of 35-75 years, with the typical being 45 years. The company considered the following factors with respect to the useful life of the poles.

Mechanical stress and environmental factors are high and medium, respectively. The poles are not overloaded with weight, as the system has the typical length between poles. Historical experience shows the poles are being replaced between 45-50 years. The company has determined a useful life of 45 years is appropriate.

The company currently includes conductors and switches in the same GL account. It has been determined that switches do not make up a significant share of the account. Going forward, it is not expected there will be material amounts of switches added that justifies a separate component. The company also determined that they are not replacing conductors more often than switches or re-closers, which has led to the determination of a single component for these assets. The company has a regular maintenance program on the switches and as a result, failure is not typical.

In terms of useful life, the Kinectrics report gave a range of 50-75 years (typical 60 years) for OH conductors and 30-55 years (typical 45 years) for line switches. The company has determined its conductors fit the typical life span, given historical experience and pole spans being typical (which reduces strain on the conductor). Since switches were determined to be immaterial in this component, a useful life of 60 years is appropriate. Typically, switches are only replaced prior to replacing the conductor, when the switch fails. Failure is not typically seen with the exception of lightning strikes.

Overhead and underground transformers are currently grouped together. Useful lives of the two types of transformers are expected to be similar since the system is not overloaded. There are no plans to remove underground transformers from service prior to 40 years unless they are overloaded. Kinectrics useful life range is 30 to 60 years with typical of 40 years. Electrical loading and mechanical stress are low and environmental factors are considered to be normal. Kinectrics typical useful life is based upon moderate electrical loading. The company's low electrical loading would extend useful life beyond the typical range. Life should be 45 years based upon the utilization factors.

Secondary cable (Services) has been classified into two separate components (underground and overhead) due to the significantly different useful lives based on the type of wire used for each. Overhead wire is PILC (covered wire).

OH secondary cable experience tree wear from rubbing. The cable is insulated, which tends to deteriorate over time. The company's experience has shown this cable does not last longer than about 60 years. A useful life of 60 years is considered appropriate.

TS Stations

Two components identified – Transformers and Other

The company has assessed the different assets that comprise the two TS currently owned. The unique parts are power transformers, stations switch, breakers and switches, relays, bus-bars and steel structures. The company has determined the power transformers are by far the most significant component in the TS stations and should be accounted for as a separate component.

The other components are not considered material and useful lives are not significantly different to warrant any further componentization for the other assets comprising the TS station. Kinectrics life range for the transformers is 30-60 years with 45 being typical. The company does not have much experience with the life span of this component as the oldest asset is from 1985. Electrical loading and environmental factors do not differ from Kinectrics typical, which is moderate. Typical useful life of 45 years is appropriate.

The other assets component (stations switch, breakers and switches, relays, bus-bars and steel structures) have a life range of between 30 and 60 years with typical being 50 years. The station switches and breakers etc. are regularly maintained and the operational practices of the switches are low to moderate which would suggest a higher useful life than typical. 55 years is considered an appropriate life.

DS Station

The King St. DS Station is expected to be decommissioned in 2013. Based on the expected decommission, the useful life of this asset on January 1, 2013 will be one year.

Underground System

Three Components identified – Underground Cable (Primary) & Devices, Underground Conduit and Secondary Cable (Underground)

The company has determined that underground primary cable and devices represent a single component. The assets in this class have similar useful lives. The Kinectrics report gives useful life ranges of 35-55 years (typical 40 years). The company's assets in this component include both direct buried and in duct, with the majority being in-duct (direct buried has a lower life and only in one or two subdivisions). Mechanical stress, electrical loading, and environmental conditions are considered moderate in the Kinectrics report, but the company has assessed electrical loading as lower. The company has also considered historical experience for these assets. There is currently direct buried cable with a life of 30 years in operation and it is expected that these will last at least 10 more years as no major issues have been encountered at 30 years of life. Based on these factors, the company has assessed these assets with a useful life of 45 years, higher than typical based upon the low electrical loading. The company has determined that ducts, foundations, vaults and duct banks all form the Underground Conduit component. These assets have similar useful lives. The Kinectrics report gives useful life ranges from 30-85 years for these assets (typical 50-55 years). The company has assessed mechanical stress lower than Kinectrics report (assets are under grass not under roads) which leads to a longer expected life. The company has assessed 65 years as appropriate for these assets.

Secondary cable (Services) has been classified into two separate components (underground and overhead) due to the significantly different useful lives based on the type of wire used for each. Overhead wire is PILC (covered wire).

The Kinectrics report has the useful life of underground secondary cable as a range of 35-60 years (typical 40 years). The company has determined there are no factors that would suggest the useful life is any different from the underground primary cable. As such, a useful life of 45 years is appropriate.

SCADA software: Has been assessed as a single component, since radios are already included under communication equipment. The company is aware this software is updated on an irregular basis (that may exceed annual) but the original firmware may be considered to have a useful life of 8-10 years before it is completely replaced. Therefore a useful life of 10 years has been chosen for this component.

Minor assets

Office Equipment: Has been assessed as a single component as assets have similar useful lives. The current useful life is 10 years, and there are no indications this should change.

Vehicles < 3 tonnes: Single component. Policy is to replace after 5 years, therefore this is the useful life.

Vehicles > 3 tonnes: Single component. Policy is to replace after 10 years, therefore this is the useful life.

Trailers: Single component. Estimated useful life is 15 years based upon planned replacement cycle.

Administrative Buildings: Single component. Kinectrics report gives useful life of 50 – 75 years. The company's administrative building is fairly new. The building was constructed under a low budget (minimum standards) which indicates the maximum useful life is not appropriate. A useful life of 60 years has been determined.

Station Buildings: It has been determined not to separate these assets out from the TS (insignificant in relation to the equipment in the TS station)

Computer Equipment (Hardware): Single component. Policy is replacement every 3 years; therefore the useful life is 3 years.

Computer Equipment (Software): Single component. Policy is replacement every 3 years; therefore the useful life is 3 years. Technological obsolescence limits the life.

Communication Equipment: Single component that includes a computer station that works with the SCADA equipment, towers, radio and phone system. The company does not have any reason as to why this should vary from the rate it is currently being depreciated over, which is 10 years. This component is subject to technological obsolescence so anything higher than 10 years would not be appropriate.

Miscellaneous Equipment (tools and shop): Single component. Based on experience, assets in this class can last 5-10 years, but individually the assets are immaterial. As such, an average life of 8 years is considered appropriate.

Miscellaneous Equipment (stores and warehouse): Single component. The company has assessed at maximum life of 10 years based on Kinectrics report and experience with life of shelving equipment.

Meters: 4 Components were decided

1) Smart Meters: These are material and have a significantly different useful life (no history yet on how long they will last). The company discussed the need to split out into further components (data collectors). It was determined that useful life of data collectors and the meter are similar and therefore no need to break down into further components. The company does not expect useful life to exceed 10 years given problems already encountered with these meters. However, will use same rate as industry (15 years) and assess the appropriateness of this at end of each reporting period.

2) Stranded Meters: Life kept at OEB rate of 25 years.

3) Other Meters: These meters have been lasting 25 years. Technological obsolescence will limit the life of these assets to a certain extent so extending this beyond the 25 years is not appropriate.

4) CT's and PT's: These are material and have a significantly different useful life. Kinectrics report indicates a range of 35-50 years. The company has determined a 40 year life is reasonable for these assets.

Table 4.37: Service Life Comparison

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Asset Details: Category| Component | Type		Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL? Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall	35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
	8	OH Conductors		50	60	75	1835	Overhead Conductors & Devices	60	2%	60	2%	No	No
	8	OH Conductors		50	60	75	1855	Services-OH	60	2%	60	2%	No	No
	9	OH Transformers & Voltage Regulators		30	40	60	1850	Line Transformers	45	2%	45	2%	No	No
TS & MS	12	Power Transformers	Overall	30	45	60	1815	TS Equipment>50KV-Transformer	45	2%	45	2%	No	No
	18	Station Switch		30	50	60	1815	TS Equipment>50KV-Transformer	55	2%	55	2%	No	No
UG	29	Primary TR XLPE Cables in Duct		35	40	55	1845	Underground Conductors & Devices	45	2%	45	2%	No	No
	32	Secondary Cables in Duct		35	40	60	1855	Services-UG	45	2%	45	2%	No	No
	34	Pad-Mounted Transformers		25	40	45	1850	Line Transformers	45	2%	45	2%	No	No
	39	Pad-Mounted Switchgear		20	30	45	1845	Underground Conductors & Devices	45	2%	45	2%	No	No
	40	Ducts		30	50	85	1840	Underground Conduit	65	2%	65	2%	No	No
	41	Concrete Encased Duct Banks		35	55	80	1840	Underground Conduit	65	2%	65	2%	No	No
S	43	Remote SCADA		15	20	30	1980	System Supervisory Equipment	10	10%	10	10%	Yes	No

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL? Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture & Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment >3 Tons	10	10%	10	10%	No	No
		Trailers	5	20	1930	Transportation Equipment- Trailers	15	7%	15	7%	No	No
		Vans	5	10	1930	Transportation Equipment <3 Tons	5	20%	5	20%	No	No
3	Administrative Buildings		50	75	1908	Building & Fixtures	60	2%	60	2%	No	No
					1908	Building & Fixtures-PCB Shed	30	3%	30	3%	No	Yes
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	3	33%	3	33%	No	No
		Software	2	5	1925	Computer Equipment - Software	3	33%	3	33%	No	No
7	Equipment	Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shops Garage Equipment	8	13%	8	13%	No	No
8	Communication	Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters-Non Stranded	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters-CT/PT	40	3%	40	3%	No	No
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
15	Data Collectors - Smart Metering		15	20	1860	Meters	15	7%	15	7%	No	No

NOTL Hydro's amortization rates are presented Appendix 2-BB and are applied on a straight-line basis utilizing the half-year rule. All assets are componentized and depreciated individually according to asset life span as per the Kinectrics Report with the exceptions noted above. NOTL Hydro will be continuing this method of depreciation in the Test Year and beyond.

Continuity Statements of the historical and forecasted depreciation expenses are presented in Appendix 2-C.

2.4.4.2 Depreciation Expense

In accordance with the Board's filing requirements, NOTL Hydro has completed the following depreciation and amortization expense tables attached as Appendix 2-C -NOTL_2019-Fiiling-Requirements-Chapter2_Appendix2C-20180718:

a) App.2-C_Dep Exp – 2014
b) App.2-C_Dep Exp – 2015
c) App.2-C_Dep Exp – 2016

d) App.2-C_Dep Exp – 2017
e) App.2-C_Dep Exp – 2018
f) App.2-C_Dep Exp - 2019

The amounts in the above appendices tie back to the accumulated depreciation balances in the fixed asset continuity schedule Appendix 2-BA.

Year	App.2-BA_Fixed Asset Cont Column J	App2-C-_DepExp Column X	Variance	Variance %
2014 - Actual	$ 1,006,611	$ 1,006,539	$ 72	0.0%
2015 - Actual	$ 1,043,515	$ 1,043,451	$ 64	0.0%
2016 - Actual	$ 1,051,852	$ 1,051,842	$ 9	0.0%
2017 - Actual	$ 1,038,029	$ 1,038,155	$ (126)	(0.0%)
2018 - Bridge Year	$ 1,069,267	$ 1,069,204	$ 63	0.0%

NOTL Hydro implemented New CGAAP amortization policies beginning January 1, 2013 and previously rebased in 2014 under the revised useful lives.

2.4.4.3 Asset Retirement Obligations

At this time, NOTL Hydro does not have any Asset Retirement Obligations, associated depreciation or accretion expenses in relation to asset retirement obligations to report as part of the application.

2.4.4.4 Half Year Rule

NOTL Hydro confirms that it has applied the half-year rule for the purposes of computing the net book value of Property, Plant and Equipment and General Plant to include in rate base. Under the half-year rule acquisitions and investments made during the year are amortized assuming they entered service at the mid-point of the year. NOTL Hydro will be continuing this method of depreciation in the Test Year and beyond.

2.4.4.5 Depreciation/Amortization Policy

A copy of NOTL Hydro's complete depreciation policy is included in Appendix 4E - IFRS Policy.

In summary all NOTL Hydro assets are depreciated on straight-line based on the service lives as set out it section 2.4.4.1 utilizing the half year rule. Depreciation of assets begins when the asset is ready for use (i.e. when it is in the location and condition necessary for it to be capable of

operating the manner intended by management. Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with IFRS 5 and the date that the asset is derecognized.

NOTL Hydro has not changed its depreciation policy or useful asset lives since it's last cost of service filing in 2014.

2.4.4.6 Components

NOTL Hydro's depreciates significant parts or components of each item of PP&E separately in accordance with IFRS.

2.4.4.7 Regulatory Accounting Changes for Depreciation Expense

NOTL Hydro deferred the adoption of IFRS and remained under CGAAP in 2012 and made regulatory changes for depreciation expense and capitalization policies on January 1, 2013.

2.4.5 Taxes or Payments In Lieu of Taxes (PILs) and Property Taxes

2.4.5.1 Overview of PILs

NOTL Hydro is required to make payments in lieu of income taxes ("taxes") based on its taxable income. NOTL Hydro files Federal/Provincial tax returns annually though both are submitted to the Ontario Ministry of Finance. There have been no special circumstances that would require specific tax planning measures to minimize taxes payable. There are no outstanding audits, reassessments or disputes relating the tax returns filed by NOTL Hydro.

There are no non-utility activities included in NOTL Hydro's financial results, therefore the entire amount of PILs payable is considered in the proposed allowance to be included in the revenue requirement.

Property Taxes

NOTL Hydro pays property taxes to the Town of Niagara-on-the-Lake for its office premises and other property. The table below show the actual's for 2014-2018. For the Test Year 2019 NOTL Hydro has forecasted an increase of 1.2% which is its standard inflation assumption:

Table 4.38: Property Taxes

	Board Approved	2014	2015	2016	2017	2018	2019
Property Taxes	$28,596	$29,811	$30,837	$31,773	$32,377	$34,540	$34,955
%Change (year over year)		4.2%	3.4%	3.0%	1.9%	6.7%	1.2%

The table below summarizes NOTL Hydro's taxes for the 2014-2017 Historical Years, 2018 Bridge Year and 2019 Test Year. NOTL Hydro had a loss for income tax purposes in the years 2014-2016 so no income tax expense was calculated.

Table 4.39: Tax Provision by Year

	2014		2015		2016		2017		2018		2019	
Regulatory Taxable Income	**(51,083)**		**(383,781)**		**(18,286)**		**1,421,293**		**300,044**		**304,617**	
Ontario Income Taxes												
Income tax rate **Ontario Income Tax**	*11.50%*	**0**	*11.50%*	**0**	*11.50%*	**0**	*11.50%*	**163,449**	*11.50%*	**34,505**	*11.50%*	**35,031**
Small business credit												
Ontario Small Business Threshold	0		0		0		500,000		0		0	
Rate reduction	*(7.00%)*	0	*(7.00%)*	0	*(7.00%)*	0	*(7.00%)*	0	*(7.00%)*	0	*0.00%*	0
Ontario Income tax		**0**		**0**		**0**		**163,449**		**34,505**		**35,031**
Combined Tax Rate and PILs												
Effective Ontario Tax Rate	*0.00%*		*0.00%*		*0.00%*		*11.50%*		*11.50%*		*11.50%*	
Federal tax rate	*0.00%*		*0.00%*		*0.00%*		*15.00%*		*15.00%*		*15.00%*	
Combined tax rate	*0.00%*		*0.00%*		*0.00%*		*26.50%*		*26.50%*		*26.50%*	
Total Income Taxes		**0**		**0**		**0**		**376,643**		**79,512**		**80,723**
Investment Tax Credits		0		0		0		2,000		0		0
Miscellaneous Tax Credits												
Total Tax Credits		0		0		0		2,000		0		0
Corporate PILs/Income Tax Provision		**0**		**0**		**0**		**374,643**		**79,512**		**80,723**
Corporate PILs/Income Tax Provision Gross Up	*100.00%*	0	*100.00%*	0	*100.00%*	0	*73.50%*	135,075	*73.50%*	28,668	*73.50%*	29,104
Income Tax (grossed-up)		**0**		**0**		**0**		**509,718**		**108,179**		**109,828**

The table on the next page provides the calculation of income for regulatory taxation purposes.

Table 4.40: Taxable Regulatory Income by Year

	T2 S1 line #	2014 Utility Only	2015 Utility Only	2016 Utility Only	2017 Utility Only	2018 Taxable Income	2019 Taxable Income
Income/(Loss) before PILs/Taxes (Accounting) [1]		1,121,147.00	111,165.00	1,337,690.00	1,644,113.00	1,034,431.57	1,105,128.39
Additions:							
Interest and penalties on taxes	103	1,271.00	-	-	-	-	-
Amortization of tangible assets	104	912,849.00	1,021,974.00	1,095,472.00	1,103,773.00	1,158,737.62	1,271,114.36
Loss on disposal of assets	111	46,404.00	12,958.00	8,590.00	23,657.00	-	-
Charitable donations	112	-	400.00	-	-	-	-
Non-deductible meals and entertainment expense	121	-	-	1,343.00	1,789.00	1,789.00	1,789.00
Reserves from financial statements- balance at end of year (employee future benefits and allowance for doubtful accounts)	126	469,548.00	361,122.00	425,135.00	574,218.00	601,740.00	630,204.00
Other Additions:		-	-	-	-		
Interest Expensed on Capital Leases	290	340,997.00	245,827.00	-	-		
Realized Income from Deferred Credit Accounts	291	-	89,817.00	-	-		
Pensions	292	-	1,181,992.00	-	-		
Non-deductible penalties	293	6,488.00	610,722.00	-	-		
Coop Tax Credit on 550	294	93,017.00	-	-	-		
OITC/ORDTC/BCRDT/ABRDTC from previous years	295	-	-	-	-		
Inducement under 12(1)(x) ITA (apprentice tax credit)					9,973.00	-	-
Customer Deposits (2335)					377,590.00	377,590.00	377,590.00
Tax included in net movement in reg balances					-		
Capital Contibutions Received (2440)					319,954.00	1,983,945.15	787,136.00
Regulatory Adjustment					769,773.00	-	-
					-		
					-		
Miscellaneous other additions	296	-	-	1,860,528.00	1,477,290.00	2,361,535.15	1,164,726.00
Total Additions		1,899,415.00	3,524,812.00	3,391,068.00	3,180,727.00	4,125,801.78	3,067,833.36
Deductions:							
Gain on disposal of assets per financial statements	401	-	-	-	-		
Dividends not taxable under section 83	402	-	-	-	-		
Capital cost allowance from Schedule 8	403	1,711,670.00	1,745,293.00	1,792,904.00	1,806,061.00	1,834,965.45	1,978,057.15
Terminal loss from Schedule 8	404	-	-	-	-		
Cumulative eligible capital deduction from Schedule 10 CEC (2017 included in UCC)	405	688.00	640.00	595.00	-	-	-
Reserves from financial statements - balance at beginning of year	414	473,290.00	469,548.00	361,122.00	425,135.00	574,218.00	601,740.00
Interest capitalized for accounting deducted for tax	390	45,452.00	36,133.00	-	-		
Capital Lease Payments	391	340,997.00	245,827.00	-	-		
Non-taxable imputed interest income on deferral and variance accounts	392	-	20,539.00	-	-		
	393	499,548.00	901,056.00	-	-		
	394	-	600,722.00	-	-		
Unrealized gain on deriviatives (4340)				65,352.00	46,137.00	-	-
Customer deposits				236,840.00	377,590.00	377,590.00	377,590.00
Amortization of deferred capital contributions				44,491.00	65,652.00	89,470.28	123,821.84
Capital contributions received				1,603,277.00	319,954.00	1,983,945.15	787,136.00
Adjustment for regulatory assets				642,463.00	-	-	-
Tax inlcuded in regulatory balances				-	323,875.00		
Tax on EFB				-	38,743.00		
				-	-		
Miscellaneous other deductions	396	-	-	2,592,423.00	1,171,951.00	2,451,005.44	1,288,547.84
ITA 13(7.4) Election - Capital Contributions Received		-	-	-	-		
Total Deductions		3,071,645.00	4,019,758.00	4,747,044.00	3,403,147.00	4,860,188.88	3,868,344.99
NET INCOME (LOSS) FOR TAX PURPOSES		- 51,083.00	- 383,781.00	- 18,286.00	1,421,693.00	300,044.46	304,616.75
Charitable donations from Schedule 2	311			-	400.00		
TAXABLE INCOME (LOSS)		- 51,083.00	- 383,781.00	- 18,286.00	1,421,293.00	300,044.46	304,616.75

2.4.5.2 Latest Filed Tax Return, Tax Assessments and Correspondence

NOTL Hydro's latest tax return is included in the Appendix.

2.4.5.3 Calculation of Tax Credits

NOTL Hydro is not claiming an Apprenticeship Training Tax Credit in the 2019 Test Year.

2.4.5.4 Other Additions and Deductions

- 2017 Historic Year - Other Additions
  - $9,973 – Inducement under 12(1)(x): Relates to the income inclusion under 12(1)(x) of the ITA for the prior year Ontario Apprenticeship Training Tax Credits.
  - $377,590 – Customer Deposits 12(1)(a): Relates to the income inclusion under 12(1)(a) of the ITA for customer deposits received in the year. An allowable reserve under 20(1)(m) of the ITA is taken on the customer deposits.
  - $319,954 – Capital Contributions Received 12(1)(x): Relates to the income inclusion under 12(1)(x) of the ITA for capital contributions received in the year. A deduction and election under 13(7.4) of the ITA is taken to apply the capital contributions to the capital cost of the property on Schedule 8 (i.e. reduces the capital cost of the property).
  - $769,773 – Regulatory Adjustment: Relates to the regulatory balances included in the P&L, excluding taxes.
- 2017 Historic Year - Other Deductions
  - $46,137 Unrealized Gain on Derivatives: Relates to the unrealized gain on interest rate swaps.
  - $377,590 – Customer Deposits 20(1)(m): Relates to an allowable reserve under 20(1)(m) ITA for the income inclusion under 12(1)(a) of the ITA.
  - $65,562 – Amortization of Deferred Capital Contributions: Relates to the amortization of deferred capital contributions in the P&L in the year. The capital contributions were previously applied to reduce the capital cost of the additions under 13(7.4) of the ITA.
  - $319,954 – Capital Contributions Received 13(7.4): A deduction and election under 13(7.4) is taken to apply the capital contributions to the capital cost of the property on Schedule 8 (i.e. reduces the capital cost of the property).
  - $323,875 – Tax included in Net Movements in Regulatory Balances: Relates to an adjustment to reverse the tax included in the regulatory balances. A separate adjustment is required as the tax was not reversed on line 101 or 102 of Schedule 1.

- $38,743 – Tax in EFBs: Relates to an adjustment to reverse the tax included in the EFB's. A separate adjustment is required as the tax was not reversed on line 101 or 102 of Schedule 1.

- 2018 Bridge Year - Other Additions
  - $2,000 - 12(1)(x) related to the apprentice claim in 2017.
  - $377,590 – Customer Deposits 12(1)(a): Relates to the income inclusion under 12(1)(a) of the ITA for customer deposits received in the year. An allowable reserve under 20(1)(m) of the ITA is taken on the customer deposits. NOTL Hydro does not anticipate and significant changes in Customer Deposits and therefore the historical year amount was used.
  - $1,983,945 – Capital Contributions Received 12(1)(x): Relates to the income inclusion under 12(1)(x) of the ITA for capital contributions received in the year. A deduction and election under 13(7.4) of the ITA is taken to apply the capital contributions to the capital cost of the property on Schedule 8 (i.e. reduces the capital cost of the property). Amounts are consistent with the Capital Contributions as presented in Chapter 2 Appendix 2-BA for 2018.
- 2018 Bridge Year - Other Deductions
  - $377,590 – Customer Deposits 20(1)(m): Relates to an allowable reserve under 20(1)(m) ITA for the income inclusion under 12(1)(a) of the ITA. NOTL Hydro does not anticipate and significant changes in Customer Deposits and therefore the historical year amount was used.
  - $89,470 – Amortization of Deferred Capital Contributions: Relates to the amortization of deferred capital contributions in the P&L in the year. The capital contributions were previously applied to reduce the capital cost of the additions under 13(7.4) of the ITA). Amounts are consistent with the amortization of Capital Contributions as presented in Chapter 2 Appendix 2-BA for 2018.
  - $1,983,945 – Capital Contributions Received 13(7.4): A deduction and election under 13(7.4) is taken to apply the capital contributions to the capital cost of the property on Schedule 8 (i.e. reduces the capital cost of the property). Amounts are consistent with the Capital Contributions as presented in Chapter 2 Appendix 2-BA for 2018.

- 2019 Test Year - Other Additions
    - $377,590 – Customer Deposits 12(1)(a): Relates to the income inclusion under 12(1)(a) of the ITA for customer deposits received in the year. An allowable reserve under 20(1)(m) of the ITA is taken on the customer deposits. NOTL Hydro does not anticipate and significant changes in Customer Deposits and therefore the historical year amount was used.
    - $787,136 – Capital Contributions Received 12(1)(x): Relates to the income inclusion under 12(1)(x) of the ITA for capital contributions received in the year. A deduction and election under 13(7.4) of the ITA is taken to apply the capital contributions to the capital cost of the property on Schedule 8 (i.e. reduces the capital cost of the property). Amounts are consistent with the Capital Contributions as presented in Chapter 2 Appendix 2-BA for 2019.
- 2019 Bridge Year - Other Deductions
    - $377,590 – Customer Deposits 20(1)(m): Relates to an allowable reserve under 20(1)(m) ITA for the income inclusion under 12(1)(a) of the ITA. NOTL Hydro does not anticipate and significant changes in Customer Deposits and therefore the historical year amount was used.
    - $123,822 – Amortization of Deferred Capital Contributions: Relates to the amortization of deferred capital contributions in the P&L in the year. The capital contributions were previously applied to reduce the capital cost of the additions under 13(7.4) of the ITA). Amounts are consistent with the amortization of Capital Contributions as presented in Chapter 2 Appendix 2-BA for 2019.
    - $787,136 – Capital Contributions Received 13(7.4): A deduction and election under 13(7.4) is taken to apply the capital contributions to the capital cost of the property on Schedule 8 (i.e. reduces the capital cost of the property). Amounts are consistent with the Capital Contributions as presented in Chapter 2 Appendix 2-BA for 2019.

2.4.5.5 Non-recoverable and Disallowed Expenses (OEB Ref 2.4.5.1)

NOTL Hydro confirms that expenses that are deemed non-recoverable in the revenue requirement (e.g. certain charitable donations) or disallowed for regulatory purposes have been excluded from the regulatory tax calculation. There are no reconciling items to arrive at Regulatory Taxable Income form Net Income for Tax Purposes in the Test year.

2.4.5.6 Integrity Checklist

NOTL Hydro has had the PILS model reviewed by its external auditors, KPMG. The utility affirms that the integrity checks in tab S1 of the PILS model have been completed.

Table 4.41: Integrity Checks – 2019 PILS Model



Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non- distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the UCC schedules for the same years filed in the application	Y	
5	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y	
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.	Y	
9	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the application.	Y	

2.4.6 Conservation and Demand Side Management

2.4.6.1 Overview of CDM

The 2015-2020 Energy Conservation Agreement was signed with an effective date of December 10, 2014. NOTL Hydro received first iteration CDM Plan approval from the IESO on June 16, 2015 with the Conservation First launch planned for January 1, 2016. Costs associated with CDM initiatives are paid through the PAB budget provided by the IESO.

NOTL Hydro does not apply any OM&A costs related to the administration and delivery of CDM programs to be recovered through the revenue requirement.

NOTL Hydro has a target of 11.68 GWh for the 2015-2020 Conservation First Initiative. As of December 31, 2017, NOTL Hydro had achieved 10.50 GWh or 90% of its target. The 90% achievement was ranked 12th best in the province.

2.4.6.2 Lost Revenue Adjustment Mechanism (OEB Ref 2.4.6.1)

NOTL Hydro last applied for an LRAM adjustment in 2016 (EB-2016-0095) which cleared the balances up to 2015.

2.4.6.3 Disposition of the LRAMVA

The table below illustrates the balances recorded in NOTL Hydro's LRAMVA account by rate class for the program period 2011 to 2017:

Table 4.42: Summary of Requested LRAMVA Amounts

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	Street Lighting	Unmetered Scattered Load	General Service 50 - 4,999 kW	Total
		kWh	kWh	kW	kWh	kW	
2011 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2012 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2013 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2014 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2015 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2016 Actuals	☐	$22,353.60	$30,305.37	$31,223.24	$0.00	$24,738.05	$108,620.26
2016 Forecast		($4,979.74)	($14,033.57)	$0.00	$0.00	($2,379.45)	($21,392.76)
Amount Cleared							
2017 Actuals		$25,384.05	$36,341.80	$31,743.35	$0.00	$35,082.11	$128,551.31
2017 Forecast		($3,550.37)	($14,279.77)	$0.00	$0.00	($2,419.08)	($20,249.23)
Amount Cleared							
2018 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2018 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2019 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2019 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2020 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2020 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
Carrying Charges		$1,374.16	$1,335.55	$2,243.95	$0.00	$1,905.82	$6,859.48
Total LRAMVA Balance		**$40,582**	**$39,669**	**$65,211**	**$0**	**$56,927**	**$202,389**

In reviewing the above table, it should be noted that:

- NOTL Hydro is only claiming LRAMVA disposition for 2016 and 2017.
- The LRAMVA is based on results from the IESO's "2017 Final Verified Annual LDC CDM Program Results for Niagara-on-the-Lake Hydro Inc." report issued on June 29, 2018.
- Forecast CDM savings with respect to the 2016 and 2017 LRAMVA are as follows:

Table 4.43: Forecast CDM Savings for 2016 and 2017 (kWh)

	Residential	GS< 50 kW	Streetlighting	USL	GS>50 kW	Total
Actual 2016	1,109,104	690,381	117	-	4,208	1,803,810
Actual 2017	1,274,055	817,770	-	-	4,548	2,096,373
Forecast 2017	461,087	1,231,015	-	-	1,104	1,693,206

- There were no projects in the calculations not included in the IESO report.
- Rate class allocations were determined on a program by program basis.

Table 4.44: LRAMVA Balance for Disposition

Account Name	Account Number	Actual CDM Savings ($)	Forecasted CDM Savings ($)	Carrying Charges ($)	Total Claim
LRAMVA	1568	$237,172	-$41,642	$6,859	$202,389

A copy of the IESO's "2017 Final Verified Annual LDC CDM Program Results for Niagara-on-the-Lake Hydro Inc." report issued on June 29, 2018, containing the actuals for NOTL Hydro for the end of 2017 is included in the Appendix.

Appendix

List of Appendices

Appendix 4A	Collective Agreements
Appendix 4B	Tax Return Exempt Client
Appendix 4C	Tax Return PILS Client
Appendix 4D	IESO's "2017 Final Verified Annual LDC CDM Program Results for Niagara-on-the-Lake Hydro Inc." report issued on June 29, 2018
Appendix 4E	Depreciation and Capitalization Policy
Appendix 4F	Purchasing & Procurement Policy
Appendix 4G	Actuarial Report
Appendix 4H	Appendix 2-C -NOTL_2019-Fiiling-Requirements-Chapter2_Appendix2C-20180718

APPENDIX

4A

2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056



COLLECTIVE AGREEMENT

between

NIAGARA-ON-THE-LAKE HYDRO INC.

and

LOCAL UNION NO. 636

of the

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

May 1, 2016 to April 30, 2020

(Line/Engineering Staff)

TABLE OF CONTENTS

ARTICLE 1 - RECOGNITION 1
ARTICLE 2 - UNION SECURITY AND CHECK-OFF 1
ARTICLE 3 - MANAGEMENT RIGHTS 1
ARTICLE 4 - CORPORATION SERVICE CREDIT 1
Definition 1
ARTICLE 5 - EMPLOYEE CATEGORIES 2
ARTICLE 6 - LOCKOUTS AND STRIKES 2
ARTICLE 7 - GRIEVANCE PROCEDURE 2
ARTICLE 8 - ARBITRATION PROCEDURE 3
ARTICLE 9 - HOURS OF WORK AND OVERTIME 3
Hours of Work 4
Overtime 4
ARTICLE 10 - ON-CALL AND MINIMUM CALL-OUT 4
Outage Calls 4
Minimum Call-Out 5
ARTICLE 11 - RECOGNIZED HOLIDAYS 5
ARTICLE 12 - VACATIONS 5
ARTICLE 13 - SICK LEAVE PLAN 6
ARTICLE 14 - HEALTH PLAN 6
ARTICLE 15 - PENSION AND INSURANCE 7
ARTICLE 16 - JOB POSTING AND SELECTION 7
ARTICLE 17 - LAY OFF AND RECALL 7
ARTICLE 18 - LEAVE OF ABSENCE FROM WORK 7
Bereavement 7
Leave for Union Business 8
Jury Duty/Crown Witness 8
Personal Leave 8
ARTICLE 19 – WORKPLACE SAFETY AND INSURANCE BOARD(W.S.I.B.) 8
ARTICLE 20 - ALLOWANCES 8
Equipment 8
Clothing Allowance 9
Meals 9
Relief in Another Classification 9
Safety Boots 9
Tools 9
ARTICLE 21 - GENERAL 9
Committee and Stewards 9
Contracting Out 10
Health and Safety 10
ARTICLE 22 - WAGES AND PROGRESSIONS 10
ARTICLE 23 - DURATION 10
SCHEDULE "A" - WAGES 12
SCHEDULE "B" - SICK LEAVE PLAN 13

COLLECTIVE AGREEMENT
between

NIAGARA-ON-THE-LAKE HYDRO INC.
(Hereinafter called the "Corporation")
and

LOCAL UNION NO. 636
of the
INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS
(Hereinafter called the "Union")

ARTICLE 1 - RECOGNITION

1.1 Corporation hereby recognizes the Union as the sole collective bargaining agent for all employees of Niagara-on-the-Lake Hydro Inc. at Niagara-on-the-Lake, Ontario save and except foremen, all persons above the rank of foreman, all office employees, persons regularly employed for not more than twenty-four (24) hours per week, students employed during the school vacation period, students employed on a cooperative training program and individuals hired on a government-sponsored program.

ARTICLE 2 - UNION SECURITY AND CHECK-OFF

2.1 All employees covered under Article 1 of this agreement who are members of the Union shall remain members of the Union and all new employees shall become and remain members of the Union after thirty (30) calendar days of employment.

2.2 All employees in the bargaining unit shall be required to sign an authorization assigning to the union an amount equivalent to regular monthly dues and the Corporation shall deduct such amounts from the weekly wages of employees and to remit the dues to the financial secretary of Local 636 by the 15th of the month following the month in which the deductions were made with a list of the names of the employees from whose pay such deductions have been made. The Corporation will provide the minimum information to calculate union dues when requested. The Corporation will also deduct a one-time union initiation fee in addition to the weekly dues as described by the union. The dues to be included on the T4 slip

2.3 It is understood and agreed that the Union will save the Corporation harmless from any and all claims which may be made against it by an employee or employees for amounts deducted from earnings as herein provided.

2.4 A Union Negotiating Committee shall consist of a maximum of two (2) members plus the Union Business Manager or designate for the purpose of Collective Bargaining. Members so appointed, excluding the Union Business Manager or designate must be employees of the Corporation covered by this Collective Agreement and have completed the probation period as set out in Article 5.

2.5 Both the Corporation and the Union recognize their respective responsibilities under the Human Rights Code and any other statutory requirements.

ARTICLE 3 - MANAGEMENT RIGHTS

3.1 The Union acknowledges and agrees that the Corporation has the exclusive right to manage its business, and without limiting the generality of the foregoing, to direct the working force, to hire, promote, transfer, demote or lay off employees, discharge, or otherwise discipline employees, for just cause, and to make, amend and enforce such rules and regulations as shall from time to time be required, provided that they are not inconsistent with the provisions of this agreement.

3.2 All functions and prerogatives heretofore vested in and exercised by the Corporation shall remain solely with the Corporation except as specifically limited by the express provision of this agreement.

ARTICLE 4 - CORPORATION SERVICE CREDIT

Definition

4.1 The length of continuous service a regular employee has established with the Corporation from the most recent date the employee entered the employ of the Corporation.

4.2 The Corporation shall maintain a seniority list showing the date upon which each employee's Corporation service commenced. An up-to-date seniority and classification list shall be sent to the Union and posted on all bulletin boards in January of each year.

4.3 A regular employee shall lose seniority rights and have his name removed from the employment records if he:

(I) retires;
(II) resigns;
(III) is discharged for just cause and not reinstated through the grievance/arbitration procedure;
(IV) is absent from work for three (3) working days without notification to the employer, unless a satisfactory explanation is provided for this absence;
(V) fails to report to work within ten (10) working days following recall after a lay off unless a satisfactory explanation is provided for this failure;
(VI) is absent from work because of lay off or leave of absence for a period greater than one (1) year;
(VII) fails to return to work within twenty-four (24) months as a result of a non-occupational illness or injury.
(VIII) fails to return to work within twenty-four (24) months as a result of an occupational illness or injury.

ARTICLE 5 - EMPLOYEE CATEGORIES

5.1 **Temporary employees** are those hired for a period of not more than six (6) consecutive months or for a specific task or twelve (12) consecutive months to cover off maternity/parental leave requirements under the Employment Standards Act. They shall not accumulate Corporation Service Credit nor shall they be entitled to any of the rights or privileges accruing to regular or probationary employees, nor shall they have recourse to the grievance and arbitration procedures.

5.2 **Probationary employees** are those who are hired on trial basis to determine their suitability for employment in regular positions. An employee shall be considered probationary for a period of six (6) months worked, at the discretion of Management.

5.3 Where it is mutually agreed that the ability to assess an employee is affected by periods of non-working time such as sickness, leaves of absence, etc., the probationary period may be extended in direct proportion to the periods of lost time after consultation with the Union.

5.4 During this period of probation, he shall be entitled to all the rights and privileges set out in the collective agreement, except that he shall not have recourse to the grievance and arbitration procedure on termination.

5.5 **Regular employees** are persons who have satisfactorily served a probationary period and are currently in the employ of the Corporation.

5.6 The term "employee" when used in this agreement shall mean "regular employee" unless specifically stated otherwise.

5.7 **Government Sponsored Program Employees**

Employees who may be hired under the provision of Article 1, Cooperative Training Program and Government Sponsored Program shall not be employees to replace regular employees.

5.8 **Singular or Masculine**

Whenever the singular or masculine is used in the agreement, it shall be used as if plural or feminine has been used where the context of the agreement so indicates.

ARTICLE 6 - LOCKOUTS AND STRIKES

6.1 There shall be no "lockout" by the Corporation and no interruption, work stoppage or "strike" during the term of this agreement. The terms "strike" and "lockout" shall be interpreted in accordance with the definitions as set out in the Labour Relations Act.

ARTICLE 7 - GRIEVANCE PROCEDURE

7.1 For the purpose of this agreement, a dispute, claim or complaint which involves the interpretation, application, administration or alleged violation of some provisions of this agreement, shall be considered to be a fit matter for a grievance and shall be dealt with as specified below.

7.2 Complaints and grievances shall be dealt with in the following manner and all grievances must be in writing and filed within fourteen (14) calendar days of the circumstances giving rise to the grievance.

7.3 **Step 1**
The employee, accompanied by a steward if the employee wishes, may take the matter up with the appropriate department head who will give his reply in writing within three (3) working days. Failing settlement of this stage, the employee may immediately proceed to Step 2, within three (3) working days.

7.4 **Step 2**
The employee, accompanied by a steward and/or a representative of the Union, may take the matter up with the general manager or designate who will reply in writing within five (5) working days. Failing settlement of this stage, the matter may then be referred to Article 8 of this agreement within twenty (20) working days.

7.5 Where a dispute involving a question of general application or interpretation occurs or where a group of employees or the Union has a grievance, Step 1 of this Article may be bypassed and such grievance submitted at Step 2 within five (5) working days of the occurrence of the event giving rise to the grievance.

7.6 A claim by an employee that he has been suspended or discharged without just cause shall be treated as a grievance if a written statement of such grievance is lodged with the general manager at Step 2 within five (5) working days after notice by management to the Union Steward of the suspension or discharge.

7.7 The time limits provided in this article may be extended by mutual written agreement between the parties concerned.

7.8 Notwithstanding the above, the parties may reach settlement to a grievance through the services of a Grievance Settlement Officer or other mutually agreeable third party facilitator. The parties shall jointly bear the expense of the Grievance Settlement Officer or other agreed-upon third party.

ARTICLE 8 - ARBITRATION PROCEDURE

8.1 Where a difference arises between the parties relating to the interpretation, application or administration of this agreement, including any question as to whether a matter is arbitrable, or where an allegation is made that this agreement has been violated, either of the parties may, after exhausting any grievance procedure established by this agreement, notify the other party in writing of its desire to submit the difference or allegation to arbitration. The parties to this agreement may request the Ontario Minister of Labour to appoint a single arbitrator in accordance with the provisions of the Labour Relations Act (Ontario) or the parties may otherwise agree to the appointment of a sole arbitrator.

8.2 The arbitrator shall hear and determine the difference or allegation and shall issue a decision and the decision shall be final and binding upon the parties and upon any employee or employer affected by it.

8.3 The arbitrator shall not make any decision inconsistent with the provisions of this agreement, nor alter, modify or amend any part of this agreement, but shall only consider the question in dispute.

8.4 No matter shall be submitted to arbitration, which has not been properly lodged and carried through all previous steps of the Grievance Procedure.

8.5 The proceedings of the arbitrator will be expedited by the parties hereto, and the decision of the arbitrator shall be final and binding upon all parties concerned.

8.6 The expense of the arbitrator together with any incidental or general expense connected with the arbitration proceedings shall be divided equally between the parties hereto.

ARTICLE 9 - HOURS OF WORK AND OVERTIME

9.1 This section provides the basis for establishing work schedules and for the calculation and payment of overtime, but shall not be read or construed as a guarantee of hours of work per day or week or a guarantee of days of work per week.

Hours of Work

9.2 The normal work week of employees shall be forty (40) hours of work per week consisting of five (5) days of eight (8) hours each from Monday to Friday inclusive between the hours of 0800 and 1630 with one-half (½) hour lunch period.

Overtime

9.3 Due to the nature of its operations the Corporation may require employees to work at other than their normal hours and in addition to their normal hours beyond the limits as described above. An employee shall be paid for overtime at the rate of two (2) times his regular hourly rate for all work performed from normal quitting time until normal starting time and on Saturday, Sunday and Recognized Holidays.

9.4 An employee who is required to work for more than sixteen (16) hours or an employee who accumulates sixteen (16) hours of working time in any twenty-four (24) hour period shall be entitled to an eight (8) hour rest period.

9.5 An employee will qualify for 4 hours of rest time to commence at the start of the next regular shift should he/she work more than three (3) consecutive hours during the period between midnight and the next regular shift and 8 hours rest time to commence at the start of the next regular shift should he/she work five (5) or more consecutive hours between midnight and the next regular shift. All rest time will be paid at straight time pay.

9.6 Should the employee be required to continue working beyond the sixteen (16) hour period, the employee shall be paid 2 times his regular hourly rate until an eight (8) hour rest period is granted.

9.7 All employees will be permitted to bank lieu time hours of overtime. The amount added into the bank is not to exceed eighty (80) hours during the calendar year. The employee will have the opportunity to carry-over up to one (1) week of lieu time provided the combination of lieu time and vacation time carryover does not exceed a total of two (2) weeks. All other lieu time will be cashed out. If lieu time is cashed out throughout the year, it may not be replenished. Employees will give two weeks' notice if they wish to cash out any portion of their lieu time throughout the year.

ARTICLE 10 - ON-CALL AND MINIMUM CALL-OUT

Outage Calls

10.1 On-call duty for outage calls is defined as that duty performed by qualified employees who are required by the Corporation to be readily available within thirty-five (35) minutes (by means of normal driving conditions) of the service territory for emergency service at other than normal working hours.

10.2 Qualified employees will be required to perform on-call duty on a weekly basis in accordance with a list posted by Management. The employee on-call duty is required to hold himself readily available outside of normal hours of work for dispatch on calls.

10.3 The employee designated for on-call duty for outage calls will be paid an additional $275.00 per week for such duty effective May 1, 2016; $280.00 per week for such duty effective May 1, 2017; $285.00 per week for such duty effective May 1, 2018 and $290.00 per week for such duty effective May 1, 2019. An additional $85.00 will be paid for statutory holidays effective May 1, 2016; $90.00 effective May 1, 2017; $95.00 effective May 1, 2018 and $100.00 effective May 1, 2019. Should an employee be called out on a statutory holiday, he will have the option to bank 8 hours in lieu of their $85 year 1, $90 year 2, $95 year 3 and $100 year 4, provided that they have enough room in their lieu time bank per article 9.7.

In the event that the employee does not get called out on a statutory holiday, he will have the option to bank 4 hours of lieu time (subject to not exceeding their allowance per article 9.7) or receive the regular stat allowance.

10.4 The on-call week shall be from normal quitting time Thursday, to normal quitting time the following Thursday.

10.5 The Corporation will supply and pay for paging devices.

Minimum Call-Out

10.12 When an employee is called in for emergency overtime work outside of his normal working hours, he shall be provided with a minimum payment of two (2) hours' pay at the appropriate premium rate. Calls received within 15 minutes of the completion of the shift will be counted as continuous overtime and a minimum call-out will not apply.

10.13 When an employee has completed his call-out he will be allowed to return home, provided he has checked to ensure that additional calls have not been received. All calls received within two (2) hours of the first call shall be considered the same call.

10.14 There shall be no minimum payment applicable to call-outs or overtime worked contiguous to an employee's normal daily working hours. Calls received less than one hour before normal starting time do not qualify for minimum call out. Overtime rate for time worked will apply.

ARTICLE 11 - RECOGNIZED HOLIDAYS

11.1 Each employee shall be entitled to the following paid holidays:

New Year's Day	Civic Holiday
Good Friday	Labour Day
Victoria Day	Thanksgiving Day
Canada Day	One-half Day Before Christmas
Boxing Day	One-half Day Before New Year's Day
Christmas Day	Family Day

and all additional holidays proclaimed by federal and provincial governments.

11.2 Two (2) additional floater holidays at a time most desired by the employee, providing this does not impede the efficient operation of the Corporation's business.

11.3 Payments for the above-named recognized holidays will be made provided the employee works the regularly assigned day immediately preceding and succeeding the day of observance of the holiday or, unless on an authorized short term leave of absence (three (3) weeks or less), vacation or sick leave.

11.4 In the event of any of the above-named holidays falling on a Saturday and/or Sunday and not proclaimed as being observed on some other day, the preceding Friday or the following Monday as determined by the Corporation shall be deemed to be holidays for the purpose of this agreement unless otherwise agreed to by the parties.

ARTICLE 12 - VACATIONS

12.1 Vacations will, as far as it is practicable, be granted at the times most desired by the employees, providing this does not impede the efficient operation of the Corporation's business.

12.2 An employee must notify Management of his preferred vacation period by April 1 in any given year. However, Management shall retain the authority to designate vacation periods for all employees in a manner consistent with the efficient operation of the Corporation. Vacations are not cumulative and shall be taken during each calendar year unless approved by Management. Such approval must be requested by the employee, in writing, by November 31st and must be specific in the vacation request for the following year. If such application is received by November 31st, Management will reply within 10 working days. A maximum of two weeks carry-over to the following year will be allowed but must be taken before November 31st in the carry-over year.

12.3 Probationary and temporary employees shall be granted vacation entitlement as provided by the Employment Standards Act.

12.4 An employee with less than one (1) year continuous service shall be entitled to four (4) percent of gross wages at December 31, or the equivalent time off with pay.

12.5 An employee with one (1) year or more of continuous service completed during the calendar year ended December 31 will be entitled to two (2) weeks' vacation with pay at the employee's regular hourly rate based on the employee's normal work week.

12.6 An employee with three (3) years or more of continuous service completed during the calendar year ended December 31 will be entitled to three (3) weeks' vacation with pay at employee's regular hourly rate based on the employee's normal work week.

12.7 An employee with nine (9) years or more of continuous service completed during the calendar year ending December 31 will be entitled to four (4) weeks' vacation with pay at employee's regular hourly rate based on the employee's normal work week.

12.8 An employee with seventeen (17) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) weeks' vacation with pay at employee's regular hourly rate based on the employee's normal work week.

12.9 An employee with twenty-two (22) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and one (1) day with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-three (23) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and two (2) days with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-four (24) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and three (3) days with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-five (25) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and four (4) days with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-six (26) years or more of continuous service completed during the calendar year ending December 31 will be entitled to six (6) weeks' vacation with pay at employee's regular hourly rate based on the employee's normal work week.

12.10 An employee shall not be granted more than two (2) weeks' vacation during the period of July 1 to September 30 except with permission of the Management.

12.11 Vacation pay shall be based on the employee's regular hourly rate.

12.12 To be entitled to vacation pay, an employee must work forty (40) of the weeks in the year ending December 31. If an employee works fewer than forty (40) weeks his vacation shall be reduced on a pro-rata basis for each week less than the forty (40) weeks, which he does not work. Maternity leave, W.S.I.B. and Jury duty are excluded.

ARTICLE 13 - SICK LEAVE PLAN

13.1 The Sick Leave Plan as specified in detail in Schedule "B" is attached to and forms part of this agreement.

ARTICLE 14 - HEALTH PLAN

14.1 The Corporation agrees to pay for employees in receipt of regular hourly rate, one hundred percent (100%) of the premiums for the following Health Plans or equivalent:

- ClaimSecure Extended Health Plan $10/$20 deductible;
    - Includes Chiropractic at $1000/year maximum (all dependents combined)
    - Includes Massage therapy to $1000/year maximum (all dependents combined)
    - Includes Physiotherapy to $1,000/year maximum (all dependents combined)
    - Includes Semi-private coverage (if available)
    - Includes Drug dispensing cap of $12.50 effective May 1, 2016; $13.00 effective May 1, 2017; $13.50 effective May 1, 2018 and $14.00 effective May 1, 2019. Employees agree to accept 'Generic Drugs' first and 'Formulary Plan' with Doctor Override
- Basic Dental Plan (ClaimSecure Level 1 & 2) ($2,250 per person, per year maximum), Crown & Bridgework and Orthodontics coverage (ClaimSecure Level 3 & 4)(50/50 co-pay, $2,400.00 per person, per year maximum -- Orthodontic coverage to terminate at age 19). Dental recall for adults shall be every nine (9) months and for children under the age of eighteen (18) it shall be every six (6) months
- ClaimSecure Vision Plan providing a maximum benefit coverage of $450.00 every 24 months effective May 1, 2016. Eye examinations $90/two years; Vision coverage can be used towards Corrective Laser Eye Surgery.
- ClaimSecure Out-of-Province/Country maximum of 60 days/trip coverage.
- Long Term Disability Plan providing 70% income benefit to a maximum of $3,600 per month with an eighty-five (85) working-days waiting period.

14.2 The Corporation agrees to pay for employees in receipt of normal base wages one hundred percent (100%) of the premium for a Basic and Comprehensive basic Dental Service or equivalent with current O.D.A. Fee Schedule.

14.3 If there is a change in carriers, the Union must be notified immediately. The plan must be of equal or better value.

ARTICLE 15 - PENSION AND INSURANCE

15.1 All eligible employees with the Corporation shall participate in the Corporation's Pension and Insurance Plans as follows:

- Ontario Municipal Employees Retirement System Basic FAE (Final Average Earnings) on a equally shared basis with the Corporation.
- The Corporation and the employees shall participate in the Canada Pension Plan as required by the Canada Pension Act.
- The Corporation shall provide Life Insurance coverage for all regular employees in receipt of normal base wages, equivalent to current coverage of one and one-half (1½) times the employee's normal base wages.

15.2 The Corporation agrees to pay fifty percent (50%) of the premiums for Dental and Extended Health including Vision Care for all employees who retire early between the ages of 55 to 65.

ARTICLE 16 - JOB POSTING AND SELECTION

16.1 When vacancies occur within the bargaining unit, or new jobs are created within the bargaining unit, these positions shall be posted on the bulletin board, accessible to all employees, for a period of five (5) working days, during which time present employees shall have the opportunity of applying before outsiders are considered. During the posting period, the Corporation may fill a vacancy on a temporary basis. The experience gained while filling this temporary vacancy will not be used as determining factor in the job selection process.

16.2 Such notice shall contain the following information: nature of the position, qualifications, knowledge, experience, skills, and wage rates.

16.3 In filling vacancies and making transfers or promotions among employees represented by the Union, the Management will consider the qualifications and ability as the primary factors. In the event qualifications and ability of the respective applicants are relatively equal in Management's opinion, Corporation service shall govern.

16.4 Promotion shall mean advancement to a job which carries a higher rate of pay.

ARTICLE 17 - LAY OFF AND RECALL

17.1 In the event of a lay-off, Management agrees that employees shall be laid off in the reverse order of their Corporation service credit provided Management can retain a work force qualified in its opinion to perform the work remaining. Employees shall be recalled in the order of their Corporation service credit provided they are qualified, capable and have the ability to do the work available.

17.2 It shall be the responsibility of the employee to keep Management informed, in writing, of change in his postal address and telephone number.

17.3 It is understood that in exercising his accrued rights in accordance with the above, advancement to a job, which carries a higher rate of pay, is not permitted.

ARTICLE 18 - LEAVE OF ABSENCE FROM WORK

Bereavement

18.1 An employee will be allowed up to five (5) working days' leave of absence with pay in the event of the death of his spouse, child, mother or father. Such leave shall be for the purpose of making arrangements and/or attending the funeral.

18.2 An employee will be allowed up to three (3) consecutive days' leave of absence with pay in the event of the death of his brother, step-brother, sister, step-sister, grandparent, grandchild, father-in-law or mother-in-law,

step-parent, or step child. Such leave shall be for the purpose of making arrangements for and/or attending the funeral. Only that portion of the said three (3) days that would otherwise have been regular time worked will be paid.

18.3 An employee will be allowed one (1) day leave of absence with pay in the event of the death of any current staff member, brother-in-law, sister-in-law, step parent-in-law, aunt, uncle, niece, nephew or grandparent-in-law. Such leave shall be for the purpose of making arrangements for and/or attending the funeral. In the event of the death of any other relative, unpaid time off to attend the funeral may be granted, not to exceed one (1) day.

18.4 Request for additional time off is covered under Article 18.7.

Leave for Union Business

18.5 Insofar as the efficient operation of the Corporation's business will permit, requests for leave of absence without pay and benefits may be granted to Union representatives for the purpose of taking part in official Union business. Such requests shall be made, in writing, to Management at least two (2) weeks in advance of the absence.

Jury Duty/Crown Witness

18.6 The Corporation shall pay an employee, who is required for Jury Duty or subpoenaed as a witness on behalf of the Corporation, the difference between his regular hourly rate and the payment received for such activity, excluding travel and meal expenses. The employee shall present proof of such payment received.

Personal Leave

18.7 Leaves of absence require the written permission of Management. Application for leave of absence must be submitted, in writing, at least one (1) week in advance to insure consideration unless not possible by reason of unforeseen personal emergency in which case verbal application will be accepted. Unless otherwise agreed, leave of absence will be without pay and leave of absence extending beyond five (5) days will be without pay and benefits. In this case, all costs (employee and employer costs) of the normal indemnities will be payable by the employee.

18.8 In the case of a leave of absence without pay, which exceeds thirty (30) days, Corporation Service Credit of regular employees will be frozen for the duration of the leave of absence at the level attained prior to the leave of absence. Freezing of service credit will not be in conflict with the Employment Standards Act of Ontario with respect to pregnancy/parental leave.

ARTICLE 19 – WORKPLACE SAFETY AND INSURANCE BOARD (W.S.I.B.)

19.1 When an employee, through his employment by the Corporation, suffers a disability which is compensable under the Workplace Safety and Insurance Act, the employee will be paid in accordance with the Act, and the Corporation will maintain up to a maximum of one and a half (1½) years, medical benefits and life insurance coverage on behalf of the employee as if he were in receipt of his regular hourly rate from the Corporation with the employee having the option to pay all the costs himself for an additional six (6) months. However, in the event that legislative requirements reduce the amount payable to those employees eligible for W.S.I.B. assistance below the present ninety percent (90%), the employer shall make up the difference between the amount paid through W.S.I.B. requirements to a benefit equal to ninety percent (90%) of the employees take home pay.

ARTICLE 20 - ALLOWANCES

Equipment

20.1 The Corporation shall issue, where required, the following equipment to be used by the employee in the safe performance of assigned duties.

- safety hard hat

- flash goggles and face shields
- rubber gloves complete with covers
- leather work gloves
- rainwear
- rubber boots
- spurs, body belts and pole straps
- safety goggles to fit over regular glasses
- Sunscreen

The above will only be replaced when worn out or broken.

Clothing Allowance

20.2 Safety Clothing will be provided to all Employees on an as needed basis.

Meals

20.3 Two (2) hours' overtime contiguous to the normal work hours and every four (4) hours thereafter are necessary in order to qualify for an overtime meal allowance, the amount of which cannot exceed fifteen dollars ($15.00). Planned overtime is excluded from the overtime meal allowance. One (1) day notice is required for planned overtime for the purpose of sufficient notice to prepare a lunch.

20.4 Under emergency conditions, when the Corporation provides a meal, a meal allowance will not be paid.

20.5 When employees are required on a daily basis to attend training sessions or seminars and if a meal is provided during the session, a meal allowance will not be applicable. When meals are not provided, the Corporation will provide $20 dollars for lunch with no receipt required. Other meals are not applicable for daily training sessions.

20.6 When an employee is required to attend training or seminars an appropriate meal allowance will be provided each day of $15 for breakfast, $20 for lunch and $35 for dinner. Overnight accommodations will be paid by the Corporation. No receipts are required for meal allowances.

Relief in Another Classification

20.7 When an employee is detailed to relieve in a unionized classification of higher rating such employee shall receive the rate of the higher classification.

When a unionized employee is detailed temporarily in a management position such employee shall receive an additional two dollars ($2.00) per hour above the lead hand rate in cases where the appointment is to a management position.

20.8 When an employee is detailed to relieve in a position of lower rating, such employee shall continue to receive regular hourly rate.

Safety Boots

20.9 The Corporation shall provide an allowance of up to nine hundred and twenty ($920) for the length of this contract – May 1, 2016 to April 30, 2020, toward the cost of CSA approved safety boots, on presentation of proof of purchase, to each employee required to wear them.

Tools

20.10 The Corporation shall supply all new regular employees with a set of tools deemed by Management to be appropriate for the work in their classification. Such tools shall remain the property of the Corporation and be maintained by the employees. Such tools shall be replaced by the Corporation if worn out or broken while performing work for the Corporation.

ARTICLE 21 - GENERAL

Committee and Stewards

21.1 The Corporation recognizes the appointment of two (2) stewards by the Union for the purpose of conducting relevant union business. The Union will keep the Corporation informed, in writing, of such appointments.

21.2 (i) Since stewards have regular duties to perform on behalf of the Corporation, they will not leave their regular duties without receiving permission from the foreman.

(ii) It is a steward's first responsibility to perform the work required of him/her as an employee of the Corporation. It is recognized, however, that a steward is the Union representative in the workplace with who the Corporation is required to deal as require by this agreement. Accordingly, a steward will, with the advance

permission of his/her supervisor, be granted reasonable time during working hours without loss of pay to attend grievance meeting.

(iii) A steward may, where an employee so requests, attend or be called into any meeting between the employee and management which is for the purpose of issuing discipline, a suspension or discharge of the employee. The foregoing shall not apply where the suspension or discharge is not issued in person to the employee.

Contracting Out

21.3 No employee will be laid off as a result of contracting out of bargaining unit work.

Health and Safety

21.4 The Corporation and the Union recognize the obligation and responsibility of the Corporation and their employees to ensure the establishment and maintenance of good health and safety work practices. It is further recognized and understood that the employee must abide by all safety rules and regulations. It is further recognized and understood that the Corporation will not impede the health and safety of its employees while working beyond normal working hours.

ARTICLE 22 - WAGES AND PROGRESSIONS

22.1 The wage rates and classifications shall be as set out in Schedule "A" attached to and forming part of this agreement for purposes of payment of wages only.

22.2 Employees on progression shall normally be progressed in accordance with the schedule. However, if any employee fails to make satisfactory progress, his advancement will be withheld for a period of six (6) months. When progression is withheld Management shall give one (1) month's notice to the employee and reason for withholding routine progression. At the next routine progression date his general performance will be reviewed and if found satisfactory, he shall be granted routine progression. If his progress and general performance are not found to be satisfactory, he shall be transferred to another classification, if available, or dismissed.

ARTICLE 23 - DURATION

23.1 This agreement shall become effective on May 1, 2016 and such agreement shall remain in effect until April 30, 2020, and from year to year thereafter unless either party gives notice in writing to the other party within the ninety (90) day period prior to the expiry date of its desire to alter or terminate same.

23.2 In witness whereof the parties hereto have herewith set their hands and seals this 29th day of June, 2016.

Vice President, Operations

NIAGARA-ON-THE-LAKE HYDRO INC.

Tim Curtis
President

Philip Wormwell
Vice President, Finance

Hassan Syed

LOCAL UNION 636 OF THE INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

Domenic Murdaca
Business Representative

Martyn Heard
Union Steward

Jonathan Beam
Member

Kevin Sidey
Member

Barry Brown
Business Manager/Financial Secretary

SCHEDULE "A" - WAGES

Classification	%	May 1, 2016 (2.1%)	May 1, 2017 (2.1%)	May 1, 2018 (2.0%)	May 1, 2019 (2.0%)
Leadhand	107	42.73	43.62	44.50	45.39
Sr. Engineering Technologist	107	42.73	43.62	44.50	45.39
Journeyman Lineman	100	39.93	40.77	41.59	42.42
4th year	90				
3rd year	80				
2nd year	70				
1st year	65				
6 months	60				
start	55				
Engineering Technologist/Technician	100	39.93	40.77	41.59	42.42
4th year	90				
3rd year	80				
2nd year	70				
1st year	65				
6 months	60				
start	55				
Journeyman Meterman	100	32.54	33.22	33.89	34.56
4th year	90				
3rd year	80				
2nd year	70				
1st year	65				
6 months	60				
start	55				
Customer Service Representative					
1st year	100	33.38	34.08	34.76	35.45
start	90				
	80				
Ground Person	100	28.15	28.74	29.31	29.90
Meter Reader	100	22.63	23.10	23.56	24.03
Start	90				

Notes: Line Supervisor will appoint a Lead Hand for each two man crew on a daily basis as required. On-Call man (Journeyman Lineman-unless otherwise designated by Line Supervisor) will be designated as Lead Hand when an additional man is called out. In all cases there will only be one lead hand per two man crew.

SCHEDULE "B" - SICK LEAVE PLAN

B.1 The Corporation's Sick Leave Plan for regular employees was created by the Corporation to reduce the financial hardship that bona fide non-occupational illness or injury can create so far as inability to work and the consequent loss of normal wages are concerned.

B.2 To qualify for payment of sick leave pay, an employee must:

1. ensure his illness is reported to Management as soon as possible;
2. be suffering from a bona fide illness which prevents his useful employment and is not compensable under the Workplace Safety & Insurance Act and was not received while performing paid work for an employer other than the Corporation;
3. submit written verification of his illness signed by a qualified Doctor if requested, prior to returning to work or automatically if absent for five (5) days or more; The Corporation will reimburse the employee for the cost of the note.
4. submit to medical examination of a Doctor designated by Management upon request during normal working hours without loss of pay.

B.3 For every month of regular attendance a regular employee shall be entitled to a sick leave credit of one and one-half (1½) days per month and such credits shall be cumulative from month to month and year to year. From such credits shall be deducted the number of days which an employee is absent by reason of illness or injury.

B.4 Monthly sick leave credit accrues to a regular employee on the first day of the month following each completed calendar month of service and is cumulative to an amount not exceeding one hundred and eighty (180) days for a period of continuous and unbroken service with the Corporation. On extended sick leave, use of sick leave credits will be limited to the qualification period of the LTD Plan after which time the employee shall go on the LTD Plan.

B.5 An employee will accumulate sick leave credit provided he has worked more than half of the working days in any calendar month. Accumulation of sick leave credit will also continue when;

a) absence is by reason of annual vacation, or

b) absence is due to occupational illness or injury of less than three (3) months. Absence of more than three (3) months will result in no accumulation of credits for the entire period.

B.6 An employee who successfully sues a third party for losses sustained or purported to be sustained during an absence for which sick time credits were expended by the Corporation is required to reimburse the Corporation the equivalent value of sick time credits used.

B.7 An employee on pregnancy leave is not eligible for sick leave pay.

B.8 Employees on the payroll as of January 1, 1983, who terminate employment by reason of:

1. death, or;
2. retirement on pension, or;
3. retirement without pension, or;
4. voluntary retirement, other than discharge for cause;

after a period of not less than ten (10) consecutive years of service, shall be paid (or a personal representative, or failing a personal representative, such other person as the Corporation may determine) an amount computed on the basis of the rate of pay at the date of leaving the employ of the Corporation for a period equal to fifty percent (50%) of the value of the sick leave credits standing to his credit but the amount shall not exceed six (6) months' pay. In establishing credits for hourly rated employees under this paragraph, the standard number of hours normally worked per day upon which overtime is calculated shall be used.

LETTER OF UNDERSTANDING -- SUMMER/FLEX HOURS

The Niagara-on-the-Lake Hydro Inc. and Local Union 636 of the International Brotherhood of Electrical Workers agree that:

The following outline pertains to revised hours of work throughout the year.

Either party may with one week's notice, opt to return to the "regular hours of work schedule". If the Union wishes to exercise this option, a majority vote will be the deciding factor among the employees in the Line department. For employees in the Engineering department, employees may opt out on an individual basis.

Employee participation in the Line department is mandatory. Employee participation in the Engineering department is voluntary.

The hours of work will be as follows:

Line Department:	7:00 a.m. -- 3:00 p.m. paid 20 minute on-site lunch Monday to Friday
Engineering Department:	8 hour or 10 hour shift paid 20 minute on-site lunch Monday to Friday Start and stop times of shift(s) to be mutually agreed

In addition, it is agreed that sick time and vacation time will be charged out in an hourly format (i.e., in eight (8) or ten (10) hour increments)

References in the Collective Agreement to the normal work day and normal work week will revert to the hours outlined in this letter of understanding during the defined time frame.

Statutory Holidays: Will be paid in eight (8) hour segments.

Overtime: All hours worked outside of the "regular work day" will be at the applicable overtime rates.

This letter of understanding may be utilized in subsequent years of the Collective Agreement upon mutual agreement of the parties.

Dated 24th day of June, 2016

Signed for the Corporation

Tim Curtis, President

Signed for the Union

Domenic Murdaca, Business Representative

LETTER OF UNDERSTANDING -- AFTERNOON SHIFT

The Niagara-on-the-Lake Hydro Inc. and Local Union 636 of the International Brotherhood of Electrical Workers agree that:

In the event that the Niagara-on-the-Lake Hydro Electric Corporation enters into joint services with another utility, it would be beneficial to implement an afternoon shift in the line department.

The implementation of such a shift will only occur when the following conditions have been met;

(1) Joint Services are initiated with another utility.
(2) The affected employees at the other utility mutually agree to participate in an afternoon shift.

It is further understood and agreed that the terms and conditions of the shift will be negotiated and mutually agreed upon between the parties prior to implementation.

Dated 24th day of June, 2016

Signed for the Corporation

Tim Curtis, President

Signed for the Union

Domenic Murdaca, Business Representative



LETTER OF UNDERSTANDING -- MERGER, AMALGAMATION OR COMBINATION

The Niagara-on-the-Lake Hydro Inc. and Local Union 636 of the International Brotherhood of Electrical Workers agree that:

In the event that there is a merger with another Corporation, Company or Companies, in which the covered employees therein are represented by another Union, the representation rights and collective agreement in respect of Local 636 IBEW members shall be maintained until a final determination is made under the Labour Relations Act of Ontario or enabling legislation as to the representation of the combined group.

Should the Corporation merge, amalgamate or combine any of its operations or functions with another Corporation, Company or Companies, the employer agrees to give the Union as much notice as practically possible prior to any intent by the employer to implement the above.

Dated 24th day of June, 2016

Signed for the Corporation

Tim Curtis, President

Signed for the Union

Domenic Murdaca, Business Representative

COLLECTIVE AGREEMENT

between

NIAGARA-ON-THE-LAKE HYDRO INC.

and

LOCAL UNION NO. 636

of the

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

May 1, 2016 to April 30, 2020

(Office Staff)

TABLE OF CONTENTS

ARTICLE 1 - RECOGNITION 1
ARTICLE 2 - UNION SECURITY AND CHECK-OFF 1
ARTICLE 3 - MANAGEMENT RIGHTS 1
ARTICLE 4 - CORPORATION SERVICE CREDIT 2
Definition 2
ARTICLE 5 - EMPLOYEE CATEGORIES 2
ARTICLE 6 - LOCKOUTS AND STRIKES 2
ARTICLE 7 - GRIEVANCE PROCEDURE 3
ARTICLE 8 - ARBITRATION PROCEDURE 3
ARTICLE 9 - HOURS OF WORK AND OVERTIME 4
Hours of Work 4
Overtime 4
ARTICLE 10 - MINIMUM CALL-OUT 4
ARTICLE 11 - RECOGNIZED HOLIDAYS 4
ARTICLE 12 - VACATIONS 5
ARTICLE 13 - SICK LEAVE PLAN 6
ARTICLE 14 - HEALTH PLAN 6
ARTICLE 15 - PENSION AND INSURANCE 6
ARTICLE 16 - JOB POSTING AND SELECTION 7
ARTICLE 17 - LAY OFF AND RECALL 7
ARTICLE 18 - LEAVE OF ABSENCE FROM WORK 7
Bereavement 7
Leave for Union Business 8
Jury Duty/Crown Witness 8
Personal Leave 8
ARTICLE 19 – WORKPLACE SAFETY AND INSURANCE BOARD (W.S.I.B.) 8
ARTICLE 20 - ALLOWANCES 8
Meals 8
ARTICLE 21 - GENERAL 9
Committee and Stewards 9
Contracting Out 9
Health and Safety 9
Residency 9
ARTICLE 22 - WAGES AND PROGRESSIONS 9
22.3 Employees will participate in an annual performance appraisal. 9
ARTICLE 23 - DURATION 9
SCHEDULE "A" - WAGES 11
SCHEDULE "B" - SICK LEAVE PLAN 12

COLLECTIVE AGREEMENT
between

NIAGARA-ON-THE-LAKE HYDRO INC.
(Hereinafter called the "Corporation")
and

LOCAL UNION NO. 636
of the
INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS
(Hereinafter called the "Union")

ARTICLE 1 - RECOGNITION

1.1 Corporation hereby recognizes the Union as the sole collective bargaining agent for all employees of Niagara-on-the-Lake Hydro Inc. save and except billing supervisor, administrative assistant, all persons above the rank of billing supervisor, those covered by other collective agreements, persons regularly employed for not more than twenty-four (24) hours per week, students employed during the school vacation period, students employed on a cooperative training program and individuals hired on a government-sponsored program.

ARTICLE 2 - UNION SECURITY AND CHECK-OFF

2.1 All employees covered under Article 1 of this agreement, who are members of the Union shall remain members of the Union and all new employees shall become and remain members of the Union after thirty (30) calendar days of employment.

2.2 All employees in the bargaining unit shall be required to sign an authorization assigning to the union an amount equivalent to regular monthly dues and the Corporation shall deduct such amounts from the weekly wages of employees and remit the dues to the financial secretary of Local 636 by the 15th of the month following the month in which the deductions were made with a list of the names of the employees from whose pay such deductions have been made. The Corporation will provide the minimum information to calculate union dues when requested. The Corporation will also deduct a one-time union initiation fee in addition to the weekly dues as described by the union. The dues to be included on the T4 slip.

2.3 It is understood and agreed that the Union will save the Corporation harmless from any and all claims which may be made against it by an employee or employees for amounts deducted from earnings as herein provided.

2.4 A Union Negotiating Committee shall consist of a maximum of one (1) member plus the Union Business Manager or designate for the purpose of Collective Bargaining. The member so appointed, excluding the Union Business Manager or designate, must be an employee of the Corporation covered by this Collective Agreement and have completed the probation period as set out in Article 5.

2.5 Both the Corporation and the Union recognize their respective responsibilities under the Human Rights Code and other statutory requirements.

ARTICLE 3 - MANAGEMENT RIGHTS

3.1 The Union acknowledges and agrees that the Corporation has the exclusive right to manage its business, and without limiting the generality of the foregoing, to direct the working force, to hire, promote, transfer, demote or lay off employees, discharge, or otherwise discipline employees, for just cause, and to make, amend and enforce such rules and regulations as shall from time to time be required, provided that they are not inconsistent with the provisions of this agreement.

3.2 All functions and prerogatives heretofore vested in and exercised by the Corporation shall remain solely with the Corporation except as specifically limited by the express provision of this agreement.

ARTICLE 4 - CORPORATION SERVICE CREDIT

Definition

4.1 The length of continuous service a regular employee has established with the Corporation from the most recent date the employee entered the employ of the Corporation.

4.2 The Corporation shall maintain a seniority list showing the date upon which each employee's Corporation service commenced. An up-to-date seniority and classification list shall be sent to the Union and posted on all bulletin boards in January of each year.

4.3 A regular employee shall lose seniority rights and have her name removed from the employment records if she:

I. retires;
II. resigns;
III. is discharged for just cause and not reinstated through the grievance/arbitration procedure;
IV. is absent from work for three (3) working days without notification to the employer, unless a satisfactory explanation is provided for this absence;
V. fails to report to work within ten (10) working days following recall after a lay off unless a satisfactory explanation is provided for this failure;
VI. is absent from work because of lay off or leave of absence for a period greater than one (1) year.
VII. An employee who fails to return to work within twenty-four (24) months as a result of a non-occupational illness or injury shall lose her Corporation service credit and be removed from the payroll.
VIII. An employee who fails to return to work within twenty-four (24) months as a result of an occupational illness or injury shall lose her Corporation service credit and be removed from the payroll.

ARTICLE 5 - EMPLOYEE CATEGORIES

5.1 **Temporary employees** are those hired for a period of not more than six (6) consecutive months or for a specific task or twelve (12) consecutive months to cover off maternity/parental leave requirements under the Employment Standards Act. They shall not accumulate Corporation Service Credit nor shall they be entitled to any of the rights or privileges accruing to regular or probationary employees, nor shall they have recourse to the grievance and arbitration procedures.

5.2 **Probationary employees** are those who are hired on trial basis to determine their suitability for employment in regular positions. An employee shall be considered probationary for a period of six (6) months worked, at the discretion of Management.

5.3 Where it is mutually agreed that the ability to assess an employee is affected by periods of non-working time such as sickness, leaves of absence, etc., the probationary period may be extended in direct proportion to the periods of lost time after consultation with the Union.

5.4 During this period of probation, she shall be entitled to all the rights and privileges set out in the collective agreement, except that she shall not have recourse to the grievance and arbitration procedure on termination.

5.5 **Regular employees** are persons who have satisfactorily served a probationary period and are currently in the employ of the Corporation.

5.6 The term "employee" when used in this agreement shall mean "regular employee" unless specifically stated otherwise.

5.7 **Government Sponsored Program Employees**

Employees who may be hired under the provision of Article 1, Cooperative Training Program and Government Sponsored Program shall not be employees to replace regular employees.

5.8 **Singular or Feminine**

Whenever the singular or feminine is used in the agreement, it shall be used as if plural or masculine has been used where the context of the agreement so indicates.

ARTICLE 6 - LOCKOUTS AND STRIKES

6.1 There shall be no "lockout" by the Corporation and no interruption, work stoppage or "strike" during the term of this agreement. The terms "strike" and "lockout" shall be interpreted in accordance with the definitions as set out in the Labour Relations Act.

ARTICLE 7 - GRIEVANCE PROCEDURE

7.1 For the purpose of this agreement, a dispute, claim or complaint which involves the interpretation, application, administration or alleged violation of some provisions of this agreement shall be considered to be a fit matter for a grievance and shall be dealt with as specified below.

7.2 Complaints and grievances shall be dealt with in the following manner and all grievances must be in writing and filed within fourteen (14) calendar days of the circumstances giving rise to the grievance.

7.3 Step 1
The employee, accompanied by a steward if the employee wishes, may take the matter up with the billing supervisor who will give her reply in writing within three (3) working days. Failing settlement of this stage, the employee may within three (3) working days proceed to Step 2.

7.4 Step 2
The employee, accompanied by a steward and/or a representative of the Union, may take the matter up with the general manager or designate who will reply in writing within five (5) working days. Failing settlement of this stage, the matter may then be referred to Article 8 of this agreement within twenty (20) working days.

7.5 Where a dispute involving a question of general application or interpretation occurs or where a group of employees or the Union has a grievance, Step 1 of this Article may be bypassed and such grievance submitted at Step 2 within five (5) working days of the occurrence of the event giving rise to the grievance.

7.6 A claim by an employee that she has been suspended or discharged without just cause shall be treated as a grievance if a written statement of such grievance is lodged with the general manager at Step 2 within five (5) working days after notice by management to the Union Steward of the suspension or discharge.

7.7 The time limits provided in this article may be extended by mutual written agreement between the parties concerned.

7.8 Notwithstanding the above, the parties may reach settlement to a grievance through the services of a Grievance Settlement Officer or other mutually agreeable third party facilitator. The parties shall jointly bear the expense of the Grievance Settlement Officer or other agreed-upon third party.

ARTICLE 8 - ARBITRATION PROCEDURE

8.1 Where a difference arises between the parties relating to the interpretation, application or administration of this agreement, including any question as to whether a matter is arbitrable, or where an allegation is made that this agreement has been violated, either of the parties may, after exhausting any grievance procedure established by this agreement, notify the other party in writing of its desire to submit the difference or allegation to arbitration. The parties to this agreement may request the Ontario Minister of Labour to appoint a single arbitrator in accordance with the provisions of the Labour Relations Act (Ontario) or the parties may otherwise agree to the appointment of a sole arbitrator.

8.2 The arbitrator shall hear and determine the difference or allegation and shall issue a decision and the decision shall be final and binding upon the parties and upon any employee or employer affected by it.

8.3 The arbitrator shall not make any decision inconsistent with the provisions of this agreement, nor alter, modify or amend any part of this agreement, but shall only consider the question in dispute.

8.4 No matter shall be submitted to arbitration which has not been properly lodged and carried through all previous steps of the Grievance Procedure.

8.5 The proceedings of the arbitrator will be expedited by the parties hereto, and the decision of the arbitrator shall be final and binding upon all parties concerned.

8.6 The expense of the arbitrator together with any incidental or general expense connected with the arbitration proceedings shall be divided equally between the parties hereto.

ARTICLE 9 - HOURS OF WORK AND OVERTIME

9.1 This section provides the basis for establishing work schedules and for the calculation and payment of overtime, but shall not be read or construed as a guarantee of hours of work per day or week or a guarantee of days of work per week.

Hours of Work

9.2 The normal work week of employees shall be thirty-five (35) hours of work per week consisting of five (5) days of seven (7) hours each from Monday to Friday inclusive between the hours of 0830 and 1630 with one (1) hour lunch period.

Overtime

9.3 Due to the nature of its operations the Corporation may require employees to work at other than their normal hours and in addition to their normal hours beyond the limits as described above. An employee shall be paid for overtime at the rate of two (2) times their regular hourly rate for all work performed from normal quitting time until normal starting time and on Saturday, Sunday, and Recognized Holidays.

9.4 An employee who is required to work for more than sixteen (16) hours or an employee who accumulates sixteen (16) hours of working time in any twenty-four (24) hour period shall be entitled to an eight (8) hour rest period.

9.5 An employee will qualify for 4 hours of rest time to commence at the start of the next regular shift should he/she work more than three (3) consecutive hours during the period between midnight and the next regular shift and 8 hours rest time to commence at the start of the next regular shift should he/she work five (5) or more consecutive hours between midnight and the next regular shift. All rest time will be paid at straight time pay.

9.6 Should the employee he required to continue working beyond the sixteen (16) hour period, the employee shall be paid two (2) times their regular hourly rate until an eight (8) hour rest period is granted.

9.7 All employees will be permitted to bank lieu time hours of overtime. The amount added into the bank is not to exceed seventy (70) hours during the calendar year. The employee will have the opportunity to carry-over up to one (1) week of lieu time provided the combination of lieu time and vacation time carryover does not exceed a total of two (2) weeks. All other lieu time will be cashed out. If lieu time is cashed out throughout the year, it may not be replenished. Employees will give two weeks' notice if they wish to cash out any portion of their lieu time throughout the year.

ARTICLE 10 - MINIMUM CALL-OUT

10.1 When an employee is called in for emergency overtime work outside of her normal working hours, she shall be provided with a minimum payment of two (2) hours' pay at the appropriate overtime rate.

10.2 When an employee has completed her call-out she will be allowed to return home, provided she has checked to ensure that additional calls have not heen received. All calls received within two (2) hours of the first call shall be considered the same call.

10.3 There shall be no minimum payment applicable to call-outs or overtime worked contiguous to an employee's normal daily working hours. Calls received less than one hour before normal starting time do not qualify for minimum call out. Premium rate for time worked will apply.

ARTICLE 11 - RECOGNIZED HOLIDAYS

11.1 Each employee shall be entitled to the following paid holidays:

New Year's Day	Civic Holiday
Good Friday	Labour Day
Victoria Day	Thanksgiving Day
Canada Day	One-half Day Before Christmas
Boxing Day	One-half Day Before New Year's Day
Christmas Day	Family Day

and all additional holidays proclaimed by federal and provincial governments.

11.2 Two (2) additional floater holidays at a time most desired by the employee, providing this does not impede the efficient operation of the Corporation's business.

11.3 Payments for the above-named recognized holidays will be made provided the employee works the regularly assigned day immediately preceding and succeeding the day of observance of the holiday or, unless on an authorized short term leave of absence (three (3) weeks or less), vacation or sick leave.

11.4 In the event of any of the above-named holidays falling on a Saturday and/or Sunday and not proclaimed as being observed on some other day, the preceding Friday or the following Monday as determined by the Corporation shall be deemed to be holidays for the purpose of this agreement unless otherwise agreed to by the parties.

ARTICLE 12 - VACATIONS

12.1 Vacations will, as far as it is practicable, be granted at the times most desired by the employees, providing this does not impede the efficient operation of the Corporation's business.

12.2 An employee must notify Management of her preferred vacation period by May 1 in any given year. However, Management shall retain the authority to designate vacation periods for all employees in a manner consistent with the efficient operation of the Corporation. Vacations are not cumulative and shall be taken during each calendar year unless approved by Management. Such approval must be requested by the employee, in writing, by September 30th and must be specific in the vacation request for the following year. If such application is received by September 30th, Management will reply within 10 working days. A maximum of two weeks carry-over to the following year will be allowed but must be taken before October 31st in the carry-over year.

12.3 Probationary and temporary employees shall be granted vacation entitlement as provided by the Employment Standards Act.

12.4 An employee with less than one (1) year continuous service shall be entitled to four (4) percent of gross wages at December 31, or the equivalent time off with pay.

12.5 An employee with one (1) year or more of continuous service completed during the calendar year ended December 31 will be entitled to two (2) weeks' vacation with pay at the employee's regular hourly rate based on the employee's normal work week.

12.6 An employee with three (3) years or more of continuous service completed during the calendar year ended December 31 will be entitled to three (3) weeks' vacation with pay at the employee's regular hourly rate based on the employee's normal work week.

12.7 An employee with nine (9) years or more of continuous service completed during the calendar year ending December 31 will be entitled to four (4) weeks' vacation with pay at the employee's regular hourly rate based on the employee's normal work week.

12.8 An employee with seventeen (17) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) weeks' vacation with pay at employee's regular hourly rate based on the employee's normal work week.

12.9 An employee with twenty-two (22) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and one (1) day with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-three (23) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and two (2) days with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-four (24) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and three (3) days with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-five (25) years or more of continuous service completed during the calendar year ending December 31 will be entitled to five (5) and four (4) days with pay at employee's regular hourly rate based on the employee's normal work week.

An employee with twenty-six (26) years or more of continuous service completed during the calendar year ending December 31 will be entitled to six (6) weeks' vacation with pay at employee's regular hourly rate based on the employee's normal work week.

12.10 An employee shall not be granted more than two (2) weeks' vacation during the period of June 15 to September 15 except with permission of the Management.

12.11 Vacation pay shall be based on the employee's regular hourly rate.

12.12 To be entitled to vacation pay, an employee must work forty (40) of the weeks in the year ending December 31. If an employee works fewer than forty (40) weeks her vacation shall be reduced on a pro-rata basis for each week less than the forty (40) weeks which she does not work. Maternity leave, Workers' Compensation and Jury duty are excluded from this calculation.

ARTICLE 13 - SICK LEAVE PLAN

13.1 The Sick Leave Plan as specified in detail in Schedule "B" is attached to and forms part of this agreement.

ARTICLE 14 - HEALTH PLAN

14.1 The Corporation agrees to pay for employees in receipt of regular hourly rate, one hundred percent (100%) of the premiums for the following Health Plans or equivalent:

- ClaimSecure Extended Health Plan $10/$20 deductible;
    - Includes Chiropractic at $1000/year maximum (all dependents combined)
    - Includes Massage therapy to $1000/year maximum (all dependents combined)
    - Includes Physiotherapy to $1,000/year maximum (all dependents combined)
    - Includes Semi-private coverage (if available)
    - Includes Drug dispensing cap of $12.50 effective May 1, 2016; $13.00 effective May 1, 2017; $13.50 effective May 1, 2018 and $14.00 effective May 1, 2019. Employees agree to accept 'Generic Drugs' first and 'Formulary Plan' with Doctor Override
- Basic Dental Plan (ClaimSecure Level 1 & 2) ($2,250 per person, per year maximum), Crown & Bridgework and Orthodontics coverage (ClaimSecure Level 3 & 4)(50/50 co-pay, $2,400.00 per person, per year maximum -- Orthodontic coverage to terminate at age 19). Dental recall for adults shall be every nine (9) months and for children under the age of eighteen (18) it shall be every six (6) months
- ClaimSecure Vision Plan providing a maximum benefit coverage of $450.00 every 24 months effective May 1, 2016. Eye examinations $90/two years; Vision coverage can be used towards Corrective Laser Eye Surgery.
- ClaimSecure Out-of-Province/Country maximum of 60 days/trip coverage.
- Long Term Disability Plan providing 70% income benefit to a maximum of $3,600 per month with an eighty-five (85) working-days waiting period.

14.2 The Corporation agrees to pay for employees in receipt of normal base wages one hundred percent (100%) of the premium for a Basic and Comprehensive basic Dental Service or equivalent with current O.D.A. Fee Schedule.

14.3 If there is a change in carriers, the Union must be notified immediately. The plan must be of equal or better value.

14.2 The Corporation agrees to pay for employees in receipt of normal base wages one hundred percent (100%) of the premium for a Green Shield Basic and Comprehensive basic Dental Service or equivalent with current O.D.A. Fee Schedule.

14.3 If there is a change in carriers, the Union must be notified immediately. The plan must be of equal or better value.

ARTICLE 15 - PENSION AND INSURANCE

15.1 All eligible employees with the Corporation shall participate in the Corporation's Pension and Insurance Plans as follows:

- Ontario Municipal Employees Retirement System Basic FAE (Final Average Earnings) on a equally shared basis with the Corporation.
- The Corporation and the employees shall participate in the Canada Pension Plan as required by the Canada Pension Act.
- The Corporation shall provide Life Insurance coverage for all regular employees in receipt of normal base wages, equivalent to current coverage of one and one-half (1½) times the employee's normal base wages.

15.2 The Corporation agrees to pay fifty percent (50%) of the premiums for Dental, Extended Health including Vision Care for all employees who retire early between the ages of 55 to 65.

ARTICLE 16 - JOB POSTING AND SELECTION

16.1 When vacancies occur within the bargaining unit, or new jobs are created within the bargaining unit, these positions shall be posted on the bulletin board, accessible to all employees, for a period of five (5) working days, during which time present employees shall have the opportunity of applying before outsiders are considered. During the posting period, the Corporation may fill a vacancy on a temporary basis. The experience gained while filling this temporary vacancy will not be used as determining factor in the job selection process.

16.2 Such notice shall contain the following information: nature of the position, qualifications, knowledge, experience, skills, and wage rates.

16.3 In filling vacancies and making transfers or promotions among employees represented by the Union, the Management will consider the qualifications and ability as the primary factors. In the event qualifications and ability of the respective applicants are relatively equal in Management's opinion, Corporation service shall govern.

16.4 Promotion shall mean advancement to a job which carries a higher rate of pay.

ARTICLE 17 - LAY OFF AND RECALL

17.1 In the event of a lay off, Management agrees that employees shall be laid off in the reverse order of their Corporation service credit provided Management can retain a work force qualified in its opinion to perform the work remaining. Employees shall be recalled in the order of their Corporation service credit provided they are qualified, capable and have the ability to do the work available.

17.2 It shall be the responsibility of the employee to keep Management informed, in writing, of change in her postal address and telephone number.

17.3 It is understood that in exercising her accrued rights in accordance with the above, advancement to a job which carries a higher rate of pay is not permitted.

ARTICLE 18 - LEAVE OF ABSENCE FROM WORK

Bereavement

18.1 An employee will be allowed up to five (5) working days' leave of absence with pay in the event of the death of her spouse, child, father or mother. Such leave shall be for the purpose of making arrangements and/or attending the funeral.

18.2 An employee will be allowed up to three (3) consecutive days' leave of absence with pay in the event of the death of her brother, step-brother, sister, step-sister, grandparent, grandchild, father-in-law or mother-in-law, step-parent, or step child. Such leave shall be for the purpose of making arrangements for and/or attending the funeral. Only that portion of the said three (3) days that would otherwise have been regular time worked will be paid.

18.3 An employee will be allowed one (1) day leave of absence with pay in the event of the death of any current staff member, brother-in-law, sister-in-law, step parent-in-law, aunt, uncle, niece, nephew or grandparent-in-law. Such leave shall be for the purpose of making arrangements for and/or attending the funeral. In the event of the death of any other relative, unpaid time off to attend the funeral may be granted, not to exceed one (1) day

18.4 Request for additional time off is covered under Article 18.7.

Leave for Union Business

18.5 Insofar as the efficient operation of the Corporation's business will permit, requests for leave of absence may be granted without pay and benefits to Union representatives for the purpose of taking part in official Union business. Such requests shall be made, in writing, to Management at least two (2) weeks in advance of the absence.

Jury Duty/Crown Witness

18.6 The Corporation shall pay an employee, who is required for Jury Duty or subpoenaed as a witness on behalf of the Corporation, the difference between her regular hourly rate and the payment received for such activity, excluding travel and meal expenses. The employee shall present proof of such payment received.

Personal Leave

18.7 Leaves of absence require the written permission of Management. Application for leave of absence must be submitted, in writing, at least one (1) week in advance to insure consideration unless not possible by reason of unforeseen personal emergency in which case verbal application will be accepted. Unless otherwise agreed, leave of absence will be without pay and leave of absence extending beyond five (5) days will be without pay and benefits. In this case, all costs (employee and employer costs) of the normal indemnities will be payable by the employee.

18.8 In the case of a leave of absence without pay which exceeds thirty (30) days, Corporation Service Credit of regular employees will be frozen for the duration of the leave of absence at the level attained prior to the leave of absence. Freezing of service credit will not be in conflict with the Employment Standards Act of Ontario with respect to pregnancy/parental leave.

ARTICLE 19 – WORKPLACE SAFETY AND INSURANCE BOARD (W.S.I.B.)

19.1 When an employee, through her employment by the Corporation, suffers a disability which is compensable under the Workplace Safety and Insurance Act, the employee will be paid in accordance with the Act, and the Corporation will maintain up to a maximum of one and a half (1½) years, medical benefits and life insurance coverage on behalf of the employee as if she were in receipt of her regular hourly rate from the Corporation with the employee having the option to pay all the costs herself for an additional six (6) months. However, in the event that legislative requirements reduce the amount payable to those employees eligible for W.S.I.B. assistance below the present ninety per cent (90%), the employer shall make up the difference between the amount paid through W.S.I.B. requirements to a benefit equal to ninety per cent (90%) of the employees take home pay.

ARTICLE 20 - ALLOWANCES

Meals

20.1 Two (2) hours' overtime contiguous to the normal work hours and every four (4) hours thereafter are necessary in order to qualify for an overtime meal allowance, the amount of which cannot exceed fifteen dollars ($15.00) subject to provision of receipts. Planned overtime is excluded from the overtime meal allowance. One (1) day notice is required for planned overtime for the purpose of sufficient notice to prepare a lunch.

20.2 Under emergency conditions, when the Corporation provides a meal, a meal allowance will not be paid.

20.3 When employees are required on a daily basis to attend training sessions or seminars and if a meal is provided during the session, a meal allowance will not be applicable. When meals are not provided, the Corporation will provide $20 dollars for lunch with no receipt required. Other meals are not applicable for daily training sessions.

20.4 When an employee is required to attend training or seminars an appropriate meal allowance will be provided each day of $15 for breakfast, $20 for lunch and $35 for dinner. Overnight accommodations will be paid by the Corporation. No receipts are required for meal allowances.

20.5 **Relief in Another Category**

When a unionized employee provides a lead role as a result of the immediate supervisor being away, such employee shall receive an additional two dollars ($2.00) per hour above their current rate. Determination of the need for this relief and the choice of the individual unionized employee will be at the sole discretion of management, however will be at the 100% level of their classification.

ARTICLE 21 - GENERAL

Committee and Stewards

21.1 The Corporation recognizes the appointment of one (1) steward by the Union for the purpose of conducting relevant union business. The Union will keep the Corporation informed, in writing, of such appointments.

21.2 (i) Since stewards have regular duties to perform on behalf of the Corporation, they will not leave their regular duties without receiving permission from the billing supervisor.

(ii) It is a steward's first responsibility to perform the work required of him/her as an employee of the Corporation. It is recognized, however, that a steward is the Union representative in the workplace with who the Corporation is required to deal as require by this agreement. Accordingly, a steward will, with the advance permission of his/her supervisor, be granted reasonable time during working hours without loss of pay to attend grievance meeting.

(iii) A steward may, where an employee so requests, attend or be called into any meeting between the employee and management which is for the purpose of issuing discipline, a suspension or discharge of the employee. The foregoing shall not apply where the suspension or discharge is not issued in person to the employee.

Contracting Out

21.3 No employee will be laid off as a result of contracting out of bargaining unit work.

Health and Safety

21.4 The Corporation and the Union recognize the obligation and responsibility of the Corporation and their employees to ensure the establishment and maintenance of good health and safety work practices. It is further recognized and understood that the employee must abide by all safety rules and regulations. It is further recognized and understood that the Corporation will not impede the health and safety of its employees while working beyond normal working hours.

Residency

21.5 Employees shall inform the Corporation in writing of their current address and telephone number and keep the Corporation informed within five (5) days of any change.

ARTICLE 22 - WAGES AND PROGRESSIONS

22.1 The wage rates and classifications shall be as set out in Schedule "A" attached to and forming part of this agreement for purposes of payment of wages only.

22.2 Employees on progression shall normally be progressed in accordance with the schedule. However, if any employee fails to make satisfactory progress, her advancement will be withheld for a period of six (6) months. When progression is withheld, Management shall give one (1) month's notice to the employee and the reason for withholding routine progression. At the next routine progression date, her general performance will be reviewed and if found satisfactory, she shall be granted routine progression. If her progress and general performance are not found to be satisfactory, she shall be transferred to another classification, if available, or dismissed.

22.3 Employees will participate in an annual performance appraisal.

ARTICLE 23 - DURATION

23.1 This agreement shall become effective on May 1, 2016 and such agreement shall remain in effect until April 30, 2020, and from year to year thereafter unless either party gives notice in writing to the other party within the ninety (90) day period prior to the expiry date of its desire to alter or terminate same.

23.2 In witness whereof the parties hereto have herewith set their hands and seals this 24th day of June, 2016.

NIAGARA-ON-THE-LAKE HYDRO INC.

Tim Curtis
President

Philip Wormwell
Vice President, Finance

Hassan Syed
Vice President, Operations

LOCAL UNION 636 OF THE INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

Domenic Murdaca
Business Representative

Jody Keus
Union Steward

Lisa DiSanto
Member

Barry Brown
Business Manager/Financial Sec.

SCHEDULE "A" - WAGES

CLASSIFICATION	%	MAY 1, 2016 (2.1%)	MAY 1, 2017 (2.1%)	MAY 1, 2018 (2.0%)	MAY 1, 2019 (2.0%)
Customer Accounts Representative	100	**30.94**	**31.59**	**32.22**	**32.86**
1st year	90				
start	80				
Accounting Clerk	100	**31.11**	**31.76**	**32.40**	**33.05**
1st year	90				
start	80				
Accounting Officer	100	**33.38**	**34.08**	**34.76**	**35.45**
1st year	90				
start	80				
Finance and Accounting Officer	100	**35.03**	**35.77**	**36.48**	**37.21**
1st year	90				
start	80				
Business Analyst	100				
1st year	90	**33.38**	**34.08**	**34.76**	**35.45**
start	80				

SCHEDULE "B" - SICK LEAVE PLAN

B.1 The Corporation's Sick Leave Plan for regular employees was created by the Corporation to reduce the financial hardship that bona fide non-occupational illness or injury can create so far as inability to work and the consequent loss of normal wages are concerned.

B.2 To qualify for payment of sick leave pay, an employee must:

1. ensure her illness is reported to Management as soon as possible;
2. be suffering from a bona fide illness which prevents her useful employment and is not compensable under the Workplace Safety & Insurance Act and was not received while performing paid work for an employer other than the Corporation;
3. submit written verification of her illness signed by a qualified Doctor if requested, prior to returning to work or automatically if absent for five (5) days or more; The Corporation will reimburse the employee for the cost of the note.
4. submit to medical examination of a Doctor designated by Management upon request during normal working hours without loss of pay.

B.3 For every month of regular attendance a regular employee shall be entitled to a sick leave credit of one and one-half (1½) days per month and such credits shall be cumulative from month to month and year to year. From such credits shall be deducted the number of days which an employee is absent by reason of illness or injury.

B.4 Monthly sick leave credit accrues to a regular employee on the first day of the month following each completed calendar month of service and is cumulative to an amount not exceeding one hundred and eighty (180) days for a period of continuous and unbroken service with the Corporation. On extended sick leave, use of sick leave credits will be limited to the qualification period of the LTD Plan after which time the employee shall go on the LTD Plan.

B.5 An employee will accumulate sick leave credit provided she has worked more than half of the working days in any calendar month. Accumulation of sick leave credit will also continue when;

(a) absence is by reason of annual vacation, or
(b) absence is due to occupational illness or injury of less than three (3) months. Absence of more than three (3) months will result in no accumulation of credits for the entire period.

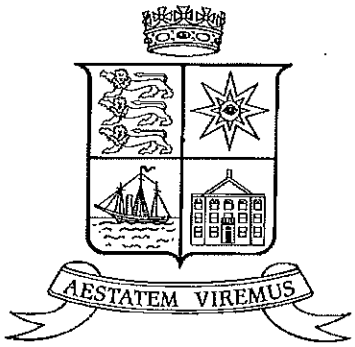
B.6 An employee who successfully sues a third party for losses sustained or purported to be sustained during an absence for which sick time credits were expended by the Corporation is required to reimburse the Corporation the equivalent value of sick time credits used.

B.7 An employee on pregnancy leave is not eligible for sick leave pay.

B.8 Employees on the payroll as of January 1, 1983, who terminate employment by reason of:

1. death, or;
2. retirement on pension, or;
3. retirement without pension, or;
4. voluntary retirement, other than discharge for cause;

after a period of not less than ten (10) consecutive years of service, shall be paid (or a personal representative, or failing a personal representative, such other person as the Corporation may determine) an amount computed on the basis of the rate of pay at the date of leaving the employ of the Corporation for a period equal to fifty percent (50%) of the value of the sick leave credits standing to her credit but the amount shall not exceed six (6) months' pay. In establishing credits for hourly rated employees under this paragraph, the standard number of hours normally worked per day upon which overtime is calculated shall be used.



LETTER OF UNDERSTANDING -- MERGER, AMALGAMATION OR COMBINATION

The Niagara-on-the-Lake Hydro Inc. and Local Union 636 of the International Brotherhood of Electrical Workers agree that:

In the event that there is a merger with another Corporation, Company or Companies, in which the covered employees therein are represented by another Union, the representation rights and collective agreement in respect of Local 636 IBEW members shall be maintained until a final determination is made under the Labour Relations Act of Ontario or enabling legislation as to the representation of the combined group.

Should the Corporation merge, amalgamate or combine any of its operations or functions with another Corporation, Company or Companies, the employer agrees to give the Union as much notice as practically possible prior to any intent by the employer to implement the above.

Dated 24th day of June, 2016

Signed for the Corporation

Tim Curtis, President

Signed for the Union

Domenic Murdaca, Business Representative

APPENDIX

4B

2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056



Canada Revenue Agency / Agence du revenu du Canada

Information Return for Corporations Filing Electronically

- You have to complete this return for every initial and amended T2 Corporation Income Tax Return electronically filed to the Canada Revenue Agency (CRA) on your behalf.
- By completing Part 2 and signing Part 3, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part 4 must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy in your own records for six years.
- **Do not submit** this form to the CRA unless we ask for it.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

Part 1 – Identification

Corporation's name	Business number
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001

Tax year ▶	From (Y M D)	To (Y M D)	Is this an amended return?	
	2017-01-01	2017-12-31	☐ Yes	☒ No

Part 2 – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income (or loss) for income tax purposes from Schedule 1, financial statements, or GIFI (line 300)	1,421,693
Part I tax payable (line 700)	
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	

Part 3 – Certification and authorization

@CRA **Sign up for online mail!** Get your CRA mail electronically delivered in My Business Account at **cra.gc.ca/mybusinessaccount**

I understand that by providing an email address, I am **registering** the corporation for the 'Manage online mail' service. I understand and agree that all notices and other correspondence eligible for electronic delivery will no longer be printed and mailed. The CRA will notify the corporation at this email address when they are available in My Business Account and requiring immediate attention. They will be presumed to have been received on the date that the email is sent.

Email address for online mail (optional): _____

I, Curtis (Last name) Timothy (First name) President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part 4 to electronically file the corporation income tax return identified in Part 1. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

Date (yyyy/mm/dd)	Signature of an authorized signing officer of the corporation	Telephone number
2018-06-07		(905) 468-4235

Part 4 – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part 1.

Name of person or firm	Electronic filer number
KPMG LLP	A6698

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html, personal information bank CRA PPU 047.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

EXEMPT FROM TAX

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see canada.ca/taxes or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 Do not use this area

Identification

Business number (BN) 001 86360 5929 RC0001

Corporation's name
002 NIAGARA-ON-THE-LAKE HYDRO INC.

Address of head office
Has this address changed since the last time we were notified? 010 1 Yes [ ] 2 No [X]
If **yes**, complete lines 011 to 018.
011
012 8 Henegan Road
City: 015 Virgil
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 L0S 1T0

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? 020 1 Yes [ ] 2 No [X]
If **yes**, complete lines 021 to 028.
021 c/o
022 P.O. Box 460
023 8 Henegan Road
City: 025 Virgil
Province, territory, or state: 026 ON
Country (other than Canada): 027 CA
Postal or ZIP code: 028 L0S 1T0

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? 030 1 Yes [ ] 2 No [X]
If **yes**, complete lines 031 to 038.
031
032
City: 035
Province, territory, or state: 036
Country (other than Canada): 037
Postal or ZIP code: 038

040 **Type of corporation at the end of the tax year** (tick one)
- [X] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [ ] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2017-01-01
Tax year-end: 061 Year Month Day 2017-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 3 Exempt under paragraph 149(1)(t)
- [X] 4 Exempt under other paragraphs of section 149

Do not use this area

095 096 898

Client Copy

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II – Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Client Copy

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	X	2 No	
Is the corporation inactive?	280	1 Yes		2 No	X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical Distribution	285	99.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes		2 No	X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes		2 No	X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes		2 No	

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 (Year Month Day)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300	1,421,693	A
Deduct:			
Charitable donations from Schedule 2	311	400	
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine made before March 22, 2017, from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction*	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal		400 ▶ 400	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")		1,421,293	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360	1,421,293	
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			Z
Taxable income for the year from a personal services business			Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Client Copy

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** 1,421,693 A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** B

Business limit (see notes 1 and 2 below) . . . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** *** 41,746 / 11,250 D = ... 1,855,378 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** F

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . G

Amount F **minus** amount G . . . . . **427** H

Small business deduction

Amount A, B, C, or H, whichever is the least x (Number of days in the tax year before January 1, 2018 / Number of days in the tax year) 365/365 x 17.5 % = 1

Amount A, B, C, or H, whichever is the least x (Number of days in the tax year after December 31, 2017, and before January 1, 2019 / Number of days in the tax year) 365/365 x 18 % = 2

Total of amounts 1 and 2 (enter amount I at amount J on page 7) **430** I

***** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

****** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Specified corporate income and assignment under subsection 125(3.2)

Applicable to tax years that begin after March 21, 2016

Except that, if the tax year of your corporation started before **and** ends on or after March 22, 2016 and in the tax year of a CCPC, you can make an assignment of business limit to that other CCPC if its tax year started after March 21, 2016.

	J1 Name of corporation receiving the income and assigned amount	J Business number of the corporation receiving the assigned amount **490**	K Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column J [3] **500**	L Business limit assigned to corporation identified in column J [4] **505**
1.				

Total **510** Total **515**

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
(I) persons (other than the private corporation) with which the corporation deals at arm's length, or
(II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column K in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425.

Client Copy

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)			A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B	
Amount 13K from Part 13 of Schedule 27		C	
Personal services business income	432	D	
Amount used to calculate the credit union deduction (amount F from Schedule 17)		E	
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least		F	
Aggregate investment income from line 440 on page 6*		G	
Subtotal (**add** amounts B to G) ▶			H
Amount A **minus** amount H (if negative, enter "0")			I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %			J

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			K
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		L	
Amount 13K from Part 13 of Schedule 27		M	
Personal services business income	434	N	
Amount used to calculate the credit union deduction (amount F from Schedule 17)		O	
Subtotal (**add** amounts L to O) ▶			P
Amount K **minus** amount P (if negative, enter "0")			Q
General tax reduction – Amount Q **multiplied** by 13 %			R

Enter amount R on line 639 on page 7.

Client Copy

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . **440** _____ x 30 2 / 3 % = _____ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . _____ B

Deduct:

Foreign investment income from Schedule 7 . . . . . **445** _____ x 8 % = _____ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") _____ ▶ _____ D

Amount A **minus** amount D (if negative, enter "0") . . . . . _____ E

Taxable income from line 360 on page 3 . . . . . 1,421,293 F

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . . _____ G

Foreign non-business income tax credit from line 632 on page 7 . . . . _____ x 75 / 29 = _____ H

Foreign business income tax credit from line 636 on page 7 . . _____ x 4 = _____ I

Subtotal (total of amounts G, H and I) _____ ▶ _____ J

Subtotal (amount F **minus** amount J) (if negative, enter "0") 1,421,293 K x 30 2 / 3 % = 435,863 L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . _____ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . . **450** _____ N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . **460** _____

Deduct: Dividend refund for the previous tax year . . . . . **465** _____

Subtotal _____ ▶ _____ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . _____ P

Total Part IV tax payable from Schedule 3 . . . . . _____ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . **480** _____

Subtotal _____ ▶ _____ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . . **485** _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 . . . . . 500,000 x 38 1 / 3 % = 191,667 S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . _____ T

Dividend refund – Amount S or T, whichever is less . . . . . _____ U

Enter amount U on line 784 on page 8.

Client Copy

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % . . . . . 550 _____ A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business . . . . . 555 _____ x 5 % = 560 _____ B

Recapture of investment tax credit from Schedule 31 . . . . . 602 _____ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . . _____ D

Taxable income from line 360 on page 3 . . . . . 1,421,293 E

Deduct:
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . . _____ F

Net amount (amount E **minus** amount F) 1,421,293 ▶ 1,421,293 G

Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G . . . . . 604 _____ H

Subtotal (**add** amounts A, B, C, and H) _____ I

Deduct:

Small business deduction from line 430 on page 4 . . . . . _____ J

Federal tax abatement . . . . . 608 _____

Manufacturing and processing profits deduction from Schedule 27 . . . . . 616 _____

Investment corporation deduction . . . . . 620 _____

Taxed capital gains 624 _____

Additional deduction – credit unions from Schedule 17 . . . . . 628 _____

Federal foreign non-business income tax credit from Schedule 21 . . . . . 632 _____

Federal foreign business income tax credit from Schedule 21 . . . . . 636 _____

General tax reduction for CCPCs from amount J on page 5 . . . . . 638 _____

General tax reduction from amount R on page 5 . . . . . 639 _____

Federal logging tax credit from Schedule 21 . . . . . 640 _____

Eligible Canadian bank deduction under section 125.21 . . . . . 641 _____

Federal qualifying environmental trust tax credit . . . . . 648 _____

Investment tax credit from Schedule 31 . . . . . 652 _____

Subtotal _____ ▶ _____ K

Part I tax payable – Amount I **minus** amount K . . . . . _____ L

Enter amount L on line 700 on page 8.

Client Copy

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source canada.ca/cra-info-source, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 7	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount U on page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 ☐ Overpayment

Balance (amount A **minus** amount B)

If the result is positive, you have a **balance unpaid**. If the result is negative, you have an **overpayment**. Enter the amount on whichever line applies. Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

For information on how to make your payment, go to canada.ca/payments.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number

918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920 A6698

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Curtis (Last name) 951 Timothy (First name) 954 President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2018-06-07 Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (905) 468-4235 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name of other authorized person

959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	6,249,975	6,574,003
	Total tangible capital assets	2008	+	32,778,940	31,043,453
	Total accumulated amortization of tangible capital assets	2009	–	3,156,763	2,538,668
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,139,022	1,958,194
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	38,011,174	37,036,982
Liabilities					
	Total current liabilities	3139	+	7,635,048	7,617,941
	Total long-term liabilities	3450	+	13,802,993	13,622,906
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	21,438,041	21,240,847
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	16,573,133	15,796,135
	Total liabilities and shareholder equity	3640	=	38,011,174	37,036,982
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	9,708,384	8,823,929

***** Generic item

Client Copy

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Current Assets

SCHEDULE 100

Form identifier 1599

Account	Description	GIFI		Current year	Prior year
Cash and deposits					
	* Cash and deposits	1000		366,780	
	Cash and deposits		+	366,780	
Accounts receivable					
	Trade accounts receivable	1062		5,679,259	5,981,259
	Accounts receivable		+	5,679,259	5,981,259
Inventories					
	* Inventories	1120		167,526	361,700
	Inventories		+	167,526	361,700
Due from/investment in related parties					
	* Due from/investment in related parties	1400		9,886	9,754
	Due from/investment in related parties		+	9,886	9,754
Other current assets					
	Taxes recoverable/refundable	1483			137,479
	Prepaid expenses	1484		26,524	83,811
	Other current assets		+	26,524	221,290
	Total current assets	1599	=	6,249,975	6,574,003

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Attached Schedule with Total

GIFI code 1062 – Trade accounts receivable

Title GIFI code 1062 – Trade accounts receivable

Description	Operator (Note)	Amount
Accounts receivable		2,842,744 00
Unbilled Revenue	+	2,836,515 00
	+	
	Total	5,679,259 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Tangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2008/2009

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
Land							
	* Land	1600	+	307,134			307,134
	Total			307,134			
Buildings							
	* Buildings	1680	+	797,582			747,892
	*Accumulated amortization of buildings	1681			–	72,629	53,268
	Total			797,582		72,629	
Machinery, equipment, furniture and fixtures							
	* Machinery, equipment, furniture, and fixtures	1740	+	1,983,392			1,715,912
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741			–	1,172,963	907,478
	Total			1,983,392		1,172,963	
Other tangible capital assets							
	* Other tangible capital assets	1900	+	28,196,333			27,497,317
	*Accumulated amortization of other tangible capital assets	1901			–	1,911,171	1,577,922
	Other capital assets under construction	1920	+	1,494,499			775,198
	Total			29,690,832		1,911,171	
	Total tangible capital assets	2008	=	32,778,940			31,043,453
	Total accumulated amortization of tangible capital assets	2009			=	3,156,763	2,538,668

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Attached Schedule with Total

Tangible capital property – GIFI code 1900 – Other tangible capital assets

Title Tangible capital property – GIFI code 1900 – Other tangible capital assets

Description	Operator (Note)	Amount
Transformer stations		6,714,868 00
Distribution stations	+	
Distributions Overhead lines	+	6,400,719 00
Distribution Transformers	+	3,574,067 00
Distribution meters	+	1,855,746 00
Distributions Underground lines	+	9,650,933 00
	+	
	Total	28,196,333 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Attached Schedule with Total

GIFI code 1901 – Accumulated amortization of other tangible capital assets

Title GIFI code 1901 – Accumulated amortization of other tangible capital assets

Description	Operator (Note)	Amount	
Transformer stations		325,798	00
Distribution stations	+		
Distribution Overhead lines	+	72,810	00
Distribution Transformers	+	104,716	00
Distribution meters	+	531,797	00
Distribution Underground lines	+	876,050	00
	+		
	Total	1,911,171	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Long-term Assets

SCHEDULE 100

Form identifier 2589

Account	Description	GIFI		Current year	Prior year
Long-term investments					
	* Long-term investments	2300		100	100
	Long-term investments		+	100	100
Other long-term assets					
	Future (deferred) income taxes	2421		1,070,302	
	Other deferred items/charges	2424		1,068,620	1,958,094
	Other long-term assets		+	2,138,922	1,958,094
	Total long-term assets	2589	=	2,139,022	1,958,194

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Current Liabilities

SCHEDULE 100

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
	* Bank overdraft	2600	+		424,343
Amounts payable and accrued liabilities					
	* Amounts payable and accrued liabilities	2620		4,354,088	4,049,300
	Amounts payable and accrued liabilities		+	4,354,088	4,049,300
	* Taxes payable	2680	+	374,929	
Short-term debt					
	Loans from Canadian banks	2701		1,915,574	2,410,504
	Short-term debt		+	1,915,574	2,410,504
	* Deferred income	2770	+	128,368	128,368
Due to related parties					
	* Due to related parties	2860		484,499	368,586
	Due to related parties		+	484,499	368,586
Other current liabilities					
	Deposits received	2961		377,590	236,840
	Other current liabilities		+	377,590	236,840
	Total current liabilities	3139	=	7,635,048	7,617,941

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Attached Schedule with Total

GIFI code 2701 – Loans from Canadian banks

Title GIFI code 2701 – Loans from Canadian banks

Description	Operator (Note)	Amount
Current portion of LT debt		1,889,234 00
Derivatives	+	26,340 00
	+	
	Total	1,915,574 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Long-term Liabilities

SCHEDULE 100

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	* Long-term debt	3140		7,005,567	7,873,375
	Long-term debt		+	7,005,567	7,873,375
	* Deferred income	3220	+	3,094,653	2,840,351
	* Future (deferred) income taxes	3240	+	1,073,186	
Other long-term liabilities					
	* Other long-term liabilities	3320		2,629,587	2,834,232
	Deferred revenue from incomplete contracts	3328			74,948
	Other long-term liabilities		+	2,629,587	2,909,180
	Total long-term liabilities	3450	=	13,802,993	13,622,906

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Attached Schedule with Total

GIFI code 3140 – Long-term debt

Title GIFI code 3140 – Long-term debt

Description	Operator (Note)	Amount
Long-Term debt		7,005,567 00
	+	
	+	
	Total	7,005,567 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Attached Schedule with Total

GIFI code 3320 – Other long-term liabilities

Title GIFI code 3320 – Other long-term liabilities

Description	Operator (Note)	Amount
Customer Deposits		
Employee Future Benefits	+	478,800 00
Other Regulatory liabilities	+	
Regulatory balances	+	2,150,787 00
	+	
	Total	2,629,587 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Shareholder Equity

SCHEDULE 100

Form identifier 3620

Account	Description	GIFI		Current year	Prior year
	* Common shares	3500	+	2,632,307	2,632,307
Contributed and other surplus					
	* Contributed and other surplus	3540		4,269,026	4,269,026
	Contributed and other surplus		+	4,269,026	4,269,026
	* Accumulated other comprehensive income	3580	+	-36,584	70,873
	* Retained earnings/deficit	3600	+	9,708,384	8,823,929
	Total shareholder equity	3620	=	16,573,133	15,796,135

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Retained Earnings/Deficit

SCHEDULE 100

Form identifier 3849

Account	Description	GIFI		Current year	Prior year
	* Retained earnings/deficit – start	3660	+	8,823,929	8,314,935
	* Net income/loss	3680	+	1,384,455	1,008,994
Dividends declared					
	* Dividends declared	3700		500,000	500,000
	Dividends declared		–	500,000	500,000
	Retained earnings/deficit – end	3849	=	9,708,384	8,823,929

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

Income statement information

Description	GIFI

Operating name 0001
Description of the operation 0002
Sequence number 0003 01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	24,198,363	26,677,590
	Cost of sales	8518	–	23,229,633	26,794,215
	Gross profit/loss	8519	=	968,730	-116,625
	Cost of sales	8518	+	23,229,633	26,794,215
	Total operating expenses	9367	+	4,123,805	4,119,962
	Total expenses (mandatory field)	9368	=	27,353,438	30,914,177
	Total revenue (mandatory field)	8299	+	29,641,101	31,982,190
	Total expenses (mandatory field)	9368	–	27,353,438	30,914,177
	Net non-farming income	9369	=	2,287,663	1,068,013
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	2,287,663	1,068,013
	Total other comprehensive income	9998	=	-107,457	
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–	536,093	-269,677
	Current income taxes	9990	–	367,115	328,696
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+	-107,457	
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,276,998	1,008,994

Client Copy

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	24,198,363	26,677,590
	Total sales of goods and services	8089	=	24,198,363	26,677,590
Investment revenue					
	* Investment revenue	8090		45,799	56,869
	Investment revenue		+	45,799	56,869
Other revenue					
	* Other revenue	8230		5,396,939	5,247,731
	Other revenue		+	5,396,939	5,247,731
	Total revenue	8299	=	29,641,101	31,982,190

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Attached Schedule with Total

GIFI code 9270 – Amount – Other expenses

Title GIFI code 9270 – Amount – Other expenses

Description	Operator (Note)	Amount
Distribution operations		1,114,974 00
	+	
	+	
	Total	1,114,974 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Attached Schedule with Total

GIFI code 8230 – Amount – Other revenue

Title GIFI code 8230 – Amount – Other revenue

Description	Operator (Note)	Amount	
Distribution Revenue		5,019,210	00
Other Operating Revenue	+	377,729	00
	+		
	+		
	Total	5,396,939	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Cost of Sales

SCHEDULE 125

Form identifier 8518

Account	Description	GIFI	Current year	Prior year
	* Purchases/cost of materials	8320 +	23,229,633	26,794,215
	Cost of sales	8518 =	23,229,633	26,794,215

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	* Amortization of tangible assets	8670	+	1,010,972	996,009
Interest and bank charges					
	* Interest and bank charges	8710		463,127	482,933
	Interest and bank charges		+	463,127	482,933
Other expenses					
	* Other expenses	9270		1,114,974	1,217,324
	Selling expenses	9273		573,154	547,188
	General and administrative expenses	9284		961,578	876,508
	Other expenses		+	2,649,706	2,641,020
	Total operating expenses	9367	=	4,123,805	4,119,962

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Other comprehensive income

SCHEDULE 125

Form identifier 9998

Account	Description	GIFI		Current year	Prior year
	Defined benefit gains/losses	7002	+	-146,200	
	Income tax relating to components of other comprehensive income	7010	−	-38,743	
	Total other comprehensive income	9998	=	-107,457	

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012*, T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation?	095	Yes	X	No	
Is the accountant connected* with the corporation?	097	Yes		No	X

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	Yes		No	X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Were notes to the financial statements prepared?	101	Yes	X	No	
If **yes**, complete lines 104 to 107 below:					
Are subsequent events mentioned in the notes?	104	Yes		No	X
Is re-evaluation of asset information mentioned in the notes?	105	Yes		No	X
Is contingent liability information mentioned in the notes?	106	Yes	X	No	
Is information regarding commitments mentioned in the notes?	107	Yes	X	No	
Does the corporation have investments in joint venture(s) or partnership(s)?	108	Yes		No	X

Client Copy

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** Yes ☐ No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** Yes ☐ No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes ☐ No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes ☐ No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** Yes ☐ No ☒

If **yes**, you have to maintain a separate reconciliation.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125 . . . . . 1,276,998 A

Add:

Provision for income taxes – current	101	367,115	
Amortization of tangible assets	104	1,103,773	
Loss on disposal of assets	111	23,657	
Non-deductible meals and entertainment expenses	121	1,789	
Reserves from financial statements – balance at the end of the year	126	574,218	
Subtotal of additions		2,070,552 ▶	2,070,552

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	9,973
2	Customer Deposits 12(1)(a)	377,590
3	capital contributions received 12(1)(x)	319,954
4	Regulatory adjustment	769,773
	Total of column 2	1,477,290 ▶ 296 1,477,290

Subtotal of other additions	199	1,477,290 ▶	1,477,290
Total additions	500	3,547,842 ▶	3,547,842 B

Amount A **plus** amount B . . . . . 4,824,840 C

Deduct:

Capital cost allowance from Schedule 8	403	1,806,061	
Reserves from financial statements – balance at the beginning of the year	414	425,135	
Subtotal of deductions		2,231,196 ▶	2,231,196

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Unrealized gain on derivatives	46,137
2	Customer Deposits 20(1)(m)	377,590
3	Amortization of deferred capital contributions	65,652
4	capital contributions received 13(7.4)	319,954
5	Tax included in net movement in regulatory balances	323,875
6	Tax on EFB	38,743
	Total of column 2	1,171,951 ▶ 396 1,171,951

Client Copy

Subtotal of other deductions	499	1,171,951 ▶	1,171,951	
Total deductions	510	3,403,147 ▶	3,403,147	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			1,421,693	E

Enter amount E on line 300 of the T2 return.

T2 SCH 1 E (17)

Canada

Client Copy

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Description	Operator (Note)	Amount
Regulatory adjustment		407,400 00
Regulatory correction PY	+	362,373 00
	+	
	Total	769,773 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) of the ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. . . . . ☐

Ontario

A		
☒	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☒	Ontario co-operative education tax credit	
☒	Ontario apprenticeship training tax credit	9,973
☐	Ontario computer animation and special effects tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario film and television tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario production services tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario interactive digital media tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario sound recording tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario book publishing tax credit	
☒	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☐	Ontario business-research institute tax credit	
☐	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the additional deduction for gifts of medicine made before March 22, 2017.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward. Provincial food donation tax credits must be applied in the current tax year.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- A gift of medicine made before March 22, 2017 to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File a completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Subtotal	
Add: Total donations of less than $100 each	
Total donations in current tax year	

Client Copy

Part 1 – Charitable donations

		Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		400	1A	400	400
Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year (amount 1A **minus** line 239)	240	400		400	400
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year	210				
Include on line 112 of Schedule 1 *Net Income (Loss) for Income Tax Purposes*					
Subtotal (line 250 **plus** line 210)			1B		
Subtotal (line 240 **plus** amount 1B)		400	1C	400	400
Adjustment for an acquisition of control	255				
Total charitable donations available (amount 1C **minus** line 255)		400	1D	400	400
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2)	260	400		400	400
Enter on line 311 of the T2 return					
Charitable donations closing balance (amount 1D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in line 260 (for donations made after December 31, 2013) **262** _____

Ontario community food program donation tax credit for farmers (line 262 **multiplied** by 25 %) _____ 1E

Enter amount 1E on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1E. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in line 260 (for donations made after December 31, 2015) **263** _____

Nova Scotia food bank tax credit for farmers (line 263 **multiplied** by 25 %) _____ 1F

Enter amount 1F on line 570 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 1F. For more information, see section 50A of the Nova Scotia *Income Tax Act*.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in line 260 (for donations made after February 16, 2016 and before January 1, 2019) **265** _____

British Columbia farmers' food donation tax credit (line 265 **multiplied** by 25 %) _____ 1G

Enter amount 1G on line 683 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 1G. For more information, see section 20.1 of the British Columbia *Income Tax Act*.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Client Copy

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31	400	400	400
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)		400	400	400

***** For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % 1,066,270 2A

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** 225

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) 227

The amount of the recapture of capital cost allowance in respect of charitable donations 230

Proceeds of disposition, **less** outlays and expenses** 2B

Capital cost** 2C

Amount 2B or 2C, whichever is less 235

Line 230 or 235, whichever is less 2D

Subtotal (**add** lines 225, 227 and amount 2D) 2E

Amount 2E **multiplied** by 25 % 2F

Subtotal (amount 2A **plus** amount 2F) 1,066,270 2G

Maximum allowable deduction for charitable donations (amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is less) 400 2H

***** For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

****** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Client Copy

Part 3 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			3A		
Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year (amount 3A **minus** line 439)	440				
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year	410				
Include on line 112 of Schedule 1					
Subtotal (line 450 **plus** line 410)			3B		
Subtotal (line 440 **plus** amount 3B)			3C		
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income	460				
Enter on line 313 of the T2 return					
Subtotal (line 455 **plus** line 460)			3D		
Gifts of certified cultural property closing balance (amount 3C **minus** amount 3D)	480				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31			
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Client Copy

Part 4 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			4A		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A **minus** line 539)	540				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			4B		
Subtotal (line 540 **plus** amount 4B)			4C		
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			4D		
Gifts of certified ecologically sensitive land closing balance (amount 4C **minus** amount 4D)	580				

***** For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Client Copy

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31			
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year*	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Client Copy

Part 5 – Additional deduction for gifts of medicine

		Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			5A		
Additional deduction for gifts of medicine expired after five tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A **minus** line 639)	640				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	602				
Cost of gifts of medicine made before March 22, 2017	601				
Subtotal (line 602 **minus** line 601)			5B		
Amount 5B **multiplied** by 50 %			5C		
Eligible amount of gifts	600				

Federal

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . 610 _____

Québec

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . _____

Alberta

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . _____

where:

a is the **lesser** of line 601 and amount 5C

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)		5D		
Subtotal (line 640 **plus** amount 5D)		5E		
Adjustment for an acquisition of control	655			
Amount applied in the current year against taxable income	660			
Enter on line 315 of the T2 return				
Subtotal (line 655 **plus** line 660)		5F		
Additional deduction for gifts of medicine closing balance (amount 5E **minus** amount 5F)	680			

***** For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Client Copy

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31			
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Client Copy

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2016-12-31	
2nd prior year	2015-12-31	
3rd prior year	2014-12-31	
4th prior year	2013-12-31	
5th prior year	2012-12-31	
6th prior year*	2011-12-31	
7th prior year	2010-12-31	
8th prior year	2009-12-31	
9th prior year	2008-12-31	
10th prior year	2007-12-31	
11th prior year	2006-12-31	
12th prior year	2005-12-31	
13th prior year	2004-12-31	
14th prior year	2003-12-31	
15th prior year	2002-12-31	
16th prior year	2001-12-31	
17th prior year	2001-09-30	
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculations

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a),(a.1), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- All legislative references are to the federal *Income Tax Act*.
- The calculations in this schedule apply only to private or subject corporations.
- A recipient corporation is **connected** with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A1 – Enter "X" if dividends received from a foreign source.
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H and I **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing column J and K use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividends under section 83 230
1			2			

Total of column E (enter amount on line 402 of Schedule 1)

Client Copy

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] 240	F1 Eligible dividends (included in column F)	F2	G Dividends included in column F that was received **before** 2016 241	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) 250	I Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2] 260	J Part IV tax before deductions. Dividends (from column G) received **before** 2016 **multiplied** by 33 1/3%[note 3] 270	K Part IV tax before deductions. Dividends received **after** 2015 (column F **minus** column G) **multiplied** by 38 1/3%[note 4] 275
1								
	Total of column F (include this amount on line 320 of the T2 Return)						**Total of column J** (enter amount on line a in Part 2)	**Total of column K** (enter amount on line b in Part 2)

1 If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270 or column 275 as applicable according to the date received. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For dividends received **before** 2016 from **connected** corporations, Part IV tax on dividends is equal to: column G **multiplied** by column I **divided** by column H.

4 For dividends received **after** 2015 from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by the result of column F **minus** column G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received **before** 2016, before deductions (total of column J in part 1) . . . . . a

Part IV tax on dividends received **after** 2015, before deductions (total of column K in part 1) . . . . . b

Part IV tax before deductions (amount a **plus** amount b) . . . . . ▶ L

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) 320

Subtotal (amount L **minus** line 320) M

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . . 330 c

Non-capital losses from previous years claimed to reduce Part IV tax . . . . . 335 d

Current-year farm loss claimed to reduce Part IV tax . . . . . 340 e

Farm losses from previous years claimed to reduce Part IV tax . . . . . 345 f

Total losses applied against Part IV tax (total of amounts c to f) g

If your tax year begins after December 31, 2015:

Amount g **multiplied** by 38 1 / 3 % . . . . . h

If your tax year begins before January 1, 2016:

Amount b or M whichever is less

_____ ÷ 38 1 / 3 % . . . = 1

Amount 1 or g, whichever is less 2

Amount g **minus** amount 2 3

Amount 2 _____ x 38 1 / 3 % = i

Amount 3 _____ x 33 1 / 3 % = j

Subtotal (amount i **plus** amount j) k

Amount h or amount k, whichever applies depending on your tax year start date . . . . . N

Part IV tax payable (amount M **minus** amount N, if negative enter "0") 360

(enter amount on line 712 of the T2 return)

Client Copy

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	O Name of connected recipient corporation 400	P Business Number 410	Q Tax year-end of connected recipient corporation in which the dividends in column R were received YYYY/MM/DD 420	R Taxable dividends paid to connected corporations 430	R1 Eligible dividends (included in column R)
1	NIAGARA-ON-THE-LAKE ENERGY INC.	86376 1490 RC0001	2017-12-31	500,000	
2					

Total of column R 500,000

Total taxable dividends paid in the tax year to other than connected corporations **450**

Eligible dividends (included in line 450) 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund
(total of column R **plus** line 450) **460** 500,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 500,000

Other dividends paid in the tax year (total of 510 to 540) . . . . .

Total dividends paid in the tax year **500** 500,000

Deduct:

Dividends paid out of capital dividend account **510**

Capital gains dividends **520**

Dividends paid on shares described in subsection 129(1.2) **530**

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year **540**

Subtotal (total of lines 510 to 540) ▶ S

Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount S) 500,000 T

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** Yes ☐ No ☒

	1 Class number * **200**	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) **203**	4 Adjustments and transfers (see note 2 below) **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see note3 below) **211**	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6)	8 CCA rate % (see note 4 below) **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see note 6 below) **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1	Dist'n Plant >87	4,370,164			0		4,370,164	4	0	0	174,807	4,195,357
2.	2	Dist'n Plant < 88	1,967,981			0		1,967,981	6	0	0	118,079	1,849,902
3.	1	Transformers > 87	3,365,049			0		3,365,049	4	0	0	134,602	3,230,447
4.	2	Transformers < 88	378,023			0		378,023	6	0	0	22,681	355,342
5.	1	Meters > 87	154,868			0		154,868	4	0	0	6,195	148,673
6.	2	Meters < 88	64,237			0		64,237	6	0	0	3,854	60,383
7.	1	Buildings	461,121			0		461,121	4	0	0	18,445	442,676
8.	2	Dist'n Stations	178,380			0		178,380	6	0	0	10,703	167,677
9.	8	Office equipment	105,631			0		105,631	20	0	0	21,126	84,505
10.	8	Stores/Comm/Supe etc	50,865			0		50,865	20	0	0	10,173	40,692
11.	10	Vehicles, trailers, transport equip	39,696	45,650		0	22,825	62,521	30	0	0	18,756	66,590
12.	10	Motor Vehicles	87,466			0		87,466	30	0	0	26,240	61,226
13.	8	Inventory spare part	9,154			0		9,154	20	0	0	1,831	7,323
14.	17	Telephone System	9,693			0		9,693	8	0	0	775	8,918
15.	8	Lighting	201			0		201	20	0	0	40	161
16.	17	Paving	8,415			0		8,415	8	0	0	673	7,742
17.	6	Fencing	2,408			0		2,408	10	0	0	241	2,167
18.	8	PCB Storage	334			0		334	20	0	0	67	267
19.	1	SCADA system	173,250			0		173,250	4	0	0	6,930	166,320
20.	2	Invent Dist'n Meter	26,863			0		26,863	6	0	0	1,612	25,251
21.	45	Computer hardware - new	1,466			0		1,466	45	0	0	660	806
22.	47	Distribution assets after Feb 22,	12,436,423	905,120		503,386	200,867	12,637,290	8	0	0	1,010,983	11,827,174
23.	50	Computer Hardware	132,068	17,583		0	8,792	140,859	55	0	0	77,472	72,179

Client Copy

	1 Class number * 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) 203	4 Adjustments and transfers (see note 2 below) 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see note3 below) 211	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6)	8 CCA rate % (see note 4 below) 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see note 6 below) 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
24.	1b	Buildings	75,388			0		75,388	6	0	0	4,523	70,865
25.	8	Smart grid	245,449	204,754		0	102,377	347,826	20	0	0	69,565	380,638
26.	14.1		7,902			0		7,902	5	0	0	553	7,349
27.	12	Computer Software		128,951		0	64,476	64,475	100	0	0	64,475	64,476
		Totals	24,352,495	1,302,058		503,386	399,337	24,751,830				1,806,061	23,345,106

* Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

Note 2. Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

Note 3. The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

Note 4. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

Note 5. For every entry in column 9, "Recapture of capital cost allowance", there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

Note 6. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Client Copy

T2 SCH 8 (17)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	NIAGARA-ON-THE-LAKE ENERGY IN		86376 1490 RC0001	1					7,054,844
2.	Energy Services Niagara Inc		86360 6125 RC0001	3					143,511
3.	Town of Niagara-on-the-Lake		NR	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Client Copy

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	EMPLOYEE FUTURE BENEFITS	330,064		478,800	330,064	478,800
2	AFDA	95,071		95,418	95,071	95,418
3						
	Reserves from Part 2 of Schedule 13					
	Totals	425,135		574,218	425,135	574,218

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) **100**	Amount of contribution $ (see note 2) **200**	Registration number (RPP, RSUBP, PRPP, and DPSP only) **300**	Name of EPSP trust **400**	Address of EPSP trust **500**	T4PS slip(s) (see note 3) **600**
1	1	154,013	490251			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . 154,013 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 154,013 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

Client Copy

T2 SCH 15 (13)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Client Copy

Allocating the business limit

Date filed (do not use this area) . . . . . 025 — Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 — Year: 2017

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 — 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year before the allocation $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	1	500,000	100.0000	500,000
2	NIAGARA-ON-THE-LAKE ENERGY INC.	86376 1490 RC0001	1	500,000		
3	Energy Services Niagara Inc	86360 6125 RC0001	1	500,000		
4	Town of Niagara-on-the-Lake	NR	4			
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

T2 SCH 23 E (15)

Canada

Client Copy

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2016-12-31				
2015-12-31	2,000			2,000
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				*
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2001-09-30				
				*
Total	2,000			2,000

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	574,218	
Capital stock (or members' contributions if incorporated without share capital)	103	2,632,307	
Retained earnings	104	9,708,384	
Contributed surplus	105		
Any other surpluses	106	4,269,026	
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	9,769,927	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		26,953,862 ▶	26,953,862 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Client Copy

Part 1 – Capital (continued)

Subtotal A (from page 1) 26,953,862 A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		▶	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	26,953,862	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	100
A loan or advance to another corporation (other than a financial institution)	402	427,037
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	427,137

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		26,953,862	C
Deduct: Investment allowance for the year (line 490)		427,137	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	26,526,725	

Client Copy

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 26,526,725 x (Taxable income earned in Canada / Taxable income) **610** 1,000 / 1,000 = **Taxable capital employed in Canada** **690** 26,526,725

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **701**

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada **711**

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **712**

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) **713**

Total deductions (**add** lines 711, 712, and 713) ▶ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") **790**

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . . F

Deduct: . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") H

Calculation for purposes of the small business deduction (amount H x 0.225%) I

Enter this amount at line 415 of the T2 return.

Client Copy

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount	
Current portion of LT debt		1,889,234	00
Long-term portion of LT debt	+	7,005,567	00
Customer Deposits	+	377,590	00
Due to town of ENSI	+	13,037	00
Due to town of NOTL (acct 2205 total)	+	484,499	00
Line of credit	+		
	+		
	+		
	Total	9,769,927	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Part 2 – A loan or advance to another corporation (other than a financial ir

Description	Operator (Note)	Amount
Special Deposits		377,590 00
Due from NOTL Energy Inc	+	22,923 00
Prepaids per BS	+	26,524 00
	+	
	Total	427,037 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description	Operator (Note)	Amount
Sch 13S reserves		574,218 00
	+	
	+	
	Total	574,218 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	Niagara-on-the-Lake Energy Inc.	86376 1490 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 53

General Rate Income Pool (GRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

On: 2017-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- Credit unions are **not** required to complete this schedule.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- When an eligible dividend was paid in the tax year or there was a change in the GRIP balance, file a completed copy of this schedule with your T2 *Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Client copy

Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year	100	5,875,166	A
Taxable income for the year (DICs enter "0") *	110		B
Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less *	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140		
Subtotal (line 130 **plus** line 140)			C
Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0")	150		
After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year))	190		D
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (line 200 **plus** line 210)			E
Becoming a CCPC (amount W5 in Part 4)	220		
Post-amalgamation (total of amounts E4 in Part 3 and amounts W5 in Part 4)	230		
Post-wind-up (total of amounts E4 in Part 3 and amounts W5 in Part 4)	240		
Subtotal (**add** lines 220, 230, and 240)	290		F
Subtotal (**add** amounts A, D, E, and F)		5,875,166	G
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
(If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.)			
Subtotal (line 300 **minus** line 310)			H
GRIP before adjustment for specified future tax consequences (amount G **minus** amount H) (amount can be negative)	490	5,875,166	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount N3 in Part 2)	560		
GRIP at the end of the tax year (line 490 **minus** line 560)	590	5,875,166	

Enter this amount on line 160 of Schedule 55.

***** For lines 110, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Client Copy

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2016-12-31

Taxable income before specified future tax consequences from the current tax year A1

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less B1

Aggregate investment income (line 440 of the T2 return) C1

Subtotal (amount B1 **plus** amount C1) ▶ D1

Subtotal (amount A1 **minus** amount D1) (if negative, enter "0") ▶ E1

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F1

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less G1

Aggregate investment income (line 440 of the T2 return) H1

Subtotal (amount G1 **plus** amount H1) ▶ I1

Subtotal (amount F1 **minus** amount I1) (if negative, enter "0") ▶ J1

Subtotal (amount E1 **minus** amount J1) (if negative, enter "0") K1

GRIP adjustment for specified future tax consequences to the first previous tax year

(amount K1 **multiplied** by 0.72) **500**

Client Copy

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Second previous tax year 2015-12-31

Taxable income before specified future tax consequences from the current tax year A2

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less B2

Aggregate investment income (line 440 of the T2 return) C2

Subtotal (amount B2 **plus** amount C2) ▶ D2

Subtotal (amount A2 **minus** amount D2) (if negative, enter "0") ▶ E2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F2

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less G2

Aggregate investment income (line 440 of the T2 return) H2

Subtotal (amount G2 **plus** amount H2) ▶ I2

Subtotal (amount F2 **minus** amount I2) (if negative, enter "0") ▶ J2

Subtotal (amount E2 **minus** amount J2) (if negative, enter "0") K2

GRIP adjustment for specified future tax consequences to the second previous tax year

(amount K2 **multiplied** by 0.72) **520**

Client Copy

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2014-12-31

Taxable income before specified future tax consequences from the current tax year A3

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less B3

Aggregate investment income (line 440 of the T2 return) C3

Subtotal (amount B3 **plus** amount C3) ▶ D3

Subtotal (amount A3 **minus** amount D3) (if negative, enter "0") ▶ E3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F3

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less G3

Aggregate investment income (line 440 of the T2 return) H3

Subtotal (amount G3 **plus** amount H3) ▶ I3

Subtotal (amount F3 **minus** amount I3) (if negative, enter "0") ▶ J3

Subtotal (amount E3 **minus** amount J3) (if negative, enter "0") K3

GRIP adjustment for specified future tax consequences to the third previous tax year

(amount K3 **multiplied by** 0.72) **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") L3

Enter amount L3 on line 560 in part 1.

Client Copy

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.

Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.

In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		A4
Eligible dividends paid by the corporation in its last tax year	B4	
Excessive eligible dividend designations made by the corporation in its last tax year	C4	
Subtotal (amount B4 **minus** amount C4) ▶		D4
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year) (amount A4 **minus** amount D4)		E4

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the E4 amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Client Copy

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.

Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.

In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year A5

The corporation's money on hand immediately before the end of its previous/last tax year B5

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses C5

Net capital losses D5
Farm losses E5
Restricted farm losses F5
Limited partnership losses G5

Subtotal (**add** amounts C5 to G5) ▶ H5

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses I5
Net capital losses J5
Farm losses K5
Restricted farm losses L5
Limited partnership losses M5

Subtotal (**add** amounts I5 to M5) ▶ N5

Unused and unexpired losses at the end of the corporation's previous/last tax year (amount H5 **minus** amount N5) ▶ O5

Subtotal (**add** amounts A5, B5, and O5) P5

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year Q5

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year R5

All the corporation's reserves deducted in its previous/last tax year S5

The corporation's capital dividend account immediately before the end of its previous/last tax year T5

The corporation's low rate income pool immediately before the end of its previous/last tax year U5

Subtotal (**add** amounts Q5 to U5) ▶ V5

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (amount P5 **minus** amount V5) (if negative, enter "0") W5

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the W5 amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Client Copy

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		500,000	
Total taxable dividends paid in the tax year	100	500,000	
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	5,875,166	B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
NIAGARA-ON-THE-LAKE HYDRO INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-07-01	1424833

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
8	Henegan Road	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 460

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Virgil	ON	CA	L0S 1T0

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [2] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Klassen (Last name) **451** Jeffrey (First name)

454 Tyler (Middle name(s)),

460 [2] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Client Copy

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 2 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 1 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Client Copy

CRA internal form identifier 547

Part 7 – Director/Officer information

- **Director:** If the individual named in this part is a director (or must be reported ceased as a director), complete lines 700 to 797.
- **Officer:** If the individual named in this part is one of the corporation's five most senior officers (or must be reported ceased in an officer position), complete lines 700 to 790 and the applicable lines from 801 to 912.
- **Director and officer:** If the individual named in this part is a director and one of the corporation's five most senior officers (or must be reported ceased in these position(s)), complete lines 700 to 797 and the applicable lines from 801 to 912.
- The corporation is required to show information on the MGS public record for all its directors and a maximum of five of its most senior officers. If the MGS public record shows more than five officer positions, report cease dates for all except the corporation's five most senior officer positions.
- To report changes to the name of a director/officer, or changes to both the address and the date elected/appointed of a director/officer, enter the director/officer information exactly as shown incorrectly on the public record, with a cease date, and then photocopy and complete only Part 7 with the correct director/officer information.

Please photocopy this page and complete Part 7 only for each additional individual for whom director/officer information changes are being reported.

Full name and address for service (P.O. box not acceptable as stand-alone address). The name entered in lines 700 to 710 must be exactly as shown on the MGS public record.

700 Last name	705 First name	710 Middle name(s)
Syed	Hassan	

720 Street number	730 Street name/Rural route/Lot and Concession number	740 Suite number
541	Winston Road	36

750 Additional address information if applicable (line 730 must be completed first)

760 Municipality (e.g., city, town)	770 Province/state	780 Country	790 Postal/zip code
Grimsby	ON	CA	L3M 0C5

Director

Is this director a resident Canadian? . . . **795** **1** Yes ☐ **2** No ☐

(applies to directors of corporations with share capital only)

796 Date elected/appointed (Year Month Day):

797 Date ceased, if applicable (Year Month Day):

Officer information

		Date appointed (Year Month Day)		Date ceased, if applicable (Year Month Day)
President	801		802	
Secretary	806		807	
Treasurer	811		812	
General Manager	816		817	
Chair	821		822	
Chairperson	826		827	
Chairman	831		832	
Chairwoman	836		837	
Vice-Chair	841		842	
Vice-President	846	2016-05-11	847	2017-05-26
Assistant Secretary	851		852	
Assistant Treasurer	856		857	
Chief Manager	861		862	
Executive Director	866		867	
Managing Director	871		872	
Chief Executive Officer	876		877	
Chief Financial Officer	881		882	
Chief Information Officer	886		887	
Chief Operating Officer	891		892	
Chief Administrative Officer	896		897	
Comptroller	901		902	
Authorized Signing Officer	906		907	
Other (untitled)	911		912	

Client Copy

Once you have completed this page, complete the certification in Part 4 of this schedule.

CRA internal form identifier 547

Part 7 – Director/Officer information

- **Director:** If the individual named in this part is a director (or must be reported ceased as a director), complete lines 700 to 797.
- **Officer:** If the individual named in this part is one of the corporation's five most senior officers (or must be reported ceased in an officer position), complete lines 700 to 790 and the applicable lines from 801 to 912.
- **Director and officer:** If the individual named in this part is a director and one of the corporation's five most senior officers (or must be reported ceased in these position(s)), complete lines 700 to 797 and the applicable lines from 801 to 912.
- The corporation is required to show information on the MGS public record for all its directors and a maximum of five of its most senior officers. If the MGS public record shows more than five officer positions, report cease dates for all except the corporation's five most senior officer positions.
- To report changes to the name of a director/officer, or changes to both the address and the date elected/appointed of a director/officer, enter the director/officer information exactly as shown incorrectly on the public record, with a cease date, and then photocopy and complete only Part 7 with the correct director/officer information.

Please photocopy this page and complete Part 7 only for each additional individual for whom director/officer information changes are being reported.

Full name and address for service (P.O. box not acceptable as stand-alone address). The name entered in lines 700 to 710 must be exactly as shown on the MGS public record.

700 Last name	705 First name	710 Middle name(s)
Marouf	Kazi	

720 Street number	730 Street name/Rural route/Lot and Concession number	740 Suite number
570	Ferndale Avenue	

750 Additional address information if applicable (line 730 must be completed first)

760 Municipality (e.g., city, town)	770 Province/state	780 Country	790 Postal/zip code
Fort Erie	ON	CA	L2A 6E3

Director

Is this director a resident Canadian? . . . 795 **1** Yes ☐ **2** No ☐

(applies to directors of corporations with share capital only)

796 Date elected/appointed Year Month Day

797 Date ceased, if applicable Year Month Day

Officer information

		Date appointed Year Month Day		Date ceased, if applicable Year Month Day
President	801		802	
Secretary	806		807	
Treasurer	811		812	
General Manager	816		817	
Chair	821		822	
Chairperson	826		827	
Chairman	831		832	
Chairwoman	836		837	
Vice-Chair	841		842	
Vice-President	846	2017-05-11	847	
Assistant Secretary	851		852	
Assistant Treasurer	856		857	
Chief Manager	861		862	
Executive Director	866		867	
Managing Director	871		872	
Chief Executive Officer	876		877	
Chief Financial Officer	881		882	
Chief Information Officer	886		887	
Chief Operating Officer	891		892	
Chief Administrative Officer	896		897	
Comptroller	901		902	
Authorized Signing Officer	906		907	
Other (untitled)	911		912	

Client Copy

Once you have completed this page, complete the certification in Part 4 of this schedule.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . . NIAGARA-ON-THE-LAKE HYDRO INC.

Taxation Year . . . . . 2017-01-01 to 2017-12-31

Jurisdiction . . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . . Y

Corporation is related . . . . . Y

Number of associated corporations . . . 3

Type of corporation . . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . .

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		1,421,693
Taxable income		
Donations		
Calculation of income from an active business carried on in Canada		1,421,693
Dividends paid		500,000
Dividends paid – Regular	500,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		5,875,166
Balance of the general rate income pool at the end of the year		5,875,166
Part I tax (base amount)		

Summary of federal carryforward/carryback information

Carryforward balances

Investment tax credits	2,000
Capital dividend amount	74,366
Financial statement reserve	574,218

Client Copy

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	1,421,693		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***			
Instalments and refundable credits			
Balance due/Refund (-)			
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Client Copy

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
NIAGARA-ON-THE-LAKE HYDRO INC.	26,853,754	26,853,754	26,526,725	26,526,725
NIAGARA-ON-THE-LAKE ENERGY INC.	8,185	8,185	5,686	5,686
Energy Services Niagara Inc	1,692,031	1,692,031	481,838	481,838
Town of Niagara-on-the-Lake				
Total	28,553,970	28,553,970	27,014,249	27,014,249

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Client Copy

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Net income	1,421,693	-18,286	-383,781	-51,083	1,527,596
Taxable income					1,522,076
Active business income	1,421,693				1,527,596
Dividends paid	500,000	500,000	500,000	250,000	
Dividends paid – Regular	500,000	500,000	500,000	250,000	
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	5,875,166	5,889,299	6,165,621	6,202,401	5,106,506
GRIP – end of the year	5,875,166	5,875,166	5,889,299	6,165,621	6,202,401
Donations			400		5,520
Balance due/refund (-)		-9,973	-100,000	-357,237	-136,179
Line 996 – Amended tax return	☐	☐	☐	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Taxable income before loss carrybacks	N/A	N/A			1,522,076
Non-capital losses	N/A	N/A			19,629
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			19,629
Adjusted taxable income after loss carrybacks	N/A	N/A			1,502,447

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Adjusted taxable income before current year loss carrybacks*	N/A				N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A				N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Client Copy

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Part I					199,470
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Investment tax credit					28,841
Abatement/other*					350,078

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
ITC refund					
Dividend refund				19,345	
Instalments			90,000	327,892	464,071
Other*		9,973	10,000	10,000	

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Client Copy

Ontario

Taxation year end	2017-12-31	2016-12-31	2015-12-31	2014-12-31	2013-12-31
Net income	1,421,693	-18,286	-383,781	-51,083	1,527,596
Taxable income					1,522,076
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income					1,522,076
Surtax					
Income tax payable before deduction					175,039
Income tax deductions /credits					41,795
Net income tax payable					133,244
Taxable capital					
Capital tax payable					
Total tax payable*					133,244
Instalments and refundable credits		9,973	10,000	10,000	4,822
Balance due/refund**		-9,973	-10,000	-10,000	128,422

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Client Copy

KPMG LLP
Commerce Place
21 King Street West Suite 700
Hamilton, ON L8P 4W7
Tel 905-523-8200
Fax 905-523-2222
www.kpmg.ca

PRIVATE AND CONFIDENTIAL

Mr. Timothy Curtis
Niagara-on-the-Lake Hydro Inc.
8 Henegan Road
Virgil ON L0S 1T0

June 7, 2018

Dear Mr. Curtis:

Corporate Income Tax Returns

Client Copy

We have enclosed the following income tax returns of Niagara-on-the-Lake Hydro Inc. (the "Company") for the year ended **December 31, 2017**:

- ☑ T2 – *Corporation Income Tax Return* – EXEMPT
- ☑ T183 *Information Return For Corporations Filing Electronically* (Federal – to be e-filed with CRA) - Exempt
- ☑ T2 – *Corporation Income Tax Return* (to be filed with Ministry of Finance) – PILS
- ☑ Instalment Schedule
- ☑ One copy of each return for your files

We have prepared these returns based on our understanding of the information provided to us by the Company and we recommend that you review the returns to ensure that all of the relevant facts are properly disclosed. When you are satisfied that the returns are in order, one copy of each return should be retained for your records (the copy stamped "Client Copy") and the remaining copies should be completed by an authorized signing officer of the Company and filed as described below.

DUE DATE OF RETURNS AND PAYMENTS

All returns must be filed with the respective taxing authorities by the due date if late filing penalties are to be avoided. We suggest that the returns be sent by registered mail and that the mailing receipt be kept on file in order to have evidence of the date of filing.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

Any balances owing must be remitted by the due date or as soon as possible if interest charges are to be minimized.

T2 – *CORPORATION INCOME TAX RETURN* (FEDERAL) CRA COPY - EXEMPT

Signature

✍ The Form T183CORP - *Information Return for Corporations Filing Electronically* should be completed and signed.

Payment

No amount is payable for the **December 31, 2017** taxation year.

Mailing

✉ One copy of the signed Form T183CORP should be returned to us in the self-addressed envelope no later than **June 30, 2018** in order to have the Company's corporate income tax return filed on or before the due date for filing. Alternatively, you can fax it to **(905) 523-2222.**

T2 – *CORPORATION INCOME TAX RETURN* - MINISTRY OF FINANCE

Signature

✍ Form T2 – *Corporate Income Tax Return*, the certification section at the bottom of page 9 should be completed and signed.

Payment

A cheque in the amount of $**374,643** should be attached for the **December 31, 2017** taxation year. Payments should be made in Canadian funds and be made payable to the Minister of Finance. Your business number should be printed on the back of the cheque or money order.

Mailing

✉ One copy of the *T2 Corporate Income Tax Return* must be received by The Ministry of Finance, HYDRO PIL DIVISION, P.O. Box 620, 33 King Street West, Oshawa, Ontario, L1H 8E9 no later than **June 30, 2018**. The Company's account number should be recorded on each of the paper documents submitted.

NOTICES OF ASSESSMENT

If your Company receives a Notice of Assessment that does not agree with the returns prepared by us, please contact us so that we can determine whether any action should be taken. The Company has only 90 days (180 days in the case of Ontario) from the date of

Client Copy

mailing of the Assessment in which to object. Failure to respond within the prescribed time limit will cause the Company to lose its right to object to the Assessment.

INSTALMENTS

We have prepared and enclose an estimate of PILS tax instalments as applicable for the Company for the **2018** taxation year. The amounts were computed with reference to the Company's taxable income, taxable capital and taxes payable for prior years. If during the year it is evident that the taxable income or taxable capital for the current year will be substantially less than for the previous taxation year, your instalments may be recalculated. Please call your KPMG advisor in order that we may determine what course of action should be taken.

In order to avoid interest charges, the Ministry of Finance must receive the instalment payments no later than the date indicated on the attached schedule.

If you have any questions concerning these returns, or if we may be of any further assistance, please do not hesitate to contact us.

Yours truly,

Tony Italiano
Partner
905-523-2227

Enclosures

Client Copy

APPENDIX

4C



2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2018-12-31

Business number 86360 5929 RC0001

The following is a list of instalments payable for the current taxation year, and the last column indicates the instalments payable to the Canada Revenue Agency (CRA). The instalments must be paid on each of the dates indicated below, otherwise non-deductible interest might be charged.

Instalment payments can be made using one of the following methods:

- electronically, using your online or telephone banking services;
- online, using the CRA's *My Payment* service, at **canada.ca/my-cra-payment**;
- by setting up a pre-authorized debit agreement, in *My Business Account*, at **canada.ca/my-cra-business-account**;
- in person, at a Canadian financial institution, **by presenting the appropriate remittance voucher** with your payment.

You can also mail a cheque or a money order payable to the Receiver General of Canada, **accompanied by the appropriate remittance voucher**, to Ministry of Finance, HYDRO PILS DIVISION, 33 King St, PO Box 620, Oshawa ON L1H 8E9

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2018-01-31	31,221				31,221
2018-02-28	31,221				31,221
2018-03-31	31,221				31,221
2018-04-30	31,221				31,221
2018-05-31	31,221				31,221
2018-06-30	31,221				31,221
2018-07-31	31,221				31,221
2018-08-31	31,221				31,221
2018-09-30	31,221				31,221
2018-10-31	31,221				31,221
2018-11-30	31,221				31,221
2018-12-31	31,212				31,212
Totals	374,643				374,643

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see canada.ca/taxes or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 **Do not use this area**

Identification

Business number (BN) 001 86360 5929 RC0001

Corporation's name

002 NIAGARA-ON-THE-LAKE HYDRO INC.

Address of head office

Has this address changed since the last time we were notified? . . . . . 010 1 Yes [ ] 2 No [X]

If **yes**, complete lines 011 to 018.

011

012 8 Henegan Road

City	Province, territory, or state
015 Virgil	016 ON
Country (other than Canada)	**Postal or ZIP code**
017	018 L0S 1T0

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 020 1 Yes [ ] 2 No [X]

If **yes**, complete lines 021 to 028.

021 c/o

022 P.O. Box 460

023 8 Henegan Road

City	Province, territory, or state
025 Virgil	026 ON
Country (other than Canada)	**Postal or ZIP code**
027 CA	028 L0S 1T0

Location of books and records (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 030 1 Yes [ ] 2 No [X]

If **yes**, complete lines 031 to 038.

031

032

City	Province, territory, or state
035	036
Country (other than Canada)	**Postal or ZIP code**
037	038

040 **Type of corporation at the end of the tax year** (tick one)

- [X] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [ ] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . 043 Year Month Day

To which tax year does this return apply?

Tax year start	Tax year-end
060 Year Month Day 2017-01-01	061 Year Month Day 2017-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . . 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes [ ] 2 No [X]

Amalgamation? . . . . . 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ]

If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 3 Exempt under paragraph 149(1)(t)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area

095 096 898

Client Copy

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II – Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Client Copy

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	X	2 No	
Is the corporation inactive?	280	1 Yes		2 No	X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical Distribution	285	99.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes		2 No	X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes		2 No	X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes		2 No	

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 (Year Month Day)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300	1,421,693	A
Deduct:			
Charitable donations from Schedule 2	311	400	
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine made before March 22, 2017, from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction*	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal		400 ▶	400 B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,421,293 C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360		1,421,293
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			1,421,293 Z
Taxable income for the year from a personal services business			Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Client Copy

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** 1,421,693 A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** 1,421,293 B

Business limit (see notes 1 and 2 below) . . . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** *** 41,746 / 11,250 D = ... 1,855,378 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** F

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . G

Amount F **minus** amount G . . . . . **427** H

Small business deduction

Amount A, B, C, or H, whichever is the least x (Number of days in the tax year before January 1, 2018 / Number of days in the tax year) 365/365 x 17.5 % = 1

Amount A, B, C, or H, whichever is the least x (Number of days in the tax year after December 31, 2017, and before January 1, 2019 / Number of days in the tax year) 365/365 x 18 % = 2

Total of amounts 1 and 2 (enter amount I at amount J on page 7) **430** I

***** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

****** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Specified corporate income and assignment under subsection 125(3.2)

Applicable to tax years that begin after March 21, 2016

Except that, if the tax year of your corporation started before **and** ends on or after March 22, 2016 and in the tax year of a CCPC, you can make an assignment of business limit to that other CCPC if its tax year started after March 21, 2016.

	J1 Name of corporation receiving the income and assigned amount	J Business number of the corporation receiving the assigned amount **490**	K Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column J [3] **500**	L Business limit assigned to corporation identified in column J [4] **505**
1.				

Total **510** Total **515**

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
(I) persons (other than the private corporation) with which the corporation deals at arm's length, or
(II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column K in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425.

Client Copy

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)			1,421,293 A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B	
Amount 13K from Part 13 of Schedule 27		C	
Personal services business income	432	D	
Amount used to calculate the credit union deduction (amount F from Schedule 17)		E	
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least		F	
Aggregate investment income from line 440 on page 6*		G	
Subtotal (**add** amounts B to G)		▶	H
Amount A **minus** amount H (if negative, enter "0")			1,421,293 I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %			184,768 J

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			K
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		L	
Amount 13K from Part 13 of Schedule 27		M	
Personal services business income	434	N	
Amount used to calculate the credit union deduction (amount F from Schedule 17)		O	
Subtotal (**add** amounts L to O)		▶	P
Amount K **minus** amount P (if negative, enter "0")			Q
General tax reduction – Amount Q **multiplied** by 13 %			R

Enter amount R on line 639 on page 7.

Client Copy

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . **440** _____ x 30 2 / 3 % = _____ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . _____ B

Deduct:

Foreign investment income from Schedule 7 . . . . . **445** _____ x 8 % = _____ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") _____ ▶ _____ D

Amount A **minus** amount D (if negative, enter "0") . . . . . _____ E

Taxable income from line 360 on page 3 . . . . . 1,421,293 F

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . . _____ G

Foreign non-business income tax credit from line 632 on page 7 . . . . _____ x 75 / 29 = _____ H

Foreign business income tax credit from line 636 on page 7 . . _____ x 4 = _____ I

Subtotal (total of amounts G, H and I) _____ ▶ _____ J

Subtotal (amount F **minus** amount J) (if negative, enter "0") 1,421,293 K x 30 2 / 3 % = 435,863 L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . 211,194 M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . . **450** _____ N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . **460** _____

Deduct: Dividend refund for the previous tax year . . . . . **465** _____

Subtotal _____ ▶ _____ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . _____ P

Total Part IV tax payable from Schedule 3 . . . . . _____ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . **480** _____

Subtotal _____ ▶ _____ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . . **485** _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 . . . . . 500,000 x 38 1 / 3 % = 191,667 S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . _____ T

Dividend refund – Amount S or T, whichever is less . . . . . _____ U

Enter amount U on line 784 on page 8.

Client Copy

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %	550		540,091	A
Additional tax on personal services business income (section 123.5)				
Taxable income from a personal services business	555	x 5 % = 560		B
Recapture of investment tax credit from Schedule 31	602			C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6				D
Taxable income from line 360 on page 3		1,421,293		E
Deduct: Amount from line 400, 405, 410, or 427 on page 4, whichever is the least				F
Net amount (amount E **minus** amount F)		1,421,293 ▶	1,421,293	G
Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G	604			H
Subtotal (**add** amounts A, B, C, and H)			540,091	I

Deduct:				
Small business deduction from line 430 on page 4				J
Federal tax abatement	608	142,129		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount J on page 5	638	184,768		
General tax reduction from amount R on page 5	639			
Federal logging tax credit from Schedule 21	640			
Eligible Canadian bank deduction under section 125.21	641			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652	2,000		
Subtotal		328,897 ▶	328,897	K

Part I tax payable – Amount I **minus** amount K 211,194 L

Enter amount L on line 700 on page 8.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source canada.ca/cra-info-source, personal information bank CRA PPU 047.

Client Copy

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 7	700	211,194
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		211,194

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	163,449
Total tax payable	770	374,643 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount U on page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	▶ B

Refund code 894 Overpayment

Balance (amount A **minus** amount B) 374,643

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the result is positive, you have a **balance unpaid**. If the result is negative, you have an **overpayment**. Enter the amount on whichever line applies. Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 374,643

For information on how to make your payment, go to canada.ca/payments.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920 A6698

Client Copy

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Curtis (Last name) 951 Timothy (First name) 954 President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2018-06-07 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (905) 468-4235 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name of other authorized person 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	6,249,975	6,574,003
	Total tangible capital assets	2008	+	32,778,940	31,043,453
	Total accumulated amortization of tangible capital assets	2009	–	3,156,763	2,538,668
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,139,022	1,958,194
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	38,011,174	37,036,982
Liabilities					
	Total current liabilities	3139	+	7,635,048	7,617,941
	Total long-term liabilities	3450	+	13,802,993	13,622,906
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	21,438,041	21,240,847
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	16,573,133	15,796,135
	Total liabilities and shareholder equity	3640	=	38,011,174	37,036,982
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	9,708,384	8,823,929

***** Generic item

Client Copy

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Current Assets

SCHEDULE 100

Form identifier 1599

Account	Description	GIFI		Current year	Prior year
Cash and deposits					
	* Cash and deposits	1000		366,780	
	Cash and deposits		+	366,780	
Accounts receivable					
	Trade accounts receivable	1062		5,679,259	5,981,259
	Accounts receivable		+	5,679,259	5,981,259
Inventories					
	* Inventories	1120		167,526	361,700
	Inventories		+	167,526	361,700
Due from/investment in related parties					
	* Due from/investment in related parties	1400		9,886	9,754
	Due from/investment in related parties		+	9,886	9,754
Other current assets					
	Taxes recoverable/refundable	1483			137,479
	Prepaid expenses	1484		26,524	83,811
	Other current assets		+	26,524	221,290
	Total current assets	1599	=	6,249,975	6,574,003

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Tangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2008/2009

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
Land							
	* Land	1600	+	307,134			307,134
	Total			307,134			
Buildings							
	* Buildings	1680	+	797,582			747,892
	*Accumulated amortization of buildings	1681			–	72,629	53,268
	Total			797,582		72,629	
Machinery, equipment, furniture and fixtures							
	* Machinery, equipment, furniture, and fixtures	1740	+	1,983,392			1,715,912
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741			–	1,172,963	907,478
	Total			1,983,392		1,172,963	
Other tangible capital assets							
	* Other tangible capital assets	1900	+	28,196,333			27,497,317
	*Accumulated amortization of other tangible capital assets	1901			–	1,911,171	1,577,922
	Other capital assets under construction	1920	+	1,494,499			775,198
	Total			29,690,832		1,911,171	
	Total tangible capital assets	2008	=	32,778,940			31,043,453
	Total accumulated amortization of tangible capital assets	2009			=	3,156,763	2,538,668

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Long-term Assets

SCHEDULE 100

Form identifier 2589

Account	Description	GIFI		Current year	Prior year
Long-term investments					
	* Long-term investments	2300		100	100
	Long-term investments		+	100	100
Other long-term assets					
	Future (deferred) income taxes	2421		1,070,302	
	Other deferred items/charges	2424		1,068,620	1,958,094
	Other long-term assets		+	2,138,922	1,958,094
	Total long-term assets	2589	=	2,139,022	1,958,194

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Current Liabilities

SCHEDULE 100

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
	* Bank overdraft	2600	+		424,343
Amounts payable and accrued liabilities					
	* Amounts payable and accrued liabilities	2620		4,354,088	4,049,300
	Amounts payable and accrued liabilities		+	4,354,088	4,049,300
	* Taxes payable	2680	+	374,929	
Short-term debt					
	Loans from Canadian banks	2701		1,915,574	2,410,504
	Short-term debt		+	1,915,574	2,410,504
	* Deferred income	2770	+	128,368	128,368
Due to related parties					
	* Due to related parties	2860		484,499	368,586
	Due to related parties		+	484,499	368,586
Other current liabilities					
	Deposits received	2961		377,590	236,840
	Other current liabilities		+	377,590	236,840
	Total current liabilities	3139	=	7,635,048	7,617,941

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Long-term Liabilities

SCHEDULE 100

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	* Long-term debt	3140		7,005,567	7,873,375
	Long-term debt		+	7,005,567	7,873,375
	* Deferred income	3220	+	3,094,653	2,840,351
	* Future (deferred) income taxes	3240	+	1,073,186	
Other long-term liabilities					
	* Other long-term liabilities	3320		2,629,587	2,834,232
	Deferred revenue from incomplete contracts	3328			74,948
	Other long-term liabilities		+	2,629,587	2,909,180
	Total long-term liabilities	3450	=	13,802,993	13,622,906

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Shareholder Equity

SCHEDULE 100

Form identifier 3620

Account	Description	GIFI		Current year	Prior year
	* Common shares	3500	+	2,632,307	2,632,307
Contributed and other surplus					
	* Contributed and other surplus	3540		4,269,026	4,269,026
	Contributed and other surplus		+	4,269,026	4,269,026
	* Accumulated other comprehensive income	3580	+	-36,584	70,873
	* Retained earnings/deficit	3600	+	9,708,384	8,823,929
	Total shareholder equity	3620	=	16,573,133	15,796,135

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Retained Earnings/Deficit

SCHEDULE 100

Form identifier 3849

Account	Description	GIFI		Current year	Prior year
	* Retained earnings/deficit – start	3660	+	8,823,929	8,314,935
	* Net income/loss	3680	+	1,384,455	1,008,994
Dividends declared					
	* Dividends declared	3700		500,000	500,000
	Dividends declared		–	500,000	500,000
	Retained earnings/deficit – end	3849	=	9,708,384	8,823,929

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

Income statement information

Description	GIFI

Operating name 0001
Description of the operation 0002
Sequence number 0003 01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	24,198,363	26,677,590
	Cost of sales	8518	–	23,229,633	26,794,215
	Gross profit/loss	8519	=	968,730	-116,625
	Cost of sales	8518	+	23,229,633	26,794,215
	Total operating expenses	9367	+	4,123,805	4,119,962
	Total expenses (mandatory field)	9368	=	27,353,438	30,914,177
	Total revenue (mandatory field)	8299	+	29,641,101	31,982,190
	Total expenses (mandatory field)	9368	–	27,353,438	30,914,177
	Net non-farming income	9369	=	2,287,663	1,068,013
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	2,287,663	1,068,013
	Total other comprehensive income	9998	=	-107,457	
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–	536,093	-269,677
	Current income taxes	9990	–	367,115	328,696
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+	-107,457	
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,276,998	1,008,994

Client Copy

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	24,198,363	26,677,590
	Total sales of goods and services	8089	=	24,198,363	26,677,590
Investment revenue					
	* Investment revenue	8090		45,799	56,869
	Investment revenue		+	45,799	56,869
Other revenue					
	* Other revenue	8230		5,396,939	5,247,731
	Other revenue		+	5,396,939	5,247,731
	Total revenue	8299	=	29,641,101	31,982,190

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Cost of Sales

SCHEDULE 125

Form identifier 8518

Account	Description	GIFI	Current year	Prior year
	* Purchases/cost of materials	8320 +	23,229,633	26,794,215
	Cost of sales	8518 =	23,229,633	26,794,215

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	* Amortization of tangible assets	8670	+	1,010,972	996,009
Interest and bank charges					
	* Interest and bank charges	8710		463,127	482,933
	Interest and bank charges		+	463,127	482,933
Other expenses					
	* Other expenses	9270		1,114,974	1,217,324
	Selling expenses	9273		573,154	547,188
	General and administrative expenses	9284		961,578	876,508
	Other expenses		+	2,649,706	2,641,020
	Total operating expenses	9367	=	4,123,805	4,119,962

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Other comprehensive income

SCHEDULE 125

Form identifier 9998

Account	Description	GIFI		Current year	Prior year
	Defined benefit gains/losses	7002	+	-146,200	
	Income tax relating to components of other comprehensive income	7010	−	-38,743	
	Total other comprehensive income	9998	=	-107,457	

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012*, T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation?	095	Yes	X	No	
Is the accountant connected* with the corporation?	097	Yes		No	X

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	Yes		No	X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Were notes to the financial statements prepared?	101	Yes	X	No	
If **yes**, complete lines 104 to 107 below:					
Are subsequent events mentioned in the notes?	104	Yes		No	X
Is re-evaluation of asset information mentioned in the notes?	105	Yes		No	X
Is contingent liability information mentioned in the notes?	106	Yes	X	No	
Is information regarding commitments mentioned in the notes?	107	Yes	X	No	
Does the corporation have investments in joint venture(s) or partnership(s)?	108	Yes		No	X

Client Copy

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** Yes ☐ No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** Yes ☐ No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes ☐ No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes ☐ No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** Yes ☐ No ☒

If **yes**, you have to maintain a separate reconciliation.

Client Copy

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

Assets – lines 1000 to 2599

1000	366,780	1062	5,679,259	1120	167,526
1400	9,886	1484	26,524	1599	6,249,975
1600	307,134	1680	797,582	1681	-72,629
1740	1,983,392	1741	-1,172,963	1900	28,196,333
1901	-1,911,171	1920	1,494,499	2008	32,778,940
2009	-3,156,763	2300	100	2421	1,070,302
2424	1,068,620	2589	2,139,022	2599	38,011,174

Liabilities – lines 2600 to 3499

2620	4,354,088	2680	374,929	2701	1,915,574
2770	128,368	2860	484,499	2961	377,590
3139	7,635,048	3140	7,005,567	3220	3,094,653
3240	1,073,186	3320	2,629,587	3450	13,802,993
3499	21,438,041				

Shareholder equity – lines 3500 to 3640

3500	2,632,307	3540	4,269,026	3580	-36,584
3600	9,708,384	3620	16,573,133	3640	38,011,174

Retained earnings – lines 3660 to 3849

3660	8,823,929	3680	1,384,455	3700	-500,000
3849	9,708,384				

Client Copy

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7002	-146,200	7010	-38,743

Revenue – lines 8000 to 8299

8000	24,198,363	8089	24,198,363	8090	45,799
8230	5,396,939	8299	29,641,101		

Cost of sales – lines 8300 to 8519

8320	23,229,633	8518	23,229,633	8519	968,730

Operating expenses – lines 8520 to 9369

8670	1,010,972	8710	463,127	9270	1,114,974
9273	573,154	9284	961,578	9367	4,123,805
9368	27,353,438	9369	2,287,663		

Extraordinary items and taxes – lines 9970 to 9999

9970	2,287,663	9985	536,093	9990	367,115
9998	-107,457	9999	1,276,998		

Client Copy

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125 . . . . . 1,276,998 A

Add:

Provision for income taxes – current	101	367,115	
Amortization of tangible assets	104	1,103,773	
Loss on disposal of assets	111	23,657	
Non-deductible meals and entertainment expenses	121	1,789	
Reserves from financial statements – balance at the end of the year	126	574,218	
Subtotal of additions		2,070,552 ▶	2,070,552

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	9,973
2	Customer Deposits 12(1)(a)	377,590
3	capital contributions received 12(1)(x)	319,954
4	Regulatory adjustment	769,773
	Total of column 2	1,477,290 ▶ 296 1,477,290

Subtotal of other additions	199	1,477,290 ▶	1,477,290
Total additions	500	3,547,842 ▶	3,547,842 B

Amount A **plus** amount B . . . . . 4,824,840 C

Deduct:

Capital cost allowance from Schedule 8	403	1,806,061	
Reserves from financial statements – balance at the beginning of the year	414	425,135	
Subtotal of deductions		2,231,196 ▶	2,231,196

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Unrealized gain on derivatives	46,137
2	Customer Deposits 20(1)(m)	377,590
3	Amortization of deferred capital contributions	65,652
4	capital contributions received 13(7.4)	319,954
5	Tax included in net movement in regulatory balances	323,875
6	Tax on EFB	38,743
	Total of column 2	1,171,951 ▶ 396 1,171,951

Client Copy

Subtotal of other deductions	499	1,171,951 ▶	1,171,951	
Total deductions	510	3,403,147 ▶	3,403,147	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			1,421,693	E

Enter amount E on line 300 of the T2 return.

T2 SCH 1 E (17)

Canada

Client Copy

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) of the ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. . . . . ☐

Ontario

A		
☒	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☒	Ontario co-operative education tax credit	
☒	Ontario apprenticeship training tax credit	9,973
☐	Ontario computer animation and special effects tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario film and television tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario production services tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario interactive digital media tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario sound recording tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario book publishing tax credit	
☒	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☐	Ontario business-research institute tax credit	
☐	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the additional deduction for gifts of medicine made before March 22, 2017.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward. Provincial food donation tax credits must be applied in the current tax year.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- A gift of medicine made before March 22, 2017 to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File a completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Subtotal	
Add: Total donations of less than $100 each	
Total donations in current tax year	

Client Copy

Part 1 – Charitable donations

		Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		400	1A	400	400
Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year (amount 1A **minus** line 239)	240	400		400	400
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year	210				
Include on line 112 of Schedule 1 *Net Income (Loss) for Income Tax Purposes*					
Subtotal (line 250 **plus** line 210)			1B		
Subtotal (line 240 **plus** amount 1B)		400	1C	400	400
Adjustment for an acquisition of control	255				
Total charitable donations available (amount 1C **minus** line 255)		400	1D	400	400
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2)	260	400		400	400
Enter on line 311 of the T2 return					
Charitable donations closing balance (amount 1D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in line 260 (for donations made after December 31, 2013) **262** _____

Ontario community food program donation tax credit for farmers (line 262 **multiplied** by 25 %) _____ 1E

Enter amount 1E on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1E. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in line 260 (for donations made after December 31, 2015) **263** _____

Nova Scotia food bank tax credit for farmers (line 263 **multiplied** by 25 %) _____ 1F

Enter amount 1F on line 570 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 1F. For more information, see section 50A of the Nova Scotia *Income Tax Act*.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in line 260 (for donations made after February 16, 2016 and before January 1, 2019) **265** _____

British Columbia farmers' food donation tax credit (line 265 **multiplied** by 25 %) _____ 1G

Enter amount 1G on line 683 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 1G. For more information, see section 20.1 of the British Columbia *Income Tax Act*.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Client Copy

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31	400	400	400
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)		400	400	400

***** For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % 1,066,270 2A

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** 225

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) 227

The amount of the recapture of capital cost allowance in respect of charitable donations 230

Proceeds of disposition, **less** outlays and expenses** 2B

Capital cost** 2C

Amount 2B or 2C, whichever is less 235

Line 230 or 235, whichever is less 2D

Subtotal (**add** lines 225, 227 and amount 2D) 2E

Amount 2E **multiplied** by 25 % 2F

Subtotal (amount 2A **plus** amount 2F) 1,066,270 2G

Maximum allowable deduction for charitable donations (amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is less) 400 2H

***** For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

****** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Client Copy

Part 3 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			3A		
Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year (amount 3A **minus** line 439)	440				
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year	410				
Include on line 112 of Schedule 1					
Subtotal (line 450 **plus** line 410)			3B		
Subtotal (line 440 **plus** amount 3B)			3C		
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income	460				
Enter on line 313 of the T2 return					
Subtotal (line 455 **plus** line 460)			3D		
Gifts of certified cultural property closing balance (amount 3C **minus** amount 3D)	480				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31			
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Client Copy

Part 4 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			4A		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A **minus** line 539)	540				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			4B		
Subtotal (line 540 **plus** amount 4B)			4C		
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			4D		
Gifts of certified ecologically sensitive land closing balance (amount 4C **minus** amount 4D)	580				

***** For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Client Copy

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31			
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year*	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Client Copy

Part 5 – Additional deduction for gifts of medicine

		Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			5A		
Additional deduction for gifts of medicine expired after five tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A **minus** line 639)	640				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	602				
Cost of gifts of medicine made before March 22, 2017	601				
Subtotal (line 602 **minus** line 601)			5B		
Amount 5B **multiplied** by 50 %			5C		
Eligible amount of gifts	600				

Federal

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . 610 _____

Québec

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . _____

Alberta

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . _____

where:

a is the **lesser** of line 601 and amount 5C

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)		5D		
Subtotal (line 640 **plus** amount 5D)		5E		
Adjustment for an acquisition of control	655			
Amount applied in the current year against taxable income	660			
Enter on line 315 of the T2 return				
Subtotal (line 655 **plus** line 660)		5F		
Additional deduction for gifts of medicine closing balance (amount 5E **minus** amount 5F)	680			

***** For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Client Copy

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2016-12-31			
2nd prior year	2015-12-31			
3rd prior year	2014-12-31			
4th prior year	2013-12-31			
5th prior year	2012-12-31			
6th prior year*	2011-12-31			
7th prior year	2010-12-31			
8th prior year	2009-12-31			
9th prior year	2008-12-31			
10th prior year	2007-12-31			
11th prior year	2006-12-31			
12th prior year	2005-12-31			
13th prior year	2004-12-31			
14th prior year	2003-12-31			
15th prior year	2002-12-31			
16th prior year	2001-12-31			
17th prior year	2001-09-30			
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Client Copy

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2016-12-31	
2nd prior year	2015-12-31	
3rd prior year	2014-12-31	
4th prior year	2013-12-31	
5th prior year	2012-12-31	
6th prior year*	2011-12-31	
7th prior year	2010-12-31	
8th prior year	2009-12-31	
9th prior year	2008-12-31	
10th prior year	2007-12-31	
11th prior year	2006-12-31	
12th prior year	2005-12-31	
13th prior year	2004-12-31	
14th prior year	2003-12-31	
15th prior year	2002-12-31	
16th prior year	2001-12-31	
17th prior year	2001-09-30	
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculations

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a),(a.1), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- All legislative references are to the federal *Income Tax Act*.
- The calculations in this schedule apply only to private or subject corporations.
- A recipient corporation is **connected** with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A1 – Enter "X" if dividends received from a foreign source.
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H and I **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing column J and K use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividends under section 83 230
1			2			

Total of column E (enter amount on line 402 of Schedule 1)

Client Copy

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] 240	F1 Eligible dividends (included in column F)	F2	G Dividends included in column F that was received **before** 2016 241	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) 250	I Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2] 260	J Part IV tax before deductions. Dividends (from column G) received **before** 2016 **multiplied** by 33 1/3%[note 3] 270	K Part IV tax before deductions. Dividends received **after** 2015 (column F **minus** column G) **multiplied** by 38 1/3%[note 4] 275
1								
	Total of column F (include this amount on line 320 of the T2 Return)						**Total of column J** (enter amount on line a in Part 2)	**Total of column K** (enter amount on line b in Part 2)

1 If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270 or column 275 as applicable according to the date received. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For dividends received **before** 2016 from **connected** corporations, Part IV tax on dividends is equal to: column G **multiplied** by column I **divided** by column H.

4 For dividends received **after** 2015 from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by the result of column F **minus** column G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received **before** 2016, before deductions (total of column J in part 1) . . . . . a

Part IV tax on dividends received **after** 2015, before deductions (total of column K in part 1) . . . . . b

Part IV tax before deductions (amount a **plus** amount b) . . . . . ▶ L

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) 320

Subtotal (amount L **minus** line 320) M

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . . 330 c

Non-capital losses from previous years claimed to reduce Part IV tax . . . . . 335 d

Current-year farm loss claimed to reduce Part IV tax . . . . . 340 e

Farm losses from previous years claimed to reduce Part IV tax . . . . . 345 f

Total losses applied against Part IV tax (total of amounts c to f) g

If your tax year begins after December 31, 2015:

Amount g **multiplied** by 38 1 / 3 % . . . . . h

If your tax year begins before January 1, 2016:

Amount b or M whichever is less

_____ ÷ 38 1 / 3 % . . . = 1

Amount 1 or g, whichever is less 2

Amount g **minus** amount 2 3

Amount 2 _____ x 38 1 / 3 % = i

Amount 3 _____ x 33 1 / 3 % = j

Subtotal (amount i **plus** amount j) k

Amount h or amount k, whichever applies depending on your tax year start date . . . . . N

Part IV tax payable (amount M **minus** amount N, if negative enter "0") 360

(enter amount on line 712 of the T2 return)

Client Copy

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	O Name of connected recipient corporation 400	P Business Number 410	Q Tax year-end of connected recipient corporation in which the dividends in column R were received YYYY/MM/DD 420	R Taxable dividends paid to connected corporations 430	R1 Eligible dividends (included in column R)
1	NIAGARA-ON-THE-LAKE ENERGY INC.	86376 1490 RC0001	2017-12-31	500,000	
2					

Total of column R 500,000

Total taxable dividends paid in the tax year to other than connected corporations **450**

Eligible dividends (included in line 450) 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund
(total of column R **plus** line 450) **460** 500,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 500,000

Other dividends paid in the tax year (total of 510 to 540) . . . . .

Total dividends paid in the tax year **500** 500,000

Deduct:

Dividends paid out of capital dividend account **510**

Capital gains dividends **520**

Dividends paid on shares described in subsection 129(1.2) **530**

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year **540**

Subtotal (total of lines 510 to 540) ▶ S

Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount S) 500,000 T

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Use this schedule if, during the tax year, your corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references to the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 _____ Enter the Regulation that applies (402 to 413).

A Jurisdiction (Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year.*)		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia Offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in subsection 400(2).

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Client Copy

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,421,293		1,421,293	163,449

Ontario basic income tax (from Schedule 500) 270 163,449

Ontario small business deduction (from Schedule 500) 402

Subtotal (line 270 **minus** line 402) 163,449 ▶ 163,449 5A

Ontario additional tax re Crown royalties (from Schedule 504) 274

Ontario transitional tax debits (from Schedule 506) 276

Recapture of Ontario research and development tax credit (from Schedule 508) 277

Subtotal (total of lines 274 to 277) ▶ 5B

Gross Ontario tax (amount 5A **plus** amount 5B) 163,449 5C

Ontario resource tax credit (from Schedule 504) 404

Ontario tax credit for manufacturing and processing (from Schedule 502) 406

Ontario foreign tax credit (from Schedule 21) 408

Ontario credit union tax reduction (from Schedule 500) 410

Ontario political contributions tax credit (from Schedule 525) 415

Ontario non-refundable tax credits (total of lines 404 to 415) ▶ 5D

Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0") 163,449 5E

Ontario research and development tax credit (from Schedule 508) 416

Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0") 163,449 5F

Ontario corporate minimum tax credit (from Schedule 510) 418

Ontario community food program donation tax credit for farmers (from Schedule 2) 420

Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative enter "0") 163,449 5G

Ontario corporate minimum tax (from Schedule 510) 278

Ontario special additional tax on life insurance corporations (from Schedule 512) 280

Subtotal (line 278 **plus** line 280) ▶ 5H

Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H) 163,449 5I

Ontario qualifying environmental trust tax credit 450

Ontario co-operative education tax credit (from Schedule 550) 452

Ontario apprenticeship training tax credit (from Schedule 552) 454

Ontario computer animation and special effects tax credit (from Schedule 554) 456

Ontario film and television tax credit (from Schedule 556) 458

Ontario production services tax credit (from Schedule 558) 460

Ontario interactive digital media tax credit (from Schedule 560) 462

Ontario sound recording tax credit (from Schedule 562) 464

Ontario book publishing tax credit (from Schedule 564) 466

Ontario innovation tax credit (from Schedule 566) 468

Ontario business-research institute tax credit (from Schedule 568) 470

Ontario refundable tax credits (total of lines 450 to 470) ▶ 5J

Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) 290 163,449

(if a credit, enter a negative amount) Include this amount on line 255.

Client Copy

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits 255 163,449

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** Yes ☐ No ☒

	1 Class number * **200**	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) **203**	4 Adjustments and transfers (see note 2 below) **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see note3 below) **211**	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6)	8 CCA rate % (see note 4 below) **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see note 6 below) **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1	Dist'n Plant >87	4,370,164			0		4,370,164	4	0	0	174,807	4,195,357
2.	2	Dist'n Plant < 88	1,967,981			0		1,967,981	6	0	0	118,079	1,849,902
3.	1	Transformers > 87	3,365,049			0		3,365,049	4	0	0	134,602	3,230,447
4.	2	Transformers < 88	378,023			0		378,023	6	0	0	22,681	355,342
5.	1	Meters > 87	154,868			0		154,868	4	0	0	6,195	148,673
6.	2	Meters < 88	64,237			0		64,237	6	0	0	3,854	60,383
7.	1	Buildings	461,121			0		461,121	4	0	0	18,445	442,676
8.	2	Dist'n Stations	178,380			0		178,380	6	0	0	10,703	167,677
9.	8	Office equipment	105,631			0		105,631	20	0	0	21,126	84,505
10.	8	Stores/Comm/Supe etc	50,865			0		50,865	20	0	0	10,173	40,692
11.	10	Vehicles, trailers, transport equip	39,696	45,650		0	22,825	62,521	30	0	0	18,756	66,590
12.	10	Motor Vehicles	87,466			0		87,466	30	0	0	26,240	61,226
13.	8	Inventory spare part	9,154			0		9,154	20	0	0	1,831	7,323
14.	17	Telephone System	9,693			0		9,693	8	0	0	775	8,918
15.	8	Lighting	201			0		201	20	0	0	40	161
16.	17	Paving	8,415			0		8,415	8	0	0	673	7,742
17.	6	Fencing	2,408			0		2,408	10	0	0	241	2,167
18.	8	PCB Storage	334			0		334	20	0	0	67	267
19.	1	SCADA system	173,250			0		173,250	4	0	0	6,930	166,320
20.	2	Invent Dist'n Meter	26,863			0		26,863	6	0	0	1,612	25,251
21.	45	Computer hardware - new	1,466			0		1,466	45	0	0	660	806
22.	47	Distribution assets after Feb 22,	12,436,423	905,120		503,386	200,867	12,637,290	8	0	0	1,010,983	11,827,174
23.	50	Computer Hardware	132,068	17,583		0	8,792	140,859	55	0	0	77,472	72,179

Client Copy

	1 Class number * 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) 203	4 Adjustments and transfers (see note 2 below) 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see note3 below) 211	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6)	8 CCA rate % (see note 4 below) 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see note 6 below) 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
24.	1b	Buildings	75,388			0		75,388	6	0	0	4,523	70,865
25.	8	Smart grid	245,449	204,754		0	102,377	347,826	20	0	0	69,565	380,638
26.	14.1		7,902			0		7,902	5	0	0	553	7,349
27.	12	Computer Software		128,951		0	64,476	64,475	100	0	0	64,475	64,476
		Totals	24,352,495	1,302,058		503,386	399,337	24,751,830				1,806,061	23,345,106

* Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

Note 2. Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

Note 3. The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

Note 4. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

Note 5. For every entry in column 9, "Recapture of capital cost allowance", there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

Note 6. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Client Copy

T2 SCH 8 (17)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		1,302,058		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Other (specify):				
Contributed capital additions, not in NBV below	+	319,954		
Total additions per books	=	1,622,012	▶	1,622,012
Proceeds up to original cost – Schedule 8 regular classes		503,386		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
Recovery on ICM asset (recovery in reg)	+	-452,598		
Change in WIP	+	-719,301		
Regulatory adjustment to PPE	+	18,767		
Rounding	+	2		
Transfers (nbv) to inventory	+	26,933		
Total proceeds per books	=	-622,811	▶	-622,811
Depreciation and amortization per accounts – Schedule 1			–	1,103,773
Loss on disposal of fixed assets per accounts			–	33,071
Gain on disposal of fixed assets per accounts			+	9,413
Net change per tax return			=	1,117,392

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		29,315,043
Opening net book value	–	28,197,651
Net change per financial statements	=	1,117,392

If the amounts from the tax return and the financial statements differ, explain why below.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	NIAGARA-ON-THE-LAKE ENERGY IN		86376 1490 RC0001	1					7,054,844
2.	Energy Services Niagara Inc		86360 6125 RC0001	3					143,511
3.	Town of Niagara-on-the-Lake		NR	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Client Copy

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	EMPLOYEE FUTURE BENEFITS	330,064		478,800	330,064	478,800
2	AFDA	95,071		95,418	95,071	95,418
3						
	Reserves from Part 2 of Schedule 13					
	Totals	425,135		574,218	425,135	574,218

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) **100**	Amount of contribution $ (see note 2) **200**	Registration number (RPP, RSUBP, PRPP, and DPSP only) **300**	Name of EPSP trust **400**	Address of EPSP trust **500**	T4PS slip(s) (see note 3) **600**
1	1	154,013	490251			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . 154,013 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 154,013 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

Client Copy

T2 SCH 15 (13)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Client Copy

Allocating the business limit

Date filed (do not use this area) . . . . . 025 — Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 — Year: 2017

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 — 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year before the allocation $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	1	500,000	100.0000	500,000
2	NIAGARA-ON-THE-LAKE ENERGY INC.	86376 1490 RC0001	1	500,000		
3	Energy Services Niagara Inc	86360 6125 RC0001	1	500,000		
4	Town of Niagara-on-the-Lake	NR	4			
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

T2 SCH 23 E (15)

Canada

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1);
  - to request a credit carryback to one or more previous years;
  - if you are subject to a recapture of ITC; or
  - if you are claiming:
    - the **Ontario Research and Development Tax Credit**;
    - the **Ontario Innovation Tax Credit.**
- Unless otherwise stated, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
    - Expenditures related to child care spaces incurred after March 21, 2017 no longer qualify for the investment tax credit. If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.
- File this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide* and read Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see guide T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For tax purposes**,** Canada includes the **exclusive economic zone of Canada** as defined in the *Oceans Act* (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Client Copy

Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15 % rate.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures***:	
– after March 28, 2012, and before 2014	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred expenditures after March 18, 2007 and before March 22, 2017 (or before 2020 if you entered into a written agreement before March 22, 2017) for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** A transitional relief rate may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraphs (k)(ii) and (iii) of the definition of **specified percentage** in subsection 127(9) for more information.

Client Copy

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . **101** 1 Yes [X] 2 No [ ]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** 1 Yes [ ] 2 No [X]

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . . **103** _____
Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012. For contributions made **before** 2013, include all of the contributions.

Client Copy

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**

Total of investments for qualified property and qualified resource property _____ A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year B1

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal (line 210 **plus** line 215) ▶ C1

ITC at the beginning of the tax year (amount B1 **minus** amount C1) 220

Credit transferred on an amalgamation or the wind-up of a subsidiary 230

ITC from repayment of assistance 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) . . . . . x 5 % = 242

Credit allocated from a partnership 250

Subtotal (total of lines 230 to 250) ▶ D1

Total credit available (line 220 **plus** amount D1) E1

Credit deducted from Part I tax 260

Credit carried back to previous years (amount H1 in Part 6) . . . . . a

Credit transferred to offset Part VII tax liability 280

Subtotal (total of line 260, amount a, and line 280) ▶ F1

Credit balance before refund (amount E1 **minus** amount F1) G1

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) 310

ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 901

Credit to be applied 902

Credit to be applied 903

Total of lines 901 to 903 H1
Enter at amount a in Part 5.

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5) I1

Credit balance before refund (from amount G1 in Part 5) J1

Refund (40 % of amount I1 or J1, whichever is less) K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter on line 780 of the T2 return if you do not claim an SR&ED ITC refund).

Client Copy

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 557 on Form T661) . . . . . .

Contributions to agricultural organizations for SR&ED . . . . . .

Deduct:

Government assistance, non-government assistance, or contract payment . . . . . .

Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* . . . . . + ▶

Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)*	▶	350	
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**		360	
Repayments made in the year (from line 560 on Form T661)		370	
Qualified SR&ED expenditures (total of lines 350 to 370)		380	

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . 385 1 Yes ☐ 2 No ☒

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, the amounts for associated corporations will be determined on Schedule 49.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) 390

Enter your taxable capital employed in Canada for the previous tax year 26,853,754
minus $10 million. If this amount is nil or negative, enter "0".
If this amount is over $40 million, enter $40 million 398 16,853,754

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation: $ 8,000,000

Taxable income for the previous tax year (line 390 in Part 9) or $500,000, whichever is more 500,000 x 10 = 5,000,000 A2

Excess ($8,000,000 **minus** amount A2; if negative, enter "0") 3,000,000 B2

$ 40,000,000 **minus** line 398 in Part 9 . . . . . 23,146,246 b

Amount b **divided** by $ 40,000,000 . . . . . 0.57866 C2

Expenditure limit for the stand-alone corporation (amount B2 **multiplied** by amount C2)* 1,735,980 D2

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49* 400 E2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D2 or E2 x (Number of days in the tax year / 365) = ... F2

Your SR&ED expenditure limit for the year (enter amount D2, E2, or F2, whichever applies) 410 1,735,980

* Amount D2 or E2 cannot be more than $3,000,000.

Client Copy

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less* . . . . . **420** _____ x 35 % = _____ G2

Line 350 **minus** line 410 (if negative, enter "0") . . . . . **430** _____

Amount from line 430 _____ x (Number of days in the tax year before 2014 / Number of days in the tax year) _____ x 20% = _____ c

Amount from line 430** _____ x (Number of days in the tax year after 2013 / Number of days in the tax year) 365/365 x 15 % = _____ d

Subtotal (amount c **plus** amount d) . . . . . ▶ _____ H2

Line 410 **minus** line 350 (if negative, enter "0") . . . . . 1,735,980 e

Capital expenditures (line 360 in Part 8) or amount e, whichever is less* . . . . . **440** _____ x 35 % = _____ I2

Line 360 **minus** amount e (if negative, enter "0") . . . . . **450** _____

Amount from line 450 _____ x (Number of days in the tax year before 2014 / Number of days in the tax year) _____ x 20% = _____ f

Amount from line 450** _____ x (Number of days in the tax year after 2013 / Number of days in the tax year) 365/365 x 15 % = _____ g

Subtotal (amount f **plus** amount g) . . . . . ▶ _____ J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . . _____

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC*** . . . . . **460** _____ x 35 % = _____ h

Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred before 2015 . . . . **480** _____ x 20 % = _____ i

Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred after 2014 . . . . . **490** _____ x 15 % = _____ j

Subtotal (**add** amounts h to j) ▶ _____ K2

Current-year SR&ED ITC (total of amounts G2 to K2; enter on line 540 in Part 12) . . . . . _____ L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start **before** 2014, the reduction is pro-rated based on the number of days in the tax year that are **after** 2013. For tax years that have a start date **after** 2013, **multiply** the amount by 15%.

*** If you were a Canadian-controlled private corporation (CCPC), this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Client Copy

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				M2
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)		▶		
ITC at the beginning of the tax year (amount M2 **minus** amount N2)		520		N2
Credit transferred on an amalgamation or the wind-up of a subsidiary	530			
Total current-year credit (from amount L2 in Part 11)	540			
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)		▶		O2
Total credit available (line 520 **plus** amount O2)				P2
Credit deducted from Part I tax	560			
Credit carried back to previous years (amount S2 in Part 13)			k	
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount k, and line 580)		▶		Q2
Credit balance before refund (amount P2 **minus** amount Q2)				R2
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)		610		
ITC closing balance on SR&ED (amount R2 **minus** line 610)		620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total of lines 911 to 913 Enter at amount k in Part 12.		S2

Client Copy

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . **650** 1 Yes ☐ 2 No ☒ X

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) I

Refundable credits (amount I or amount R2 in Part 12, whichever is less)* T2

Amount T2 or amount G2 in Part 11, whichever is less U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") V2

Amount V2 **multiplied** by 40 % W2

Amount U2 . . . . . X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (amount R2 in Part 12) Z2

Amount Z2 or amount G2 in Part 11, whichever is less AA2

Net amount (amount Z2 **minus** amount AA2; if negative, enter "0") BB2

Amount BB2 or amount I2 in Part 11, whichever is less CC2

Amount CC2 **multiplied** by 40 % DD2

Amount AA2 . . . . . EE2

Refund of ITC (amount DD2 **plus** amount EE2) FF2

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Client Copy

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal
Enter at amount C3 in Part 17. A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal(total of column F)
Enter at amount D3 in Part 17. B3

Client Copy

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** _____
Enter at amount E3 in Part 17.

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16	_____	C3
Recaptured ITC from calculation 2, amount B3 in Part 16	_____	D3
Recaptured ITC from calculation 3, line 760 in Part 16	_____	E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3) Enter at amount A8 in Part 29.	_____	F3

Client Copy

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that you incurred in the tax year (**before** January 1, 2014) for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting 810

Geological, geophysical, or geochemical surveys 811

Drilling by rotary, diamond, percussion, or other methods 812

Trenching, digging test pits, and preliminary sampling 813

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping 820

Sinking a mine shaft, constructing an adit, or other underground entry 821

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826
Total of column 826	▶ A4

Total pre-production mining expenditures (total of lines 810 to 821 and amount A4) 830

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above 832

Excess (line 830 **minus** line 832) (if negative, enter "0") B4

Repayments of government and non-government assistance 835

Pre-production mining expenditures (amount B4 **plus** line 835) C4

* A pre-production mining expenditure is defined under subsection 127(9).

Client Copy

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year D4

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ▶ E4

ITC at the beginning of the tax year (amount D4 **minus** amount E4) 850

Credit transferred on an amalgamation or the wind-up of a subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18)	870	x	10 %	=	m
Pre-production mining exploration expenditures** incurred in 2013 (applicable part from amount C4 in Part 18)	872	x	5 %	=	n
Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18)	874	x	7 %	=	o
Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18)	876	x	4 %	=	p

Current year credit (total of amounts m to p) 880 ▶ F4

Total credit available (total of lines 850, 860, and amount F4) G4

Credit deducted from Part I tax 885

Credit carried back to previous years (amount I4 in Part 20) . . . . . q

Subtotal (line 885 **plus** amount q) ▶ H4

ITC closing balance from pre-production mining expenditures (amount G4 **minus** amount H4) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

** Also include pre-production mining development expenditures incurred in 2015 if the expense is described in subparagraph (a)(ii) of the definition **pre-production mining expenditure** in subsection 127(9) of the Act because of paragraph (g.4) of the definition **Canadian exploration expense** in subsection 66.1(6) of the Act.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total of lines 921 to 923 I4
Enter at amount q in Part 19.

Client Copy

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . . **611** 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**

Total current-year credit (total of column E) Enter on line 640 in Part 22. A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year 2,000 B5

Credit deemed as a remittance of co-op corporations **612**

Credit expired after 20 tax years **615**

Subtotal (line 612 **plus** line 615) ▶ C5

ITC at the beginning of the tax year (amount B5 **minus** amount C5) **625** 2,000

Credit transferred on an amalgamation or the wind-up of a subsidiary **630**

ITC from repayment of assistance **635**

Total current-year credit (amount A5 in Part 21) **640**

Credit allocated from a partnership **655**

Subtotal (total of lines 630 to 655) ▶ D5

Total credit available (line 625 **plus** amount D5) 2,000 E5

Credit deducted from Part I tax **660** 2,000

Credit carried back to previous years (amount G5 in Part 23) . . . . . r

Subtotal (line 660 **plus** amount r) 2,000 ▶ 2,000 F5

ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5) **690**

Client Copy

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

. . . . . Credit to be applied **931**

. . . . . Credit to be applied **932**

. . . . . Credit to be applied **933**

Total of lines 931 to 933 Enter at amount r in Part 22. G5

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred after March 18, 2007 and before March 22, 2017* to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures.

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695) **715** _____

Specified child care start-up expenditures from the current tax year . . . . . **705** _____

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . _____ A6

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . **725** _____

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . . _____ B6

Repayments by the corporation of government and non-government assistance . . . . . **735** _____

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) . . . . . **745** _____

* If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . . _____ x 25 % = _____ C6

Number of child care spaces . . . . . **755** _____ x $ 10,000 = _____ D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) . . . . . _____ E6

Client Copy

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			F6
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal (line 765 **plus** line 770)		▶	G6
ITC at the beginning of the tax year (amount F6 **minus** amount G6)	775		
Credit transferred on an amalgamation or the wind-up of a subsidiary	777		
Total current-year credit (amount E6 in Part 25)	780		
Credit allocated from a partnership	782		
Subtotal (total of lines 777 to 782)		▶	H6
Total credit available (line 775 **plus** amount H6)			I6
Credit deducted from Part I tax	785		
Credit carried back to previous years (amount K6 in Part 27)		s	
Subtotal (line 785 **plus** amount s)		▶	J6
ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6)	790		

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2016-12-31	Credit to be applied	941	
2nd previous tax year	2015-12-31	Credit to be applied	942	
3rd previous tax year	2014-12-31	Credit to be applied	943	
		Total of lines 941 to 943 Enter at amount s in Part 26.		K6

Client Copy

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) **792**

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC **795**

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property **797**

Amount from line 795 or line 797, whichever is less A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799**

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) B7

Enter at amount B8 in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount F3 in Part 17) A8

Recaptured child care spaces ITC (amount B7 in Part 28) B8

Total recapture of investment tax credit (amount A8 **plus** amount B8) C8

Enter on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5) D8

ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12) E8

ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 19) F8

ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 22) 2,000 G8

ITC from child care space expenditures deducted from Part I tax (line 785 in Part 26) H8

Total ITC deducted from Part I tax (total of amounts D8 to H8) 2,000 I8

Enter on line 652 of the T2 return.

Client Copy

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2016-12-31				
2015-12-31	2,000		2,000	
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				*
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2001-09-30				
				*
Total	2,000		2,000	

B+C+D+G **Total ITC utilized** 2,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	574,218	
Capital stock (or members' contributions if incorporated without share capital)	103	2,632,307	
Retained earnings	104	9,708,384	
Contributed surplus	105		
Any other surpluses	106	4,269,026	
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	9,769,927	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		26,953,862 ▶	26,953,862 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Client Copy

Part 1 – Capital (continued)

Subtotal A (from page 1) 26,953,862 A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		▶	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	26,953,862	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	100
A loan or advance to another corporation (other than a financial institution)	402	427,037
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	427,137

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		26,953,862	C
Deduct: Investment allowance for the year (line 490)		427,137	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	26,526,725	

Client Copy

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 26,526,725 x (Taxable income earned in Canada / Taxable income) **610** 1,421,293 / 1,421,293 = **Taxable capital employed in Canada** **690** 26,526,725

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **701**

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada **711**

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **712**

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) **713**

Total deductions (**add** lines 711, 712, and 713) ▶ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") **790**

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . . F

Deduct: . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") H

Calculation for purposes of the small business deduction (amount H x 0.225%) I

Enter this amount at line 415 of the T2 return.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	Niagara-on-the-Lake Energy Inc.	86376 1490 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 53

General Rate Income Pool (GRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

On: 2017-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- Credit unions are **not** required to complete this schedule.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- When an eligible dividend was paid in the tax year or there was a change in the GRIP balance, file a completed copy of this schedule with your T2 *Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Client copy

Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year			100	5,875,166 A
Taxable income for the year (DICs enter "0") *	110	1,421,293 B		
Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140			
Subtotal (line 130 **plus** line 140)		▶		C
Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0")	150	1,421,293		
After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year))			190	1,023,331 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (line 200 **plus** line 210)		▶		E
Becoming a CCPC (amount W5 in Part 4)	220			
Post-amalgamation (total of amounts E4 in Part 3 and amounts W5 in Part 4)	230			
Post-wind-up (total of amounts E4 in Part 3 and amounts W5 in Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)	290	▶		F
Subtotal (**add** amounts A, D, E, and F)				6,898,497 G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
(If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.)				
Subtotal (line 300 **minus** line 310)		▶		H
GRIP before adjustment for specified future tax consequences (amount G **minus** amount H) (amount can be negative)			490	6,898,497
Total GRIP adjustment for specified future tax consequences to previous tax years (amount N3 in Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	6,898,497

Enter this amount on line 160 of Schedule 55.

***** For lines 110, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Client Copy

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2016-12-31

Taxable income before specified future tax consequences from the current tax year A1

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less B1

Aggregate investment income (line 440 of the T2 return) C1

Subtotal (amount B1 **plus** amount C1) ▶ D1

Subtotal (amount A1 **minus** amount D1) (if negative, enter "0") ▶ E1

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F1

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less G1

Aggregate investment income (line 440 of the T2 return) H1

Subtotal (amount G1 **plus** amount H1) ▶ I1

Subtotal (amount F1 **minus** amount I1) (if negative, enter "0") ▶ J1

Subtotal (amount E1 **minus** amount J1) (if negative, enter "0") K1

GRIP adjustment for specified future tax consequences to the first previous tax year

(amount K1 **multiplied** by 0.72) **500**

Client Copy

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Second previous tax year 2015-12-31

Taxable income before specified future tax consequences from the current tax year A2

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less B2

Aggregate investment income (line 440 of the T2 return) C2

Subtotal (amount B2 **plus** amount C2) ▶ D2

Subtotal (amount A2 **minus** amount D2) (if negative, enter "0") ▶ E2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F2

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less G2

Aggregate investment income (line 440 of the T2 return) H2

Subtotal (amount G2 **plus** amount H2) ▶ I2

Subtotal (amount F2 **minus** amount I2) (if negative, enter "0") ▶ J2

Subtotal (amount E2 **minus** amount J2) (if negative, enter "0") K2

GRIP adjustment for specified future tax consequences to the second previous tax year

(amount K2 **multiplied** by 0.72) **520**

Client Copy

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2014-12-31

Taxable income before specified future tax consequences from the current tax year A3

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less B3

Aggregate investment income (line 440 of the T2 return) C3

Subtotal (amount B3 **plus** amount C3) ▶ D3

Subtotal (amount A3 **minus** amount D3) (if negative, enter "0") ▶ E3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences F3

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less G3

Aggregate investment income (line 440 of the T2 return) H3

Subtotal (amount G3 **plus** amount H3) ▶ I3

Subtotal (amount F3 **minus** amount I3) (if negative, enter "0") ▶ J3

Subtotal (amount E3 **minus** amount J3) (if negative, enter "0") K3

GRIP adjustment for specified future tax consequences to the third previous tax year

(amount K3 **multiplied by** 0.72) **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") L3

Enter amount L3 on line 560 in part 1.

Client Copy

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.

Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.

In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		A4
Eligible dividends paid by the corporation in its last tax year	B4	
Excessive eligible dividend designations made by the corporation in its last tax year	C4	
Subtotal (amount B4 **minus** amount C4) ▶		D4
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year) (amount A4 **minus** amount D4)		E4

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the E4 amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Client Copy

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.

Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.

In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year A5

The corporation's money on hand immediately before the end of its previous/last tax year B5

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses C5

Net capital losses D5
Farm losses E5
Restricted farm losses F5
Limited partnership losses G5

Subtotal (**add** amounts C5 to G5) ▶ H5

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses I5
Net capital losses J5
Farm losses K5
Restricted farm losses L5
Limited partnership losses M5

Subtotal (**add** amounts I5 to M5) ▶ N5

Unused and unexpired losses at the end of the corporation's previous/last tax year (amount H5 **minus** amount N5) ▶ O5

Subtotal (**add** amounts A5, B5, and O5) P5

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year Q5

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year R5

All the corporation's reserves deducted in its previous/last tax year S5

The corporation's capital dividend account immediately before the end of its previous/last tax year T5

The corporation's low rate income pool immediately before the end of its previous/last tax year U5

Subtotal (**add** amounts Q5 to U5) ▶ V5

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (amount P5 **minus** amount V5) (if negative, enter "0") W5

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the W5 amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		500,000	
Total taxable dividends paid in the tax year	100	500,000	
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	6,898,497	B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- Use this schedule if the corporation had a permanent establishment, under section 400 of the federal *Income Tax Regulations,* in Ontario at any time in the tax year and had Ontario taxable income in the year.
- Legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and is not required to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Ontario basic income tax

Ontario taxable income *	1,421,293	A
Ontario basic rate of tax for the year	11.5 %	B
Ontario basic income tax (amount A **multiplied** by amount B **)	163,449	C

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or amount Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

** If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1).

Amount from line 400 of the T2 return	1,421,693	1	
Amount from line 405 of the T2 return	1,421,293	2	
Amount from line 427 of the T2 return		3	
Enter the least of amounts 1, 2 or 3		▶	D

Ontario domestic factor (ODF): Taxable income for Ontario * / Taxable income for all provinces ** = 1,421,293.00 / 1,421,293 = 1.00000 E

Amount D **multiplied** by amount E		4	
Ontario taxable income (amount A from Part 1)	1,421,293	5	
Ontario small business income (lesser of amount 4 or amount 5)		▶	F

Ontario small business deduction rate for the year

Number of days in the tax year before January 1, 2018 / Number of days in the tax year: 365 / 365 x 7 % = 7.00000 % G1

Number of days in the tax year after December 31, 2017 / Number of days in the tax year: ____ / 365 x 8 % = ____ % G2

OSBD rate for the year (rate G1 **plus** rate G2)	7.00000 %	▶ 7.00000 %	G
Ontario small business deduction (amount F **multiplied** by rate G)			H

Enter amount H on line 402 of Schedule 5.

* Enter amount A from Part 1.

** Includes the offshore areas for Nova Scotia and Newfoundland and Labrador.

Client Copy

Part 3 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount 5) I

Enter amount I at amount K in Part 4 of this schedule or at amount B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 4 – Credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount N from Part 5 of Schedule 17 . . . . . J

Ontario adjusted small business income (amount I) . . . . . K

Subtotal (amount J **minus** amount K, if negative, enter "0") L

Amount L **multiplied** by amount G . . . . . M

Ontario domestic factor (amount E) . . . . . 1.00000 N

Ontario credit union tax reduction (amount M **multiplied** by amount N) . . . . . O

Enter amount O on line 410 of Schedule 5.

Client Copy

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2017-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
NIAGARA-ON-THE-LAKE HYDRO INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-07-01	1424833

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
8	Henegan Road	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 460

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Virgil	ON	CA	L0S 1T0

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [2] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Klassen (Last name) **451** Jeffrey (First name)

454 Tyler (Middle name(s)),

460 [2] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Client Copy

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 2 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 1 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Client Copy

CRA internal form identifier 547

Part 7 – Director/Officer information

- **Director:** If the individual named in this part is a director (or must be reported ceased as a director), complete lines 700 to 797.
- **Officer:** If the individual named in this part is one of the corporation's five most senior officers (or must be reported ceased in an officer position), complete lines 700 to 790 and the applicable lines from 801 to 912.
- **Director and officer:** If the individual named in this part is a director and one of the corporation's five most senior officers (or must be reported ceased in these position(s)), complete lines 700 to 797 and the applicable lines from 801 to 912.
- The corporation is required to show information on the MGS public record for all its directors and a maximum of five of its most senior officers. If the MGS public record shows more than five officer positions, report cease dates for all except the corporation's five most senior officer positions.
- To report changes to the name of a director/officer, or changes to both the address and the date elected/appointed of a director/officer, enter the director/officer information exactly as shown incorrectly on the public record, with a cease date, and then photocopy and complete only Part 7 with the correct director/officer information.

Please photocopy this page and complete Part 7 only for each additional individual for whom director/officer information changes are being reported.

Full name and address for service (P.O. box not acceptable as stand-alone address). The name entered in lines 700 to 710 must be exactly as shown on the MGS public record.

700 Last name	705 First name	710 Middle name(s)
Syed	Hassan	

720 Street number	730 Street name/Rural route/Lot and Concession number	740 Suite number
541	Winston Road	36

750 Additional address information if applicable (line 730 must be completed first)

760 Municipality (e.g., city, town)	770 Province/state	780 Country	790 Postal/zip code
Grimsby	ON	CA	L3M 0C5

Director

Is this director a resident Canadian? . . . **795** **1** Yes ☐ **2** No ☐

(applies to directors of corporations with share capital only)

796 Date elected/appointed (Year Month Day):

797 Date ceased, if applicable (Year Month Day):

Officer information

		Date appointed (Year Month Day)		Date ceased, if applicable (Year Month Day)
President	801		802	
Secretary	806		807	
Treasurer	811		812	
General Manager	816		817	
Chair	821		822	
Chairperson	826		827	
Chairman	831		832	
Chairwoman	836		837	
Vice-Chair	841		842	
Vice-President	846	2016-05-11	847	2017-05-26
Assistant Secretary	851		852	
Assistant Treasurer	856		857	
Chief Manager	861		862	
Executive Director	866		867	
Managing Director	871		872	
Chief Executive Officer	876		877	
Chief Financial Officer	881		882	
Chief Information Officer	886		887	
Chief Operating Officer	891		892	
Chief Administrative Officer	896		897	
Comptroller	901		902	
Authorized Signing Officer	906		907	
Other (untitled)	911		912	

Client Copy

Once you have completed this page, complete the certification in Part 4 of this schedule.

CRA internal form identifier 547

Part 7 – Director/Officer information

- **Director:** If the individual named in this part is a director (or must be reported ceased as a director), complete lines 700 to 797.
- **Officer:** If the individual named in this part is one of the corporation's five most senior officers (or must be reported ceased in an officer position), complete lines 700 to 790 and the applicable lines from 801 to 912.
- **Director and officer:** If the individual named in this part is a director and one of the corporation's five most senior officers (or must be reported ceased in these position(s)), complete lines 700 to 797 and the applicable lines from 801 to 912.
- The corporation is required to show information on the MGS public record for all its directors and a maximum of five of its most senior officers. If the MGS public record shows more than five officer positions, report cease dates for all except the corporation's five most senior officer positions.
- To report changes to the name of a director/officer, or changes to both the address and the date elected/appointed of a director/officer, enter the director/officer information exactly as shown incorrectly on the public record, with a cease date, and then photocopy and complete only Part 7 with the correct director/officer information.

Please photocopy this page and complete Part 7 only for each additional individual for whom director/officer information changes are being reported.

Full name and address for service (P.O. box not acceptable as stand-alone address). The name entered in lines 700 to 710 must be exactly as shown on the MGS public record.

700 Last name	705 First name	710 Middle name(s)
Marouf	Kazi	

720 Street number	730 Street name/Rural route/Lot and Concession number	740 Suite number
570	Ferndale Avenue	

750 Additional address information if applicable (line 730 must be completed first)

760 Municipality (e.g., city, town)	770 Province/state	780 Country	790 Postal/zip code
Fort Erie	ON	CA	L2A 6E3

Director

Is this director a resident Canadian? . . . 795 **1** Yes ☐ **2** No ☐

(applies to directors of corporations with share capital only)

796 Date elected/appointed Year Month Day

797 Date ceased, if applicable Year Month Day

Officer information

		Date appointed Year Month Day		Date ceased, if applicable Year Month Day
President	801		802	
Secretary	806		807	
Treasurer	811		812	
General Manager	816		817	
Chair	821		822	
Chairperson	826		827	
Chairman	831		832	
Chairwoman	836		837	
Vice-Chair	841		842	
Vice-President	846	2017-05-11	847	
Assistant Secretary	851		852	
Assistant Treasurer	856		857	
Chief Manager	861		862	
Executive Director	866		867	
Managing Director	871		872	
Chief Executive Officer	876		877	
Chief Financial Officer	881		882	
Chief Information Officer	886		887	
Chief Operating Officer	891		892	
Chief Administrative Officer	896		897	
Comptroller	901		902	
Authorized Signing Officer	906		907	
Other (untitled)	911		912	

Client Copy

Once you have completed this page, complete the certification in Part 4 of this schedule.

KPMG LLP
Commerce Place
21 King Street West Suite 700
Hamilton, ON L8P 4W7
Tel 905-523-8200
Fax 905-523-2222
www.kpmg.ca

PRIVATE AND CONFIDENTIAL

Mr. Timothy Curtis
Niagara-on-the-Lake Hydro Inc.
8 Henegan Road
Virgil ON L0S 1T0

June 7, 2018

Dear Mr. Curtis:

Corporate Income Tax Returns

Client Copy

We have enclosed the following income tax returns of Niagara-on-the-Lake Hydro Inc. (the "Company") for the year ended **December 31, 2017**:

- ☑ T2 – *Corporation Income Tax Return* – EXEMPT
- ☑ T183 *Information Return For Corporations Filing Electronically* (Federal – to be e-filed with CRA) - Exempt
- ☑ T2 – *Corporation Income Tax Return* (to be filed with Ministry of Finance) – PILS
- ☑ Instalment Schedule
- ☑ One copy of each return for your files

We have prepared these returns based on our understanding of the information provided to us by the Company and we recommend that you review the returns to ensure that all of the relevant facts are properly disclosed. When you are satisfied that the returns are in order, one copy of each return should be retained for your records (the copy stamped "Client Copy") and the remaining copies should be completed by an authorized signing officer of the Company and filed as described below.

DUE DATE OF RETURNS AND PAYMENTS

All returns must be filed with the respective taxing authorities by the due date if late filing penalties are to be avoided. We suggest that the returns be sent by registered mail and that the mailing receipt be kept on file in order to have evidence of the date of filing.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

Any balances owing must be remitted by the due date or as soon as possible if interest charges are to be minimized.

T2 – *CORPORATION INCOME TAX RETURN* (FEDERAL) CRA COPY - EXEMPT

Signature

✍ The Form T183CORP - *Information Return for Corporations Filing Electronically* should be completed and signed.

Payment

No amount is payable for the **December 31, 2017** taxation year.

Mailing

✉ One copy of the signed Form T183CORP should be returned to us in the self-addressed envelope no later than **June 30, 2018** in order to have the Company's corporate income tax return filed on or before the due date for filing. Alternatively, you can fax it to **(905) 523-2222.**

T2 – *CORPORATION INCOME TAX RETURN* - MINISTRY OF FINANCE

Signature

✍ Form T2 – *Corporate Income Tax Return*, the certification section at the bottom of page 9 should be completed and signed.

Payment

A cheque in the amount of $**374,643** should be attached for the **December 31, 2017** taxation year. Payments should be made in Canadian funds and be made payable to the Minister of Finance. Your business number should be printed on the back of the cheque or money order.

Mailing

✉ One copy of the *T2 Corporate Income Tax Return* must be received by The Ministry of Finance, HYDRO PIL DIVISION, P.O. Box 620, 33 King Street West, Oshawa, Ontario, L1H 8E9 no later than **June 30, 2018**. The Company's account number should be recorded on each of the paper documents submitted.

NOTICES OF ASSESSMENT

If your Company receives a Notice of Assessment that does not agree with the returns prepared by us, please contact us so that we can determine whether any action should be taken. The Company has only 90 days (180 days in the case of Ontario) from the date of

Client Copy

mailing of the Assessment in which to object. Failure to respond within the prescribed time limit will cause the Company to lose its right to object to the Assessment.

INSTALMENTS

We have prepared and enclose an estimate of PILS tax instalments as applicable for the Company for the **2018** taxation year. The amounts were computed with reference to the Company's taxable income, taxable capital and taxes payable for prior years. If during the year it is evident that the taxable income or taxable capital for the current year will be substantially less than for the previous taxation year, your instalments may be recalculated. Please call your KPMG advisor in order that we may determine what course of action should be taken.

In order to avoid interest charges, the Ministry of Finance must receive the instalment payments no later than the date indicated on the attached schedule.

If you have any questions concerning these returns, or if we may be of any further assistance, please do not hesitate to contact us.

Yours truly,

Tony Italiano
Partner
905-523-2227

Enclosures

Client Copy

APPENDIX

4D

2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056



2017 Final Verified Annual LDC CDM Program Results Report
Letter from the Vice-President, Policy, Engagement & Innovation

June 29, 2018

To: Ontario's Local Distribution Companies

At the mid-way point of the Conservation First Framework (CFF) Ontario's Local Distribution Companies (LDCs) along with the IESO have shown significant progress towards the 2020 CFF 7.0 TWh target. The province has achieved 1.8 TWh of persisting energy savings in 2017, the highest performing year on record. Approximately 20% ($364M) of the allocated $1.835B CFF LDC Conservation Demand Management (CDM) budget was accounted for in 2017. From 2015, LDCs have achieved 4.8 TWh of energy savings, representing 69% of the CFF 7.0 TWh target. The savings realized to date demonstrate the significant efforts made by LDCs and the IESO in delivering and promoting conservation programs across the province.

Key highlights from the 2017 results include:

- The share of residential portfolio savings increased for the third consecutive year, accounting for 46% of 2017 results, while the business portfolio program contributed to 45%, and local/pilot/centrally delivered programs accounting for 9% of 2017 savings.

- The Coupon & Instant Discount residential retail program produced a record achievement of 740 GWh of persisting energy savings, increasing by over 53% of the results from 2016. LED light bulbs remained the most common measure accounting 91% of savings.

- The Retrofit program achieved 663 GWh of persisting energy savings in 2017, which represents a small reduction in savings despite completing approximately half the number projects compared to 2016 results (including adjustments). Lighting continues to represent the majority of results, representing 79% of savings in 2017.

- The Process and Systems Upgrades Program achieved 15 GWh in 2017, but also verified an additional 65 GWh in 2016 completed projects and 11 GWh in 2015 completed projects as part of this year's evaluation. Behind-the-meter generation projects account for 82% of program savings-to-date.

    - The data lag associated with unreported (yet completed) 2017 projects for the Retrofit and Process and Systems Upgrade programs remain an ongoing challenge. Together with the Heating & Cooling program, these programs have approximately 723 GWh in unverified savings yet to be reported by LDCs for which is anticipated to be reported a future verified annual results reports as 2017 adjustments.

Minor revisions were made to the final 2017 results relative to the preliminary 2017 results issued to LDCs on June 1, 2018. Details on the revisions between the 2017 preliminary and final verified results can be found in the 2017 Frequently Asked Questions (FAQs) along with key 2017 evaluation findings and province-wide and local program cost effectiveness test results posted alongside LDC results.

Consistent with prior year evaluation cycles, all 2017 final verified annual results reports will be posted on the IESO website in early July. LDC-specific cost effectiveness test results (program- and portfolio-level) will be available by September 15, 2017. Finally, 2017 EM&V reports will be available later this summer along with key program recommendations to be shared with the Joint Program Operations Committee (JPOC) and associated committees.

I look forward to the continued collaboration with LDCs and stakeholders building off lessons learned and implementing feedback from the mid-term review process to enhance current programs and future efforts.

Sincerely,

Terry Young
Vice-President, Policy, Engagement & Innovation
Independent Electricity System Operator

2017 Final Verified Annual LDC CDM Program Results Report
Table of Contents

#	Worksheet Name	Worksheet Description
1	How to Use This Report	Describes the contents and structure of this report
2	Report Summary	A high level summary of the Final 2017 Annual Verified Results Report, including: 1) progress toward the LDC's: a) Allocated 2020 Annual Energy Savings Target; b) Allocated 2015-2020 LDC CDM Plan Budget; c) CDM Plan 2015-2020 Forecasts; 3) annual savings and spending; 4) Annual FCR Progress; 5) annual LDC CDM Plan spending progress; 6) graphs describing: a) contribution to 2020 Target Achievement by program; b) 2017 LDC CDM Plan Budget Spending by Sector; c) annual energy savings persistence to 2020 by year; d) your Allocated Target achievement progress relative to your peers; and e) your LDC CDM Plan Budget Spending progress relative to your peers;
3	LDC Rankings	A comprehensive report of each LDC's performance rankings against all other LDCs in major performance categories.
4	LDC Progress	A comprehensive report of 2017 conservation results including: 1) activity; 2) savings including; a) energy and peak demand; b) net and gross; c) CDM Plan forecasts, verified actuals and relative progress; d) Allocated Target and Target acheivement; and 3) spending, including participant incentives and administrative expenses and IESO Value Added Services Costs. Data is grouped by category and summarized at the LDC level.
5	Province-Wide Progress	A comprehensive report of 2016 conservation results including: 1) activity; 2) savings including; a) energy and peak demand; b) net and gross; c) CDM Plan forecasts, verified actuals and relative progress; d) Allocated Target and Target acheivement; and 3) spending, including participant incentives and administrative expenses and IESO Value Added Services Costs. Data is grouped by category and summarized at the province wide level.
6	LDC Savings Persistence	A report detailing the gross and net energy and peak demand savings persistence by program and implementation year (2015, 2015 Adjustment, 2016, 2016 Adjustment and 2017) at the LDC Level.
7	Province-Wide Savings Persistence	A report detailing the gross and net energy and peak demand savings persistence by program and implementation year (2015, 2015 Adjustment, 2016, 2016 Adjustment and 2017) at the province wide Level.
8	Methodology	A description of the methods used to calculate energy savings, financial results and cost-effectiveness.
9	Reference Table	Provides detailing how Province wide Consumer Program results were allocated to specific LDCs.
10	Glossary	Definitions for the terms used throughout this report.

2017 Final Verified Annual LDC CDM Program Results Report
How to Use this Report

The IESO is pleased to provide you with the 2017 Final Verified Annual LDC CDM Program Results Report.

This report provides:
1) electricity savings;
2) annual Full Cost Recovery funding model program progress; and
3) peak demand savings;
4) IESO Value Added Services Costs
in accordance with Section 9.2(b)(i) of the Energy Conservation Agreement.

In addition to the above, this report also provides in greater detail:
1) program participation results including:
   a) forecasts; b) actuals; and c) progress (forecast versus (vs) actuals);

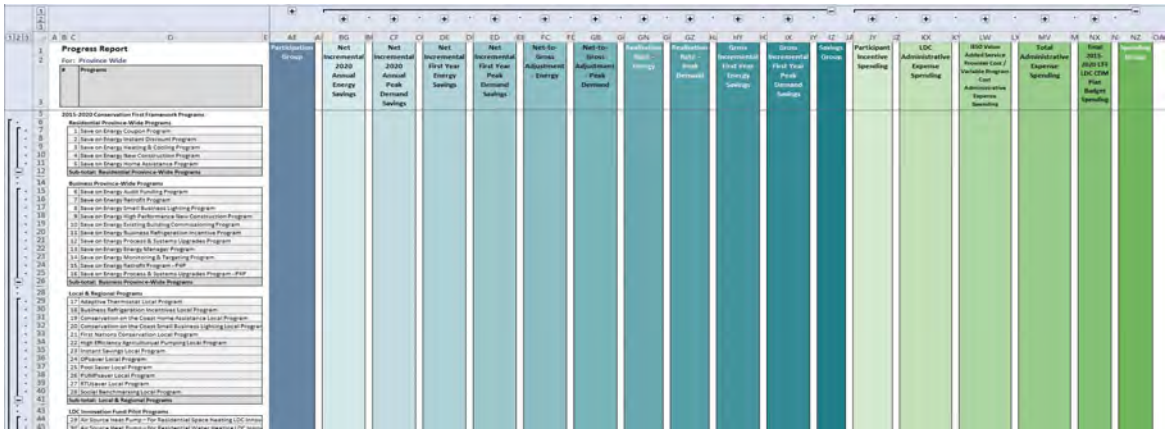
2) program savings results including:
   a) net 2020 annual energy and peak demand savings;
   b) allocated target, target achievement and progress towards target;
   c) incremental net first year energy and peak demand savings;
   d) annual net-to-gross and realization rate adjustments; and
   e) incremental gross first year energy and peak demand savings;
   and where available reported by: i) forecasts; ii) verified actuals; and iii) progress (forecast vs actuals);

3) program spending including:
   a) participation incentive spending;
   b) administrative expense spending (including IESO value-added services costs);
   c) aggregated total spending; and
   d) allocated budget, LDC CDM Plan budget spending and progress towards budget;
   and for each cost: i) forecasts; ii) verified actuals; and iii) progress (forecast vs actuals);

4) program savings results persistence for:
   a) gross energy savings;
   b) gross peak demand savings;
   c) net energy savings; and
   d) net peak demand savings;

by both the LDC specific level and the province-wide aggregated level for 2017, 2016 including adjustments, and 2015 including adjustments.

This report's format is consistent with the IESO issued Monthly Participation and Cost Report in that it is a dynamic sheet that can be expanded or collapsed by clicking the + button or "Show Detail" feature under the Data tab. Each of the four results categories listed above have been grouped together for easy accessibility.



Please note:
1) Cost Effectiveness Test (CET) results at the: a) province-wide / program level is available and posted separately on LDC Extranet; b) LDC / program level will be available on the LDC Extranet by September 15, 2018; as per the Energy Conservation Agreement, version 3.0;

2) forecasts of: a) activity; b) savings; and c) spending; included in this report are based on approved LDC CDM Plan - Cost Effectiveness Tools as of December 31, 2017 (from the i) Program Design; ii) Budget Inputs; and iii) Savings Results worksheets);

3) Annual FCR Progress only includes Full Cost Recovery funding model program savings results and excludes Pay-for-Performance funding model program savings results;

4) The complete list of approved programs and pilots as of December 31, 2017 approved LDC CDM Plans have been included, however only programs and pilots in market for a sufficient period of time to enable a valid EM&V process will have verified results;

5) 2017 Verified Adjustments to prior years consists of projects completed in the associated year but were not reported to the IESO by previous year's reporting deadlines (March 31, 2016 and April 15, 2017);

6) Pilot program savings are attributed to the LDC where the pilot program project is located in; and

7) This Annual Verified Results Report provides results for the LDC and province only. No aggregated reporting is provided for LDCs that are part of a joint CDM plan;

2017 Final Verified Annual LDC CDM Program Results Report Summary

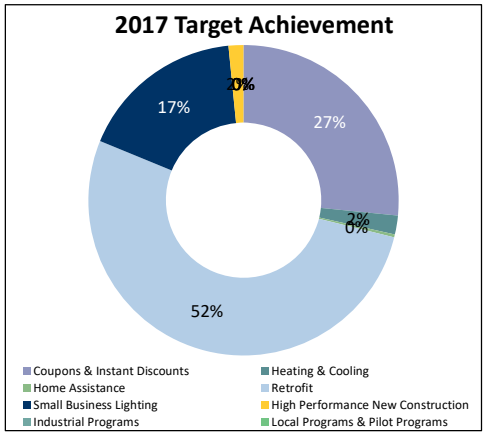
For: Niagara-on-the-Lake Hydro Inc.

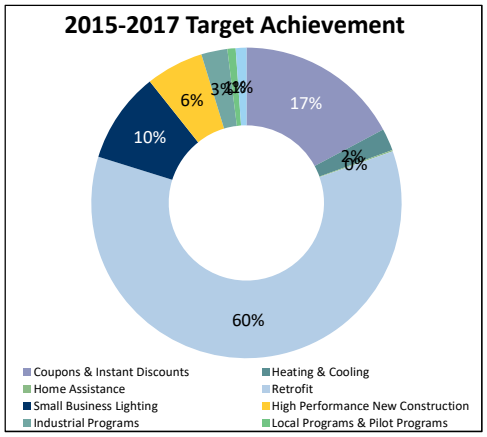
Results

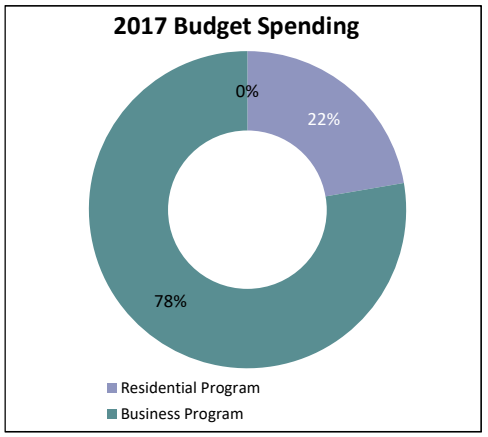
#	Metric	2015 Verified Results	2016 Verified Results	2017 Verified Results	2015-2017 Verified Results	Allocated Target / Budget	2015-2017 Progress versus Allocated Target / Budget	2015-2020 LDC CDM Plan Forecast	2015-2017 Progress versus 2015-2020 LDC CDM Plan Forecast	2017 LDC CDM Plan Forecast	2017 Progress versus 2017 LDC CDM Plan Forecast	2015-2017 LDC CDM Plan Forecast	2015-2017 Progress versus 2015-2017 LDC CDM Plan Forecast
1	Net Verified Annual Energy Savings Persisting to 2020	3,063 MWh	3,988 MWh	3,445 MWh	10,497 MWh	11,680 MWh	90 %	12,188 MWh	86 %	2,472 MWh	139 %	9,028 MWh	116 %
2	LDC Ranking - Net Verified Annual Energy Savings Persisting to 2020	38	36	40	38	43	12	43	8	37	30	37	46
3	Total Spending ($)	$ 0	$ 425,446	$ 647,548	$ 1,072,994	$ 2,993,633	36 %	$ 2,221,857	48 %	$ 674,316	96 %	$ 1,099,317	98 %
4	LDC Ranking - Total Spending ($)	41	41	41	40	43	22	46	4	39	29	40	17

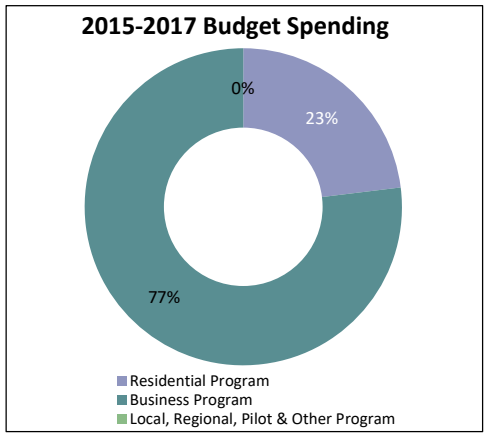
Annual FCR Progress

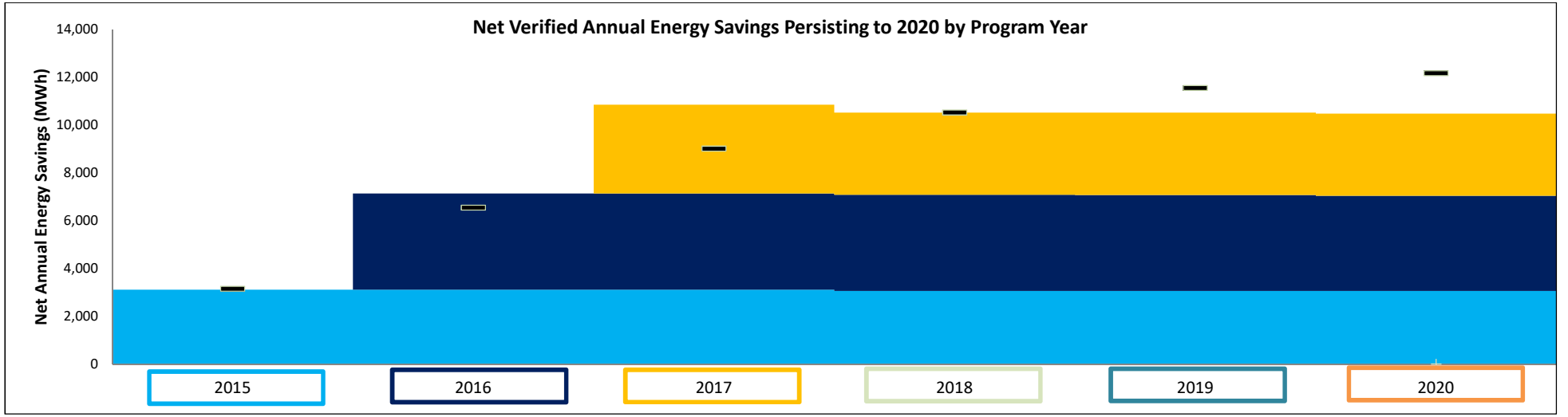
#	Metric	2015 Program Year	2016 Program Year	2017 Program Year	Total 2015-2017 Framework-to-Date
1	Net Verified 2020 Annual Energy Savings from Full Cost Recovery Programs	18 MWh	3,988 MWh	3,445 MWh	**7,451 MWh**
2	CDM Plan Forecasted Net 2020 Annual Energy Savings from Full Cost Recovery Programs	2,607 MWh *(2015 Annual Milestone from FCR Programs)*	2,729 MWh *(2016 Annual Milestone from FCR Programs)*	2,184 MWh *(2017 Annual Milestone from FCR Programs)*	**7,520 MWh** ***(Cumulative FCR Milestone)***
FCR Progress					**99.1 %**

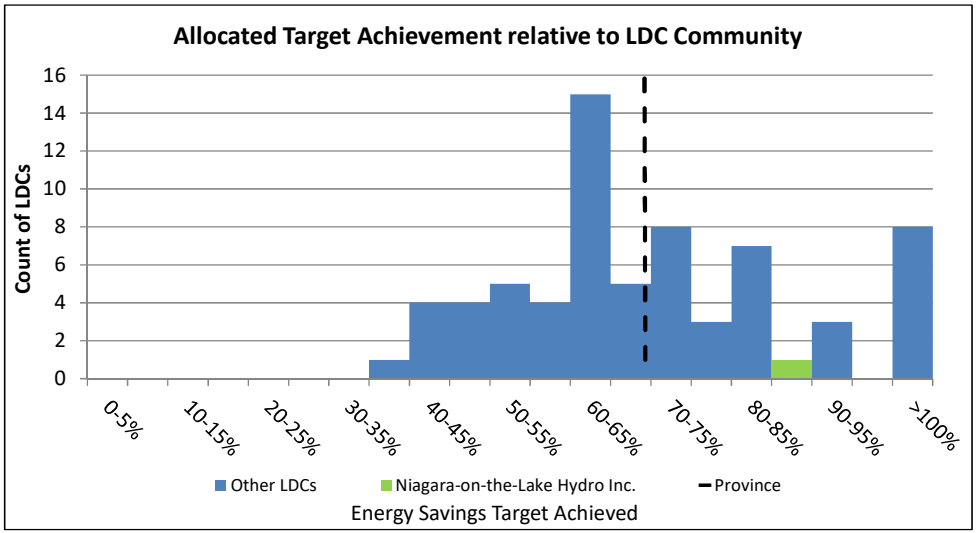


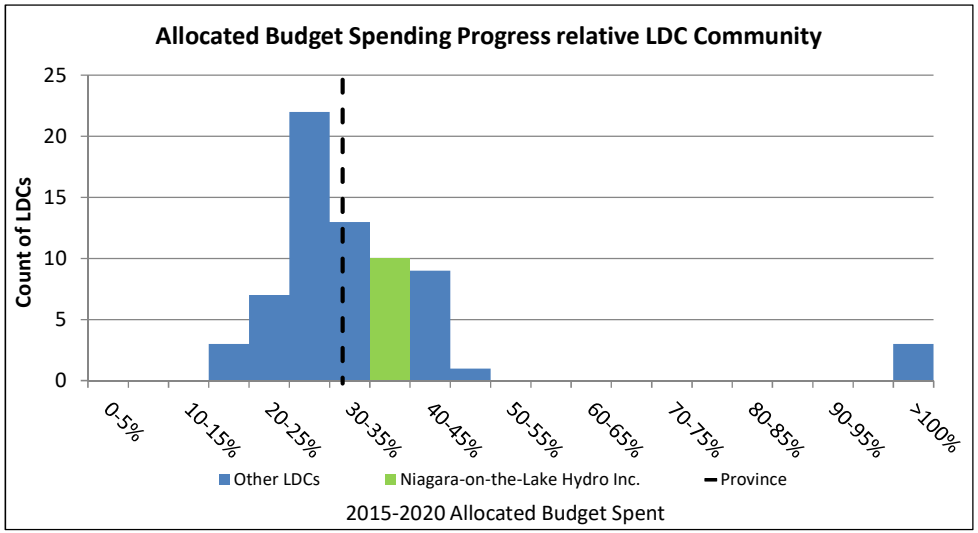







Net Verified Annual Energy Savings Persisting to 2020 by Program Year
Net Annual Energy Savings (MWh)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2015
2016
2017
2018
2019
2020


Allocated Target Achievement relative to LDC Community
Count of LDCs
16
14
12
10
8
6
4
2
0
0-5%
10-15%
20-25%
30-35%
40-45%
50-55%
60-65%
70-75%
80-85%
90-95%
>100%
Other LDCs
Niagara-on-the-Lake Hydro Inc.
Province
Energy Savings Target Achieved


Allocated Budget Spending Progress relative LDC Community
Count of LDCs
25
20
15
10
5
0
0-5%
10-15%
20-25%
30-35%
40-45%
50-55%
60-65%
70-75%
80-85%
90-95%
>100%
Other LDCs
Niagara-on-the-Lake Hydro Inc.
Province
2015-2020 Allocated Budget Spent

2017 Final Verified Annual LDC CDM Program Results Report
LDC Rankings

#	LDC	Net Verified Annual Energy Savings Persisting to 2020													
		2015 Verified 2015 Savings		2016 Verified 2015 Adjustment Savings		2017 Verified 2015 Adjustment Savings		Total Verified 2015 Savings		2016 Verified 2016 Savings		2017 Verified 2016 Adjustment Savings		Total Verified 2016 Savings	
		Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)
44	Niagara-on-the-Lake Hydro Inc.	2,598,018	39	369,192	37	96,276	30	3,063,486	38	3,401,852	33	586,267	38	3,988,119	36
LDC Total		**1,117,211,477**		**372,759,951**		**68,785,651**		**1,558,757,080**		**1,152,109,308**		**357,805,953**		**1,509,915,261**	
Independent Electricity System Operator		**278,348**		**16,467**		**0**		**294,815**		**2,045,490**		**35,884**		**2,081,374**	
Province-Wide Total		**1,117,489,826**		**372,776,418**		**68,785,651**		**1,559,051,895**		**1,154,154,798**		**357,841,837**		**1,511,996,635**	



2017 Verified 2017 Savings		Total Verified 2015-2017 Savings		Allocated Savings Target		2017 Progress Savings versus Allocated Savings Target		2015-2017 Progress Savings versus Allocated Savings Target		2015-2020 LDC CDM Plan Savings Forecast		2017 Progress versus 2015-2020 LDC CDM Plan Savings Forecast		2015-2017 Progress versus 2015-2020 LDC CDM Plan Savings Forecast		2017 LDC CDM Plan Savings Forecast		2017 Progress versus 2017 LDC CDM Plan Savings Forecast		2015-2017 LDC CDM Plan Savings Forecast
Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)
3,445,058	40	10,496,663	38	11,680,000	43	29	16	90	12	12,187,558	43	28	14	86	8	2,471,690	37	139	30	9,027,755
1,790,833,794		**4,859,506,135**		**6,999,990,000**		**26**		**69**		**7,402,554,217**		**24**		**66**		**1,268,253,723**		**141**		**3,844,200,598**
1,773,007		**4,149,196**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**
1,792,606,801		**4,863,655,331**		**6,999,990,000**		**26**		**69**		**7,402,554,217**		**24**		**66**		**1,268,253,723**		**141**		**3,844,200,598**

			Total Spending																	
	2015-2017 Progress versus 2015-2017 LDC CDM Plan Savings Forecast		2015 Verified 2015 Spending		2016 Verified 2015 Adjustment Spending		2017 Verified 2015 Adjustment Spending		Total Verified 2015 Spending		2016 Verified 2016 Spending		2017 Verified 2016 Adjustment Spending		Total Verified 2016 Spending		2017 Verified 2017 Spending		Total Verified 2015-2017 Spending	
LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)
37	116	46	0	28	0	27	0	1	0	41	424,921	41	525	12	425,446	41	647,548	41	1,072,994	40
	126		**22,389,524**		**2,398,698**		**0**		**24,788,222**		**205,478,076**		**27,300**		**205,505,376**		**362,798,888**		**593,092,486**	
	n/a		**0**		**0**		**0**		**0**		**0**		**0**		**0**		**0**		**0**	
	126		**22,389,524**		**2,398,698**		**0**		**24,788,222**		**205,478,076**		**27,300**		**205,505,376**		**362,798,888**		**593,092,486**	

Allocated Budget		2017 Progress Spending versus Allocated Budget		2015-2017 Progress Spending versus Allocated Budget		2015-2020 LDC CDM Plan Spending Forecast		2017 Progress versus 2015-2020 LDC CDM Plan Spending Forecast		2015-2017 Progress versus 2015-2020 LDC CDM Plan Spending Forecast		2017 LDC CDM Plan Spending Forecast		2017 Progress versus 2017 LDC CDM Plan Spending Forecast		2015-2017 LDC CDM Plan Spending Forecast		2015-2017 Progress versus 2015-2017 LDC CDM Plan Spending Forecast	
Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)
2,993,633	43	22	23	36	22	2,221,857	46	29	5	48	4	674,316	39	96	29	1,099,317	40	98	17
1,835,264,933		**20**		**32**		**1,800,344,744**		**20**		**33**		**400,311,151**		**91**		**724,466,399**		**82**	
n/a		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**		**n/a**	
1,835,264,933		**20**		**32**		**1,800,344,744**		**20**		**33**		**400,311,151**		**91**		**724,466,399**		**82**	

Progress Report

For: Niagara-on-the-Lake Hydro Inc.

Participation

#	Programs	Unit of Measure	Forecasted (#) 2015	2016	2017	2018	2019	2020	Total	Verified (#) 2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Progress vs Forecast (%) Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total
2015-2020 Conservation First Framework Programs																						
Residential Province-Wide Programs																						
1	Save on Energy Coupon Program	Products	-	-	-	-	-	-	-	-	-	-	-	21,107	2,390	23,497	20,272	43,769	#VALUE!			#VALUE!
2	Save on Energy Instant Discount Program	Products	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,765	15,765				
3	Save on Energy Heating & Cooling Program	Equipment	-	-	-	-	-	-	-	-	-	-	-	224	2	226	79	305				
4	Save on Energy New Construction Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
5	Save on Energy Home Assistance Program	Homes	1	1	-	-	-	-	2	-	-	-	-	3	-	3	5	8	-	300		400
Sub-total: Residential Province-Wide Programs																						
Business Province-Wide Programs																						
6	Save on Energy Audit Funding Program	Projects	1	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-			-
7	Save on Energy Retrofit Program	Projects	1	1	49	21	17	9	98	-	-	-	-	53	2	55	45	100	-	5,500	92	196
8	Save on Energy Small Business Lighting Program	Projects	1	1	104	43	12	-	161	-	-	-	-	48	1	49	106	155	-	4,900	102	146
9	Save on Energy High Performance New Construction Program	Projects	1	1	1	1	1	2	7	-	-	-	-	4	-	4	1	5	-	400	100	167
10	Save on Energy Existing Building Commissioning Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
11	Save on Energy Business Refrigeration Incentive Program	Projects	-	-	20	30	-	-	50	-	-	-	-	-	-	-	-	-			-	-
12	Save on Energy Process & Systems Upgrades Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
13	Save on Energy Energy Manager Program	Projects	1	-	-	140	50	-	191	-	-	-	-	-	-	-	-	-	-			-
14	Save on Energy Monitoring & Targeting Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
15	Save on Energy Retrofit Program - P4P	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
16	Save on Energy Process & Systems Upgrades Program - P4P	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Business Province-Wide Programs																						
Local & Regional Programs																						
17	Adaptive Thermostat Local Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
18	Business Refrigeration Incentives Local Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
19	Conservation on the Coast Home Assistance Local Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
20	Conservation on the Coast Small Business Lighting Local Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
21	First Nations Conservation Local Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
22	High Efficiency Agriculturual Pumping Local Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
23	Instant Savings Local Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
24	OPsaver Local Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
25	Pool Saver Local Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
26	PUMPsaver Local Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
27	RTUsaver Local Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
28	Social Benchmarking Local Program	Participants	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Local & Regional Programs																						
LDC Innovation Fund Pilot Programs																						
29	Air Source Heat Pump – For Residential Space Heating LDC Innovation Fund	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
30	Air Source Heat Pump – For Residential Water Heating LDC Innovation Fund	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
31	Block Heater Timer LDC Innovation Fund Pilot Program	Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
32	Commercial Energy Management and Load Control (CEMLC) LDC Innovation	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
33	Conservation Cultivator LDC Innovation Fund Pilot Program	Projects	1	-	-	-	-	-	1	-	-	4	4	-	-	-	-	4	400			400
34	Data Centre LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
35	Electronics Take Back LDC Innovation Fund Pilot Program	Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
36	Energy Reinvestment LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
37	Home Energy Assessment & Retrofit LDC Innovation Fund Pilot Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
38	Hotel/Motel LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
39	Intelligent Air Technology LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
40	OPsaver LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
41	PUMPsaver LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
42	Residential Direct Install LDC Innovation Fund Pilot Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
43	Residential Direct Mail LDC Innovation Fund Pilot Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
44	Residential Ductless Heat Pump LDC Innovation Fund Pilot Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
45	Retrocomissioning LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
46	RTUsaver LDC Innovation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
47	Small & Medium Business Energy Management System LDC Innovation Fun	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
48	Solar Powered Attic Ventilation LDC Innovation Fund Pilot Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
49	Toronto Hydro – Enbridge Joint Low-Income Program LDC Innovation Fund	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
50	Truckload Event LDC Innovation Fund Pilot Program	Products	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: LDC Innovation Fund Pilot Programs																						
Centrally Delivered Programs																						
51	Industrial Accelerator Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
52	Save on Energy Energy Performance Program for Multi-Site Customers	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
53	Whole Home Pilot Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Centrally Delivered Programs																						
Program Enabled Savings																						
54	Save on Energy Retrofit Program Enabled Savings	Claims	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	1				
55	Save on Energy High Performance New Construction Program Enabled Savi	Claims	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
56	Save on Energy Process & Systems Upgrades Program Enabled Savings	Claims	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Program Enabled Savings																						
Other																						
57	Non-Approved Program	Various	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
58	Unassigned Program	Various	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Other																						
Sub-total: 2015-2020 Conservation First Framework																						
Conservation Fund																						
59	Conservation Voltage Reduction Conservation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
60	EnerNOC Conservation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
61	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Progra	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
62	Loblaw P4P Conservation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
63	Ontario Clean Water Agency P4P Conservation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
64	Performance Based Conservation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
65	Social Benchmarking Conservation Fund Pilot Program	Participants	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
66	Strategic Energy Group Conservation Fund Pilot Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Conservation Fund																						
2011-2014+2015 Extension Legacy Framework Programs																						
Residential Program																						
67	Appliance Retirement Initiative	Appliances	-	-	-	-	-	-	-	8	-	-	8	-	-	-	-	8				
68	Coupon Initiative	Products	1	1	9,000	9,000	9,000	7,500	34,502	3,549	938	-	4,487	-	-	-	-	4,487	448,700	-	-	50
69	Bi-Annual Retailer Event Initiative	Products	-	-	-	-	-	-	-	6,102	67	-	6,169	-	-	-	-	6,169				
70	HVAC Incentives Initiative	Equipment	1	1	70	120	50	-	242	174	1	-	175	-	-	-	-	175	17,500	-	-	243
71	Residential New Construction and Major Renovation Initiative	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Residential Program																						
Commercial & Institutional Program																						
72	Energy Audit Initiative	Projects	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	1				
73	Efficiency: Equipment Replacement Incentive Initiative	Projects	-	-	-	-	-	-	-	70	8	3	81	-	-	-	-	81				
74	Direct Install Lighting and Water Heating Initiative	Projects	-	-	-	-	-	-	-	47	-	-	47	-	-	-	-	47				
75	New Construction and Major Renovation Initiative	Projects	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	1				
76	Existing Building Commissioning Incentive Initiative	Projects	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	1				
Sub-total: Commercial & Institutional Program																						
Industrial Program																						
77	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
78	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Projects	-	-	-	-	-	-	-	5	-	-	5	-	-	-	-	5				
79	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiat	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Sub-total: Industrial Program																						
Low Income Program																						
80	Low Income Initiative	Homes	-	-	-	-	-	-	-	2	-	-	2	-	-	-	-	2				
Sub-total: Low-Income Program																						
Other																						
81	Aboriginal Conservation Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
82	Program Enabled Savings	Claims	1	-	-	-	-	-	1	1	-	-	1	-	-	-	-	1	100			100
Sub-total: Other																						
Sub-total: 2011-2014+2015 Extension Legacy Framework																						
Total																						

Participation Group	Net Incremental 2020 Annual Energy Savings																						
	Forecasted (kWh)							Verified (kWh)									Progress (%)				2015-2020 CFF LDC CDM Plan Allocated Target (kWh)	Progress versus Target (%)
	2015	2016	2017	2018	2019	2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total		
	-	-	-	-	-	-	-	-	-	-	-	566,176	64,552	630,728	497,523	**1,128,251**						
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	418,242	**418,242**						
	-	-	-	-	-	-	-	-	-	-	-	106,387	1,977	108,364	67,894	**176,258**						
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**						
	2,326	2,661	-	-	-	-	**4,987**	-	-	-	-	2,661	-	2,661	10,395	**13,056**	-	100		**262**		
	2,326	**2,661**	**-**	**-**	**-**	**-**	**4,987**	**-**	**-**	**-**	**-**	**675,224**	**66,529**	**741,753**	**994,054**	**1,735,807**	**-**	**27,875**		**34,807**		
	76,159	-	-	-	-	-	**76,159**	-	-	-	-	-	-	-	-	**-**	-			**-**		
	1,747,175	2,303,157	1,737,959	734,038	603,524	285,591	**7,411,444**	-	17,921	-	17,921	2,303,157	465,001	2,768,158	1,804,151	**4,590,230**	1	120	104	**79**		
	71,527	271,274	290,157	124,958	39,182	-	**797,098**	-	-	-	-	271,274	54,736	326,010	593,836	**919,846**	-	120	205	**145**		
	425,850	152,197	57,000	57,000	57,000	114,000	**863,047**	-	-	-	-	152,197	-	152,197	53,016	**205,213**	-	100	93	**32**		
	-	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	**-**						
	-	-	98,400	147,600	-	-	**246,000**	-	-	-	-	-	-	-	-	**-**			-	**-**		
	-	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	**-**						
	283,809	-	-	133,000	47,500	-	**464,309**	-	-	-	-	-	-	-	-	**-**	-			**-**		
	-	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	**-**						
	-	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	**-**						
	-	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	**-**						
	2,604,520	**2,726,628**	**2,183,516**	**1,196,596**	**747,206**	**399,591**	**9,858,057**	**-**	**17,921**	**-**	**17,921**	**2,726,628**	**519,737**	**3,246,365**	**2,451,003**	**5,715,289**	**1**	**119**	**112**	**76**		
	-	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	**-**			

Net Incremental 2020 Annual Energy Savings	Net Incremental 2020 Annual Peak Demand Savings																				Net Incremental 2020 Annual Peak Demand Savings	Net Incremental First Year Energy Savings				
	Forecasted (kW)							Verified (kW)									Progress (%)					Forecasted (kWh)				
	2015	2016	2017	2018	2019	2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total		2015	2016	2017	2018	2019
	-	-	-	-	-	-	-	-	-	-	-	37	4	41	35	**76**						-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29	**29**						-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	32	1	33	19	**52**						-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	**1**						2,326	2,661	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	69	5	74	84	**158**						**2,326**	**2,661**	-	-	-
	16	-	-	-	-	-	**16**	-	-	-	-	-	-	-	-	-	-			-		76,159	-	-	-	-
	256	385	291	119	101	44	**1,196**	-	5	-	5	385	55	440	421	**866**	2	114	145	**93**		1,747,175	2,303,157	1,737,959	734,038	603,524
	16	54	41	18	6	-	**135**	-	-	-	-	54	11	65	145	**210**	-	120	354	**189**		71,527	271,274	290,157	124,958	39,182
	66	37	18	18	18	36	**193**	-	-	-	-	37	-	37	10	**47**	-	100	56	**39**		425,850	152,197	57,000	57,000	57,000
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-
	-	-	12	18	-	-	**30**	-	-	-	-	-	-	-	-	-			-	-		-	-	98,400	147,600	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-
	44	-	-	15	5	-	**64**	-	-	-	-	-	-	-	-	-	-			-		283,809	-	-	133,000	47,500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-
	398	**476**	**362**	**188**	**130**	**80**	**1,634**	-	**5**	-	**5**	**476**	**66**	**542**	**576**	**1,123**	**1**	**114**	**159**	**91**		**2,604,520**	**2,726,628**	**2,183,516**	**1,196,596**	**747,206**
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-

		Verified (kWh)									Progress (%)				Net Incremental First Year Energy Savings	Net Incremental First Year Peak Demand Savings										
																Forecasted (kW)							Verified (kW)			
2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total		2015	2016	2017	2018	2019	2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments
-	-	-	-	-	-	566,176	64,552	630,728	618,234	**1,248,962**						-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	577,532	**577,532**						-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	106,387	1,977	108,364	67,894	**176,258**						-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-
-	**4,987**	-	-	-	-	2,661	-	2,661	10,395	**13,056**	-	100		**262**		-	-	-	-	-	-	-	-	-	-
-	**4,987**	-	-	-	-	**675,224**	**66,529**	**741,753**	**1,274,055**	**2,015,808**	-	**27,875**		**40,421**		-	-	-	-	-	-	-	-	-	-
-	**76,159**	-	-	-	-	-	-	-	-	-	-			-		16	-	-	-	-	-	**16**	-	-	-
285,591	**7,411,444**	-	17,921	-	17,921	2,356,545	411,613	2,768,158	1,798,912	**4,584,991**	1	120	104	**79**		256	385	291	119	101	44	**1,196**	-	5	-
-	**797,098**	-	-	-	-	304,897	62,454	367,351	596,919	**964,270**	-	135	206	**152**		16	54	41	18	6	-	**135**	-	-	-
114,000	**863,047**	-	-	-	-	152,197	-	152,197	53,016	**205,213**	-	100	93	**32**		66	37	18	18	18	36	**193**	-	-	-
-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-
-	**246,000**	-	-	-	-	-	-	-	-	-			-	-		-	-	12	18	-	-	**30**	-	-	-
-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-
-	**464,309**	-	-	-	-	-	-	-	-	-	-			-		44	-	-	15	5	-	**64**	-	-	-
-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-
399,591	**9,858,057**	-	**17,921**	-	**17,921**	**2,813,639**	**474,067**	**3,287,706**	**2,448,847**	**5,754,474**	**1**	**121**	**112**	**77**		**398**	**476**	**362**	**188**	**130**	**80**	**1,634**	-	**5**	-
-	-	-	-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-

Progress (%)										Net Incremental First Year Peak Demand Savings	Net-to-Gross Adjustment - Energy																					
											Forecasted (%)							Verified (%)												Comparison (%)	
Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total		2015	2016	2017	2018	2019	2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results
-	37	4	41	43	**84**																	150	150	150	129				
-	-	-	-	40	**40**																				133				
-	32	1	33	19	**52**																	71	71	71	78				
-	-	-	-	-	**-**																								
-	-	-	-	1	**1**																								
-	**69**	**5**	**74**	**103**	**177**						100	100										100		100	100			-	
-	-	-	-	-	**-**	-			-																				
5	396	44	440	420	**865**	2	114	144	**93**		100	100	72	73	72	72			100		100	97	97	97	90		-	-3	
-	58	12	70	146	**216**	-	130	356	**195**		100	100	94	94	94							103	103	103	83			3	
-	37	-	37	10	**47**	-	100	56	**39**		100	100	54	54	54	54						64		64	57			-36	
-	-	-	-	-	**-**																								
-	-	-	-	-	**-**			-	**-**				82	82															
-	-	-	-	-	**-**																								
-	-	-	-	-	**-**	-			**-**		100			95	95														
-	-	-	-	-	**-**																								
-	-	-	-	-	**-**																								
-	-	-	-	-	**-**																								
5	**491**	**56**	**547**	**576**	**1,128**	**1**	**115**	**159**	**91**																				
-	-	-	-	-	**-**			

2017 Verified 2017 Results	Total	Net-to-Gross Adjustment - Energy	Net-to-Gross Adjustment - Peak Demand																			Net-to-Gross Adjustment - Peak Demand	Realization Rate - Energy			
			Forecasted (%)							Verified (%)									Comparison (%)					Verified (%)			
			2015	2016	2017	2018	2019	2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total		2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results
														148	133	146	130									
																	138									
														73	100	73	79									
																	100									
18			100																							
-11			100	100	73	76	74	75			100		100	97	96	96	112		-	-4	39				101		101
3			100	100	93	95	100							95	92	95	83			-5	-10						
			100	100	53	53	53	54						65		65	56			-35	3						
					86	86																				
			100			94	83																			

					Realization Rate - Energy									Realization Rate - Peak Demand	Gross Incremental First Year Energy Savings							
						Realization Rate - Peak Demand									Forecasted (kWh)							Verified (kW
2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total		Verified (%)									2015	2016	2017	2018	2019	2020	Total	2015 Verified 2015 Results
						2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total								
163	177	164	274							167	150	165	275		-	-	-	-	-	-	-	-
			88										88		-	-	-	-	-	-	-	-
112	112	112	109							110	100	110	71		-	-	-	-	-	-	-	-
															-	-	-	-	-	-	-	-
65		65	70							-		-	17		2,326	2,661	-	-	-	-	4,987	-
															2,326	2,661	-	-	-	-	4,987	-
															76,159	-	-	-	-	-	76,159	-
97	105	98	102				100		100	96	131	99	110		1,747,175	2,303,157	2,411,692	1,001,062	836,880	396,441	8,696,407	-
74		90	87							53		64	67		71,527	271,274	308,677	132,934	41,683	-	826,095	-
123		123	114							121		121	113		425,850	152,197	105,555	105,555	105,555	211,111	1,105,823	-
															-	-	-	-	-	-	-	-
															-	-	120,000	180,000	-	-	300,000	-
															-	-	-	-	-	-	-	-
															283,809	-	-	140,000	50,000	-	473,809	-
															-	-	-	-	-	-	-	-
															-	-	-	-	-	-	-	-
															-	-	-	-	-	-	-	-
															2,604,520	2,726,628	2,945,924	1,559,551	1,034,118	607,552	11,478,293	-
															-	-	-	-	-	-	-

2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Progress (%) Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Gross Incremental First Year Energy Savings	Gross Incremental First Year Peak Demand Savings Forecasted (kW) 2015	2016	2017	2018	2019	2020	Total	Verified (kW) 2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments
-	-	-	378,082	43,107	421,189	479,095	900,284						-	-	-	-	-	-	-	-	-	-	-	25	3
-	-	-	-	-	-	433,191	433,191						-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	150,667	2,797	153,464	87,201	240,665						-	-	-	-	-	-	-	-	-	-	-	44	1
-	-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	2,661	-	2,661	10,395	13,056	-	100		262		-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	531,410	45,904	577,314	1,009,882	1,587,196	-	21,695		31,827		-	-	-	-	-	-	-	-	-	-	-	69	4
-	-	-	-	-	-	-	-	-			-		16	-	-	-	-	-	16	-	-	-	-	-	-
17,921	-	17,921	2,431,204	424,654	2,855,858	2,002,149	4,875,928	1	124	83	75		256	385	396	157	137	59	1,390	-	5	-	5	410	46
-	-	-	297,014	60,840	357,854	719,798	1,077,652	-	132	233	165		16	54	44	19	6	-	139	-	-	-	-	61	13
-	-	-	237,108	-	237,108	93,636	330,744	-	156	89	48		66	37	34	34	34	67	272	-	-	-	-	57	-
-	-	-	-	-	-	-	-				-		-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-				-		-	-	14	21	-	-	35	-	-	-	-	-	-
-	-	-	-	-	-	-	-				-		-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-			-		44	-	-	16	6	-	66	-	-	-	-	-	-
-	-	-	-	-	-	-	-				-		-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-				-		-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-				-		-	-	-	-	-	-	-	-	-	-	-	-	-
17,921	-	17,921	2,965,326	485,494	3,450,820	2,815,583	6,284,324	1	127	96	76		398	476	488	247	183	126	1,918	-	5	-	5	528	59
-	-	-	-	-	-	-	-				-		-	-	-	-	-	-	-	-	-	-	-	-	-

Total Verified 2016 Results	2017 Verified 2017 Results	Total	Progress (%) Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Gross Incremental First Year Peak Demand Savings	Savings Group	Participant Incentive Spending Forecasted ($) 2015	2016	2017	2018	2019	2020	Total	Verified ($) 2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Progress (%) Total Verified 2015 Results	Total Verified 2016 Results
28	33	61							-	-	-	-	-	-	-	-	-	-	-	34,037	-	34,037	82,002	116,039		
-	29	29							-	-	-	-	-	-	-	-	-	-	-	-	-	-	19,871	19,871		
45	24	69							-	-	-	-	-	-	-	-	-	-	-	55,150	-	55,150	19,050	74,200		
-	-	-							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
-	1	1							-	1,421	-	-	-	-	1,421	-	-	-	-	1,421	-	1,421	8,070	9,491		100
73	87	160							-	1,421	-	-	-	-	1,421	-	-	-	-	90,608	-	90,608	128,993	219,601		6,376
-	-	-	-			-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
456	375	836	2	118	95	81			-	159,156	280,500	108,000	97,000	40,500	685,156	-	-	-	-	159,156	-	159,156	216,492	375,648		100
74	176	250	-	137	400	219			-	48,093	103,200	33,400	7,850	-	192,543	-	-	-	-	48,093	-	48,093	125,129	173,222		100
57	18	75	-	154	53	55			-	6,074	5,000	5,000	5,000	10,000	31,074	-	-	-	-	6,074	-	6,074	18,302	24,376		100
-	-	-							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
-	-	-			-	-			-	-	25,000	37,500	-	-	62,500	-	-	-	-	-	-	-	-	-		
-	-	-							-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,000	10,000		
-	-	-	-			-			-	-	-	39,900	15,000	-	54,900	-	-	-	-	-	-	-	-	-		
-	-	-							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
-	-	-							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
-	-	-							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
587	569	1,161	1	123	117	85			-	213,323	413,700	223,800	124,850	50,500	1,026,173	-	-	-	-	213,323	-	213,323	369,923	583,246		100
-	-	-							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

2017 Verified 2017 Results	Total	Participant Incentive Spending	LDC Administrative Expense Spending																				LDC Administrative Expense Spending	IESO Value Added S		
			Forecasted ($)							Verified ($)									Progress (%)					Forecasted ($)		
			2015	2016	2017	2018	2019	2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total		2015	2016	2017
			-	-	-	-	-	-	-	-	-	-	-	2,116	-	2,116	3,400	5,516						-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-
			-	-	-	-	-	-	-	-	-	-	-	2,150	-	2,150	-	2,150						-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-
	668		-	2,970	-	-	-	-	2,970	-	-	-	-	2,962	-	2,962	2,937	5,899		100		199		-	-	-
	15,454		-	2,970	-	-	-	-	2,970	-	-	-	-	7,228	-	7,228	6,337	13,565		243		457		-	-	-
			-	-	-	-	-	-	-	-	-	-	-	199	-	199	192	391						-	-	-
77	85		-	91,000	148,000	164,000	160,000	159,000	722,000	-	-	-	-	90,452	525	90,977	107,755	198,732		100	73	83		-	-	-
121	114		-	8,000	12,750	12,750	6,750	2,000	42,250	-	-	-	-	7,946	-	7,946	18,470	26,416		99	145	127		-	-	7,696
366	220		-	1,700	6,500	6,500	6,500	6,500	27,700	-	-	-	-	1,700	-	1,700	3,791	5,491		100	58	67		-	-	-
			-	-	-	-	-	-	-	-	-	-	-	1	-	1	-	1						-	-	-
-	-		-	-	1,500	1,000	1,000	2,000	5,500	-	-	-	-	-	-	-	-	-			-	-		-	-	-
			-	-	-	-	-	-	-	-	-	-	-	376	-	376	3,024	3,400						-	-	-
			-	8,100	350	350	-	-	8,800	-	-	-	-	8,100	-	8,100	-	8,100		100	-	96		-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-
89	93		-	108,800	169,100	184,600	174,250	169,500	806,250	-	-	-	-	108,774	525	109,299	133,232	242,531		100	79	87		-	-	7,696
			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-	-	-

ervice Provider Cost / Variable Program Cost Administrative Expense Spending

				Verified ($)								Progress (%)			
2018	2019	2020	Total	2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total
-	-	-	-	-	-	-	-	3,338	-	3,338	7,485	**10,823**				
-	-	-	-	-	-	-	-	-	-	-	931	**931**				
-	-	-	-	-	-	-	-	1,651	-	1,651	648	**2,299**				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	4,989	-	4,989	9,064	14,053				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
3,182	888	-	11,766	-	-	-	-	-	-	-	-	-			-	-
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
-	-	-	-	-	-	-	-	-	-	-	-	-				
3,182	**888**	**-**	**11,766**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**			**-**	**-**
-	-	-	-	-	-	-	-	-	-	-	-	-			

2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Progress (%) Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total	Total Administrative Expense Spending	Total 2015-2020 CFF LDC CDM Plan Budget Spending — Forecasted ($) 2015	2016	2017	2018	2019	2020	Total	Verified ($) 2015 Verified 2015 Results	2016 Verified 2015 Results Adjustments	2017 Verified 2015 Results Adjustments	Total Verified 2015 Results	2016 Verified 2016 Results	2017 Verified 2016 Results Adjustments	Total Verified 2016 Results
-	-	5,454	-	5,454	10,885	**16,339**						-	-	-	-	-	-	-	-	-	-	-	39,491	-	39,491
-	-	-	-	-	931	**931**						-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	3,801	-	3,801	648	**4,449**						-	-	-	-	-	-	-	-	-	-	-	58,951	-	58,951
-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	2,962	-	2,962	2,937	**5,899**		100		**199**		-	4,391	-	-	-	-	**4,391**	-	-	-	-	4,383	-	4,383
-	**-**	**12,217**	**-**	**12,217**	**15,401**	**27,618**		**411**		**930**		**-**	**4,391**	**-**	**-**	**-**	**-**	**4,391**	**-**	**-**	**-**	**-**	**102,825**	**-**	**102,825**
-	-	199	-	199	192	**391**						-	-	-	-	-	-	-	-	-	-	-	199	-	199
-	-	90,452	525	90,977	107,755	**198,732**		100	73	**83**		-	250,156	428,500	272,000	257,000	199,500	**1,407,156**	-	-	-	-	249,608	525	250,133
-	-	7,946	-	7,946	18,470	**26,416**		99	90	**93**		-	56,093	123,646	49,332	15,488	2,000	**246,559**	-	-	-	-	56,039	-	56,039
-	-	1,700	-	1,700	3,791	**5,491**		100	58	**67**		-	7,774	11,500	11,500	11,500	16,500	**58,774**	-	-	-	-	7,774	-	7,774
-	-	1	-	1	-	**1**						-	-	-	-	-	-	-	-	-	-	-	1	-	1
-	-	-	-	-	-	-			-	-		-	-	26,500	38,500	1,000	2,000	**68,000**	-	-	-	-	-	-	-
-	-	376	-	376	3,024	**3,400**						-	-	-	-	-	-	-	-	-	-	-	376	-	376
-	-	8,100	-	8,100	-	**8,100**		100	-	**96**		-	8,100	350	40,250	15,000	-	**63,700**	-	-	-	-	8,100	-	8,100
-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	**-**	**108,774**	**525**	**109,299**	**133,232**	**242,531**		**100**	**75**	**85**		**-**	**322,123**	**590,496**	**411,582**	**299,988**	**220,000**	**1,844,189**	**-**	**-**	**-**	**-**	**322,097**	**525**	**322,622**
-	-	-	-	-	-	-						-	-	-	-	-	-	-	-	-	-	-	-	-	-

		Progress (%)						Total 2015-2020 CFF LDC CDM Plan Budget Spending	Spending Group
2017 Verified 2017 Results	Total	Total Verified 2015 Results	Total Verified 2016 Results	2017 Verified 2017 Results	Total	2015-2020 CFF LDC CDM Plan Allocated Budget ($)	Progress versus Budget (%)		
92,887	**132,378**								
20,802	**20,802**								
19,698	**78,649**								
-	**-**								
11,007	**15,390**		100		**350**				
144,394	**247,219**		**2,342**		**5,630**				
192	**391**								
324,247	**574,380**		100	76	**85**				
143,599	**199,638**		100	116	**111**				
22,093	**29,867**		100	192	**155**				
-	**1**								
-	**-**			-	**-**				
13,024	**13,400**								
-	**8,100**		100	-	**96**				
-	**-**								
-	**-**								
-	**-**								
503,155	**825,777**		**100**	**85**	**90**				
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-	**-**								
-

Savings Persistence Report

For: Niagara-on-the-Lake Hydro Inc.

#	Program / Initiative Name	Gross Verified Annual Energy Savings (kWh)																	
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2015 Verified 2015 Results																			
67	Appliance Retirement Initiative	7,121	7,121	7,121	7,121	5,247	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Coupon Initiative	52,483	51,998	51,998	51,998	51,998	51,998	51,998	51,987	51,987	51,987	48,253	48,092	48,092	47,940	47,940	47,921	17,365	17,365
69	Bi-Annual Retailer Event Initiative	89,393	87,804	87,804	87,804	87,804	87,804	87,804	87,758	87,758	87,758	80,925	76,759	76,759	75,108	75,108	74,932	27,760	27,760
70	HVAC Incentives Initiative	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547	145,547
72	Energy Audit Initiative	82,968	82,968	82,968	82,968	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Efficiency: Equipment Replacement Incentive Initiative	2,399,823	2,399,823	2,392,286	2,392,286	2,392,286	2,392,286	2,327,844	2,327,844	2,224,911	2,011,032	1,472,863	1,446,146	484,394	484,394	484,394	415,995	344,646	344,646
74	Direct Install Lighting and Water Heating Initiative	126,937	107,703	80,330	80,330	80,330	80,330	80,330	80,330	80,330	80,330	80,330	17,532	-	-	-	-	-	-
75	New Construction and Major Renovation Initiative	851,700	851,700	414,612	414,612	414,612	414,612	414,612	414,612	414,612	414,612	414,612	414,612	367,612	367,612	367,612	-	-	-
76	Existing Building Commissioning Incentive Initiative	60,772	60,772	60,772	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	Process and Systems Upgrades Initiatives - Energy Manager Initiative	378,412	378,412	378,412	378,412	378,412	378,412	378,412	129,968	17,448	17,448	-	-	-	-	-	-	-	-
80	Low Income Initiative	2,983	2,510	2,418	2,326	2,326	2,326	2,326	2,326	1,614	1,614	1,461	1,461	1,461	1,461	561	479	479	479
82	Program Enabled Savings	40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	-	-	-	-	-	-	-
Subtotal: 2015 Verified 2015 Results		**4,238,889**	**4,217,108**	**3,745,018**	**3,684,154**	**3,599,312**	**3,594,065**	**3,529,623**	**3,281,122**	**3,064,957**	**2,851,078**	**2,284,741**	**2,150,149**	**1,123,865**	**1,122,062**	**1,121,162**	**684,874**	**535,797**	**535,797**
2016 Verified 2015 Results Adjustments																			
89	Save on Energy Retrofit Program	17,921	17,921	17,921	17,921	17,921	17,921	17,921	17,921	17,921	17,921	-	-	-	-	-	-	-	-
150	Coupon Initiative	14,137	14,006	14,006	14,006	14,006	14,006	14,006	14,002	14,002	14,002	13,804	13,796	13,796	13,778	13,778	13,764	4,932	4,932
151	Bi-Annual Retailer Event Initiative	925	914	914	914	914	914	914	912	912	912	773	767	767	743	743	740	309	309
152	HVAC Incentives Initiative	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,428
154	Energy Audit Initiative	5,583	5,583	5,583	5,583	88,551	88,551	88,551	88,551	88,551	88,551	88,551	88,551	88,551	61,986	-	-	-	-
155	Efficiency: Equipment Replacement Incentive Initiative	41,677	41,677	41,677	41,677	41,677	41,677	41,677	41,677	41,677	41,677	41,677	12,149	12,149	12,149	12,149	10,031	2,285	2,285
157	New Construction and Major Renovation Initiative	-	-	437,089	437,089	437,089	437,089	437,089	437,089	437,089	437,089	437,089	437,089	-	-	-	-	-	-
Subtotal: 2016 Verified 2015 Results Adjustments		**81,671**	**81,529**	**518,618**	**518,618**	**601,586**	**601,586**	**601,586**	**601,580**	**601,580**	**601,580**	**583,322**	**553,780**	**116,691**	**90,084**	**28,098**	**25,963**	**8,954**	**8,954**
2017 Verified 2015 Results Adjustments																			
197	Conservation Cultivator LDC Innovation Fund Pilot Program	90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	78,912	78,912	78,912	78,912	-	-	-
237	Efficiency: Equipment Replacement Incentive Initiative	-9,650	-9,650	-2,113	158	158	158	64,599	64,599	74,662	59,472	6,017	158	-7,087	-7,087	-7,087	-7,271	-7,943	-7,943
238	Direct Install Lighting and Water Heating Initiative	-46,441	-27,207	166	8,072	8,072	8,072	8,072	8,072	8,072	8,072	8,072	7,003	-	-	-	-	-	-
Subtotal: 2017 Verified 2015 Results Adjustments		**34,027**	**53,261**	**88,171**	**98,348**	**98,348**	**98,348**	**162,789**	**162,789**	**172,852**	**157,662**	**104,207**	**86,073**	**71,825**	**71,825**	**71,825**	**-7,271**	**-7,943**	**-7,943**
2016 Verified 2016 Results																			
247	Save on Energy Coupon Program	-	378,082	378,082	378,082	378,082	378,082	378,082	378,082	378,031	378,031	376,350	371,702	371,489	371,489	369,535	316,752	316,752	137,774
249	Save on Energy Heating & Cooling Program	-	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667	150,667
251	Save on Energy Home Assistance Program	-	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,256	2,256	2,206	2,206	2,206	2,206	2,206
253	Save on Energy Retrofit Program	-	2,431,204	2,376,125	2,376,125	2,376,125	2,376,125	2,293,723	2,293,723	2,293,723	2,293,723	2,293,723	2,293,500	1,692,513	511,763	511,763	396,834	1,464	1,464
254	Save on Energy Small Business Lighting Program	-	297,014	297,014	296,457	292,048	264,261	238,404	185,502	138,852	54,231	29,258	17,649	15,622	4,223	4,223	4,223	4,223	4,223
255	Save on Energy High Performance New Construction Program	-	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	237,108	206,743	189,715
Subtotal: 2016 Verified 2016 Results		**-**	**3,496,736**	**3,441,657**	**3,441,100**	**3,436,691**	**3,408,904**	**3,300,645**	**3,247,743**	**3,201,042**	**3,116,421**	**3,089,767**	**3,072,882**	**2,469,655**	**1,277,456**	**1,275,502**	**1,107,790**	**682,055**	**486,049**
2017 Verified 2016 Results Adjustments																			
329	Save on Energy Coupon Program	-	43,107	43,107	43,107	43,107	43,107	43,107	43,107	43,103	43,103	43,163	43,190	43,228	43,228	43,120	37,244	37,244	14,661
331	Save on Energy Heating & Cooling Program	-	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797	2,797
335	Save on Energy Retrofit Program	-	424,654	479,733	479,733	479,733	479,733	479,733	479,733	479,733	431,891	431,891	431,747	333,382	-	-	-	-	-
336	Save on Energy Small Business Lighting Program	-	60,840	60,840	60,617	59,293	53,321	45,821	36,015	27,227	13,186	9,338	7,795	7,180	2,009	2,009	2,009	2,009	2,009
Subtotal: 2017 Verified 2016 Results Adjustments		**-**	**531,398**	**586,477**	**586,254**	**584,930**	**578,958**	**571,458**	**561,652**	**552,860**	**490,977**	**487,189**	**485,529**	**386,587**	**48,034**	**47,926**	**42,050**	**42,050**	**19,467**
2017 Verified 2017 Results																			
411	Save on Energy Coupon Program	-	-	479,095	385,552	385,552	385,552	385,552	385,552	385,552	385,548	385,548	384,600	376,548	376,488	376,488	376,459	320,009	320,009
412	Save on Energy Instant Discount Program	-	-	433,191	310,003	310,003	310,003	310,003	310,003	310,003	309,995	309,995	309,995	305,446	305,066	305,066	255,395	255,395	195,047
413	Save on Energy Heating & Cooling Program	-	-	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201	87,201
415	Save on Energy Home Assistance Program	-	-	10,395	10,395	10,395	10,395	10,395	10,395	10,395	10,395	10,395	10,395	9,340	9,340	9,340	9,340	9,081	8,926
417	Save on Energy Retrofit Program	-	-	2,002,149	2,007,980	2,007,980	2,007,980	2,007,980	1,969,326	1,969,326	1,969,326	1,968,784	1,968,784	1,901,476	1,699,446	697,261	592,374	178,261	-
418	Save on Energy Small Business Lighting Program	-	-	719,798	719,798	719,244	716,081	710,345	670,467	584,771	494,935	298,487	153,154	48,835	30,430	19,553	8,218	-	-
419	Save on Energy High Performance New Construction Program	-	-	93,636	93,636	93,636	93,636	93,636	93,636	93,636	93,636	93,636	93,636	93,636	93,636	93,636	-	-	-
Subtotal: 2017 Verified 2017 Results		**-**	**-**	**3,825,465**	**3,614,565**	**3,614,011**	**3,610,848**	**3,605,112**	**3,526,580**	**3,440,884**	**3,351,036**	**3,154,046**	**3,007,765**	**2,822,482**	**2,601,607**	**1,588,545**	**1,328,987**	**849,947**	**611,183**
Total		**4,354,587**	**8,380,032**	**12,205,406**	**11,943,039**	**11,934,878**	**11,892,709**	**11,771,213**	**11,381,466**	**11,034,175**	**10,568,754**	**9,703,272**	**9,356,178**	**6,991,105**	**5,211,068**	**4,133,058**	**3,182,393**	**2,110,860**	**1,653,507**

2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17,365	17,365	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27,760	27,760	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
138,539	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
344,646	344,646	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
479	479	479	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
528,789	**390,250**	**479**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4,932	4,932	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	309	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1,428	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2,285	2,285	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8,954	**7,526**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-7,943	-7,943	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-7,943	**-7,943**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150,667	147,614	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2,206	2,206	2,206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1,464	1,464	1,464	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4,223	4,223	1,375	784	784	784	784	784	-	-	-	-	-	-	-	-	-	-
64,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222,963	**155,507**	**5,045**	**784**	**784**	**784**	**784**	**784**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2,797	2,734	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2,009	2,009	662	382	382	382	382	382	-	-	-	-	-	-	-	-	-	-
4,806	**4,743**	**662**	**382**	**382**	**382**	**382**	**382**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
37,478	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
164,316	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87,201	87,201	86,436	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8,926	8,926	8,926	8,926	3,584	3,584	3,584	3,584	3,584	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297,921	**96,127**	**95,362**	**8,926**	**3,584**	**3,584**	**3,584**	**3,584**	**3,584**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
1,055,490	**646,210**	**101,548**	**10,092**	**4,750**	**4,750**	**4,750**	**4,750**	**3,584**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Gross Verified Energy Savings

Gross Verified Annual Peak Demand Savings (kW)

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
6	6	6	6	6	6	6	6	6	6	5	5	5	5	5	5	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-
77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	18	18	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
367	367	365	365	365	365	352	352	318	275	161	152	137	137	137	126	111	111	111	111	-	-	-	-	-	-	-	-	-	-	-	-	-
30	25	18	18	18	18	18	18	18	18	18	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
132	132	68	68	68	68	68	68	68	68	68	68	61	61	61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	20	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	54	54	54	54	54	54	13	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
713	**708**	**635**	**615**	**597**	**596**	**583**	**542**	**497**	**454**	**337**	**309**	**283**	**283**	**283**	**211**	**191**	**191**	**183**	**114**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1	1	1	1	19	19	19	19	19	19	19	19	19	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	12	12	12	12	12	12	12	12	12	12	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	64	64	64	64	64	64	64	64	64	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**20**	**84**	**84**	**102**	**102**	**102**	**102**	**102**	**102**	**97**	**87**	**23**	**17**	**4**	**4**	**3**	**3**	**3**	**2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
12	12	12	12	12	12	12	12	12	12	12	8	8	8	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-3	-3	-	-	-	-	13	13	18	14	2	-	-2	-2	-2	-2	-2	-2	-2	-2	-	-	-	-	-	-	-	-	-	-	-	-	-
-11	-7	-	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-2	**2**	**12**	**14**	**14**	**14**	**27**	**27**	**32**	**28**	**16**	**10**	**6**	**6**	**6**	**-2**	**-2**	**-2**	**-2**	**-2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	25	25	25	25	25	25	25	25	25	25	24	24	24	24	20	20	9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	41	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	410	398	398	398	398	385	385	385	385	385	385	275	93	93	86	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-
-	61	61	61	60	57	54	44	35	16	10	7	6	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-
-	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	46	39	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	**597**	**585**	**585**	**584**	**581**	**565**	**555**	**546**	**527**	**521**	**517**	**406**	**220**	**220**	**209**	**113**	**95**	**60**	**44**	**1**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
-	46	57	57	57	57	57	57	57	57	57	57	36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	13	13	13	12	11	9	7	4	3	3	3	3	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
-	**63**	**74**	**74**	**74**	**73**	**72**	**70**	**68**	**65**	**64**	**64**	**43**	**5**	**5**	**4**	**4**	**3**	**2**	**2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	-	33	27	27	27	27	27	27	27	27	27	25	25	25	25	21	21	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	29	21	21	21	21	21	21	21	21	21	20	20	20	17	17	13	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	23	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	375	376	376	376	376	370	370	370	370	370	357	318	82	52	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	176	176	176	175	175	169	156	136	86	46	14	9	5	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	18	18	18	18	18	18	18	18	18	18	18	18	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	**-**	**656**	**643**	**643**	**642**	**642**	**630**	**617**	**597**	**547**	**507**	**458**	**414**	**174**	**120**	**77**	**58**	**38**	**24**	**23**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
731	**1,390**	**2,046**	**2,015**	**2,014**	**2,008**	**1,991**	**1,926**	**1,862**	**1,773**	**1,582**	**1,494**	**1,219**	**945**	**692**	**546**	**386**	**348**	**284**	**184**	**24**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

2048	2049	2050	Gross Verified Peak Demand Savings	Gross Verified Savings	Net Verified Annual Energy Savings (kWh)																								
					2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
-	-	-			3,267	3,267	3,267	3,267	2,442	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			85,913	85,119	85,119	85,119	85,119	85,119	85,119	85,102	85,102	85,102	78,989	78,726	78,726	78,476	78,476	78,445	28,426	28,426	28,426	28,426	-	-	-	-	-	-
-	-	-			146,333	143,732	143,732	143,732	143,732	143,732	143,732	143,657	143,657	143,657	132,472	125,651	125,651	122,949	122,949	122,662	45,442	45,442	45,442	45,442	-	-	-	-	-	-
-	-	-			65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	65,698	62,534	-	-	-	-	-	-	-
-	-	-			71,357	71,357	71,357	71,357	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			1,703,597	1,703,597	1,697,753	1,697,753	1,697,753	1,697,753	1,659,705	1,659,705	1,581,164	1,454,662	1,134,788	1,117,463	371,683	371,683	371,683	319,623	266,462	266,462	266,462	266,462	-	-	-	-	-	-
-	-	-			113,027	95,901	71,527	71,527	71,527	71,527	71,527	71,527	71,527	71,527	71,527	15,611	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			425,850	425,850	207,306	207,306	207,306	207,306	207,306	207,306	207,306	207,306	207,306	207,306	183,806	183,806	183,806	-	-	-	-	-	-	-	-	-	-	-
-	-	-			57,642	57,642	57,642	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			283,809	283,809	283,809	283,809	283,809	283,809	283,809	97,476	13,086	13,086	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			2,983	2,510	2,418	2,326	2,326	2,326	2,326	2,326	1,614	1,614	1,461	1,461	1,461	1,461	561	479	479	479	479	479	479	-	-	-	-	-
-	-	-			40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	40,750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			3,000,226	2,979,232	2,730,378	2,672,644	2,600,462	2,598,020	2,559,972	2,373,547	2,209,904	2,083,402	1,732,991	1,611,916	827,025	824,073	823,173	586,907	406,507	406,507	403,343	340,809	479	-	-	-	-	-
-	-	-			17,921	17,921	17,921	17,921	17,921	17,921	17,921	17,921	17,921	17,921	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			23,142	22,927	22,927	22,927	22,927	22,927	22,927	22,921	22,921	22,921	22,597	22,583	22,583	22,554	22,554	22,531	8,074	8,074	8,074	8,074	-	-	-	-	-	-
-	-	-			1,514	1,496	1,496	1,496	1,496	1,496	1,496	1,492	1,492	1,492	1,265	1,255	1,255	1,217	1,217	1,212	506	506	506	506	-	-	-	-	-	-
-	-	-			645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	-	-	-	-	-	-	-
-	-	-			4,802	4,802	4,802	4,802	76,159	76,159	76,159	76,159	76,159	76,159	76,159	76,159	76,159	53,311	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			31,501	31,501	31,501	31,501	31,501	31,501	31,501	31,501	31,501	31,501	31,501	8,603	8,603	8,603	8,603	7,073	1,477	1,477	1,477	1,477	-	-	-	-	-	-
-	-	-			-	-	218,544	218,544	218,544	218,544	218,544	218,544	218,544	218,544	218,544	218,544	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			79,525	79,292	297,836	297,836	369,193	369,193	369,193	369,183	369,183	369,183	350,711	327,789	109,245	86,330	33,019	31,461	10,702	10,702	10,702	10,057	-	-	-	-	-	-
-	-	-			90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	90,118	78,912	78,912	78,912	78,912	-	-	-	-	-	-	-	-	-	-	-
-	-	-			-8,635	-8,635	-2,791	-1,029	-1,029	-1,029	37,018	37,018	43,544	34,798	2,770	-1,029	-6,647	-6,647	-6,647	-6,610	-6,473	-6,473	-6,473	-6,473	-	-	-	-	-	-
-	-	-			-41,352	-24,226	148	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188	6,236	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			40,131	57,257	87,475	96,277	96,277	96,277	134,324	134,324	140,850	132,104	100,076	84,119	72,265	72,265	72,265	-6,610	-6,473	-6,473	-6,473	-6,473	-	-	-	-	-	-
-	-	-			-	566,176	566,176	566,176	566,176	566,176	566,176	566,176	566,100	566,100	563,582	556,623	556,303	556,303	553,377	474,334	474,334	206,315	-	-	-	-	-	-	-	-
-	-	-			-	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	106,387	103,334	-	-	-	-	-	-
-	-	-			-	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,256	2,256	2,206	2,206	2,206	2,206	2,206	2,206	2,206	2,206	-	-	-	-	-
-	-	-			-	2,356,545	2,303,157	2,303,157	2,303,157	2,303,157	2,223,286	2,223,286	2,223,286	2,223,286	2,223,286	2,223,070	1,640,538	496,047	496,047	384,648	1,419	1,419	1,419	1,419	1,419	-	-	-	-	-
-	-	-			-	304,897	304,897	304,325	299,799	271,274	244,731	190,426	142,537	55,670	30,034	18,117	16,037	4,335	4,335	4,335	4,335	4,335	4,335	4,335	1,411	805	805	805	805	805
-	-	-			-	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	152,197	132,706	121,775	41,339	-	-	-	-	-	-
-	-	-			-	3,488,863	3,435,475	3,434,903	3,430,377	3,401,852	3,295,438	3,241,133	3,193,168	3,106,301	3,078,147	3,058,650	2,473,718	1,317,475	1,314,549	1,124,107	721,387	442,437	155,686	111,294	5,036	805	805	805	805	805
-	-	-			-	64,552	64,552	64,552	64,552	64,552	64,552	64,552	64,546	64,546	64,637	64,677	64,734	64,734	64,572	55,772	55,772	21,954	-	-	-	-	-	-	-	-
-	-	-			-	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,914	-	-	-	-	-	-
-	-	-			-	411,613	465,001	465,001	465,001	465,001	465,001	465,001	465,001	418,628	418,628	418,488	323,144	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-			-	62,454	62,454	62,226	60,867	54,736	47,037	36,971	27,950	13,536	9,586	8,002	7,371	2,062	2,062	2,062	2,062	2,062	2,062	2,062	679	392	392	392	392	392
-	-	-			-	540,596	593,984	593,756	592,397	586,266	578,567	568,501	559,474	498,687	494,828	493,144	397,226	68,773	68,611	59,811	59,811	25,993	4,039	3,976	679	392	392	392	392	392
-	-	-			-	-	618,234	497,523	497,523	497,523	497,523	497,523	497,523	497,518	497,518	496,295	485,905	485,828	485,828	485,790	412,946	412,946	48,362	-	-	-	-	-	-	-	-
-	-	-			-	-	577,532	418,242	418,242	418,242	418,242	418,242	418,242	418,234	418,234	418,234	410,619	409,904	409,904	346,108	346,108	268,077	212,470	-	-	-	-	-	-	-	-
-	-	-			-	-	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	67,894	66,556	-	-	-	-	-
-	-	-			-	-	10,395	10,395	10,395	10,395	10,395	10,395	10,395	10,395	10,395	10,395	9,340	9,340	9,340	9,340	9,081	8,926	8,926	8,926	8,926	8,926	3,584	3,584	3,584	3,584
-	-	-			-	-	1,798,912	1,804,151	1,804,151	1,804,151	1,804,151	1,769,421	1,769,421	1,769,421	1,768,934	1,768,934	1,708,458	1,526,936	626,483	532,243	160,166	-	-	-	-	-	-	-	-	-
-	-	-			-	-	596,919	596,919	596,459	593,836	589,079	556,009	484,942	410,443	247,531	127,009	40,499	25,235	16,215	6,815	-	-	-	-	-	-	-	-	-	-
-	-	-			-	-	53,016	53,016	53,016	53,016	53,016	53,016	53,016	53,016	53,016	53,016	53,016	53,016	53,016	-	-	-	-	-	-	-	-	-	-	-
-	-	-			-	-	3,722,902	3,448,140	3,447,680	3,445,057	3,440,300	3,372,500	3,301,433	3,226,921	3,063,522	2,941,777	2,775,731	2,578,153	1,668,680	1,448,190	996,195	757,843	337,652	76,820	75,482	8,926	3,584	3,584	3,584	3,584
0	0	0			3,119,882	7,145,240	10,868,050	10,543,556	10,536,386	10,496,665	10,377,794	10,059,188	9,774,012	9,416,598	8,820,275	8,517,395	6,655,210	4,947,069	3,980,297	3,243,866	2,188,129	1,637,009	904,949	536,483	81,676	10,123	4,781	4,781	4,781	4,781

| 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | Net Verified Energy Savings | Net Verified Annual Peak Demand Savings (kW) | | |

2017 Final Verified Annual LDC CDM Program Results Report Methodology

General

All results are at the end-user level, i.e. not including losses as a result transmission and distribution lines.

2015 results are based on projects completed between January 1, 2015 and December 31, 2015; 2016 results are based on projects completed between January 1, 2016 and December 31, 2016; and 2017 results are based on projects completed between January 1, 2017 and December 31, 2017.

The 2015 verified results considers projects reported to the IESO between January 1, 2015 and March 31, 2016; the 2016 verified results considers projects reported to the IESO between April 1, 2016 and April 15, 2017; the 2017 verified results considers projects reported to the IESO between April 16, 2017 and April 15, 2018.

Legacy Framework results are based on projects begun prior to an LDC's transition to the Conservation First Framework program and completed by December 31, 2015. Conservation First Framework results are based on projects begun on or after an LDC's transition to the Conservation First Framework program and projects transitioned to the Conservation First Framework through a valid Extension Agreement for eligible Programs.

Savings Calculations

#	Project Type	Attributing Savings to LDCs
1	Prescriptive Measures and Projects Programs	**Gross Reported Savings** = Activity * Per Unit Assumption Savings **Gross Verified Savings** = Gross Reported Savings * Realization Rate **Net Verified Savings** = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
2	Engineered and Custom Projects / Programs	**Gross Reported Savings** = Reported Savings **Gross Verified Savings** = Gross Reported Savings * Realization Rate **Net Verified Savings** = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
3	Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the annual effect of energy savings.

Cost Determination

Costs are determined and allocated to the period based on the date the cost has been reported to the IESO regardless of when the cost was incurred.

E.g. if an LDC reports by the December 2017 IESO Reporting Period: 1) program savings; and 2) Participant Incentives; associated with a 2017 completed project, as well as 3) Administrative Expenses; then: a) the savings; b) expenditures; and c) corresponding cost effectiveness; are attributed to the 2017 program year.

However if the same is reported in or after the January 2018 IESO Reporting Period: only the i) the savings and ii) costs for the purposes of Cost Effectiveness Test calculations will be attributed to the 2017 program year; The expenditures for the purposes of spending reporting (in the Monthly Participation & Cost Report and this Verified Annual LDC CDM Program Results Report) will be allocated to the 2018 program year and will not appear.

2015-2020 Conservation First Framework

#	Program	Attributing Savings to LDCs	Project List Date	Savings 'start' Date	Calculating Resource Savings
1	Save on Energy Coupon Program	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on Consumer Program Allocation Reference Table.	April 15, 2018	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Save on Energy Instant Discount Program	Results are allocated based on Consumer Program Allocation Reference Table.	April 15, 2018	Savings are considered to begin in the year in which the event occurred.	
3	Save on Energy Heating & Cooling Program	Results directly attributed to LDC based on customer applications and postal code.	April 15, 2018	Savings are considered to begin in the year that the installation occurred.	
4	Save on Energy New Construction Program	Results are directly attributed to LDC based on LDC identified in LDC Report	April 15, 2018	Savings are considered to begin in the year of the project completion date.	
5	Save on Energy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year in which the measures were installed.	
6	Save on Energy Audit Funding Program	Projects are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

7	Save on Energy Retrofit Program	Projects are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year of the actual project completion date as reported in the LDC Report	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
8	Save on Energy Small Business Lighting Program	Results are directly attributed to LDC based on the LDC specified on the work order.	April 15, 2018	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
9	Save on Energy High Performance New Construction Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined by the total savings for a given project as reported in the CDM LDC Report Template. Preliminary unverified net savings are calculated by multiplying reported savings by 2016 Net-to-gross ratios and realization rates.
10	Save on Energy Existing Building Commissioning Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year of the actual project completion date.	
11	Save on Energy Business Refrigeration Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year of the actual project completion date.	
12	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	April 15, 2018	Savings are considered to begin in the year in which the project was in-service.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
13	Save on Energy Energy Manager Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year in which the project was completed by the energy manager.	
14	Save on Energy Monitoring and Targeting Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year in which the incentive project was completed.	

2011-2014+2015 Extension Legacy Framework

#	Initiative	Attributing Savings to LDCs	Project List Date	Savings 'start' Date	Calculating Resource Savings
1	saveONenergy Appliance Retirement Initiative	2015 Results only. Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	April 15, 2018	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	saveONenergy Conservation Instant Coupon Booklet	2015 Results only. LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	April 15, 2018	Savings are considered to begin in the year in which the coupon was redeemed.	
3	saveONenergy Bi-Annual Retailer Event	2015 Results only. Results are allocated based on average of 2008 & 2009 residential throughput.	April 15, 2018	Savings are considered to begin in the year in which the event occurs.	
4	saveONenergy HVAC Incentives	2015 Results only. Results directly attributed to LDC based on customer applications and postal code.	April 15, 2018	Savings are considered to begin in the year that the installation occurred.	
5	saveONenergy Residential New Construction	2015 Results only. Results are directly attributed to LDC based on LDC identified in application in the iCon system.	April 15, 2018	Savings are considered to begin in the year of the project completion date.	
6	saveONenergy Energy Audit	2015 Results only. Projects are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

7	saveONenergy Efficiency: Equipment Replacement	2015 Results only. Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	April 15, 2018	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2015)
8	saveONenergy Direct Installed Lighting	2015 Results only. Results are directly attributed to LDC based on the LDC specified on the work order.	April 15, 2018	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
9	saveONenergy New Construction and Major Renovation Incentive	2015 Results only. Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018		Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
10	saveONenergy Existing Building Commissioning Incentive	2015 Results only. Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018		
11	saveONenergy Process & System Upgrades	2015 Results only. Results are directly attributed to LDC based on LDC identified in application.	April 15, 2018	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	saveONenergy Energy Manager	2015 Results only. Results are directly attributed to LDC based on LDC identified in application.	April 15, 2018	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	
13	saveONenergy Monitoring & Targeting	2015 Results only. Results are directly attributed to LDC based on LDC identified in application.	April 15, 2018	Savings are considered to begin in the year in which the incentive project was completed.	
14	saveONenergy Home Assistance Program	2015 Results only. Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
15	Aboriginal Conservation Program	2015 Results only. Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2018		
16	Program Enabled Savings	2015 Results only.	April 15, 2018		

2017 Final Verified Annual LDC CDM Program Results Report
Consumer Program Allocation Reference Table

#	Local Distribution Company	Allocation (%)
1	Alectra Utilities Corporation	19.77
2	Algoma Power Inc.	0.18
3	Atikokan Hydro Inc.	0.02
4	Attawapiskat Power Corporation	0.01
5	Bluewater Power Distribution Corporation	0.62
6	Brantford Power Inc.	0.67
7	Burlington Hydro Inc.	1.34
8	Canadian Niagara Power Inc.	0.35
9	Centre Wellington Hydro Ltd.	0.11
10	Chapleau Public Utilities Corporation	0.03
11	COLLUS PowerStream Corp.	0.25
12	Cooperative Hydro Embrun Inc.	0.06
13	E.L.K. Energy Inc.	0.25
14	Energy+ Inc.	1.12
15	Entegrus Powerlines Inc.	0.70
16	EnWin Utilities Ltd.	1.49
17	Erie Thames Powerlines Corporation	0.32
18	Espanola Regional Hydro Distribution Corporation	0.06
19	Essex Powerlines Corporation	0.61
20	Festival Hydro Inc.	0.32
21	Fort Albany Power Corporation	0.01
22	Fort Frances Power Corporation	0.09
23	Greater Sudbury Hydro Inc.	0.80
24	Grimsby Power Incorporated	0.18
25	Guelph Hydro Electric Systems Inc.	0.85
26	Halton Hills Hydro Inc.	0.59
27	Hearst Power Distribution Company Limited	0.05
28	Hydro 2000 Inc.	0.04
29	Hydro Hawkesbury Inc.	0.15
30	Hydro One Networks Inc.	27.29
31	Hydro Ottawa Limited	6.61
32	InnPower Corporation	0.33

33	Kashechewan Power Corporation	0.02
34	Kenora Hydro Electric Corporation Ltd.	0.09
35	Kingston Hydro Corporation	0.29
36	Kitchener-Wilmot Hydro Inc.	1.51
37	Lakefront Utilities Inc.	0.11
38	Lakeland Power Distribution Ltd.	0.23
39	London Hydro Inc.	2.61
40	Midland Power Utility Corporation	0.10
41	Milton Hydro Distribution Inc.	0.66
42	Newmarket-Tay Power Distribution Ltd.	0.60
43	Niagara Peninsula Energy Inc.	0.82
44	Niagara-on-the-Lake Hydro Inc.	0.13
45	North Bay Hydro Distribution Limited	0.42
46	Northern Ontario Wires Inc.	0.09
47	Oakville Hydro Electricity Distribution Inc.	1.51
48	Orangeville Hydro Limited	0.20
49	Orillia Power Distribution Corporation	0.22
50	Oshawa PUC Networks Inc.	1.48
51	Ottawa River Power Corporation	0.12
52	Peterborough Distribution Incorporated	0.46
53	PUC Distribution Inc.	0.65
54	Renfrew Hydro Inc.	0.05
55	Rideau St. Lawrence Distribution Inc.	0.07
56	Sioux Lookout Hydro Inc.	0.08
57	St. Thomas Energy Inc.	0.28
58	Thunder Bay Hydro Electricity Distribution Inc.	0.82
59	Tillsonburg Hydro Inc.	0.12
60	Toronto Hydro-Electric System Limited	15.57
61	Veridian Connections Inc.	2.39
62	Wasaga Distribution Inc.	0.18
63	Waterloo North Hydro Inc.	0.96
64	Welland Hydro-Electric System Corp.	0.31
65	Wellington North Power Inc.	0.06
66	West Coast Huron Energy Inc.	0.06
67	Westario Power Inc.	0.37
68	Whitby Hydro Electric Corporation	1.12
Total		**100.00**

2017 Final Verified Annual LDC CDM Program Results Report Glossary

#	Term	Definition
	Reporting Terms	
1	Forecast	An LDCs' forecast of program activity, savings, net-to-gross adjustments, expenditures and cost effectiveness as indicated in each LDC's submitted CDM Plan Cost Effectiveness Tools. Forecasts at the province wide level are the sum of all LDCs' forecasts.
2	Reported	Program activity savings and expenditures as determined by the LDC. For savings: 1) for prescriptive projects/programs: calculating quantity x prescriptive savings assumptions; and 2) for engineered or custom program projects/programs: calculated using prescribed methodologies.
3	Verified	The IESO's annually EM&V assessed program activity, savings, net-to-gross, expenditures and cost effectiveness. Preliminary Verified results are provided by June 1st of each year and Final Verfied results are provided by July 1st of each year.
4	Adjustment	Verified results that were achieved in previous years but were not provided in a previous years' Annual Verified Results Report.
5	Progress or Comparison	An assessment of Actual results versus Verified results.
	Framework Terms	
6	2011-2014+2015 Extension Legacy Framework	Programs in market from 2011-2015 resulting from the April 23, 2010 GEA CDM Ministerial Directive and funded separately from 2015-2020 Conservation First Framework Programs but whose savings in 2015 are attributed towards the 2015-2020 Conservation First Framework target.
7	2015-2020 Conservation First Framework	Programs in market from 2015-2020 resulting from the March 31, 2014 CFF Ministerial Directive and funded separately from 2011-2014+2015 Extension Legacy Framework Programs.
8	LDC Innovation Fund	A source of funding under the 2015-2020 Conservation First Framework separate from LDC CDM Plan Budgets that the IESO maintains to support LDC led program design and market testing of new initiatives. Savings from LDC Innovation Fund pilot programs contribute to the LDCs savings targets based on the LDC service territory the pilot program is delivered in.
9	Conservation Fund	A source of funding external to the 2015-2020 Conservation First Framework that provides financial support for innovative electricity conservation technologies, practices, research, and pilot programs. Savings from Conservation Fund pilot programs contribute to the LDCs savings targets based on the LDC service territory the pilot program is delivered in.
	Programs Terms	
10	Program	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (e.g. Coupon; or Retrofit;) from the 2015-2020 Conservation First Framework.
11	Province-Wide Program	Programs available to all LDCs to deliver and that are consistent across the province.
12	Regional Program	Programs designed by LDCs to serve their region and approved by the IESO.
13	Local Program	Programs designed by LDCs to serve their communities and approved by the IESO.
14	Pilot Program	A program pilot that may achieve energy or demand savings and is funded separately from an LDC's CDM Plan Budget.
15	Initiative	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (e.g. Fridge & Freezer Pickup) from the 2011-2014+2015 Extension Legacy Framework.
	Activity Terms	
16	Participation	A measure of the level of program participation, such as number of projects, homes, equipment, etc..
17	Unit of Measure	For a specific initiative the relevant type of participation acquired in the market place (e.g. appliances picked up; coupon products installed; HVAC equipment installed; audits performed; or projects completed;).

	Savings Terms	
18	Energy Savings	Energy savings attributable to conservation and demand management activities.
19	Peak Demand Savings	Peak Demand savings attributable to conservation and demand management activities, as determined by the IESO's EM&V Protocols.
20	Incremental Savings	The energy or peak demand savings newly attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'. Savings attributed to activity performed or completed in 2016 are presented as 2016 savings.
21	First Year Savings	The energy or peak demand savings that occur in the year it was achieved (includes resource savings from only new program activity).
22	Annual Savings	The energy or peak demand savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).
23	Gross Savings	The energy or peak demand savings that have been reported based on a conservation and demand management program's participation tracking.
24	Net Savings	The energy or peak demand savings attributable to conservation and demand management activities, net of free-riders, spill over, etc.
25	Realization Rate	A comparison of originally reported savings and observed or measured savings that adjusts reported savings to arrive at verified savings. Accounts for discrepancies such as audited measure counts; adjustment for connected demand savings to peak demand savings; etc.
26	Net-to-Gross Adjustment	The ratio of net savings to gross savings, which takes into account factors such as free-ridership, spillover, etc.
27	Free-ridership	The percentage of participants who would have implemented the program measure or practice in the absence of the program.
28	Spillover	Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.
29	Allocated Target	Each LDC's assigned portion of the Province's 7 TWh Net 2020 Annual Energy Savings Target of the 2015-2020 Conservation First Framework.

	Costs Terms	
30	Participant Incentive	Costs incurred in the delivery of a program related to incenting participants to perform peak demand or energy savings.
31	LDC Administrative Expense	Costs reported by the LDC in the delivery of a program related to labour, marketing, third-party expenses, etc.
32	IESO Value Added Services Cost	Costs incurred by the IESO's Value Added Service Provider related to associated programs (Coupons and Heating & Cooling), and charged to the LDC in which the programs's activity took place.
33	Total Administrative Expense	The sum of LDC Adminsitrative Expense and IESO Value Added Services Cost.
34	Delivery Cost	The sum of Total Administrative Expenses and Participant Incentives. **All costs are presented based on the period reported by LDCs to the IESO, not necessarily associated with reported activity.** **E.g. if an LDC reports by the December 2016 IESO Reporting Period: 1) program savings; 2) Participant Incentives; and 3) Administrative Expenses associated with a 2016 completed project, then: a) the savings; b) expenditures; and c) corresponding cost effectiveness; are attributed to the 2016 program year.** **However if the same is reported in or after the January 2017 IESO Reporting Period: i) the savings will be attributed to the 2016 program year; ii) the expenditures will be attributed to the 2017 program year and will not appear in the 2016 Verified Results Report; but iii) the project's Participant Incentives will be used to calculate 2016 Cost Effectiveness;**
35	Allocated Budget	Each LDC's assigned portion of the Province's $ 1.835 billion CDM Plan Budget of the 2015-2020 Conservation First Framework.

	Cost Effectiveness Terms	
36	Total Resource Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on the total costs of the program including both participants' and utility's costs.
37	Program Administrator Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on costs incurred by the program administrator, including incentive costs and excluding net costs incurred by the participant.
38	Levelized Unit Energy Cost Cost Effectiveness Test	A cost effectiveness test that normalizes the costs incurred by the program administrator per unit of energy or demand reduced.

APPENDIX

4E



2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056

Policies and Procedures	
Niagara On-The-Lake HYDRO **IFRS Policy**	Policy: Page: 1 of Location: X:\NOTLinc\Policies Issued: Issue No.:

1. **Purpose:** To document the company policies for compliance with International Accounting Standard IAS16 as part of future conversion to IFRS accounting requirements.

2. Scope:

Currently, the mandatory date of implementation to IFRS, according to the Accounting Standards Board of Canada, is January 1, 2014[1]. NOTL Hydro has chosen not to change to IFRS before January 1, 2014. Thus, if the mandatory date remains at January 1, 2014, NOTL Hydro's financial statements for the fiscal year 2014 will be in IFRS, with historical results for 2013 stated in both CGAAP and IFRS. NOTL Hydro's 2012 and 2013 financial statements will remain in CGAAP accounting.

However, the Ontario Energy Board, by letter dated July 17, 2012, requires that policies for componentization and depreciation[2] and for capitalization (burdens)[3] for the fiscal year 2013 will be in accordance with IFRS, even though the LDC may remain under CGAAP in 2013, as will be the case for NOTL Hydro. LDCs are permitted to make this accounting change in 2012. However, NOTL Hydro has chosen not to make the change until 2013.

3. Policy: The "Conclusion Documents"[4] in the following pages provide NOTL Hydro's policies in relation to IAS16 standards for:

- Componentization and Depreciation
- Capitalization – Burdens
- Property, Plant and Equipment – Fair Value vs. Carrying Value as Deemed Cost
- Property, Plant and Equipment – Measurement after Recognition
- Property, Plant and Equipment – De-recognition
- Property, Plant and Equipment – Borrowing Costs

---

1 This date is sometimes referred to as the "IFRS Changeover Date". The "IFRS Transition Date" is the beginning of the previous year, in this case January 1, 2013 from which date IFRS comparative figures are required for the 2014 financial statements.

[2] See 1st item under "Policy"

[3] See 2nd item under "Policy"

[4] These documents were prepared with the guidance of KPMG on technical IFRS accounting matters.

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective:

To document the accounting policy on componentization and depreciation of property, plant and equipment for Niagara-On-The-Lake Hydro Inc. ("the company")

Background:

Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

An entity should allocate the amount initially recognized in respect of an item of PPE to its significant parts to be depreciated separately.

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

Depreciation is to be computed on a systematic basis over the estimated useful life of the item of PP&E. The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with **IAS 8** *Accounting Policies, Changes in Accounting Estimates and Errors.*

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with **IFRS 5** and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted under IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense under IFRS, will be set out in Table 1 as attached.

Overhead system

Four components identified – Poles, OH Conductors/Switches, Transformers and OH Secondary Cable.

The company currently has only wood poles and has determined that there are no components of the pole that are material in dollar value or have a significantly different useful life. Therefore, the company has concluded that there is only one component comprised of the fully dressed wood pole. This component includes the standoff brackets and guy wires which are considered immaterial.

In terms of useful life, the Kinetrics report gave a range of 35-75 years, with the typical being 45 year. The company considered the following factors with respect to the useful life of the poles. Mechanical stress and environmental factors are high and medium, respectively. The poles are not overloaded with weight, as the system has the typical length between poles. Historical experience shows the poles are being replaced between 45-50 years. The company has determined a useful life of 45 years is appropriate.

The company currently includes conductor and switches in the same GL account. It has been determined that switches do not make up a significant share of the account. Going forward, it is not expected there will be material amounts of switches added that justifies a separate component. The company also determined that they are not replacing conductor more often than switches or re-closers, which has led to the determination of a single component for these assets. The company has a regular maintenance program on the switches and as a result, failure is not typical.

In terms of useful life, the Kinetrics report gave a range of 50-75 years (typical 60 years) for OH conductors and 30-55 years (typical 45 years) for line switches. The company has determined its conductors fit the typical life span, given historical experience and pole spans being typical (which reduces strain on the conductor). Since switches were determined to be immaterial in this component, a useful life of 60 years is appropriate. Typically, switches are only replaced prior to replacing the conductor, when the switch fails. Failure is not typically seen with the exception of lightning strikes.

Overhead and underground transformers are currently grouped together. Useful lives of the two types of transformers are expected to be similar since the system is not overloaded. There are no plans to remove underground transformers from service prior to 40 years unless they are overloaded. Kinectrics useful life range is 30 to 60 years with typical of 40 years. Electrical loading and mechanical stress are low and environmental factors are considered to be normal. Kinectrics typical useful life is based upon moderate electrical loading. The company's low electrical loading would extend useful life beyond the typical range. Life should be 45 years based upon the utilization factors.

Secondary cable (Services) has been classified into two separate components (underground and overhead) due to the significantly different useful lives based on the type of wire used for each. Overhead wire is PILC (covered wire).

OH secondary cable experience tree wear from rubbing. The cable is insulated, which tends to deteriorate over time. The company's experience has shown this cable does not last longer than about 60 years. A useful life of 60 years is considered appropriate.

TS Stations

Two components identified – Transformers and Other

The company has assessed the different assets that comprise the two TS currently owned. The unique parts are power transformers, stations switch, breakers and switches, relays, bus-bars and steel structures. The company has determined the power transformers are by far the most significant component in the TS stations and should be accounted for as a separate component.

The other components are not considered material and useful lives are not significantly different to warrant any further componentization for the other assets comprising the TS station.

Kinetrics life range for the transformers is 30-60 years with 45 being typical. The company does not have much experience with the life span of this component as the oldest asset is from 1985. Electrical loading and environmental factors do not differ from Kinetrics typical, which is moderate. Typical useful life of 45 years is appropriate.

The other assets component (stations switch, breakers and switches, relays, bus-bars and steel structures) have a life range of between 30 and 60 years with typical being 50 years. The station switches and breakers etc. are regularly maintained and the operational practices of the switches are low to moderate which would suggest a higher useful life than typical. 55 years is considered an appropriate life.

DS Station

The King St. DS Station is expected to be decommissioned in 2013. Based on the expected decommission, the useful life of this asset on January 1, 2013 will be one year.

Underground System

Three Components identified – Underground Cable (Primary) & Devices, Underground Conduit and Secondary Cable (Underground)

The company has determined that underground primary cable and devices represent a single component. The assets in this class have similar useful lives. The Kinetrics report gives useful life ranges of 35-55 years (typical 40 years). The company's assets in this component include both direct buried and in duct, with the majority being in-duct (direct buried has a lower life and only in one or two subdivisions). Mechanical stress, electrical loading, and environmental conditions are considered moderate in the Kinectrics report, but the company has assessed electrical loading as lower. The company has also considered historical experience for these assets. There is currently direct buried cable with a life of 30 years in operation and it is expected that these will last at least 10 more years as no major issues have been encountered at 30 years of life. Based on these factors, the company has assessed these assets with a useful life of 45 years, higher than typical based upon the low electrical loading.

The company has determined that ducts, foundations, vaults and duct banks all form the Underground Conduit component. These assets have similar useful lives. The Kinetrics report gives useful life ranges from 30-85 years for these assets (typical 50-55 years). The company has assessed mechanical stress lower than Kinetrics report (assets are under grass not under roads) which leads to a longer expected life. The company has assessed 65 years as appropriate for these assets.

Secondary cable (Services) has been classified into two separate components (underground and overhead) due to the significantly different useful lives based on the type of wire used for each. Overhead wire is PILC (covered wire).

The Kinectrics report has the useful life of underground secondary cable as a range of 35-60 years (typical 40 years). The company has determined there are no factors that would suggest the useful life is any different from the underground primary cable. As such, a useful life of 45 years is appropriate.

SCADA software: Has been assessed as a single component, since radios are already included under communication equipment. The company is aware this software is updated on an irregular basis (that may exceed annual) but the original firmware may be considered to have a

useful life of 8-10 years before it is completely replaced. Therefore a useful life of 10 years has been chosen for this component.

Minor assets

Office Equipment: Has been assessed as a single component as assets have similar useful lives. The current useful life is 10 years, and there are no indications this should change.

Vehicles < 3 tonnes: Single component. Policy is to replace after 5 years, therefore this is the useful life.

Vehicles > 3 tonnes: Single component. Policy is to replace after 10 years, therefore this is the useful life.

Trailers: Single component. Estimated useful life is 15 years based upon planned replacement cycle.

Administrative Buildings: Single component. Kinetrics report gives useful life of 50 – 75 years. The company's administrative building is fairly new. The building was constructed under a low budget (minimum standards) which indicates the maximum useful life is not appropriate. A useful life of 60 years has been determined.

Station Buildings: It has been determined not to separate these assets out from the TS (insignificant in relation to the equipment in the TS station)

Computer Equipment (Hardware): Single component. Policy is replacement every 3 years; therefore the useful life is 3 years.

Computer Equipment (Software): Single component. Policy is replacement every 3 years; therefore the useful life is 3 years. Technological obsolescence limits the life.

Communication Equipment: Single component that includes a computer station that works with the SCADA equipment, towers, radio and phone system. The company does not have any reason as to why this should vary from the rate it is currently being depreciated over, which is 10 years. This component is subject to technological obsolescence so anything higher than 10 years would not be appropriate.

Miscellaneous Equipment (tools and shop): Single component. Based on experience, assets in this class can last 5-10 years, but individually the assets are immaterial. As such, an average life of 8 years is considered appropriate.

Miscellaneous Equipment (stores and warehouse): Single component. The company has assessed at maximum life of 10 years based on Kinetrics report and experience with life of shelving equipment.

Meters: 4 Components were decided

1) Smart Meters: These are material and have a significantly different useful life (no history yet on how long they will last). The company discussed the need to split out into further components (data collectors). It was determined that useful life of data collectors and the meter are similar and therefore no need to break down into further components. The company does not expect useful life to exceed 10 years given problems already encountered with these meters. However, will use same rate as industry (15 years) and assess the appropriateness of this at end of each reporting period.
2) Stranded Meters: Life kept at OEB rate of 25 years.

3) Other Meters: These meters have been lasting 25 years. Technological obsolescence will limit the life of these assets to a certain extent so extending this beyond the 25 years is not appropriate.

4) CT's and PT's: These are material and have a significantly different useful life. Kinetrics report indicates a range of 35-50 years. The company has determined a 40 year life is reasonable for these assets.

Conclusion:

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2013[5]. The net book value as deemed cost exemption (available to rate regulated entities) will be applied so that the opening values at January 1, 2013[6] do not need to be restated and therefore, componentization does not need to be applied retroactively.

[5] *This date assumes the current mandatory IFRS implementation date (or "changeover date") of January 1, 2014, which requires 2013 historical data in 2014 financial statements to be in both CGAAP and IFRS.*
[6] *See Footnote above*

Table 1: Niagara-On-The-Lake Hydro – PP&E Components and Estimated Useful Lives

Component	Previous Component	Proposed Useful Life	Existing Useful Life
Poles	1830 -	45	25
OH Conductors and Switches	1835 -	60	25
Transformers (UG and OH)	1850 -	45	25
Transformers (Substation)	1815-1051 (York) and 1815-1052 (NOTL DS)	45	40
Station Switch, Breakers, Bus-bars	1815-1051 (York) and 1815-1052 (NOTL DS)	55	40
DS Station	1820 -	1 year [i.e. 2013]	25
UG Conductors and Devices	1845 -	45	25
UG Conduit	1840 -	65	25
UG Services	1855-1135 -	45	25
OH Services	1855-1130 -	60	25
SCADA	1980 -	10	15
Office Equipment	1915 -	10	10
Trucks (<3 tonnes)	1930 -7102 -	5	5
Trucks (>3 tonnes)	1930 -7103 -	10	8
Trailers	1930-7104 -	15	5
Administrative Buildings	1908-1030	60	50
PCB Shed	1908-1031	30	30
Computer Hardware	1920 -	3	5
Computer Software	1925 -	3	3
Communication equipment	1955 -	10	10
Miscellaneous Tools	1940 -	8	10
Stores and Warehouse equipment	1935 -	10	10
Stranded Meters	1860 -	25	25
Other Meters	1860 -	25	25
CT/PT	1860 -	40	25
Smart Meters	1860[7]-	15	N/A
Smart Metering – Data Collectors	1860[8]-	15	N/A

[7] *Previously 1555, prior to OEB approval of disposition of the variance account.*
[8] *See footnote 7*

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Capitalization - Burdens

Objective:

To document the accounting policy on the capitalization of burdens.

Background:

Core Principle

The cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)
d) Administration and other general overhead costs; and,
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

Directly attributable

The term “directly attributable” is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort, making the asset more capable of being used than if the cost had not been incurred.

General and administrative overhead

IFRS does not provide a definition of general and administrative overhead (G&A). The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E.

G&A costs typically benefit the organization as a whole or areas of the organization more broadly rather than contributing directly to bringing a physical asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The more the nature of a particular cost strays from being directly attributable to an item of PP&E, then the more likely it is that the cost will be determined to be in the nature of G&A.

Day-to-day servicing costs

Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the “repairs and maintenance” of the item of PP&E.

Feasibility studies and pre-construction activities

Normally, feasibility studies are not capitalized under IFRS as these costs do not always result in asset construction, and therefore may not meet the criteria of providing a future economic benefit. Additionally, the associated costs must be directly attributable to an item of PP&E. Pre-construction activities (such as design work) prior to a decision to go ahead with a capital project do not qualify for capitalization.

Considerations:

Canadian GAAP allowed for capitalization of general and administrative overhead, training costs, etc. while IFRS does not.

The Ontario Energy Board (OEB) requires electricity distributors to be in full compliance with IFRS requirements as applicable to non-regulated enterprises and only where Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.

Niagara-On-The-Lake Hydro (“the company”) performed a review of the costs currently included in burdens to assess recognition criteria as an item of PP&E under IFRS.

Payroll allocation

Payroll allocation consists of the following benefits paid to employees: health benefits such as drugs, dental/vision, LTD, out of country medical, OMERS, WSIB, Employment insurance, CPP, EHT, and down time (which includes vacation, sick time, bereavement pay). IAS 16 specifically allows for benefits as defined in IAS 19 arising directly from the construction or acquisition of an item of PPE to be included as a directly attributable cost. The payroll allocation is allocated to capital based upon labour dollars charged to capital. Benefits are accumulated in the general ledger for all employees and allocated based upon where the employees charge their time (capital, maintenance, other operating, etc.). The company does not include training costs in payroll burden and downtime due to inclement weather is also not included in payroll burden.

No changes were identified for this burden under IFRS.

The following benefits were considered for inclusion in the burden rate as follows:

Truck allocation

Truck allocation consists of fuel, vehicle maintenance labour, repair parts, licenses and license renewals and amortization. Insurance is currently not included in the burden; however, the company will include insurance costs upon adoption to IFRS. Trucks and company vehicles are used on the job site and are directly related to the construction of an asset as they are required to construct the asset and are dedicated to the asset for a period of time. Truck expenses are allocated to capital based upon the time used on the job site.

With regards to repairs and maintenance costs, the company must decide whether the IFRS standard on this topic precludes capitalization of any repairs and maintenance costs or just specifically the repair and maintenance of the particular item (vehicle) repaired. For example the repairs and maintenance on a truck are not capitalizable to the cost of the truck (IAS 16.12), however an argument can be made that it is capitalizable to the specific capital job the repaired truck was assigned to such as a pole line construction. The company will interpret IAS 16.12 to apply only to repairs and maintenance of an item of PPE. Therefore repairs and maintenance cannot be capitalized to the cost of the item repaired. The company has determined that the repairs and maintenance account (account 91009102) can be included in the burden rate and be capitalized to the cost of a constructed asset when a vehicle is used on the job site for the construction of the asset.

Fuel, amortization (of the truck), truck insurance and license renewals can be capitalized because they are costs required to keep the trucks in running order and are not specifically excluded from capitalization in IAS 16 and they are directly attributable when used to construct an asset and bring it to its intended use. Amortization is currently included in the truck allocation under CGAAP, and the company will continue to include amortization under IFRS.

Stores allocation

The company noted that inventory is not currently recorded at cost. Inventory is recorded at cost plus (cost +10%, which represents the stores burden). This grossed up cost is charged to the specific job when the inventory item is used on the job.

Under IFRS, general and administrative expenses are not capitalized. General and administrative expenses tend to benefit the organization as a whole rather than a single job (or item of PPE) Typically, maintaining stores are more efficient than having parts delivered directly to the job site as they are needed. The company discussed whether stores costs should be capitalized or expensed. The company has structured its operations such that the time needed in stores is actually directly attributable. For example, there is no full time position in stores, but rather when stock is received, it is specifically tracked in the warehouse and segregated for the job for which it is intended. This leads to the conclusion that this time is directly attributable to specific jobs. Further, it would not be difficult for the staff person to track their time to specific jobs if required. The stores burden will continue to be charged to the capital job

Conclusion:

The company will capitalize all costs, including the above burdens, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management.

Any general and administrative costs currently included in the various burden rates, such as training and other administrative expenses, will not be capitalized.

The following changes were made to the capitalization policy as a result of the transition to IFRS.

Payroll allocation

No changes were identified for this allocation.

Truck allocation

Insurance will be capitalized under IFRS.

Stores allocation

No changes were identified for this allocation.

Conclusion Document

Standard: IFRS 1 – Elective Exemption, IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Fair Value vs. Carrying Value as Deemed Cost

Objective:

To determine the policy on initial measurement of property, plant and equipment (PP&E) on the date of transition to IFRS

Background:

Niagara-On-The-Lake Hydro Inc. ("NOTL") may elect to measure an item of PP&E at its fair value on the date of transition to IFRS. The fair value would then represent deemed cost at that date for purposes of subsequent measurement and amortization ("deemed cost election").

An additional IFRS 1 exemption is available to rate regulated entities. The exemption allows an entity to measure an item of PP&E at its previously recorded carrying value (i.e. net book value) on transition to IFRS. As NOTL's operations are rate regulated, they are eligible to apply this exemption.

If an Elective Exemption with respect to PP&E is not taken, NOTL would have to account for PP&E as if the requirements of IAS 16 had always been applied. This would require retrospective restatements of all PP&E balances in accordance with IFRS.

Considerations:

Retroactive restatements will be onerous and impractical as documentation for historical costs are not available.

The fair value exemption is not allowed by the OEB for rate setting purposes.

Fair values are more costly to obtain.

Electing the IFRS 1 exemption for rate regulated entities is more favourable to NOTL. Regulated Net Book Value ("regulated NBV") as at the date of transition to IFRS would be used for rate setting purposes. The OEB requires the use of regulated NBV as the basis for setting the opening rate base values upon transition to IFRS. Therefore, using the carrying value as deemed cost exemption would more closely align financial reporting with the basis in which regulated cash flows and income are determined by the regulator.

Conclusion:

NOTL has concluded that it will elect the IFRS 1 Exemption for rate regulated entities and use net book value as at date of transition to IFRS[9] as deemed cost.

[9] *The transition date is currently January 1, 2013 if the changeover date remains at January 1, 2014.*

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Measurement after Recognition

Objective:

To determine the policy on measurement of property, plant and equipment (PP&E) after initial recognition

Background:

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E.

Cost Model

After recognition as an asset, an item of PP&E shall be carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Revaluation Model

After recognition as an asset, an item of PP&E whose fair value can be measured reliably shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated depreciation and subsequent accumulated impairment losses. IAS 16 defines fair value as “the amount for which an asset could be exchanged between knowledgeable, willing parties in an arm’s length transaction.” It also mentions that, if there is no market-based evidence of fair value because of the specialized nature of a particular PP&E item and the item is rarely sold (except as part of a continuing business), an entity may need to estimate fair value using an income or a depreciated replacement cost approach.

Revaluation shall be made with sufficient regularity to ensure that the carrying amount does not differ materially from that which would be determined using fair value at the end of the reporting period. If an item of PP&E is revalued, the entire class of PP&E to which that asset belongs shall be revalued.

Ontario Energy Board

In its report of the Board on Transition to International Financial Reporting Standards, the OEB will require the use of historical acquisition cost as the basis for reporting PP&E for regulatory purposes.

Conclusion:

Niagara-On-The-Lake Hydro Inc. has concluded that it will choose the Cost Model to measure PP&E after initial recognition under IFRS.

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – De-recognition of PP&E

Objective:

To document the accounting policy on de-recognition of property, plant and equipment.

Background:

The carrying amount of an item of property, plant and equipment (PP&E) shall be derecognized:

(a) On disposal; or

(b) When no future economic benefits are expected from its use or disposal (e.g. the item is removed from use).

When a part of an item of PP&E is replaced and that replacement is capitalized under the recognition principle in IAS 16, then the replaced part is derecognized regardless of whether the replaced part has been identified as a separate component and depreciated separately.

The gain or loss arising from the derecognition of an item of PP&E shall be included in profit or loss when the item is derecognized. Gains shall not be classified as revenue, and instead should be presented as other income or expense.

The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale, by entering into a finance lease, by donation, etc.) In determining the date of disposal of an item, an entity applies the criteria in IAS 18 for recognizing revenue from the sale of goods. Under IAS 18.14, revenue from the sale of goods shall be recognized when all the following conditions have been satisfied:

(a) The entity has transferred to the buyer the significant risks and rewards of ownership of the goods

(b) The entity retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the goods sold;

(c) The amount of revenue can be measured reliably;

(d) It is probable that the economic benefits associated with the transition will flow to the entity; and

(e) The costs incurred or to be incurred in respect of the transactions can be measure reliably.

The gain or loss arising from derecognizing an item of PP&E shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

Considerations:

Currently the pooled method of accounting for capital assets for Utility companies is applied and is an approved method by the Ontario Energy Board (“OEB”).

The pooled method of accounting, pools like assets together based on the year of addition as the pooling method assumes that each asset will last, on average, their full useful life.

Under the pooled method there is an assumption that there are assets within the same asset pool which will last longer or shorter than the estimated useful life and therefore, in the end everything balances out on average. However, the assumption does not always hold true, especially if assets are removed from service before the end of their useful life, for example, when a road is widened.

Under the pooled method, if an asset is removed from service prior to the end of its useful life, there is no change to the accounting to remove the asset – it remains in the GL (i.e. it is not derecognized).

Currently, Niagara-On-The-Lake Hydro Inc. (“the company”) records their capital assets using the pooled method of accounting and does not derecognize assets removed from service prior to the end of their useful life.

Since the company removes assets from service prior to the end of their useful life from time to time, these removed assets should be derecognized. The company must derecognize the cost of the asset which was removed/disposed. A write-off would be recorded in the amount of the remaining NBV of the asset removed/disposed. Any proceeds on the disposal of the asset would offset the write-off.

In order to properly account for assets that are removed from service in the accounting records, a process needs to be developed which alerts the accounting department when an asset has been removed from service in order to write-off the asset (long-term issue).

Conclusion:

For IFRS purposes a process will need to be developed and implemented which notifies the accounting department of changes which occur in the field which require accounting for the removal of the fixed assets and recording the loss in the income statement.

Conclusion Document

Standard: IAS 23 – Borrowing Costs

Topic: Property, Plant and Equipment – Borrowing Costs

Objective:

To determine the policy on accounting for borrowing costs for property, plant and equipment.

Background:

Borrowing costs are interest and other costs that an entity incurs in connection with the borrowing of funds. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. A substantial period of time is not defined in the IFRS standard. Guidance provided by KPMG suggests that a substantial period of time would be considered to be a period well in excess of 6 months.

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E. Niagara-On-The-Lake Hydro Inc. ("NOTL") has chosen to use the cost model in accordance with the OEB requirements.

IAS 23 requires that borrowing costs be expensed as they are incurred unless they relate to "qualifying assets", in which case they must be capitalized if certain conditions are met. When interest is capitalized, IAS 23 requires the following steps:

- Begin capitalization when borrowing costs and expenditures are incurred and activities to develop a qualifying asset for its intended use are in progress;
- Suspend capitalization when development is interrupted for extended periods; and
- Cease capitalization when a qualifying asset is ready for its intended use or sale and all activities related thereto are complete.

Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. All other borrowing costs are recognized as interest expense.

The borrowing costs capitalized must reflect the weighted average of the actual borrowing costs incurred. The OEB requires the actual interest rate on the debt to be used if the related debt was acquired in an arm's length basis. If the debt is acquired in a non-arm's length basis then the interest rate used cannot exceed the Board's published rates for CWIP for rate setting purposes.

Definitions:

Qualifying asset – NOTL defines a qualifying asset as one that takes in excess of 6 months to construct or get ready for its intended use.

Considerations:

NOTL currently does not have any qualifying assets as the average time frame of constructing an item of PP&E typically does not exceed 6 months.

Conclusion:

Eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets. Interest rate to be used for capitalization will be the actual cost of borrowing when debt is borrowed specifically to obtain the asset or the weighted average cost of borrowing when general borrowings are used to obtain the asset.

APPENDIX

4F

2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056



Government payments are payments to any government body required in the ordinary course of business. Examples of such payments include, but are not limited to:

- IESO
- Ministry of Energy
- Ontario Energy Board
- Canada Revenue Agency or Ministry of Finance

Internal payments include payments between NOTL Energy, NOTL Hydro and ESNI and payments to the Town of Niagara-on-the-Lake.

6.0 Conflicts of Interest

6.1 No requisition, vouchers, petty cash funds or any other order, written or verbal, shall be issued for personal goods and/or services for employees of the Company, any member of Board, or the public.

6.2 No purchase of goods or services shall be made from any employee or Board member of NOTL Hydro, or from any company in which an employee or Board member of NOTL Hydro has an interest without prior written approval by the Board. A contract for goods and services placed with a relative of an employee of NOTL Hydro shall be declared and that employee shall not be placed in a position to supervise or approve the execution of that contract

6.3 No employee or elected official shall purchase surplus assets except by bidding on the same at public auction or by sealed bid.

7.0 Local Preference

7.1 In accordance with the Discriminatory Business Practices Act, Revised Statutes of Ontario, 1990, Chapter D.12 there shall be no local preference for purchases.

7.2 All else being equal, preference will be given to purchase goods and/or services firstly from Niagara-on-the-Lake based businesses, secondly from businesses located in the Niagara Region, and thirdly from Canadian owned businesses.

The employee must solicit a minimum of two (2) quotes without formal advertising or receipt of sealed bids. The requirements of the competitive process may only be waived under the authority of the President. In this case, the competitive process will be replaced by the negotiated method.

7.4 Request for Proposal (Written) - $20,000 or Greater

In general, the Request for Proposal process encourages different solutions from vendors and actively searches for better and more creative ideas for supply of goods and services. It provides a process whereby the negotiation and award is based on demonstrated competence, qualifications and the technical merits of the Proposal at a fair price.

The President or Vice President shall prepare a Request for Proposal document which provides prospective bidders with a general requirement or overview of the problem.

A minimum of three quotes will be obtained.

Purchases over $20,000 without competitive quotes require prior approval of the Board.

4.0 Payment Authority

$ Limit	Signature Type	Authority
$50,000	Facsimile	President and Board Chair
>$50,000 Government or Internal	Handwritten	Two of President, VP Finance or any Board member
>$50,000	Handwritten	President and any Board member or any two Board members

The same level of authority is required whether payment is by cheque, electronic funds transfer, bank transfer or any other form of funds transfer.

5.0 Government or Internal Payments

Board member approval is not required for payments deemed Government or Internal.

3.0 Purchasing Authority

$ Limit	Purchasing Procedure	Authority
$2,000	Direct Purchase	Manager
$20,000	Competitive Process	Vice President
$50,000	Obtain 3 quotes	President or Board member
>$50,000	Obtain 3 quotes	President and any Board member or any two Board members

7.1 Petty Cash- $100 or Less

A petty cash fund will be maintained in the Finance Department to meet the requirements of acquisitions of goods and services having a value of $100 or less.

Petty cash should only be used when it is not feasible to use a purchasing card.

All petty cash disbursements shall be evidenced by a receipt and Petty Cash Summary Slips. The slips must accompany the receipt in order to replenish the fund.

7.2 Purchasing Card or Direct Purchase- $2,000 or less

Purchases not exceeding $2,000 may be made using a purchasing card or direct purchase.

The Purchasing Card or Direct Purchase Process is a method of making smaller dollar purchases.

The acquisition of goods and/or services having a value of up to $2,000.00 per transaction, including taxes, shall be carried out by an employee with a company credit card with prior approval from the President of VP Finance.

7.3 Competitive Process- $2,000 to $19,999

Purchases with an estimated value greater than $2,000 but less than $20,000 shall be obtained using a competitive process.

Niagara On-The-Lake HYDRO	Policy:	NOTLH-FIN-1
	Page:	1 of 4
	Re-Issued:	May 8, 2018
NOTL Hydro Purchasing Policy	Issue No.:	1.0

1.0 Purpose

To set forth the policy of the corporation regarding the approval procedure for purchasing capital and operational expenditures.

2.0 Scope

2.1 This policy is applicable to all employees of Niagara-on-the-Lake Hydro (NOTL Hydro) as well as to purchases made on behalf of either Energy Services Niagara Inc. (ESNI) or Niagara-on-the-Lake Energy Inc. (NOTL Energy).

2.2 To ensure that employees who are responsible for requisitioning and purchasing goods and services are accountable for their actions and decisions;

2.3 To promote the most cost effective and efficient use of company funds and resources by acquiring the goods and services at the optimum quality, quantity, price, delivery and performance;

2.4 NOTL Hydro.'s employees will appreciate that they are utilizing the public's (rate-payer's) money and will be held to the highest possible standard when making purchasing decisions;

2.5 To participate with other local distribution companies (LDCs) in cooperative / collaborative purchasing activities where they are in the best interest of the company.

2.6 To always think about the "total acquisition cost" rather than the lowest bid. This includes, but is not limited to such factors as repairs, staff training, suitability, compatibility, warranty, trade-in values, recycling and disposal concerns. To consider "Value for money".

APPENDIX

4G

2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056



NIAGARA-ON-THE-LAKE HYDRO INC.

REPORT ON THE ACTUARIAL VALUATION OF POST-RETIREMENT NON-PENSION BENEFITS

AS AT DECEMBER 31, 2017

February 22, 2018 – FINAL

THE POWER OF BEING UNDERSTOOD
AUDIT | TAX | CONSULTING

RSM

TABLE OF CONTENTS

Executive Summary **1**

Purpose 1

Section A — Valuation Results **2**

Valuation Results 3
Sensitivity Analysis 4
Development of Changes in the Present Value of Defined Benefit Obligation 5

Section B — Plan Participants **6**

Participation Data 7
Participant Reconciliation 9

Section C — Summary of Actuarial Method and Assumptions **10**

Actuarial Method 10
Management's Best Estimate Assumptions 11
Economic Assumptions 11
Demographic Assumptions 12
Other Assumptions 13

Section D — Summary of Post-Retirement Benefits **14**

Eligibility 14
Participant Contributions 14
Summary of Benefits 14

Actuarial Certification **16**

Section E — Employer Certification **17**

Appendix — Detailed Accounting Schedules **18**

EXECUTIVE SUMMARY

Purpose

RSM Canada Consulting LP was engaged by Niagara-on-the-Lake Hydro Inc. ("the Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2017. The nature of these benefits is defined benefit.

This report is prepared in accordance with the International Financial Reporting Standards ("IFRS") guidelines for post-retirement non-pension benefits as outlined in the International Accounting Standard 19 – Employee Benefits ("IAS 19").

The most recent full valuation was prepared as at December 31, 2014 based on the then appropriate assumptions and in accordance with IAS 19.

The purpose of this valuation is threefold:

i) To determine the Corporation's liabilities in respect of post-retirement non-pension benefits at December 31, 2017;

ii) To determine the defined benefit costs to be recognized for fiscal year 2017; and

iii) To provide all other pertinent information necessary for compliance with IAS 19.

Note that all monetary figures in this report are rounded to the nearest hundreds of dollars and summated figures in this report may not match total figures due to rounding.

The intended users of this report include the Corporation and its auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

Included in the Appendix attached hereto are detailed accounting schedules containing the results of the valuation and projections for future periods (if applicable).

© 2018 RSM Canada. All Rights Reserved.

SECTION A — VALUATION RESULTS

Section A - 1 shows the key valuation results compared to previous year's figures projected from the most recent full valuation as well as a breakdown between active and retired individuals and type of benefit.

Section A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown an increase/decrease in the health and dental claims cost trend rates by 1% per annum and an increase/decrease in the discount rate by 1% per annum.

Section A - 3 shows the development of changes in the present value of defined benefit obligation as a result of the re-measurement at December 31, 2017.

© 2018 RSM Canada. All Rights Reserved.

Valuation Results

Section A.1—Valuation Results

Results from the actuarial valuation as at December 31, 2017 compared to previous year's figures projected from the most recent full valuation:

	December 31, 2016	December 31, 2017
Present Value of Defined Benefit Obligation (PV DBO)	**330,100**	**478,800**

	CY 2016	CY 2017
Current Service Cost	22,400	23,300
Interest Cost	12,700	12,800
Defined Benefit Cost Recognized in Income Statement	**35,100**	**36,100**
Actuarial (Gain)/Loss	-	146,200
Defined Benefit Cost Recognized In OCI	**-**	**146,200**
Defined Benefit Cost	**35,100**	**182,400**

The following table provides results from the actuarial valuation as at December 31, 2017 broken down by active (including LTD) and retired individuals and type of post-retirement non-pension benefit:

Dec. 31, 2017 PV DBO	Actives (incl. LTD)	Retirees	Total
Life	37,400	124,900	**162,300**
Health	209,800	37,900	**247,700**
Dental	57,900	10,800	**68,700**
Total	**305,200**	**173,600**	**478,800**

© 2018 RSM Canada. All Rights Reserved.

Sensitivity Analysis

Section A.2—Sensitivity Analysis

	Dec. 31, 2017 PV DBO	Difference	% Difference
Base Assumptions	478,800		
Cost Trends +1%	514,500	35,700	7%
Cost Trends -1%	448,400	(30,400)	-6%
Discount Rate +1%	418,900	(59,900)	-13%
Discount Rate -1%	555,600	76,800	16%

Management's best estimate assumptions are those outlined in *Section C – Summary of Actuarial Method and Assumptions* in this report.

© 2018 RSM Canada. All Rights Reserved.

Development of Changes in the Present Value of Defined Benefit Obligation

Section A.3—Development of Changes in the Present Value of Defined Benefit Obligation

PV DBO at December 31, 2016	330,100
2017 Current Service Cost	23,300
2017 Benefit Payments	(33,600)
2017 Interest Cost	12,800
Expected PV DBO at December 31, 2017	**332,600**
Actuarial (Gain)/Loss at December 31, 2017	146,200
PV DBO at December 31, 2017	**478,800**

The increase indicated above of $146,200 in the PV DBO from the expected PV DBO at December 31, 2017 is due to the re-measurement of the liability; a breakdown of the changes is as follows:

Change in composition of active and retiree data (actual experience different than expected)	99,200
Change in assumptions:	
Discount rate	37,600
Health/dental claims costs	4,600
Claims cost trend rate	3,700
Mortality improvement	1,100
Total Actuarial (Gain)/Loss at December 31, 2017	**146,200**

Pursuant to IAS 19, the re-measurement of the PV DBO at December 31, 2017 based on the changes in the assumptions and experience is recognized immediately in other comprehensive income at December 31, 2017.

© 2018 RSM Canada. All Rights Reserved.

SECTION B — PLAN PARTICIPANTS

Section B – 1 sets out the summary information with respect to the plan participants valued in the current valuation compared to those valued in the previous valuation.

Section B – 2 reconciles the number of participants in the previous valuation to the number of participants in the current valuation.

© 2018 RSM Canada. All Rights Reserved.

Participation Data

Section B.1—Participant Data

Membership data as at December 31, 2017 was received from the Corporation via e-mail and included information such as name, sex, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the previous valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of hire prior to date of birth;
- Ages under 18 or over 100;
- Abnormal levels of benefits and/or premiums; and
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

	December 31, 2014	December 31, 2017
Employee Count		
Male	9.0	12.0
Female	4.0	7.0
Total	**13.0**	**19.0**
Employee Average Service		
Male	7.3	7.5
Female	10.3	8.8
Total	**8.2**	**8.0**
Retiree (in Receipt of Benefits) Count		
Male	7.0	7.0
Female	6.0	5.0
Total	**13.0**	**12.0**

© 2018 RSM Canada. All Rights Reserved.

	Employee Count as of Dec. 31, 2017			Employee Avg Service as of Dec. 31, 2017		
Age	**Male**	**Female**	**Total**	**Male**	**Female**	**Total**
< 30	3	1	4	6	2	5
30 - 35	1	1	2	1	8	4
36 - 40	3	2	5	7	9	8
41 - 45	1	1	2	2	17	9
46 - 50	2	-	2	10	-	10
51 - 55	2	2	4	14	9	16
56 - 60	-	-	-	-	-	-
61 - 65	-	-	-	-	-	-
66 - 70	-	-	-	-	-	-
71 - 75	-	-	-	-	-	-
> 75	-	-	-	-	-	-
Total	**12.0**	**7.0**	**19.0**	**7.5**	**8.8**	**8.0**

© 2018 RSM Canada. All Rights Reserved.

Participant Reconciliation

Section B.2—Participation Reconciliation

	Actives	Disabled	Retired
As at December 31, 2014	**13**	**1**	**12**
New Entrants	6	-	-
Actives	-	-	-
Terminated	(1)	-	-
Retired	-	-	-
Deceased	-	-	-
Disabled	-	-	-
No Longer Eligible	-	-	-
As at December 31, 2017	**18**	**1**	**12**

© 2018 RSM Canada. All Rights Reserved.

SECTION C —
SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

Actuarial Method

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions for discount rates, mortality, and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and,
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The Defined Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by IAS 19. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. IAS 19 stipulates that the attribution period commences on the date when service by the employee first leads to benefits under the plan (whether or not the benefits are conditional on further service) and ends on the date when further service by the employee will lead to no material amount of further post-retirement non-pension benefits under the plan, other than from further salary increases.

For each employee not yet fully eligible for benefits, the Present Value of the Defined Benefit Obligation (PV DBO) is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

The PV DBO at December 31, 2017 is based on membership data as at December 31, 2017 and management's best estimate assumptions established for calculations as at December 31, 2017.

The Corporation self-insures its health and dental benefits. For these benefits, we have used the following average monthly benefit claims costs for 2018, which includes corresponding expenses and taxes, as an estimate of the claims to be incurred. These benefit claims costs have been calculated based on plan experience for the Corporation from January 2012 to September 2017:

	Health		Dental	
Effective Date	**Single**	**Family**	**Single**	**Family**
January 1, 2015 – December 31, 2015 (Previous Valuation)	$161.70	$323.40	$60.50	$121.00
January 1, 2018 – December 31, 2018	$207.00	$413.00	$61.00	$121.00

The above benefit cost levels were provided by the Corporation and represent the rates at 100%, prior to any cost-sharing provisions. For eligible union retirees, the Corporation will pay 50% of these cost levels in line with the co-pay benefit structure for post-retirement benefits.

© 2018 RSM Canada. All Rights Reserved.

Management's Best Estimate Assumptions

The following are management's best estimate economic and demographic assumptions for calculations as at December 31, 2017.

Economic Assumptions

Discount Rate

The rate used to discount future benefits is assumed to be 3.50% per annum as at December 31, 2017. This rate reflects the Corporation's expected projected benefit cash flows for post-retirement non-pension benefits and the market yields on high quality bonds at December 2017.

This assumption chosen for the previous valuation at was 4.10% per annum.

Salary Increase Rate

The rate used to increase salaries is assumed to be 3.30% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion and for company-specific information.

This assumption remains unchanged from the previous valuation.

Claims Cost Trend Rate

The table below summarizes the health and dental trend rate assumption chosen for the current valuation as well as the assumption chosen for the previous valuation:

	Survey Results		Previous Valuation	
End of Year	**Health**	**Dental**	**Health**	**Dental**
2018	6.20%	4.50%	5.83%	4.50%
2019	5.96%	4.50%	5.61%	4.50%
2020	5.71%	4.50%	5.39%	4.50%
2021	5.47%	4.50%	5.17%	4.50%
2022	5.23%	4.50%	4.94%	4.50%
2023	4.99%	4.50%	4.72%	4.50%
2024	4.74%	4.50%	4.50%	4.50%
2025 and Thereafter	4.50%	4.50%	4.50%	4.50%

© 2018 RSM Canada. All Rights Reserved.

Demographic Assumptions

Mortality Table

The mortality tables used are as per the Canadian Institute of Actuaries Canadian Pensioners' Mortality Pension Experience Subcommittee final report dated February 11, 2014 (CIA Report). More specifically, the Canada Pensioners Mortality ("CPM") Table Public Sector (CPM2014 PUBL) has been used with the generational projection of mortality improvement based upon CPM Improvement Scale B-2014.

The mortality table assumption remains unchanged from the previous valuation, but the mortality improvement assumption has been updated from the one-dimensional version of the same table.

Rates of Withdrawal

Termination of employment is assumed to be in accordance with the following withdrawal table:

Age Bucket	Current Valuation
18 – 29	3.50%
30 – 34	2.50%
35 – 39	2.15%
40 – 49	1.75%
50 – 54	1.40%

The table above summarizes the withdrawal rates based on our recent analysis which are the same as the withdrawal rates chosen for the previous valuation.

Retirement Age

All active employees are assumed to retire at age 56 (or immediately if currently over age 56), which was based on the Corporation's retirement experience as well as the experience of other similar companies for which data was available.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability. For any employees currently disabled, it is assumed that they will remain disabled until retirement at age 65.

This assumption remains unchanged from the previous valuation.

© 2018 RSM Canada. All Rights Reserved.

Other Assumptions

Family/Single Coverage

The following assumptions were chosen for the current valuation and are unchanged from the previous valuation:

- Coverage Type at Retirement (i.e. family, single) – The employee's coverage type at the valuation date will remain the same until the employee reaches the assumed retirement age.
- Spousal Gender – For employees with family coverage, the retiree has a spouse of the opposite gender at the date of retirement.
- Spousal Age Offset – Male spouses are assumed to be three years older than female spouses.

Expenses and Taxes

The taxes and expenses are included in the benefit cost levels assumed for health and dental benefits.

We have assumed 10% of benefits is required for the cost of sponsoring the program for post-retirement life insurance.

These assumptions remain unchanged from the previous valuation.

© 2018 RSM Canada. All Rights Reserved.

SECTION D —
SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation, based on information provided by and discussions with the Corporation.

Eligibility

All employees who retire from the Corporation are eligible for post-retirement life insurance. In addition, all employees who retire from the Corporation with an OMERS pension are eligible for post-retirement health, vision and dental benefits. .

Participant Contributions

The Corporation shall pay 100% of the cost of the post-retirement life, health, vision and dental benefits for the eligible management retirees. The Corporation shall pay 100% of the cost of the post-retirement life insurance benefits and 50% of the cost of the health, vision and dental benefits for eligible union retirees.

Summary of Benefits

Life Insurance

Upon retirement, all employees are entitled to post-retirement life insurance benefits, as per the MEARIE plan, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
A	Flat $2,000.	Employee retires with less than 10 years of service in the Plan.
B, C1	50% of final annual earnings, reducing by 2.5% of final annual earnings each year for 10 years, to a final benefit equal to 25% of final annual earnings. Reduction occurs on the anniversary date of retirement.	Employee retires with 10 or more years of service in the Plan and was hired before June 16, 1989. OR Employee was insured under the superseded plan and elected coverage under option 2, 3, or 4, or employee was not insured under the superseded plan.
C2	50% of final annual earnings.	Employee was insured under the superseded plan and was hired on or after May 1, 1967 and elected coverage under option 1 only.
C3	70% of final amount insured under the life plan immediately prior to retirement.	Employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under option 1 only.

© 2018 RSM Canada. All Rights Reserved.

Health and Dental Benefits

Effective July 1, 2006, the Corporation self-insures its health and dental benefits. Eligible employees are entitled to post-retirement health and dental benefits to age 65. Health and dental benefits continue to the eligible dependent(s) of a deceased management retiree until the retiree would have turned age 65.

A detailed description of the health and dental benefits covered under the post-retirement non-pension benefits can be found in the above-noted documents.

© 2018 RSM Canada. All Rights Reserved.

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by Niagara-on-the-Lake Hydro Inc. ("the Corporation") as at December 31, 2017, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations) and we express no opinion on them;
3. All known legal and constructive obligations with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
4. This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are not aware of any subsequent events after the date of completing this valuation that would have a significant effect on the valuation results contained herein.

The latest date on which the next actuarial valuation should be performed is December 31, 2020. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,
RSM CANADA CONSULTING LP



Stanley Caravaggio, FSA, FCIA
Senior Manager



Jamie Wong, ASA, ACIA
Consultant

Toronto, Ontario

February 22, 2018

© 2018 RSM Canada. All Rights Reserved.

SECTION E —
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Niagara-on-the-Lake Hydro Inc.
Actuarial Valuation as at December 31, 2017

I hereby confirm, as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Niagara-on-the-Lake Hydro Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) The membership data summarized in Section B is accurate and complete;

ii) The assumptions upon which this report is based as summarized in Section C, are management's best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) The summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on December 31, 2017.

NIAGARA-ON-THE-LAKE HYDRO INC.

Feb 13, 2018
Date

Signature

Jeff Klassen
Name

VP Finance
Title

© 2018 RSM Canada. All Rights Reserved.

APPENDIX —
DETAILED ACCOUNTING SCHEDULES

© 2018 RSM Canada. All Rights Reserved.

RSM

Niagara-On-The-Lake
Estimated Benefit Expense (IAS 19)
CONSOLIDATED
FINAL

	Actuals CY 2017 *	Projected ** CY 2018	Projected ** CY 2019	Projected ** CY 2020
Discount Rate at January 1	4.10%	3.50%	3.50%	3.50%
Discount Rate at December 31	3.50%	3.50%	3.50%	3.50%
Health Benefit Cost Trend Rate at December 31				
Initial Trend Rate	6.20%	5.96%	5.71%	5.47%
Ultimate Rate	4.50%	4.50%	4.50%	4.50%
Year Ultimate Rate Reached	2025	2025	2025	2025
Dental Benefit Cost Trend Rate at December 31	4.50%	4.50%	4.50%	4.50%
Assumed Increase in Employer Contributions	actual	expected ***	expected ***	expected ***
A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet				
Net Defined Benefit Liability/(Asset) as at January 1	330,064	478,806	506,322	534,786
Defined Benefit Cost Recognized in Income Statement	36,168	52,585	47,472	44,165
Defined Benefit Cost Recognized in Other Comprehensive Income	146,216	-	-	-
Benefits Paid by the Employer	(33,643)	(25,070)	(19,008)	(22,201)
Net Defined Benefit Liability/(Asset) as at December 31	478,806	506,322	534,786	556,749
B. Determination of Defined Benefit Cost				
B1. Determination of Defined Benefit Cost Recognized in Income Statement				
Current Service Cost	23,325	36,266	30,083	25,836
Interest Cost	12,843	16,319	17,389	18,329
Defined Benefit Cost Recognized in Income Statement	36,168	52,585	47,472	44,165
B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income				
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	45,928	-	-	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	1,093	-	-	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	99,195	-	-	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-	-	-	-
Change in Effect of Asset Ceiling	-	-	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	146,216	-	-	-
Total Defined Benefit Cost	182,385	52,585	47,472	44,165
C. Change in the Present Value of Defined Benefit Obligation				
Present Value of Defined Benefit Obligation as at January 1	330,064	478,806	506,322	534,786
Current Service Cost	23,325	36,266	30,083	25,836
Interest Cost	12,843	16,319	17,389	18,329
Benefits Paid	(33,643)	(25,070)	(19,008)	(22,201)
Net Actuarial Loss/(Gain)	146,216	-	-	-
Present Value of Defined Benefit Obligation as at December 31	478,806	506,322	534,786	556,749

* The CY 2017 defined benefit cost and expected PV DBO at December 31, 2017 are calculated based on membership data and management's best estimate assumptions at December 31, 2014.

** Projected CY 2018, 2019 and 2020 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on expected benefits to be paid to those eligible for benefits.

RSM

Niagara-On-The-Lake
Estimated Benefit Expense (IAS 19)
CONSOLIDATED
FINAL

	Actuals CY 2017 *	Projected ** CY 2018	Projected ** CY 2019	Projected ** CY 2020
Discount Rate at January 1	4.10%	3.50%	3.50%	3.50%
Discount Rate at December 31	3.50%	3.50%	3.50%	3.50%
Health Benefit Cost Trend Rate at December 31				
Initial Trend Rate	6.20%	5.96%	5.71%	5.47%
Ultimate Rate	4.50%	4.50%	4.50%	4.50%
Year Ultimate Rate Reached	2025	2025	2025	2025
Dental Benefit Cost Trend Rate at December 31	4.50%	4.50%	4.50%	4.50%
Assumed Increase in Employer Contributions	actual	expected ***	expected ***	expected ***
D. Calculation of Component Items				
Service Cost				
Current Service Cost	23,325	36,266	30,083	25,836
Interest Cost				
Present Value of Defined Benefit Obligation as at January 1	330,064	478,806	506,322	534,786
Benefits Paid	(16,821)	(12,535)	(9,504)	(11,101)
Accrued Benefits	313,243	466,271	496,818	523,685
Interest Cost	12,843	16,319	17,389	18,329
Expected Present Value of Defined Benefit Obligation as at December 31				
Present Value of Defined Benefit Obligation as at January 1	330,064	478,806	506,322	534,786
Current Service Cost	23,325	36,266	30,083	25,836
Benefits Paid	(33,643)	(25,070)	(19,008)	(22,201)
Interest Cost	12,843	16,319	17,389	18,329
Expected Present Value of Defined Benefit Obligation as at December 31	332,590	506,322	534,786	556,749
E. Net Actuarial Loss/(Gain)				
Net Actuarial Loss/(Gain) as at December 31				
Expected Present Value of Defined Benefit Obligation	332,590	506,322	534,786	556,749
Actual Present Value of Defined Benefit Obligation	478,806	506,322	534,786	556,749
Net Actuarial Loss/(Gain) as at December 31	146,216	-	-	-

* The CY 2017 defined benefit cost and expected PV DBO at December 31, 2017 are calculated based on membership data and management's best estimate assumptions at December 31, 2014.

** Projected CY 2018, 2019 and 2020 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on expected benefits to be paid to those eligible for benefits.



rsmcanada.com

RSM Canada LLP is a limited liability partnership that provides public accounting services and is the Canadian member firm of RSM International, a global network of independent audit, tax and consulting firms. RSM Canada Consulting LP is a limited partnership that provides consulting services and is an affiliate of RSM US LLP, a member firm of RSM International. The member firms of RSM International collaborate to provide services to global clients, but are separate and distinct legal entities that cannot obligate each other. Each member firm is responsible only for its own acts and omissions, and not those of any other party. Visit rsmcanada.com/about us for more information regarding RSM Canada and RSM International.

RSM® and the RSM logo are registered trademarks of RSM International Association, used under licence.

The power of being understood® is a registered trademark of RSM US LLP, used under licence.

©2018. RSM Canada LLP. All Rights Reserved.

APPENDIX

4H

2019

NIAGARA-ON-THE-LAKE HYDRO

COST OF SERVICE RATE APPLICATION

EB-2018-0056



Appendix 2-C
Depreciation and Amortization Expense

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012.	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013.	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2014	MIFR

		Book Values													Service Lives				Depreciation Expense							
Account	Description	Opening NBV of Assets at Date of Policy Change- Jan. 1, 2013	Less Fully Depreciated / Disposals Previous Years	Fully Depreciated Current Year (NBV)	Less Disposals (NBV)	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [c]	Depreciation Expense on Disposals Current Year	Opening Gross Book Value of Assets Acquired After Policy Change	Less Fully Depreciated Previous Years	Less Fully Depreciated Current Year	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [i]	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions (1/2 year rule)	Adjustments	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J 2014	Variance
		a	b	c	d	e = a - b - c - d	f	g	h	i	j	k = h - i - j	l	m	n	o = 1/n	p	q = 1/p	r = e/n + f + g	s = k/p +l	t = m/p x 0.5	u	v = r + s + t + u	w	x = w - v
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 -TX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	45.00	2.22%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 OTHER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	55.00	1.82%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 165,566	$ 54,937	$ 14,513	$ -	$ 96,115	$ 3,206	$ -	104,895	-	-	104,895	-	129,375	2.59	38.64%	3.00	33.33%	$ 40,344	$ 34,965	$ 21,563	$ -	$ 96,872	$ 96,872	$ (0)
1925	CIS Upgrade	$ 119,000	$ -	$ -	$ -	$ 119,000	$ -	$ -	-	-	-	-	-	-	3.50	28.58%	3.00	33.33%	$ 34,013	$ -	$ -	$ -	$ 34,013	$ 34,013	$ (0)
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 258,134	$ -	$ -	$ -	$ 258,134	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV York (TX)	$ 630,588	$ -	$ -	$ -	$ 630,588	$ -	$ -	-	-	-	-	-	-	35.52	2.82%	45.00	2.22%	$ 17,753	$ -	$ -	$ -	$ 17,753	$ 17,753	$ -
1815	Transformer Station Equipment >50 kV York Other	$ 1,466,075	$ -	$ -	$ -	$ 1,466,075	$ -	$ -	-	-	-	-	-	11,056	45.66	2.19%	55.00	1.82%	$ 32,109	$ -	$ 101	$ -	$ 32,210	$ 32,210	$ (0)
1815	Transformer Station Equipment >50 kV Conc 5 (TX)	$ 544,453	$ -	$ -	$ -	$ 544,453	$ -	$ -	-	-	-	-	-	-	37.52	2.67%	45.00	2.22%	$ 14,511	$ -	$ -	$ -	$ 14,511	$ 14,511	$ -
1815	Transformer Station Equipment >50 kV Conc 5 Other	$ 1,664,608	$ -	$ -	$ -	$ 1,664,608	$ -	$ -	-	-	-	-	-	-	48.16	2.08%	55.00	1.82%	$ 34,567	$ -	$ -	$ -	$ 34,567	$ 34,567	$ (0)
1820	Distribution Station Equipment <50 kV	$ 47,927	$ 47,927	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,130,517	$ 1,659	$ -	2,824	$ 2,126,035	$ -	$ -	261,715	-	-	261,715	-	188,907	26.93	0.04	45.00	2.22%	$ 78,938	$ 5,816	$ 2,099	$ -	$ 86,853	$ 86,853	$ -
1835	Overhead Conductors & Devices	$ 2,838,661	$ 1,850	$ -	$ 1,988	$ 2,834,822	$ -	$ -	145,956	-	-	145,956	-	259,557	41.85	0.02	60.00	1.67%	$ 67,742	$ 2,433	$ 2,163	$ -	$ 72,337	$ 72,337	$ -
1840	Underground Conduit	$ 2,705,310	$ -	$ -	$ -	$ 2,705,310	$ -	$ -	261,599	-	-	261,599	-	343,462	53.26	0.02	65.00	1.54%	$ 50,790	$ 4,025	$ 2,642	$ -	$ 57,457	$ 57,457	$ (0)
1845	Underground Conductors & Devices	$ 4,168,057	$ -	$ -	$ -	$ 4,168,057	$ -	$ -	518,222	-	-	518,222	-	483,538	29.89	3.35%	45.00	2.22%	$ 139,468	$ 11,516	$ 5,373	$ -	$ 156,357	$ 156,357	$ -
1850	Line Transformers	$ 3,765,974	$ 51,007	$ 115	$ 70,993	$ 3,643,859	$ 9	$ -	197,981	-	-	197,981	-	254,423	31.95	3.13%	45.00	2.22%	$ 114,074	$ 4,400	$ 2,827	$ -	$ 121,301	$ 121,301	$ -
1850	Line Transformers-Inventory	$ 96,563	$ -	$ -	$ -	$ 96,563	$ -	$ -	624	-	-	624	-	14,263	34.67	2.88%	45.00	2.22%	$ 2,786	$ 14	$ 158	$ -	$ 2,958	$ 2,958	$ 0
1850	Line Transformers-Damaged	$ 9,005	$ -	$ -	$ -	$ 9,005	$ -	$ -	-	-	-	-	-	-	1.03	96.73%	45.00	2.22%	$ 8,710	$ -	$ -	$ -	$ 8,710	$ 8,710	$ -
1850	Line Transformers-Spare	$ 73,441	$ -	$ -	$ -	$ 73,441	$ -	$ -	50,711	-	-	50,711	-	(43,251)	41.12	2.43%	45.00	2.22%	$ 1,786	$ 1,127	$ (481)	$ -	$ 2,432	$ 2,428	$ (4)
1855	Services (Overhead)	$ 443,107	$ -	$ -	$ -	$ 443,107	$ -	$ -	30,148	-	-	30,148	-	13,740	55.08	1.82%	60.00	1.67%	$ 8,044	$ 502	$ 114	$ -	$ 8,661	$ 8,661	$ 0
1855	Services (Underground)	$ 1,679,060	$ -	$ -	$ -	$ 1,679,060	$ -	$ -	225,648	-	-	225,648	-	276,278	38.61	2.59%	45.00	2.22%	$ 43,484	$ 5,014	$ 3,070	$ -	$ 51,569	$ 51,569	$ (0)
1860	Meters	$ 197,059	$ 308	$ 720	$ 269	$ 195,761	$ 360	$ -	-	-	-	-	-	14,163	23.67	4.23%	25.00	4.00%	$ 8,631	$ -	$ 283	$ -	$ 8,915	$ 8,915	$ -
1860	Meters (Smart Meters)	$ 1,370,813	$ -	$ -	$ 3,839	$ 1,366,975	$ -	$ -	26,675	-	-	26,675	-	35,905	12.39	8.07%	15.00	6.67%	$ 110,369	$ 1,778	$ 1,197	$ -	$ 113,344	$ 113,344	$ -
1860	Stranded Meters	$ 102,246	$ 95,264	$ 1,225	$ -	$ 5,757	$ 613	$ -	-	-	-	-	-	-	12.14	8.24%	-	0.00%	$ 1,087	$ -	$ -	$ -	$ 1,087	$ 1,087	$ -
1860	Non Stranded Meters-Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27,758	-	-	27,758	-	-	-	0.00%	25.00	4.00%	$ -	$ 1,110	$ -	$ -	$ 1,110	$ 1,110	$ -
1860	Non Stranded Meters-CT/PT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters Inventory	$ 39,189	$ -	$ -	$ -	$ 39,189	$ -	$ -	(1,256)	-	-	(1,256)	-	3,359	16.29	6.14%	25.00	4.00%	$ 2,406	$ (50)	$ 67	$ -	$ 2,423	$ 2,423	$ -
1860	Smart Meters Inventory	$ 46,634	$ -	$ -	$ -	$ 46,634	$ -	$ -	(8,030)	-	-	(8,030)	-	(14,985)	14.10	7.09%	15.00	6.67%	$ 3,308	$ (535)	$ (499)	$ -	$ 2,273	$ 2,273	$ 0
1860	Non Stranded Meters-CT/PT Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1905	Land	$ 49,000	$ -	$ -	$ -	$ 49,000	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures-8 Henegan Rd	$ 678,370	$ -	$ -	$ -	$ 678,370	$ -	$ -	1,060	-	-	1,060	-	5,717	39.33	2.54%	60.00	1.67%	$ 17,249	$ 18	$ 48	$ -	$ 17,314	$ 17,314	$ 0
1908	Buildings & Fixtures-PCB Shed	$ 1,606	$ -	$ -	$ -	$ 1,606	$ -	$ -	-	-	-	-	-	-	5.00	19.99%	30.00	3.33%	$ 321	$ -	$ -	$ -	$ 321	$ 321	$ 0
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 43,264	$ -	$ 258	$ -	$ 43,006	$ 86	$ -	2,509	-	-	2,509	-	-	6.25	16.00%	10.00	10.00%	$ 6,964	$ 251	$ -	$ -	$ 7,215	$ 7,215	$ 0
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 38,222	$ 14,787	$ 9,257	$ -	$ 14,178	$ 3,769	$ -	38,762	-	-	38,762	-	6,033	2.64	37.85%	3.00	33.33%	$ 9,136	$ 12,921	$ 1,006	$ -	$ 23,062	$ 23,062	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment < 3 Tons	$ 11,707	$ 3,415	$ 7,616	$ -	$ 676	$ 2,525	$ -	53,681	-	-	53,681	-	-	3.42	29.27%	5.00	20.00%	$ 2,722	$ 10,736	$ -	$ -	$ 13,459	$ 13,459	$ (0)
1930	Transportation Equipment > 3 Tons	$ 623,113	$ -	$ -	$ -	$ 623,113	$ -	$ -	-	-	-	-	-	-	7.86	12.72%	10.00	10.00%	$ 79,258	$ -	$ -	$ -	$ 79,258	$ 79,258	$ 0
1930	Transportation Equipment Trailers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment	$ 6,309	$ -	$ 1	$ -	$ 6,308	$ 1	$ -	-	-	-	-	-	-	6.04	16.55%	10.00	10.00%	$ 1,045	$ -	$ -	$ -	$ 1,045	$ 1,045	$ (0)
1940	Tools, Shop & Garage Equipment	$ 63,171	$ 8,828	$ 2,303	$ -	$ 52,041	$ 763	$ -	7,788	-	-	7,788	-	512	3.77	26.53%	8.00	12.50%	$ 14,570	$ 973	$ 32	$ -	$ 15,575	$ 15,575	$ 0
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 15,938	$ -	$ -	$ -	$ 15,938	$ -	$ -	-	-	-	-	-	-	3.99	25.07%	10.00	10.00%	$ 3,995	$ -	$ -	$ -	$ 3,995	$ 3,995	$ (0)
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 110,749	$ 16,302	$ 10,489	$ -	$ 83,958	$ 3,477	$ -	237,952	-	-	237,952	-	-	2.97	33.73%	10.00	10.00%	$ 31,792	$ 23,795	$ -	$ (5,568)	$ 50,019	$ 50,094	$ 75
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants-Poles	$ (169,565)	$ -	$ -	$ -	$ (169,565)	$ -	$ -	(6,683)	-	-	(6,683)	-	-	38.55	2.59%	45.00	2.22%	$ (4,399)	$ (149)	$ -	$ -	$ (4,548)	$ (4,548)	$ 0
1995	Contributions & Grants-OH Conductor	$ (164,116)	$ -	$ -	$ -	$ (164,116)	$ -	$ -	-	-	-	-	-	-	52.82	1.89%	60.00	1.67%	$ (3,107)	$ -	$ -	$ -	$ (3,107)	$ (3,107)	$ 0
1995	Contributions & Grants-O/H Services	$ (88,520)	$ -	$ -	$ -	$ (88,520)	$ -	$ -	(9,014)	-	-	(9,014)	-	-	51.24	1.95%	60.00	1.67%	$ (1,728)	$ (150)	$ -	$ -	$ (1,878)	$ (1,878)	$ (0)
1995	Contributions & Grants-UG Conduit	$ (578,117)	$ -	$ -	$ -	$ (578,117)	$ -	$ -	(97,678)	-	-	(97,678)	-	-	60.82	1.64%	65.00	1.54%	$ (9,505)	$ (1,503)	$ -	$ -	$ (11,008)	$ (11,008)	$ -
1995	Contributions & Grants-UG Conductor	$ (1,090,529)	$ -	$ -	$ -	$ (1,090,529)	$ -	$ -	(144,330)	-	-	(144,330)	-	-	37.42	2.67%	45.00	2.22%	$ (29,142)	$ (3,207)	$ -	$ -	$ (32,349)	$ (32,349)	$ -
1995	Contributions & Grants-UG Services	$ (1,031,865)	$ -	$ -	$ -	$ (1,031,865)	$ -	$ -	(171,231)	-	-	(171,231)	-	-	38.47	2.60%	45.00	2.22%	$ (26,819)	$ (3,805)	$ -	$ -	$ (30,625)	$ (30,625)	$ (0)
1995	Contributions & Grants-TX	$ (1,509,639)	$ -	$ -	$ -	$ (1,509,639)	$ -	$ -	(143,573)	-	-	(143,573)	-	-	38.31	2.61%	45.00	2.22%	$ (39,401)	$ (3,191)	$ -	$ -	$ (42,592)	$ (42,592)	$ -
1995	Contributions & Grants-Meters	$ (4,319)	$ -	$ -	$ -	$ (4,319)	$ -	$ -	-	-	-	-	-	-	14.70	6.80%	25.00	4.00%	$ (294)	$ -	$ -	$ -	$ (294)	$ (294)	$ 0
1995	Contributions & Grants-Buildings	$ (9,620)	$ -	$ -	$ -	$ (9,620)	$ -	$ -	-	-	-	-	-	-	47.00	2.13%	60.00	1.67%	$ (205)	$ -	$ -	$ -	$ (205)	$ (205)	$ (0)
1995	Contributions & Grants-Rolling Stock	$ 0	$ -	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ 0	$ 0
1605	Organization	$ 9,807	$ -	$ -	$ 9,807	$ (0)	$ -	$ 1,252	-	-	-	-	-	-	20.00	5.00%	-	0.00%	$ 1,252	$ -	$ -	$ -	$ 1,252	$ 1,252	$ 0
2440	Def Rev-Contributions & Grants-O/H Poles	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	9,252	-	0.00%	45.00	2.22%	$ -	$ -	$ 103	$ -	$ 103	$ 103	$ -
2440	Def Rev-Contributions & Grants-O/H Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	168	-	0.00%	60.00	1.67%	$ -	$ -	$ 1	$ -	$ 1	$ 1	$ -
2440	Def Rev-Contributions & Grants-O/H Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	(15,377)	-	0.00%	60.00	1.67%	$ -	$ -	$ (128)	$ -	$ (128)	$ (128)	$ -
2440	Def Rev-Contributions & Grants-U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	(219,667)	-	0.00%	65.00	1.54%	$ -	$ -	$ (1,690)	$ -	$ (1,690)	$ (1,690)	$ -
2440	Def Rev-Contributions & Grants-U/G Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	(212,022)	-	0.00%	45.00	2.22%	$ -	$ -	$ (2,356)	$ -	$ (2,356)	$ (2,356)	$ -
2440	Def Rev-Contributions & Grants-U/G Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	(207,443)	-	0.00%	45.00	2.22%	$ -	$ -	$ (2,305)	$ -	$ (2,305)	$ (2,305)	$ -
2440	Def Rev-Contributions & Grants-Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	(63,055)	-	0.00%	45.00	2.22%	$ -	$ -	$ (701)	$ -	$ (701)	$ (701)	$ -
2440	Def Rev-Contributions & Grants-Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	(320)	-	0.00%	25.00	4.00%	$ -	$ -	$ (6)	$ -	$ (6)	$ (6)	$ 0
2440	Def Rev-Contributions & Grants-Admin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	60.00	1.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Rolling Stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def Rev-Contributions & Grants-Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Battery	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 21,566,951**	**$ 296,285**	**$ 46,497**	**$ 89,720**	**$ 21,134,449**	**$ 14,808**	**$ 1,252**	**1,611,888**	**-**	**-**	**1,611,888**	**-**	**1,273,589**					**$ 868,623**	**$ 108,804**	**$ 34,680**	**-$ 5,568**	**$ 1,006,539**	**$ 1,006,610**	**$ 71**
														1,273,589.12 -										1,006,610.77 (0.61)	

Appendix 2-C
Depreciation and Amortization Expense

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012.	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013.	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2015	MIFR

		Book Values													Service Lives				Depreciation Expense							
Account	Description	Opening NBV of Assets at Date of Policy Change- Jan. 1, 2013	Less Fully Depreciated / Disposals Previous Years	Fully Depreciated Current Year (NBV)	Less Disposals (NBV)	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [c]	Depreciation Expense on Disposals Current Year	Opening Gross Book Value of Assets Acquired After Policy Change	Less Fully Depreciated Previous Years	Less Fully Depreciated Current Year	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [i]	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions (1/2 year rule)	Adjustments	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J 2015	Variance
		a	b	c	d	e = a - b - c - d	f	g	h	i	j	k = h - i - j	l	m	n	o = 1/n	p	q = 1/p	r = e/n + f + g	s = k/p +l	t = m/p x 0.5	u	v = r + s + t + u	w	x = w - v
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 -TX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	1,661,056	-	0.00%	45.00	2.22%	$ -	$ -	$ 18,456	$ -	$ 18,456	$ 18,456	$ -
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 OTHER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	875,691	-	0.00%	55.00	1.82%	$ -	$ -	$ 7,961	$ -	$ 7,961	$ 7,961	$ -
1611	Computer Software (Formally known as Account 1925)	$ 165,566	$ 69,451	$ 96,115	$ -	$ (0)	$ 21,838	$ -	234,271	-	-	234,271	-	108,818	-	0.00%	3.00	33.33%	$ 21,838	$ 78,090	$ 18,136	$ -	$ 118,064	$ 118,064	$ 0
1925	CIS Upgrade	$ 119,000	$ -	$ -	$ -	$ 119,000	$ -	$ -	-	-	-	-	-	-	3.50	28.58%	3.00	33.33%	$ 34,013	$ -	$ -	$ -	$ 34,013	$ 34,013	$ 0
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 258,134	$ -	$ -	$ -	$ 258,134	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV York (TX)	$ 630,588	$ -	$ -	$ -	$ 630,588	$ -	$ -	-	-	-	-	-	-	35.52	2.82%	45.00	2.22%	$ 17,753	$ -	$ -	$ -	$ 17,753	$ 17,753	$ -
1815	Transformer Station Equipment >50 kV York Other	$ 1,466,075	$ -	$ -	$ -	$ 1,466,075	$ -	$ -	11,056	-	-	11,056	-	-	45.66	2.19%	55.00	1.82%	$ 32,109	$ 201	$ -	$ -	$ 32,310	$ 32,310	$ (0)
1815	Transformer Station Equipment >50 kV Conc 5 (TX)	$ 544,453	$ -	$ -	$ -	$ 544,453	$ -	$ -	-	-	-	-	-	-	37.52	2.67%	45.00	2.22%	$ 14,511	$ -	$ -	$ -	$ 14,511	$ 14,511	$ -
1815	Transformer Station Equipment >50 kV Conc 5 Other	$ 1,664,608	$ -	$ -	$ -	$ 1,664,608	$ -	$ -	-	-	-	-	-	-	48.16	2.08%	55.00	1.82%	$ 34,567	$ -	$ -	$ -	$ 34,567	$ 34,567	$ (0)
1820	Distribution Station Equipment <50 kV	$ 47,927	$ 47,927	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,130,517	$ 4,483	$ -	2,986	$ 2,123,049	$ -	$ -	450,622	-	-	450,622	-	178,746	27.13	0.04	45.00	2.22%	78,268	$ 10,014	$ 1,986	$ -	$ 90,268	$ 90,268	$ -
1835	Overhead Conductors & Devices	$ 2,838,661	$ 3,838	$ 12,499	$ 8,181	$ 2,814,143	$ 4,166	$ -	405,513	-	-	405,513	-	149,660	44.53	0.02	60.00	1.67%	67,363	$ 6,759	$ 1,247	$ -	$ 75,369	$ 75,369	$ -
1840	Underground Conduit	$ 2,705,310	$ -	$ -	$ -	$ 2,705,310	$ -	$ -	605,060	-	-	605,060	-	205,441	53.29	0.02	65.00	1.54%	50,763	$ 9,309	$ 1,580	$ -	$ 61,652	$ 61,652	$ -
1845	Underground Conductors & Devices	$ 4,168,057	$ -	$ -	$ -	$ 4,168,057	$ -	$ -	1,001,761	-	-	1,001,761	-	288,464	29.89	3.35%	45.00	2.22%	139,442	$ 22,261	$ 3,205	$ -	$ 164,908	$ 164,908	$ -
1850	Line Transformers	$ 3,765,974	$ 122,116	$ -	$ 33,033	$ 3,610,825	$ -	$ -	452,404	-	-	452,404	-	221,555	32.08	3.12%	45.00	2.22%	112,559	$ 10,053	$ 2,462	$ -	$ 125,074	$ 125,074	$ -
1850	Line Transformers-Inventory	$ 96,563	$ -	$ -	$ -	$ 96,563	$ -	$ -	14,887	-	-	14,887	-	56,545	34.67	2.88%	45.00	2.22%	2,786	$ 331	$ 628	$ -	$ 3,745	$ 3,745	$ 0
1850	Line Transformers-Damaged	$ 9,005	$ -	$ -	$ -	$ 9,005	$ -	$ -	-	-	-	-	-	-	-	0.00%	45.00	2.22%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	Line Transformers-Spare	$ 73,441	$ -	$ -	$ -	$ 73,441	$ -	$ -	7,461	-	-	7,461	-	23,793	41.12	2.43%	45.00	2.22%	1,786	$ 166	$ 264	$ -	$ 2,216	$ 2,216	$ 0
1855	Services (Overhead)	$ 443,107	$ -	$ -	$ -	$ 443,107	$ -	$ -	43,888	-	-	43,888	-	14,725	55.08	1.82%	60.00	1.67%	8,044	$ 731	$ 123	$ -	$ 8,898	$ 8,898	$ (0)
1855	Services (Underground)	$ 1,679,060	$ -	$ -	$ -	$ 1,679,060	$ -	$ -	501,926	-	-	501,926	-	335,556	38.61	2.59%	45.00	2.22%	43,484	$ 11,154	$ 3,728	$ -	$ 58,367	$ 58,367	$ (0)
1860	Meters	$ 197,059	$ 1,298	$ 113	$ -	$ 195,648	$ 38	$ -	14,163	-	-	14,163	-	9,511	21.35	4.68%	25.00	4.00%	9,203	$ 567	$ 190	$ -	$ 9,960	$ 9,960	$ -
1860	Meters (Smart Meters)	$ 1,370,813	$ 3,839	$ -	$ -	$ 1,366,975	$ -	$ -	62,580	-	-	62,580	-	33,503	12.47	8.02%	15.00	6.67%	109,631	$ 4,172	$ 1,117	$ -	$ 114,919	$ 114,919	$ -
1860	Stranded Meters	$ 102,246	$ 96,489	$ 193	$ -	$ 5,565	$ 64	$ -	-	-	-	-	-	-	12.21	8.19%	-	0.00%	$ 520	$ -	$ -	$ -	$ 520	$ 520	$ -
1860	Non Stranded Meters-Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27,758	-	-	27,758	-	-	-	0.00%	25.00	4.00%	$ -	$ 1,110	$ -	$ -	$ 1,110	$ 1,110	$ -
1860	Non Stranded Meters-CT/PT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters Inventory	$ 39,189	$ -	$ -	$ -	$ 39,189	$ -	$ -	2,104	-	-	2,104	-	659	16.15	6.19%	25.00	4.00%	2,426	$ 84	$ 13	$ -	$ 2,524	$ 2,524	$ -
1860	Smart Meters Inventory	$ 46,634	$ -	$ -	$ -	$ 46,634	$ -	$ -	(23,015)	-	-	(23,015)	-	7,367	14.01	7.14%	15.00	6.67%	3,330	$ (1,534)	$ 246	$ -	$ 2,041	$ 2,041	$ 0
1860	Non Stranded Meters-CT/PT Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1905	Land	$ 49,000	$ -	$ -	$ -	$ 49,000	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures-8 Henegan Rd	$ 678,370	$ -	$ -	$ -	$ 678,370	$ -	$ -	6,777	-	-	6,777	-	7,008	39.33	2.54%	60.00	1.67%	17,249	$ 113	$ 58	$ -	$ 17,420	$ 17,420	$ 0
1908	Buildings & Fixtures-PCB Shed	$ 1,606	$ -	$ -	$ -	$ 1,606	$ -	$ -	-	-	-	-	-	-	5.00	19.99%	30.00	3.33%	321	$ -	$ -	$ -	$ 321	$ 321	$ (0)
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 43,264	$ 258	$ 1,277	$ -	$ 41,729	$ 254	$ -	2,509	-	-	2,509	-	4,302	6.55	15.26%	10.00	10.00%	6,621	$ 251	$ 215	$ -	$ 7,087	$ 7,087	$ (0)
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 38,222	$ 24,044	$ 14,178	$ -	$ (0)	$ 3,445	$ -	44,795	-	-	44,795	-	18,754	-	0.00%	3.00	33.33%	3,445	$ 14,932	$ 3,126	$ -	$ 21,502	$ 21,502	$ (0)
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment < 3 Tons	$ 11,707	$ 11,031	$ -	$ -	$ 676	$ -	$ -	53,681	-	-	53,681	-	44,963	3.42	29.27%	5.00	20.00%	$ 198	$ 10,736	$ 4,496	$ -	$ 15,430	$ 15,430	$ 0
1930	Transportation Equipment > 3 Tons	$ 623,113	$ -	$ -	$ -	$ 623,113	$ -	$ -	-	-	-	-	-	-	7.86	12.72%	10.00	10.00%	$ 79,258	$ -	$ -	$ -	$ 79,258	$ 79,258	$ (0)
1930	Transportation Equipment Trailers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment	$ 6,309	$ 1	$ -	$ -	$ 6,308	$ -	$ -	-	-	-	-	-	-	6.04	16.55%	10.00	10.00%	$ 1,044	$ -	$ -	$ -	$ 1,044	$ 1,044	$ (0)
1940	Tools, Shop & Garage Equipment	$ 63,171	$ 11,131	$ 15,347	$ -	$ 36,694	$ 3,049	$ -	8,300	-	-	8,300	-	3,842	4.79	20.87%	8.00	12.50%	$ 10,706	$ 1,037	$ 240	$ -	$ 11,984	$ 11,984	$ 0
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 15,938	$ -	$ 5,573	$ -	$ 10,364	$ 1,107	$ -	-	-	-	-	-	-	5.88	17.00%	10.00	10.00%	$ 2,869	$ -	$ -	$ -	$ 2,869	$ 2,869	$ (0)
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 110,749	$ 26,791	$ 55,491	$ -	$ 28,467	$ 11,025	$ -	237,952	-	-	237,952	-	-	4.68	21.36%	10.00	10.00%	17,107	$ 23,795	$ -	$ (5,568)	$ 35,334	$ 35,409	$ 75
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants-Poles	$ (169,565)	$ -	$ -	$ -	$ (169,565)	$ -	$ -	(6,683)	-	-	(6,683)	-	-	38.55	2.59%	45.00	2.22%	$ (4,399)	$ (149)	$ -	$ -	$ (4,548)	$ (4,548)	$ 0
1995	Contributions & Grants-OH Conductor	$ (164,116)	$ -	$ -	$ -	$ (164,116)	$ -	$ -	-	-	-	-	-	-	52.82	1.89%	60.00	1.67%	$ (3,107)	$ -	$ -	$ -	$ (3,107)	$ (3,107)	$ 0
1995	Contributions & Grants-O/H Services	$ (88,520)	$ -	$ -	$ -	$ (88,520)	$ -	$ -	(9,014)	-	-	(9,014)	-	-	51.24	1.95%	65.00	1.54%	$ (1,728)	$ (139)	$ -	$ -	$ (1,866)	$ (1,878)	$ (12)
1995	Contributions & Grants-UG Conduit	$ (578,117)	$ -	$ -	$ -	$ (578,117)	$ -	$ -	(97,678)	-	-	(97,678)	-	-	59.13	1.69%	65.00	1.54%	$ (9,777)	$ (1,503)	$ -	$ -	$ (11,280)	$ (11,280)	$ (0)
1995	Contributions & Grants-UG Conductor	$ (1,090,529)	$ -	$ -	$ -	$ (1,090,529)	$ -	$ -	(144,330)	-	-	(144,330)	-	-	37.00	2.70%	45.00	2.22%	$ (29,473)	$ (3,207)	$ -	$ -	$ (32,681)	$ (32,681)	$ 0
1995	Contributions & Grants-UG Services	$ (1,031,865)	$ -	$ -	$ -	$ (1,031,865)	$ -	$ -	(171,231)	-	-	(171,231)	-	-	38.47	2.60%	45.00	2.22%	$ (26,819)	$ (3,805)	$ -	$ -	$ (30,625)	$ (30,625)	$ (0)
1995	Contributions & Grants-TX	$ (1,509,639)	$ -	$ -	$ -	$ (1,509,639)	$ -	$ -	(143,573)	-	-	(143,573)	-	-	38.06	2.63%	45.00	2.22%	$ (39,669)	$ (3,191)	$ -	$ -	$ (42,859)	$ (42,859)	$ (0)
1995	Contributions & Grants-Meters	$ (4,319)	$ -	$ -	$ -	$ (4,319)	$ -	$ -	-	-	-	-	-	-	14.70	6.80%	25.00	4.00%	$ (294)	$ -	$ -	$ -	$ (294)	$ (294)	$ 0
1995	Contributions & Grants-Buildings	$ (9,620)	$ -	$ -	$ -	$ (9,620)	$ -	$ -	-	-	-	-	-	-	47.00	2.13%	60.00	1.67%	$ (205)	$ -	$ -	$ -	$ (205)	$ (205)	$ (0)
1995	Contributions & Grants-Rolling Stock	$ 0	$ -	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1605	Organization	$ 9,807	$ 9,807	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	20.00	5.00%	-	0.00%	$ (0)	$ -	$ -	$ -	$ (0)	$ (6)	$ 0
2440	Def Rev-Contributions & Grants-O/H Poles	$ -	$ -	$ -	$ -	$ -	$ -	$ -	9,252	-	-	9,252	-	(4,658)	-	0.00%	45.00	2.22%	$ -	$ 206	$ (52)	$ -	$ 154	$ 154	$ -
2440	Def Rev-Contributions & Grants-O/H Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	168	-	-	168	-	(4,516)	-	0.00%	60.00	1.67%	$ -	$ 3	$ (38)	$ -	$ (35)	$ (35)	$ 0
2440	Def Rev-Contributions & Grants-O/H Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(15,377)	-	-	(15,377)	-	(8,277)	-	0.00%	60.00	1.67%	$ -	$ (256)	$ (69)	$ -	$ (325)	$ (325)	$ 0
2440	Def Rev-Contributions & Grants-U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(219,667)	-	-	(219,667)	-	(95,395)	-	0.00%	65.00	1.54%	$ -	$ (3,379)	$ (734)	$ -	$ (4,113)	$ (4,113)	$ -
2440	Def Rev-Contributions & Grants-U/G Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(212,022)	-	-	(212,022)	-	(108,236)	-	0.00%	45.00	2.22%	$ -	$ (4,712)	$ (1,203)	$ -	$ (5,914)	$ (5,914)	$ (0)
2440	Def Rev-Contributions & Grants-U/G Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(207,443)	-	-	(207,443)	-	(262,080)	-	0.00%	45.00	2.22%	$ -	$ (4,610)	$ (2,912)	$ -	$ (7,522)	$ (7,522)	$ (0)
2440	Def Rev-Contributions & Grants-Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(63,055)	-	-	(63,055)	-	(110,362)	-	0.00%	45.00	2.22%	$ -	$ (1,401)	$ (1,226)	$ -	$ (2,627)	$ (2,627)	$ 0
2440	Def Rev-Contributions & Grants-Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(320)	-	-	(320)	-	(7,196)	-	0.00%	25.00	4.00%	$ -	$ (13)	$ (144)	$ -	$ (157)	$ (157)	$ 0
2440	Def Rev-Contributions & Grants-Admin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	60.00	1.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Rolling Stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def Rev-Contributions & Grants-Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Battery	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 21,566,951**	**$ 432,502**	**$ 200,786**	**$ 44,200**	**$ 20,889,463**	**$ 44,986**	**$ -**	**2,885,478**	**-**	**-**	**2,885,478**	**-**	**3,649,238**					**$ 807,742**	**$ 178,176**	**$ 63,102**	**-$ 5,568**	**$ 1,043,451**	**$ 1,043,515**	**$ 63**
														3,649,237.73										1,043,515.11	
														0.00										(0.26)	

Appendix 2-C
Depreciation and Amortization Expense

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012.	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013.	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2016	MIFR

		Book Values													Service Lives				Depreciation Expense						
Account	Description	Opening NBV of Assets at Date of Policy Change- Jan. 1, 2013	Less Fully Depreciated / Disposals Previous Years	Fully Depreciated Current Year (NBV)	Less Disposals (NBV)	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [c]	Depreciation Expense on Disposals Current Year	Opening Gross Book Value of Assets Acquired After Policy Change	Less Fully Depreciated Previous Years	Less Fully Depreciated Current Year	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [i]	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions (1/2 year rule)	Adjustments	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J 2016	Variance
		a	b	c	d	e = a - b - c - d	f	g	h	i	j	k = h - i - j	l	m	n	o = 1/n	p	q = 1/p	r = e/n + f + g	s = k/p +l	t = m/p x 0.5	u	v = r + s + t + u	w	x = w - v
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 -TX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,661,056	-	-	1,661,056	-	30,906	-	0.00%	45.00	2.22%	$ -	$ 36,912	$ 343	$ -	$ 37,256	$ 37,256	$ -
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 OTHER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	875,691	-	-	875,691	-	16,642	-	0.00%	55.00	1.82%	$ -	$ 15,922	$ 151	$ -	$ 16,073	$ 15,878	$ (195)
1611	Computer Software (Formally known as Account 1925)	$ 165,566	$ 165,566	$ -	$ -	$ (0)	$ -	$ -	343,088	-	104,895	238,193	17,483	110,456	-	0.00%	3.00	33.33%	$ -	$ 96,880	$ 18,409	$ -	$ 115,290	$ 115,290	$ (0)
1925	CIS Upgrade	$ 119,000	$ -	$ 119,000	$ -	$ 0	$ 16,960	$ -	-	-	-	-	-	-	-	0.00%	3.00	33.33%	$ 16,960	$ -	$ -	$ -	$ 16,960	$ 16,960	$ 0
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 258,134	$ -	$ -	$ -	$ 258,134	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV York (TX)	$ 630,588	$ -	$ -	$ -	$ 630,588	$ -	$ -	-	-	-	-	-	-	35.52	2.82%	45.00	2.22%	$ 17,753	$ -	$ -	$ 49	$ 17,801	$ 17,801	$ -
1815	Transformer Station Equipment >50 kV York Other	$ 1,466,075	$ -	$ -	$ -	$ 1,466,075	$ -	$ -	11,056	-	-	11,056	-	29,230	45.66	2.19%	55.00	1.82%	$ 32,109	$ 201	$ 266	$ 88	$ 32,664	$ 32,664	$ (0)
1815	Transformer Station Equipment >50 kV Conc 5 (TX)	$ 544,453	$ -	$ -	$ -	$ 544,453	$ -	$ -	-	-	-	-	-	-	37.52	2.67%	45.00	2.22%	$ 14,511	$ -	$ -	$ -	$ 14,511	$ 14,511	$ -
1815	Transformer Station Equipment >50 kV Conc 5 Other	$ 1,664,608	$ -	$ -	$ -	$ 1,664,608	$ -	$ -	-	-	-	-	-	-	47.97	2.08%	55.00	1.82%	$ 34,701	$ -	$ -	$ -	$ 34,701	$ 34,701	$ -
1820	Distribution Station Equipment <50 kV	$ 47,927	$ 47,927	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,130,517	$ 7,469	$ 28,686	$ 2,487	$ 2,091,875	$ 7,186	$ -	629,368	-	-	629,368	-	389,988	29.64	0.03	45.00	2.22%	$ 77,760	$ 13,986	$ 4,333	$ -	$ 96,080	$ 96,080	$ -
1835	Overhead Conductors & Devices	$ 2,838,661	$ 24,518	$ -	$ 2,539	$ 2,811,604	$ -	$ -	555,172	-	-	555,172	-	220,211	44.65	0.02	60.00	1.67%	$ 62,970	$ 9,253	$ 1,835	$ -	$ 74,058	$ 74,058	$ -
1840	Underground Conduit	$ 2,705,310	$ -	$ -	$ -	$ 2,705,310	$ -	$ -	810,501	-	-	810,501	-	242,371	53.12	0.02	65.00	1.54%	$ 50,929	$ 12,469	$ 1,864	$ -	$ 65,263	$ 65,263	$ -
1845	Underground Conductors & Devices	$ 4,168,057	$ -	$ -	$ -	$ 4,168,057	$ -	$ -	1,290,225	-	-	1,290,225	-	490,830	29.81	3.35%	45.00	2.22%	$ 139,823	$ 28,672	$ 5,454	$ -	$ 173,949	$ 173,949	$ -
1850	Line Transformers	$ 3,765,974	$ 155,149	$ 2,512	$ 33,412	$ 3,574,902	$ 629	$ -	673,958	-	-	673,958	-	793,436	32.46	3.08%	45.00	2.22%	$ 110,766	$ 14,977	$ 8,816	$ -	$ 134,559	$ 134,559	$ (0)
1850	Line Transformers-Inventory	$ 96,563	$ -	$ -	$ -	$ 96,563	$ -	$ -	71,432	-	-	71,432	-	(67,705)	34.67	2.88%	45.00	2.22%	$ 2,786	$ 1,587	$ (752)	$ -	$ 3,621	$ 3,621	$ 0
1850	Line Transformers-Damaged	$ 9,005	$ -	$ -	$ -	$ 9,005	$ -	$ -	-	-	-	-	-	-	30.34	3.30%	45.00	2.22%	$ 297	$ -	$ -	$ -	$ 297	$ 297	$ -
1850	Line Transformers-Spare	$ 73,441	$ -	$ -	$ -	$ 73,441	$ -	$ -	31,254	-	-	31,254	-	45,642	41.12	2.43%	45.00	2.22%	$ 1,786	$ 695	$ 507	$ -	$ 2,988	$ 2,988	$ (0)
1855	Services (Overhead)	$ 443,107	$ -	$ -	$ -	$ 443,107	$ -	$ -	58,613	-	-	58,613	-	10,231	54.93	1.82%	60.00	1.67%	$ 8,066	$ 977	$ 85	$ -	$ 9,128	$ 9,128	$ -
1855	Services (Underground)	$ 1,679,060	$ -	$ -	$ -	$ 1,679,060	$ -	$ -	837,483	-	-	837,483	-	282,564	38.51	2.60%	45.00	2.22%	$ 43,604	$ 18,611	$ 3,140	$ -	$ 65,354	$ 65,354	$ -
1860	Meters	$ 197,059	$ 1,411	$ 1,890	$ 3,006	$ 190,752	$ 474	$ -	23,675	-	-	23,675	-	52,668	20.18	4.95%	25.00	4.00%	$ 9,925	$ 947	$ 1,053	$ -	$ 11,926	$ 11,926	$ -
1860	Meters (Smart Meters)	$ 1,370,813	$ 3,839	$ -	$ 753	$ 1,366,222	$ -	$ -	96,083	-	-	96,083	-	93,188	12.61	7.93%	15.00	6.67%	$ 108,335	$ 6,406	$ 3,106	$ -	$ 117,846	$ 117,846	$ -
1860	Stranded Meters	$ 102,246	$ 96,682	$ 3,217	$ -	$ 2,348	$ 806	$ -	-	-	-	-	-	-	12.21	8.19%	-	0.00%	$ 998	$ -	$ -	$ -	$ 998	$ 998	$ -
1860	Non Stranded Meters-Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27,758	-	-	27,758	-	-	-	0.00%	25.00	4.00%	$ -	$ 1,110	$ -	$ -	$ 1,110	$ 1,110	$ -
1860	Non Stranded Meters-CT/PT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters Inventory	$ 39,189	$ -	$ -	$ -	$ 39,189	$ -	$ -	2,763	-	-	2,763	-	(18,903)	16.15	6.19%	25.00	4.00%	$ 2,426	$ 111	$ (378)	$ -	$ 2,159	$ 2,159	$ -
1860	Smart Meters Inventory	$ 46,634	$ -	$ -	$ -	$ 46,634	$ -	$ -	(15,648)	-	-	(15,648)	-	(590)	14.01	7.14%	15.00	6.67%	$ 3,330	$ (1,043)	$ (20)	$ -	$ 2,267	$ 2,267	$ -
1860	Non Stranded Meters-CT/PT Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	5,962	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ 75	$ 75
1905	Land	$ 49,000	$ -	$ -	$ -	$ 49,000	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures-8 Henegan Rd	$ 678,370	$ -	$ -	$ -	$ 678,370	$ -	$ -	13,785	-	-	13,785	-	81,142	39.22	2.55%	60.00	1.67%	$ 17,296	$ 230	$ 676	$ -	$ 18,202	$ 18,202	$ -
1908	Buildings & Fixtures-PCB Shed	$ 1,606	$ -	$ -	$ -	$ 1,606	$ -	$ -	-	-	-	-	-	-	5.00	19.99%	30.00	3.33%	$ 321	$ -	$ -	$ -	$ 321	$ 322	$ 1
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 43,264	$ 1,535	$ 3,663	$ -	$ 38,066	$ 522	$ -	6,811	-	-	6,811	-	1,542	7.14	14.01%	10.00	10.00%	$ 5,857	$ 681	$ 77	$ -	$ 6,615	$ 6,615	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 38,222	$ 38,222	$ -	$ -	$ (0)	$ -	$ -	63,549	-	38,762	24,787	6,460	9,825	-	0.00%	3.00	33.33%	$ -	$ 14,723	$ 1,638	$ -	$ 16,360	$ 16,360	$ (0)
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment < 3 Tons	$ 11,707	$ 11,031	$ 676	$ -	$ 0	$ 82	$ -	98,643	-	-	98,643	-	-	-	0.00%	5.00	20.00%	$ 82	$ 19,729	$ -	$ -	$ 19,811	$ 19,811	$ (0)
1930	Transportation Equipment > 3 Tons	$ 623,113	$ -	$ -	$ -	$ 623,113	$ -	$ -	-	-	-	-	-	-	7.84	12.75%	10.00	10.00%	$ 79,475	$ -	$ -	$ -	$ 79,475	$ 79,475	$ -
1930	Transportation Equipment Trailers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment	$ 6,309	$ 1	$ -	$ -	$ 6,308	$ -	$ -	-	-	-	-	-	-	6.04	16.55%	10.00	10.00%	$ 1,044	$ -	$ -	$ -	$ 1,044	$ 1,047	$ 3
1940	Tools, Shop & Garage Equipment	$ 63,171	$ 26,478	$ 10,745	$ -	$ 25,948	$ 1,531	$ -	12,142	-	-	12,142	-	13,286	5.64	17.72%	8.00	12.50%	$ 6,130	$ 1,518	$ 830	$ -	$ 8,478	$ 8,478	$ -
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 15,938	$ 5,573	$ -	$ -	$ 10,364	$ -	$ -	-	-	-	-	-	-	5.88	17.00%	10.00	10.00%	$ 1,762	$ -	$ -	$ -	$ 1,762	$ 1,767	$ 5
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 110,749	$ 82,282	$ 11,149	$ -	$ 17,318	$ 1,589	$ -	237,952	-	-	237,952	-	43,204	5.98	16.72%	10.00	10.00%	$ 4,484	$ 23,795	$ 2,160	$ (5,568)	$ 24,871	$ 25,005	$ 133
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants-Poles	$ (169,565)	$ -	$ -	$ -	$ (169,565)	$ -	$ -	(6,683)	-	-	(6,683)	-	-	38.55	2.59%	45.00	2.22%	$ (4,399)	$ (149)	$ -	$ -	$ (4,548)	$ (4,548)	$ 0
1995	Contributions & Grants-OH Conductor	$ (164,116)	$ -	$ -	$ -	$ (164,116)	$ -	$ -	-	-	-	-	-	-	52.82	1.89%	60.00	1.67%	$ (3,107)	$ -	$ -	$ -	$ (3,107)	$ (3,107)	$ 0
1995	Contributions & Grants-O/H Services	$ (88,520)	$ -	$ -	$ -	$ (88,520)	$ -	$ -	(9,014)	-	-	(9,014)	-	-	51.24	1.95%	65.00	1.54%	$ (1,728)	$ (139)	$ -	$ -	$ (1,866)	$ (1,878)	$ (12)
1995	Contributions & Grants-UG Conduit	$ (578,117)	$ -	$ -	$ -	$ (578,117)	$ -	$ -	(97,678)	-	-	(97,678)	-	-	59.13	1.69%	65.00	1.54%	$ (9,777)	$ (1,503)	$ -	$ -	$ (11,280)	$ (11,280)	$ (0)
1995	Contributions & Grants-UG Conductor	$ (1,090,529)	$ -	$ -	$ -	$ (1,090,529)	$ -	$ -	(144,330)	-	-	(144,330)	-	-	37.00	2.70%	45.00	2.22%	$ (29,473)	$ (3,207)	$ -	$ -	$ (32,681)	$ (32,681)	$ (0)
1995	Contributions & Grants-UG Services	$ (1,031,865)	$ -	$ -	$ -	$ (1,031,865)	$ -	$ -	(171,231)	-	-	(171,231)	-	-	38.47	2.60%	45.00	2.22%	$ (26,819)	$ (3,805)	$ -	$ -	$ (30,625)	$ (30,625)	$ 0
1995	Contributions & Grants-TX	$ (1,509,639)	$ -	$ -	$ -	$ (1,509,639)	$ -	$ -	(143,573)	-	-	(143,573)	-	-	38.06	2.63%	45.00	2.22%	$ (39,669)	$ (3,193)	$ -	$ -	$ (42,859)	$ (42,859)	$ (0)
1995	Contributions & Grants-Meters	$ (4,319)	$ -	$ -	$ -	$ (4,319)	$ -	$ -	-	-	-	-	-	-	14.70	6.80%	25.00	4.00%	$ (294)	$ -	$ -	$ -	$ (294)	$ (294)	$ (0)
1995	Contributions & Grants-Buildings	$ (9,620)	$ -	$ -	$ -	$ (9,620)	$ -	$ -	-	-	-	-	-	-	47.00	2.13%	60.00	1.67%	$ (205)	$ -	$ -	$ -	$ (205)	$ (205)	$ (0)
1995	Contributions & Grants-Rolling Stock	$ 0	$ -	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1605	Organization	$ 9,807	$ 9,807	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	20.00	5.00%	-	0.00%	$ (0)	$ -	$ -	$ -	$ (0)	$ (6)	$ 0
2440	Def Rev-Contributions & Grants-O/H Poles	$ -	$ -	$ -	$ -	$ -	$ -	$ -	4,594	-	-	4,594	-	(200,138)	-	0.00%	45.00	2.22%	$ -	$ 102	$ (2,224)	$ -	$ (2,122)	$ (2,122)	$ -
2440	Def Rev-Contributions & Grants-O/H Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(4,348)	-	-	(4,348)	-	(83,434)	-	0.00%	60.00	1.67%	$ -	$ (72)	$ (695)	$ -	$ (768)	$ (768)	$ (0)
2440	Def Rev-Contributions & Grants-O/H Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(23,655)	-	-	(23,655)	-	(4,549)	-	0.00%	60.00	1.67%	$ -	$ (394)	$ (38)	$ -	$ (432)	$ (432)	$ 0
2440	Def Rev-Contributions & Grants-U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(315,062)	-	-	(315,062)	-	(128,955)	-	0.00%	65.00	1.54%	$ -	$ (4,847)	$ (992)	$ -	$ (5,839)	$ (5,839)	$ (0)
2440	Def Rev-Contributions & Grants-U/G Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(320,258)	-	-	(320,258)	-	(281,791)	-	0.00%	45.00	2.22%	$ -	$ (7,117)	$ (3,131)	$ -	$ (10,248)	$ (10,248)	$ (0)
2440	Def Rev-Contributions & Grants-U/G Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(469,524)	-	-	(469,524)	-	(195,466)	-	0.00%	45.00	2.22%	$ -	$ (10,434)	$ (2,172)	$ -	$ (12,606)	$ (12,606)	$ (0)
2440	Def Rev-Contributions & Grants-Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(173,417)	-	-	(173,417)	-	(658,899)	-	0.00%	45.00	2.22%	$ -	$ (3,854)	$ (7,321)	$ -	$ (11,175)	$ (11,175)	$ 0
2440	Def Rev-Contributions & Grants-Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(7,516)	-	-	(7,516)	-	(50,044)	-	0.00%	25.00	4.00%	$ -	$ (301)	$ (1,001)	$ -	$ (1,302)	$ (1,302)	$ 0
2440	Def Rev-Contributions & Grants-Admin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	60.00	1.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Rolling Stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def Rev-Contributions & Grants-Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Battery	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 21,566,951**	**$ 677,488**	**$ 181,538**	**$ 42,197**	**$ 20,665,728**	**$ 29,780**	**$ -**	**6,534,715**	**-**	**143,657**	**6,391,058**	**23,943**	**1,272,851**					**$ 740,815**	**$ 280,437**	**$ 36,021**	**-$ 5,432**	**$ 1,051,842**	**$ 1,051,852**	**$ 9**
														1,272,850.50										1,051,851.60	
														-										-	

Appendix 2-C
Depreciation and Amortization Expense

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012.	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013.	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2017	MIFR

		Book Values													Service Lives				Depreciation Expense							
Account	Description	Opening NBV of Assets at Date of Policy Change- Jan. 1, 2013	Less Fully Depreciated / Disposals Previous Years	Fully Depreciated Current Year (NBV)	Less Disposals (NBV)	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [c]	Depreciation Expense on Disposals Current Year	Opening Gross Book Value of Assets Acquired After Policy Change	Less Fully Depreciated Previous Years	Less Fully Depreciated Current Year	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [i]	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions (1/2 year rule)	Adjustments	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J 2017	Variance
		a	b	c	d	e = a - b - c - d	f	g	h	i	j	k = h - i - j	l	m	n	o = 1/n	p	q = 1/p	r = e/n + f + g	s = k/p +l	t = m/p x 0.5	u	v = r + s + t + u	w	x = w - v
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 -TX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,691,962	-	-	1,691,962	-	(12,199)	-	0.00%	45.00	2.22%	$ -	$ 37,599	$ (136)	$ -	$ 37,464	$ 37,464	$ -
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 OTHER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	892,333	-	-	892,333	-	(6,568)	-	0.00%	55.00	1.82%	$ -	$ 16,224	$ (60)	$ -	$ 16,165	$ 15,969	$ (195)
1611	Computer Software (Formally known as Account 1925)	$ 165,566	$ 165,566	$ -	$ -	$ (0)	$ -	$ -	453,545	104,895	129,375	219,274	21,563	128,951	-	0.00%	3.00	33.33%	$ -	$ 94,654	$ 21,492	$ -	$ 116,146	$ 116,146	$ (0)
1925	CIS Upgrade	$ 119,000	$ 119,000	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 258,134	$ -	$ -	$ -	$ 258,134	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV York (TX)	$ 630,588	$ -	$ -	$ -	$ 630,588	$ -	$ -	-	-	-	-	-	-	35.52	2.82%	45.00	2.22%	$ 17,753	$ -	$ -	$ -	$ 17,753	$ 17,753	$ -
1815	Transformer Station Equipment >50 kV York Other	$ 1,466,075	$ -	$ -	$ -	$ 1,466,075	$ -	$ -	40,286	-	-	40,286	-	-	45.66	2.19%	55.00	1.82%	$ 32,109	$ 732	$ -	$ -	$ 32,842	$ 32,842	$ (0)
1815	Transformer Station Equipment >50 kV Conc 5 (TX)	$ 544,453	$ -	$ -	$ -	$ 544,453	$ -	$ -	-	-	-	-	-	-	37.52	2.67%	45.00	2.22%	$ 14,511	$ -	$ -	$ -	$ 14,511	$ 14,511	$ -
1815	Transformer Station Equipment >50 kV Conc 5 Other	$ 1,664,608	$ -	$ -	$ -	$ 1,664,608	$ -	$ -	-	-	-	-	-	62,902	48.16	2.08%	55.00	1.82%	$ 34,567	$ -	$ 572	$ -	$ 35,139	$ 35,139	$ (0)
1820	Distribution Station Equipment <50 kV	$ 47,927	$ 47,927	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,130,517	$ 38,642	$ -	$ 11,161	$ 2,080,714	$ -	$ -	1,019,355	-	-	1,019,355	-	200,277	29.73	0.03	45.00	2.22%	$ 69,976	$ 22,652	$ 2,225	$ -	$ 94,854	$ 94,854	$ -
1835	Overhead Conductors & Devices	$ 2,838,661	$ 27,057	$ -	$ 40,569	$ 2,771,035	$ -	$ -	775,383	-	-	775,383	-	204,722	44.63	0.02	60.00	1.67%	$ 62,094	$ 12,923	$ 1,706	$ -	$ 76,723	$ 76,723	$ (0)
1840	Underground Conduit	$ 2,705,310	$ -	$ -	$ -	$ 2,705,310	$ -	$ -	1,052,872	-	-	1,052,872	-	79,252	53.24	0.02	65.00	1.54%	$ 50,817	$ 16,198	$ 610	$ -	$ 67,625	$ 67,625	$ -
1845	Underground Conductors & Devices	$ 4,168,057	$ -	$ -	$ -	$ 4,168,057	$ -	$ -	1,781,055	-	-	1,781,055	-	153,950	29.89	3.35%	45.00	2.22%	$ 139,442	$ 39,579	$ 1,711	$ -	$ 180,731	$ 180,731	$ -
1850	Line Transformers	$ 3,765,974	$ 191,072	$ -	$ 52,090	$ 3,522,812	$ -	$ -	1,467,395	-	-	1,467,395	-	337,663	32.52	3.08%	45.00	2.22%	$ 108,338	$ 32,609	$ 3,752	$ -	$ 144,699	$ 144,699	$ (0)
1850	Line Transformers-Inventory	$ 96,563	$ -	$ -	$ -	$ 96,563	$ -	$ -	3,727	-	-	3,727	-	(11,493)	34.67	2.88%	45.00	2.22%	$ 2,786	$ 83	$ (128)	$ -	$ 2,741	$ 2,741	$ (0)
1850	Line Transformers-Damaged	$ 9,005	$ -	$ -	$ -	$ 9,005	$ -	$ -	-	-	-	-	-	-	30.34	3.30%	45.00	2.22%	$ 297	$ -	$ -	$ -	$ 297	$ 297	$ -
1850	Line Transformers-Spare	$ 73,441	$ -	$ -	$ -	$ 73,441	$ -	$ -	76,896	-	-	76,896	-	(6,053)	41.12	2.43%	45.00	2.22%	$ 1,796	$ 1,709	$ (67)	$ -	$ 3,428	$ 3,428	$ 0
1855	Services (Overhead)	$ 443,107	$ -	$ -	$ -	$ 443,107	$ -	$ -	68,844	-	-	68,844	-	5,770	55.08	1.82%	60.00	1.67%	$ 8,044	$ 1,147	$ 48	$ -	$ 9,240	$ 9,240	$ (0)
1855	Services (Underground)	$ 1,679,060	$ -	$ -	$ -	$ 1,679,060	$ -	$ -	1,120,047	-	-	1,120,047	-	198,083	38.61	2.59%	45.00	2.22%	$ 43,484	$ 24,890	$ 2,201	$ -	$ 70,575	$ 70,575	$ 0
1860	Meters	$ 197,059	$ 6,308	$ 1,664	$ 95	$ 188,992	$ 333	$ -	76,343	-	-	76,343	-	4,774	21.66	4.62%	25.00	4.00%	$ 9,060	$ 3,054	$ 95	$ -	$ 12,209	$ 12,215	$ 6
1860	Meters (Smart Meters)	$ 1,370,813	$ 4,592	$ -	$ -	$ 1,366,222	$ -	$ -	189,272	-	-	189,272	-	71,670	12.56	7.96%	15.00	6.67%	$ 108,812	$ 12,618	$ 2,389	$ -	$ 123,819	$ 123,819	$ -
1860	Stranded Meters	$ 102,246	$ 99,898	$ 2,832	$ -	$ (484)	$ 566	$ -	-	-	-	-	-	-	0.86	116.90%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Non Stranded Meters-Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27,758	-	-	27,758	-	-	-	0.00%	25.00	4.00%	$ -	$ 1,110	$ -	$ -	$ 1,110	$ 1,110	$ -
1860	Non Stranded Meters-CT/PT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters Inventory	$ 39,189	$ -	$ -	$ -	$ 39,189	$ -	$ -	(16,139)	-	-	(16,139)	-	4,638	16.15	6.19%	25.00	4.00%	$ 2,426	$ (646)	$ 93	$ -	$ 1,873	$ 1,873	$ -
1860	Smart Meters Inventory	$ 46,634	$ -	$ -	$ -	$ 46,634	$ -	$ -	(16,238)	-	-	(16,238)	-	(1,661)	13.39	7.47%	15.00	6.67%	$ 3,483	$ (1,083)	$ (55)	$ -	$ 2,345	$ 2,345	$ -
1860	Non Stranded Meters-CT/PT Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	5,962	-	-	5,962	-	346	-	0.00%	40.00	2.50%	$ -	$ 149	$ 4	$ -	$ 153	$ 153	$ -
1905	Land	$ 49,000	$ -	$ -	$ -	$ 49,000	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures-8 Henegan Rd	$ 678,370	$ -	$ -	$ -	$ 678,370	$ -	$ -	94,927	-	-	94,927	-	49,690	39.33	2.54%	60.00	1.67%	$ 17,249	$ 1,582	$ 414	$ -	$ 19,245	$ 19,245	$ 0
1908	Buildings & Fixtures-PCB Shed	$ 1,606	$ -	$ 1,606	$ -	$ (0)	$ 321	$ -	-	-	-	-	-	-	5.00	19.99%	30.00	3.33%	$ 321	$ -	$ -	$ -	$ 321	$ 321	$ 0
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 43,264	$ 5,198	$ 3,292	$ -	$ 34,774	$ 363	$ -	8,353	-	-	8,353	-	4,854	7.58	13.20%	10.00	10.00%	$ 4,951	$ 835	$ 243	$ -	$ 6,029	$ 6,029	$ 0
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 38,222	$ 38,222	$ -	$ -	$ (0)	$ -	$ -	73,374	38,762	6,033	28,579	1,006	17,584	-	0.00%	3.00	33.33%	$ -	$ 10,532	$ 2,931	$ -	$ 13,463	$ 13,463	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment < 3 Tons	$ 11,707	$ 11,707	$ -	$ -	$ 0	$ -	$ -	98,643	-	-	98,643	-	-	-	0.00%	5.00	20.00%	$ -	$ 19,729	$ -	$ -	$ 19,729	$ 19,729	$ (0)
1930	Transportation Equipment > 3 Tons	$ 623,113	$ -	$ 78,117	$ -	$ 544,996	$ 8,611	$ -	-	-	-	-	-	-	8.81	11.36%	10.00	10.00%	$ 70,504	$ -	$ -	$ -	$ 70,504	$ 70,504	$ (0)
1930	Transportation Equipment Trailers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	45,650	-	0.00%	15.00	6.67%	$ -	$ -	$ 1,522	$ -	$ 1,522	$ 1,522	$ 0
1935	Stores Equipment	$ 6,309	$ 1	$ 810	$ -	$ 5,498	$ 89	$ -	-	-	-	-	-	-	6.36	15.72%	10.00	10.00%	$ 954	$ -	$ -	$ -	$ 954	$ 954	$ 0
1940	Tools, Shop & Garage Equipment	$ 63,171	$ 37,223	$ 5,738	$ -	$ 20,210	$ 633	$ -	25,428	-	-	25,428	-	9,498	6.11	16.38%	8.00	12.50%	$ 3,943	$ 3,178	$ 594	$ -	$ 7,715	$ 7,715	$ 0
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 15,938	$ 5,573	$ -	$ -	$ 10,364	$ -	$ -	-	-	-	-	-	-	5.88	17.00%	10.00	10.00%	$ 1,762	$ -	$ -	$ -	$ 1,762	$ 1,762	$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 110,749	$ 93,431	$ 8,057	$ -	$ 9,261	$ 888	$ -	281,156	-	-	281,156	-	60,943	8.39	11.92%	10.00	10.00%	$ 1,992	$ 28,116	$ 3,047	$ (5,568)	$ 27,587	$ 27,662	$ 75
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants-Poles	$ (169,565)	$ -	$ -	$ -	$ (169,565)	$ -	$ -	(6,683)	-	-	(6,683)	-	-	38.55	2.59%	45.00	2.22%	$ (4,399)	$ (149)	$ -	$ -	$ (4,548)	$ (4,548)	$ (0)
1995	Contributions & Grants-OH Conductor	$ (164,116)	$ -	$ -	$ -	$ (164,116)	$ -	$ -	-	-	-	-	-	-	52.82	1.89%	60.00	1.67%	$ (3,107)	$ -	$ -	$ -	$ (3,107)	$ (3,107)	$ (0)
1995	Contributions & Grants-O/H Services	$ (88,520)	$ -	$ -	$ -	$ (88,520)	$ -	$ -	(9,014)	-	-	(9,014)	-	-	51.24	1.95%	65.00	1.54%	$ (1,728)	$ (139)	$ -	$ -	$ (1,866)	$ (1,878)	$ (12)
1995	Contributions & Grants-UG Conduit	$ (578,117)	$ -	$ -	$ -	$ (578,117)	$ -	$ -	(97,678)	-	-	(97,678)	-	-	59.13	1.69%	65.00	1.54%	$ (9,777)	$ (1,503)	$ -	$ -	$ (11,280)	$ (11,280)	$ (0)
1995	Contributions & Grants-UG Conductor	$ (1,090,529)	$ -	$ -	$ -	$ (1,090,529)	$ -	$ -	(144,330)	-	-	(144,330)	-	-	37.00	2.70%	45.00	2.22%	$ (29,473)	$ (3,207)	$ -	$ -	$ (32,681)	$ (32,681)	$ (0)
1995	Contributions & Grants-UG Services	$ (1,031,865)	$ -	$ -	$ -	$ (1,031,865)	$ -	$ -	(171,231)	-	-	(171,231)	-	-	38.47	2.60%	45.00	2.22%	$ (26,819)	$ (3,805)	$ -	$ -	$ (30,625)	$ (30,625)	$ 0
1995	Contributions & Grants-TX	$ (1,509,639)	$ -	$ -	$ -	$ (1,509,639)	$ -	$ -	(143,573)	-	-	(143,573)	-	-	38.06	2.63%	45.00	2.22%	$ (39,669)	$ (3,193)	$ -	$ -	$ (42,859)	$ (42,859)	$ 0
1995	Contributions & Grants-Meters	$ (4,319)	$ -	$ -	$ -	$ (4,319)	$ -	$ -	-	-	-	-	-	-	14.70	6.80%	25.00	4.00%	$ (294)	$ -	$ -	$ -	$ (294)	$ (294)	$ (0)
1995	Contributions & Grants-Buildings	$ (9,620)	$ -	$ -	$ -	$ (9,620)	$ -	$ -	-	-	-	-	-	-	47.00	2.13%	60.00	1.67%	$ (205)	$ -	$ -	$ -	$ (205)	$ (205)	$ (0)
1995	Contributions & Grants-Rolling Stock	$ 0	$ -	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1606	Organization	$ 9,807	$ 9,807	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	20.00	5.00%	-	0.00%	$ (0)	$ -	$ -	$ -	$ (0)	$ -	$ 0
2440	Def Rev-Contributions & Grants-O/H Poles	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(195,544)	-	-	(195,544)	-	(5,411)	-	0.00%	45.00	2.22%	$ -	$ (4,345)	$ (60)	$ -	$ (4,406)	$ (4,406)	$ -
2440	Def Rev-Contributions & Grants-O/H Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(87,783)	-	-	(87,783)	-	(5,713)	-	0.00%	60.00	1.67%	$ -	$ (1,463)	$ (48)	$ -	$ (1,511)	$ (1,511)	$ -
2440	Def Rev-Contributions & Grants-O/H Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(28,204)	-	-	(28,204)	-	(5,774)	-	0.00%	60.00	1.67%	$ -	$ (470)	$ (48)	$ -	$ (518)	$ (518)	$ 0
2440	Def Rev-Contributions & Grants-U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(444,017)	-	-	(444,017)	-	(12,498)	-	0.00%	65.00	1.54%	$ -	$ (6,831)	$ (96)	$ -	$ (6,927)	$ (6,927)	$ 0
2440	Def Rev-Contributions & Grants-U/G Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(602,049)	-	-	(602,049)	-	(60,737)	-	0.00%	45.00	2.22%	$ -	$ (13,379)	$ (675)	$ -	$ (14,054)	$ (14,054)	$ -
2440	Def Rev-Contributions & Grants-U/G Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(664,990)	-	-	(664,990)	-	(115,089)	-	0.00%	45.00	2.22%	$ -	$ (14,778)	$ (1,279)	$ -	$ (16,056)	$ (16,056)	$ (0)
2440	Def Rev-Contributions & Grants-Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(832,316)	-	-	(832,316)	-	(102,696)	-	0.00%	45.00	2.22%	$ -	$ (18,496)	$ (1,141)	$ -	$ (19,637)	$ (19,637)	$ -
2440	Def Rev-Contributions & Grants-Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(57,560)	-	-	(57,560)	-	(12,035)	-	0.00%	25.00	4.00%	$ -	$ (2,302)	$ (241)	$ -	$ (2,543)	$ (2,543)	$ 0
2440	Def Rev-Contributions & Grants-Admin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	60.00	1.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Rolling Stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def Rev-Contributions & Grants-Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Battery	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 21,566,951**	**$ 901,223**	**$ 102,116**	**$ 103,915**	**$ 20,459,697**	**$ 11,803**	**$ -**	**7,807,566**	**143,657**	**135,409**	**7,528,500**	**22,568**	**1,283,291**					**$ 695,990**	**$ 306,118**	**$ 41,614**	**-$ 5,568**	**$ 1,038,155**	**$ 1,038,029**	**-$ 126**
														1,283,290.52 0.36										1,038,028.70 (0.01)	

Appendix 2-C
Depreciation and Amortization Expense

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012.	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013.	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2018	MIFR

		Book Values													Service Lives				Depreciation Expense							
Account	Description	Opening NBV of Assets at Date of Policy Change- Jan. 1, 2013	Less Fully Depreciated / Disposals Previous Years	Fully Depreciated Current Year (NBV)	Less Disposals (NBV)	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [c]	Depreciation Expense on Disposals Current Year	Opening Gross Book Value of Assets Acquired After Policy Change	Less Fully Depreciated Previous Years	Less Fully Depreciated Current Year	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [i]	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions (1/2 year rule)	Adjustments	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J 2018	Variance
		a	b	c	d	e = a - b - c - d	f	g	h	i	j	k = h - i - j	l	m	n	o = 1/n	p	q = 1/p	r = e/n + f + g	s = k/p +l	t = m/p x 0.5	u	v = r + s + t + u	w	x = w - v
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 -TX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,679,763	-	-	1,679,763	-	-	-	0.00%	45.00	2.22%	$ -	$ 37,328	$ -	$ -	$ 37,328	$ 37,328	$ -
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 OTHER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	885,765	-	-	885,765	-	-	-	0.00%	55.00	1.82%	$ -	$ 16,105	$ -	$ -	$ 16,105	$ 16,105	$ (0)
1611	Computer Software (Formally known as Account 1925)	$ 165,566	$ 165,566	$ -	$ -	$ (0)	$ -	$ -	582,496	234,271	108,818	239,407	18,136	14,250	-	0.00%	3.00	33.33%	$ -	$ 97,939	$ 2,375	$ -	$ 100,314	$ 100,314	$ (0)
1925	CIS Upgrade	$ 119,000	$ 119,000	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 258,134	$ -	$ -	$ -	$ 258,134	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV York (TX)	$ 630,588	$ -	$ -	$ -	$ 630,588	$ -	$ -	-	-	-	-	-	-	35.52	2.82%	45.00	2.22%	$ 17,753	$ -	$ -	$ -	$ 17,753	$ 17,753	$ (0)
1815	Transformer Station Equipment >50 kV York Other	$ 1,466,075	$ -	$ -	$ -	$ 1,466,075	$ -	$ -	40,286	-	-	40,286	-	-	45.66	2.19%	55.00	1.82%	$ 32,109	$ 732	$ -	$ -	$ 32,842	$ 32,842	$ -
1815	Transformer Station Equipment >50 kV Conc 5 (TX)	$ 544,453	$ -	$ -	$ -	$ 544,453	$ -	$ -	-	-	-	-	-	-	37.52	2.67%	45.00	2.22%	$ 14,511	$ -	$ -	$ -	$ 14,511	$ 14,511	$ (0)
1815	Transformer Station Equipment >50 kV Conc 5 Other	$ 1,664,608	$ -	$ -	$ -	$ 1,664,608	$ -	$ -	62,902	-	-	62,902	-	165,000	48.16	2.08%	55.00	1.82%	$ 34,567	$ 1,144	$ 1,500	$ -	$ 37,211	$ 37,211	$ -
1820	Distribution Station Equipment <50 kV	$ 47,927	$ 47,927	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	Poles, Towers & Fixtures	$ 2,130,517	$ 49,803	$ -	$ -	$ 2,080,714	$ -	$ -	1,219,633	-	-	1,219,633	-	1,032,487	30.15	0.03	45.00	2.22%	69,005	$ 27,103	$ 11,472	$ -	$ 107,580	$ 107,580	$ -
1835	Overhead Conductors & Devices	$ 2,838,661	$ 67,626	$ -	$ -	$ 2,771,035	$ -	$ -	980,105	-	-	980,105	-	672,255	45.13	0.02	60.00	1.67%	$ 61,404	$ 16,335	$ 5,602	$ -	$ 83,341	$ 83,341	$ -
1840	Underground Conduit	$ 2,705,310	$ -	$ -	$ -	$ 2,705,310	$ -	$ -	1,132,124	-	-	1,132,124	-	420,002	53.26	0.02	65.00	1.54%	$ 50,790	$ 17,417	$ 3,231	$ -	$ 71,438	$ 71,438	$ (0)
1845	Underground Conductors & Devices	$ 4,168,057	$ -	$ -	$ -	$ 4,168,057	$ -	$ -	1,935,005	-	-	1,935,005	-	544,852	29.89	3.35%	45.00	2.22%	$ 139,442	$ 43,000	$ 6,054	$ -	$ 188,496	$ 188,496	$ -
1850	Line Transformers	$ 3,765,974	$ 243,162	$ -	$ -	$ 3,522,812	$ -	$ -	1,805,058	-	-	1,805,058	-	253,208	33.00	3.03%	45.00	2.22%	$ 106,754	$ 40,112	$ 2,813	$ -	$ 149,680	$ 149,680	$ -
1850	Line Transformers-Inventory	$ 96,563	$ -	$ -	$ -	$ 96,563	$ -	$ -	(7,767)	-	-	(7,767)	-	-	34.67	2.88%	45.00	2.22%	$ 2,786	$ (173)	$ -	$ -	$ 2,613	$ 2,613	$ 0
1850	Line Transformers-Damaged	$ 9,005	$ -	$ -	$ -	$ 9,005	$ -	$ -	-	-	-	-	-	-	30.34	3.30%	45.00	2.22%	$ 297	$ -	$ -	$ -	$ 297	$ 297	$ -
1850	Line Transformers-Spare	$ 73,441	$ -	$ -	$ -	$ 73,441	$ -	$ -	70,843	-	-	70,843	-	-	41.12	2.43%	45.00	2.22%	$ 1,786	$ 1,574	$ -	$ -	$ 3,360	$ 3,360	$ 0
1855	Services (Overhead)	$ 443,107	$ -	$ -	$ -	$ 443,107	$ -	$ -	74,614	-	-	74,614	-	85,000	55.08	1.82%	60.00	1.67%	$ 8,044	$ 1,244	$ 708	$ -	$ 9,996	$ 9,996	$ 0
1855	Services (Underground)	$ 1,679,060	$ -	$ -	$ -	$ 1,679,060	$ -	$ -	1,318,130	-	-	1,318,130	-	817,896	38.61	2.59%	45.00	2.22%	$ 43,484	$ 29,292	$ 9,088	$ -	$ 81,864	$ 81,864	$ 0
1860	Meters	$ 197,059	$ 8,067	$ 2,184	$ -	$ 186,808	$ 364	$ -	81,117	-	-	81,117	-	44,971	22.92	4.36%	25.00	4.00%	$ 8,514	$ 3,245	$ 899	$ -	$ 12,659	$ 12,659	$ -
1860	Meters (Smart Meters)	$ 1,370,813	$ 4,592	$ -	$ -	$ 1,366,222	$ -	$ -	260,942	-	-	260,942	-	46,830	12.54	7.98%	15.00	6.67%	$ 108,965	$ 17,396	$ 1,561	$ -	$ 127,922	$ 127,922	$ -
1860	Stranded Meters	$ 102,246	$ 102,731	$ 3,717	$ -	$ (4,201)	$ 619	$ -	-	-	-	-	-	-	6.78	14.74%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Non Stranded Meters-Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27,758	-	-	27,758	-	-	-	0.00%	25.00	4.00%	$ -	$ 1,110	$ -	$ -	$ 1,110	$ 1,110	$ -
1860	Non Stranded Meters-CT/PT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters Inventory	$ 39,189	$ -	$ -	$ -	$ 39,189	$ -	$ -	(11,502)	-	-	(11,502)	-	-	17.49	5.72%	25.00	4.00%	$ 2,241	$ (460)	$ -	$ -	$ 1,781	$ 1,781	$ 0
1860	Smart Meters Inventory	$ 46,634	$ -	$ -	$ -	$ 46,634	$ -	$ -	(17,899)	-	-	(17,899)	-	-	14.01	7.14%	15.00	6.67%	$ 3,330	$ (1,193)	$ -	$ -	$ 2,136	$ 2,136	$ -
1860	Non Stranded Meters-CT/PT Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	6,308	-	-	6,308	-	-	-	0.00%	40.00	2.50%	$ -	$ 158	$ -	$ -	$ 158	$ 158	$ 0
1905	Land	$ 49,000	$ -	$ -	$ -	$ 49,000	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures-8 Henegan Rd	$ 678,370	$ -	$ -	$ -	$ 678,370	$ -	$ -	144,617	-	-	144,617	-	52,260	39.33	2.54%	60.00	1.67%	$ 17,249	$ 2,410	$ 436	$ -	$ 20,094	$ 20,094	$ 0
1908	Buildings & Fixtures-PCB Shed	$ 1,606	$ 1,606	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	30.00	3.33%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 43,264	$ 8,490	$ 2,693	$ -	$ 32,082	$ 243	$ -	13,207	-	-	13,207	-	6,078	7.83	12.78%	10.00	10.00%	$ 4,342	$ 1,321	$ 304	$ -	$ 5,966	$ 5,966	$ (0)
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 38,222	$ 38,222	$ -	$ -	$ (0)	$ -	$ -	90,958	44,795	18,754	27,409	3,126	15,000	-	0.00%	3.00	33.33%	$ -	$ 12,262	$ 2,500	$ -	$ 14,762	$ 14,762	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment < 3 Tons	$ 11,707	$ 11,707	$ -	$ -	$ 0	$ -	$ -	98,643	-	53,681	44,963	5,368	-	-	0.00%	5.00	20.00%	$ -	$ 14,361	$ -	$ -	$ 14,361	$ 14,361	$ 0
1930	Transportation Equipment > 3 Tons	$ 623,113	$ 78,117	$ -	$ -	$ 544,996	$ -	$ -	-	-	-	-	-	364,295	8.81	11.36%	10.00	10.00%	$ 61,893	$ -	$ 18,215	$ -	$ 80,108	$ 80,108	$ 0
1930	Transportation Equipment Trailers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	45,650	-	-	45,650	-	-	-	0.00%	15.00	6.67%	$ -	$ 3,043	$ -	$ -	$ 3,043	$ 3,043	$ (0)
1935	Stores Equipment	$ 6,309	$ 810	$ 723	$ -	$ 4,775	$ 65	$ -	-	-	-	-	-	5,000	6.52	15.35%	10.00	10.00%	$ 798	$ -	$ 250	$ -	$ 1,048	$ 1,048	$ 0
1940	Tools, Shop & Garage Equipment	$ 63,171	$ 42,961	$ 10,262	$ -	$ 9,948	$ 926	$ -	34,926	-	-	34,926	-	41,897	6.89	14.52%	8.00	12.50%	$ 2,370	$ 4,366	$ 2,619	$ -	$ 9,354	$ 9,354	$ 0
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 15,938	$ 5,573	$ 6,531	$ -	$ 3,833	$ 589	$ -	-	-	-	-	-	-	6.68	14.98%	10.00	10.00%	$ 1,163	$ -	$ -	$ -	$ 1,163	$ 1,163	$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 110,749	$ 101,487	$ -	$ -	$ 9,261	$ -	$ -	342,099	-	-	342,099	-	120,000	8.39	11.92%	10.00	10.00%	$ 1,104	$ 34,210	$ 6,000	$ (5,568)	$ 35,746	$ 35,821	$ 75
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants-Poles	$ (169,565)	$ -	$ -	$ -	$ (169,565)	$ -	$ -	(6,683)	-	-	(6,683)	-	-	38.55	2.59%	45.00	2.22%	$ (4,399)	$ (149)	$ -	$ -	$ (4,548)	$ (4,548)	$ (0)
1995	Contributions & Grants-OH Conductor	$ (164,116)	$ -	$ -	$ -	$ (164,116)	$ -	$ -	-	-	-	-	-	-	52.82	1.89%	60.00	1.67%	$ (3,107)	$ -	$ -	$ -	$ (3,107)	$ (3,107)	$ 0
1995	Contributions & Grants-O/H Services	$ (88,520)	$ -	$ -	$ -	$ (88,520)	$ -	$ -	(9,014)	-	-	(9,014)	-	-	51.24	1.95%	65.00	1.54%	$ (1,728)	$ (139)	$ -	$ -	$ (1,866)	$ (1,878)	$ (12)
1995	Contributions & Grants-UG Conduit	$ (578,117)	$ -	$ -	$ -	$ (578,117)	$ -	$ -	(97,678)	-	-	(97,678)	-	-	59.13	1.69%	65.00	1.54%	$ (9,777)	$ (1,503)	$ -	$ -	$ (11,280)	$ (11,280)	$ (0)
1995	Contributions & Grants-UG Conductor	$ (1,090,529)	$ -	$ -	$ -	$ (1,090,529)	$ -	$ -	(144,330)	-	-	(144,330)	-	-	37.00	2.70%	45.00	2.22%	$ (29,473)	$ (3,207)	$ -	$ -	$ (32,681)	$ (32,681)	$ 0
1995	Contributions & Grants-UG Services	$ (1,031,865)	$ -	$ -	$ -	$ (1,031,865)	$ -	$ -	(171,231)	-	-	(171,231)	-	-	38.47	2.60%	45.00	2.22%	$ (26,819)	$ (3,805)	$ -	$ -	$ (30,625)	$ (30,625)	$ 0
1995	Contributions & Grants-TX	$ (1,509,639)	$ -	$ -	$ -	$ (1,509,639)	$ -	$ -	(143,573)	-	-	(143,573)	-	-	38.06	2.63%	45.00	2.22%	$ (39,669)	$ (3,191)	$ -	$ -	$ (42,859)	$ (42,859)	$ (0)
1995	Contributions & Grants-Meters	$ (4,319)	$ -	$ -	$ -	$ (4,319)	$ -	$ -	-	-	-	-	-	-	14.70	6.80%	25.00	4.00%	$ (294)	$ -	$ -	$ -	$ (294)	$ (294)	$ (0)
1995	Contributions & Grants-Buildings	$ (9,620)	$ -	$ -	$ -	$ (9,620)	$ -	$ -	-	-	-	-	-	-	47.00	2.13%	60.00	1.67%	$ (205)	$ -	$ -	$ -	$ (205)	$ (205)	$ (0)
1995	Contributions & Grants-Rolling Stock	$ 0	$ -	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1605	Organization	$ 9,807	$ 9,807	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	20.00	5.00%	-	0.00%	$ (0)	$ -	$ -	$ -	$ (0)	$ -	$ 0
2440	Def Rev-Contributions & Grants-O/H Poles	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(200,955)	-	-	(200,955)	-	(341,390)	-	0.00%	45.00	2.22%	$ -	$ (4,466)	$ (3,793)	$ -	$ (8,259)	$ (8,259)	$ -
2440	Def Rev-Contributions & Grants-O/H Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(93,496)	-	-	(93,496)	-	(277,728)	-	0.00%	60.00	1.67%	$ -	$ (1,558)	$ (2,314)	$ -	$ (3,873)	$ (3,873)	$ 0
2440	Def Rev-Contributions & Grants-O/H Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(33,978)	-	-	(33,978)	-	(65,000)	-	0.00%	60.00	1.67%	$ -	$ (566)	$ (542)	$ -	$ (1,108)	$ (1,108)	$ 0
2440	Def Rev-Contributions & Grants-U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(456,515)	-	-	(456,515)	-	(331,732)	-	0.00%	65.00	1.54%	$ -	$ (7,023)	$ (2,552)	$ -	$ (9,575)	$ (9,575)	$ -
2440	Def Rev-Contributions & Grants-U/G Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(662,785)	-	-	(662,785)	-	(254,859)	-	0.00%	45.00	2.22%	$ -	$ (14,729)	$ (2,832)	$ -	$ (17,560)	$ (17,560)	$ 0
2440	Def Rev-Contributions & Grants-U/G Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(780,080)	-	-	(780,080)	-	(305,716)	-	0.00%	45.00	2.22%	$ -	$ (17,335)	$ (3,397)	$ -	$ (20,732)	$ (20,732)	$ -
2440	Def Rev-Contributions & Grants-Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(935,013)	-	-	(935,013)	-	(216,750)	-	0.00%	45.00	2.22%	$ -	$ (20,778)	$ (2,408)	$ -	$ (23,186)	$ (23,186)	$ (0)
2440	Def Rev-Contributions & Grants-Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(69,596)	-	-	(69,596)	-	(30,771)	-	0.00%	25.00	4.00%	$ -	$ (2,784)	$ (615)	$ -	$ (3,399)	$ (3,399)	$ 0
2440	Def Rev-Contributions & Grants-Admin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	60.00	1.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Rolling Stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def Rev-Contributions & Grants-Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	(160,000)	-	0.00%	45.00	2.22%	$ -	$ -	$ (1,778)	$ -	$ (1,778)	$ (1,778)	$ -
2440	Def rev-Contributions & Grants-Battery	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 21,566,951**	**$ 1,107,253**	**$ 26,111**	**$ -**	**$ 20,433,587**	**$ 2,806**	**$ -**	**9,090,857**	**279,066**	**181,253**	**8,630,538**	**26,630**	**2,717,335**					**$ 679,228**	**$ 340,149**	**$ 55,395**	**-$ 5,568**	**$ 1,069,204**	**$ 1,068,267**	**$ 63**
														2,717,335.31										1,069,267.34	

Appendix 2-C
Depreciation and Amortization Expense

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012.	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013.	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2019	MIFR

		Book Values													Service Lives				Depreciation Expense							
Account	Description	Opening NBV of Assets at Date of Policy Change- Jan. 1, 2013	Less Fully Depreciated / Disposals Previous Years	Fully Depreciated Current Year (NBV)	Less Disposals (NBV)	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [c]	Depreciation Expense on Disposals Current Year	Opening Gross Book Value of Assets Acquired After Policy Change	Less Fully Depreciated Previous Years	Less Fully Depreciated Current Year	Net for Depreciation	Depreciation Expense on Fully Depreciated Current Year [i]	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions (1/2 year rule)	Adjustments	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J 2019	Variance
		a	b	c	d	e = a - b - c - d	f	g	h	i	j	k = h - i - j	l	m	n	o = 1/n	p	q = 1/p	r = e/n + f + g	s = k/p +l	t = m/p x 0.5	u	v = r + s + t + u	w	x = w - v
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 -TX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,679,763	-	-	1,679,763	-	-	-	0.00%	45.00	2.22%	$ -	$ 37,328	$ -	$ -	$ 37,328	$ 37,328	$ -
1508	ICM-Transformer Station Equipment >50 kV-Conc #5 OTHER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	885,765	-	-	885,765	-	-	-	0.00%	55.00	1.82%	$ -	$ 16,105	$ -	$ -	$ 16,105	$ 16,105	$ (0)
1611	Computer Software (Formally known as Account 1925)	$ 165,566	$ 165,566	$ -	$ -	$ (0)	$ -	$ -	596,746	343,088	110,456	143,201	18,409	5,150	-	0.00%	3.00	33.33%	$ -	$ 66,143	$ 858	$ -	$ 67,001	$ 67,001	$ (0)
1925	CIS Upgrade	$ 119,000	$ 119,000	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 258,134	$ -	$ -	$ -	$ 258,134	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV York (TX)	$ 630,588	$ -	$ -	$ -	$ 630,588	$ -	$ -	-	-	-	-	-	1,655,000	35.52	2.82%	45.00	2.22%	$ 17,753	$ -	$ 18,389	$ -	$ 36,142	$ 36,142	$ (0)
1815	Transformer Station Equipment >50 kV York Other	$ 1,466,075	$ -	$ -	$ -	$ 1,466,075	$ -	$ -	40,286	-	-	40,286	-	1,655,000	45.66	2.19%	55.00	1.82%	$ 32,109	$ 732	$ 15,045	$ -	$ 47,887	$ 47,887	$ -
1815	Transformer Station Equipment >50 kV Conc 5 (TX)	$ 544,453	$ -	$ -	$ -	$ 544,453	$ -	$ -	-	-	-	-	-	-	37.52	2.67%	45.00	2.22%	$ 14,511	$ -	$ -	$ -	$ 14,511	$ 14,511	$ (0)
1815	Transformer Station Equipment >50 kV Conc 5 Other	$ 1,664,608	$ -	$ -	$ -	$ 1,664,608	$ -	$ -	227,902	-	-	227,902	-	-	48.16	2.08%	55.00	1.82%	$ 34,567	$ 4,144	$ -	$ -	$ 38,711	$ 38,711	$ -
1820	Distribution Station Equipment <50 kV	$ 47,927	$ 47,927	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	442,340	-	0.00%	10.00	10.00%	$ -	$ -	$ 22,117	$ -	$ 22,117	$ 22,117	$ -
1830	Poles, Towers & Fixtures	$ 2,130,517	$ 49,803	$ 52,483	$ -	$ 2,028,232	$ 7,495	$ -	2,252,120	-	-	2,252,120	-	344,250	32.97	0.03	45.00	2.22%	$ 69,005	$ 50,047	$ 3,825	$ -	$ 122,877	$ 122,877	$ -
1835	Overhead Conductors & Devices	$ 2,838,661	$ 67,626	$ -	$ -	$ 2,771,035	$ -	$ -	1,652,361	-	-	1,652,361	-	280,550	45.13	0.02	60.00	1.67%	$ 61,404	$ 27,539	$ 2,338	$ -	$ 91,281	$ 91,281	$ 0
1840	Underground Conduit	$ 2,705,310	$ -	$ -	$ -	$ 2,705,310	$ -	$ -	1,552,126	-	-	1,552,126	-	176,800	53.26	0.02	65.00	1.54%	$ 50,790	$ 23,879	$ 1,360	$ -	$ 76,029	$ 76,029	$ 0
1845	Underground Conductors & Devices	$ 4,168,057	$ -	$ -	$ -	$ 4,168,057	$ -	$ -	2,479,857	-	-	2,479,857	-	181,950	29.89	3.35%	45.00	2.22%	$ 139,442	$ 55,108	$ 2,022	$ -	$ 196,571	$ 196,571	$ -
1850	Line Transformers	$ 3,765,974	$ 243,162	$ -	$ -	$ 3,522,812	$ -	$ -	2,058,266	-	-	2,058,266	-	365,800	33.00	3.03%	45.00	2.22%	$ 106,754	$ 45,739	$ 4,064	$ -	$ 156,557	$ 156,557	$ -
1850	Line Transformers-Inventory	$ 96,563	$ -	$ -	$ -	$ 96,563	$ -	$ -	(7,767)	-	-	(7,767)	-	-	34.67	2.88%	45.00	2.22%	$ 2,786	$ (173)	$ -	$ -	$ 2,613	$ 2,613	$ 0
1850	Line Transformers-Damaged	$ 9,005	$ -	$ -	$ -	$ 9,005	$ -	$ -	-	-	-	-	-	-	30.34	3.30%	45.00	2.22%	$ 297	$ -	$ -	$ -	$ 297	$ 297	$ -
1850	Line Transformers-Spare	$ 73,441	$ -	$ -	$ -	$ 73,441	$ -	$ -	70,843	-	-	70,843	-	-	41.12	2.43%	45.00	2.22%	$ 1,786	$ 1,574	$ -	$ -	$ 3,360	$ 3,360	$ 0
1855	Services (Overhead)	$ 443,107	$ -	$ -	$ -	$ 443,107	$ -	$ -	159,614	-	-	159,614	-	40,750	55.08	1.82%	60.00	1.67%	$ 8,044	$ 2,660	$ 340	$ -	$ 11,044	$ 11,044	$ 0
1855	Services (Underground)	$ 1,679,060	$ -	$ -	$ -	$ 1,679,060	$ -	$ -	2,136,026	-	-	2,136,026	-	466,950	38.61	2.59%	45.00	2.22%	$ 43,484	$ 47,467	$ 5,188	$ -	$ 96,140	$ 96,140	$ (0)
1860	Meters	$ 197,059	$ 10,251	$ 123	$ -	$ 186,685	$ 18	$ -	126,087	-	-	126,087	-	50,300	24.54	4.07%	25.00	4.00%	$ 7,624	$ 5,043	$ 1,006	$ -	$ 13,674	$ 13,674	$ -
1860	Meters (Smart Meters)	$ 1,370,813	$ 4,592	$ -	$ -	$ 1,366,222	$ -	$ -	307,772	-	-	307,772	-	25,150	12.54	7.98%	15.00	6.67%	$ 108,965	$ 20,518	$ 838	$ -	$ 130,322	$ 130,322	$ -
1860	Stranded Meters	$ 102,246	$ 106,447	$ 209	$ -	$ (4,410)	$ 30	$ -	-	-	-	-	-	-	147.88	0.68%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Non Stranded Meters-Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27,758	-	-	27,758	-	-	-	0.00%	25.00	4.00%	$ -	$ 1,110	$ -	$ -	$ 1,110	$ 1,110	$ -
1860	Non Stranded Meters-CT/PT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters Inventory	$ 39,189	$ -	$ -	$ -	$ 39,189	$ -	$ -	(11,502)	-	-	(11,502)	-	-	17.49	5.72%	25.00	4.00%	$ 2,241	$ (460)	$ -	$ -	$ 1,781	$ 1,781	$ 0
1860	Smart Meters Inventory	$ 46,634	$ -	$ -	$ -	$ 46,634	$ -	$ -	(17,899)	-	-	(17,899)	-	-	14.01	7.14%	15.00	6.67%	$ 3,330	$ (1,193)	$ -	$ -	$ 2,136	$ 2,136	$ -
1860	Non Stranded Meters-CT/PT Inventory	$ -	$ -	$ -	$ -	$ -	$ -	$ -	6,308	-	-	6,308	-	-	-	0.00%	40.00	2.50%	$ -	$ 158	$ -	$ -	$ 158	$ 158	$ 0
1905	Land	$ 49,000	$ -	$ -	$ -	$ 49,000	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures-8 Henegan Rd	$ 678,370	$ -	$ -	$ -	$ 678,370	$ -	$ -	196,878	-	-	196,878	-	23,150	39.33	2.54%	60.00	1.67%	$ 17,249	$ 3,281	$ 193	$ -	$ 20,723	$ 20,723	$ (0)
1908	Buildings & Fixtures-PCB Shed	$ 1,606	$ 1,606	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	-	0.00%	30.00	3.33%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 43,264	$ 11,183	$ 1,182	$ -	$ 30,900	$ 90	$ -	19,285	-	-	19,285	-	5,000	7.89	12.68%	10.00	10.00%	$ 4,007	$ 1,928	$ 250	$ -	$ 6,186	$ 6,186	$ (0)
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 38,222	$ 38,222	$ -	$ -	$ (0)	$ -	$ -	105,958	63,549	9,825	32,584	1,638	15,450	-	0.00%	3.00	33.33%	$ -	$ 12,499	$ 2,575	$ -	$ 15,074	$ 15,074	$ (0)
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment < 3 Tons	$ 11,707	$ 11,707	$ -	$ -	$ 0	$ -	$ -	98,643	53,681	-	44,963	-	30,000	-	0.00%	5.00	20.00%	$ -	$ 8,993	$ 3,000	$ -	$ 11,993	$ 11,993	$ (0)
1930	Transportation Equipment > 3 Tons	$ 623,113	$ 78,117	$ 6,125	$ -	$ 538,871	$ 467	$ -	364,295	-	-	364,295	-	-	8.84	11.31%	10.00	10.00%	$ 61,418	$ 36,429	$ -	$ -	$ 97,848	$ 97,848	$ 0
1930	Transportation Equipment Trailers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	45,650	-	-	45,650	-	-	-	0.00%	15.00	6.67%	$ -	$ 3,043	$ -	$ -	$ 3,043	$ 3,043	$ (0)
1935	Stores Equipment	$ 6,309	$ 1,534	$ 4,733	$ -	$ 42	$ 361	$ -	5,000	-	-	5,000	-	-	9.42	10.62%	10.00	10.00%	$ 366	$ 500	$ -	$ -	$ 866	$ 866	$ 0
1940	Tools, Shop & Garage Equipment	$ 63,171	$ 53,224	$ 6,845	$ -	$ 3,102	$ 652	$ -	76,823	-	-	76,823	-	5,000	7.53	13.29%	8.00	12.50%	$ 1,064	$ 9,603	$ 313	$ -	$ 10,979	$ 10,979	$ 0
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 15,938	$ 12,105	$ 3,066	$ -	$ 767	$ 234	$ -	-	-	-	-	-	-	7.50	13.33%	10.00	10.00%	$ 336	$ -	$ -	$ -	$ 336	$ 336	$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 110,749	$ 101,487	$ 382	$ -	$ 8,879	$ 29	$ -	462,099	-	-	462,099	-	80,000	8.49	11.78%	10.00	10.00%	$ 1,075	$ 46,210	$ 4,000	$ (5,568)	$ 45,716	$ 45,791	$ 75
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants-Poles	$ (169,565)	$ -	$ -	$ -	$ (169,565)	$ -	$ -	(6,683)	-	-	(6,683)	-	-	38.55	2.59%	45.00	2.22%	$ (4,399)	$ (149)	$ -	$ -	$ (4,548)	$ (4,548)	$ (0)
1995	Contributions & Grants-OH Conductor	$ (164,116)	$ -	$ -	$ -	$ (164,116)	$ -	$ -	-	-	-	-	-	-	52.82	1.89%	60.00	1.67%	$ (3,107)	$ -	$ -	$ -	$ (3,107)	$ (3,107)	$ 0
1995	Contributions & Grants-O/H Services	$ (88,520)	$ -	$ -	$ -	$ (88,520)	$ -	$ -	(9,014)	-	-	(9,014)	-	-	51.24	1.95%	65.00	1.54%	$ (1,728)	$ (139)	$ -	$ -	$ (1,866)	$ (1,878)	$ (12)
1995	Contributions & Grants-UG Conduit	$ (578,117)	$ -	$ -	$ -	$ (578,117)	$ -	$ -	(97,678)	-	-	(97,678)	-	-	59.13	1.69%	65.00	1.54%	$ (9,777)	$ (1,503)	$ -	$ -	$ (11,280)	$ (11,280)	$ (0)
1995	Contributions & Grants-UG Conductor	$ (1,090,529)	$ -	$ -	$ -	$ (1,090,529)	$ -	$ -	(144,330)	-	-	(144,330)	-	-	37.00	2.70%	45.00	2.22%	$ (29,473)	$ (3,207)	$ -	$ -	$ (32,681)	$ (32,681)	$ 0
1995	Contributions & Grants-UG Services	$ (1,031,865)	$ -	$ -	$ -	$ (1,031,865)	$ -	$ -	(171,231)	-	-	(171,231)	-	-	38.47	2.60%	45.00	2.22%	$ (26,819)	$ (3,805)	$ -	$ -	$ (30,625)	$ (30,625)	$ 0
1995	Contributions & Grants-TX	$ (1,509,639)	$ -	$ -	$ -	$ (1,509,639)	$ -	$ -	(143,573)	-	-	(143,573)	-	-	38.06	2.63%	45.00	2.22%	$ (39,669)	$ (3,193)	$ -	$ -	$ (42,859)	$ (42,859)	$ (0)
1995	Contributions & Grants-Meters	$ (4,319)	$ -	$ -	$ -	$ (4,319)	$ -	$ -	-	-	-	-	-	-	14.70	6.80%	25.00	4.00%	$ (294)	$ -	$ -	$ -	$ (294)	$ (294)	$ (0)
1995	Contributions & Grants-Buildings	$ (9,620)	$ -	$ -	$ -	$ (9,620)	$ -	$ -	-	-	-	-	-	-	47.00	2.13%	60.00	1.67%	$ (205)	$ -	$ -	$ -	$ (205)	$ (205)	$ (0)
1995	Contributions & Grants-Rolling Stock	$ 0	$ -	$ -	$ -	$ 0	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1606	Organization	$ 9,807	$ 9,807	$ -	$ -	$ (0)	$ -	$ -	-	-	-	-	-	-	20.00	5.00%	-	0.00%	$ (0)	$ -	$ -	$ -	$ (0)	$ -	$ 0
2440	Def Rev-Contributions & Grants-O/H Poles	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(542,345)	-	-	(542,345)	-	(25,750)	-	0.00%	45.00	2.22%	$ -	$ (12,052)	$ (286)	$ -	$ (12,338)	$ (12,338)	$ -
2440	Def Rev-Contributions & Grants-O/H Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(371,224)	-	-	(371,224)	-	(25,750)	-	0.00%	60.00	1.67%	$ -	$ (6,187)	$ (215)	$ -	$ (6,402)	$ (6,402)	$ -
2440	Def Rev-Contributions & Grants-O/H Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(98,978)	-	-	(98,978)	-	(30,750)	-	0.00%	60.00	1.67%	$ -	$ (1,650)	$ (256)	$ -	$ (1,906)	$ (1,906)	$ 0
2440	Def Rev-Contributions & Grants-U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(788,247)	-	-	(788,247)	-	(61,800)	-	0.00%	65.00	1.54%	$ -	$ (12,127)	$ (475)	$ -	$ (12,602)	$ (12,602)	$ 0
2440	Def Rev-Contributions & Grants-U/G Conductor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(917,644)	-	-	(917,644)	-	(66,950)	-	0.00%	45.00	2.22%	$ -	$ (20,392)	$ (744)	$ -	$ (21,136)	$ (21,136)	$ 0
2440	Def Rev-Contributions & Grants-U/G Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(1,085,796)	-	-	(1,085,796)	-	(344,450)	-	0.00%	45.00	2.22%	$ -	$ (24,129)	$ (3,827)	$ -	$ (27,956)	$ (27,956)	$ 0
2440	Def Rev-Contributions & Grants-Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(1,151,763)	-	-	(1,151,763)	-	(72,100)	-	0.00%	45.00	2.22%	$ -	$ (25,595)	$ (801)	$ -	$ (26,396)	$ (26,396)	$ (0)
2440	Def Rev-Contributions & Grants-Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(100,366)	-	-	(100,366)	-	(15,450)	-	0.00%	25.00	4.00%	$ -	$ (4,015)	$ (309)	$ -	$ (4,324)	$ (4,324)	$ 0
2440	Def Rev-Contributions & Grants-Admin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	60.00	1.67%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def rev-Contributions & Grants-Rolling Stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Def Rev-Contributions & Grants-Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(160,000)	-	-	(160,000)	-	-	-	0.00%	45.00	2.22%	$ -	$ (3,556)	$ -	$ -	$ (3,556)	$ (3,556)	$ -
2440	Def rev-Contributions & Grants-Battery	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-	-	0.00%	10.00	10.00%	$ -	$ (7,207)	$ -	$ -	$ (7,207)	$ (7,207)	$ -
	Total	**$ 21,566,951**	**$ 1,133,364**	**$ 75,148**	**$ -**	**$ 20,358,438**	**$ 9,376**	**$ -**	**11,808,192**	**460,318**	**120,282**	**11,227,592**	**20,047**	**5,061,454**					**$ 674,934**	**$ 404,262**	**$ 73,601**	**-$ 5,568**	**$ 1,147,229**	**$ 1,147,293**	**$ 63**
														5,061,454.00									1,147,292.52	
														-									-	

TAB ii



Exhibit 4

Operations, Maintenance and Administration

Additional Evidence

The following is provided as additional evidence for NOTL Hydro's operations, maintenance and administration costs.

Before providing additional evidence about its historic and forecast OM&A costs, NOTL Hydro believes that it is appropriate and important to put those costs in the context of the overall rates paid by its customers.

Historical Rate Performance

NOTL Hydro takes a holistic approach to its operations and rates. Part of our Mission Statement is that *"Niagara-on-the-Lake Hydro continuously seeks to provide low cost energy delivery, high reliability and high power quality."* This is obtained by seeking a balance between costs, investments, reliability and power quality. Over-emphasis on one of these goals will result in the wrong mix of performance. NOTL Hydro believes it has performed strongly in achieving this balanced objective based on its performance across all categories.

With regards to providing a low cost energy delivery, NOTL Hydro has gone from having one of the highest rates in the province to one of the lowest. In 1994, NOTL Hydro had the 4th highest residential rate of 111 Ontario electric utilities reporting their rates to the Municipal Electric Association. By 2018, NOTL Hydro had the 17th lowest residential rate of 71 LDCs (lowest quartile), the 23rd lowest GS<50 kW rate of 70 LDCs, the 3rd lowest GS>50 kW rate of 70 LDCs and the lowest Large User rate, based on the forecast consumption of our Large User, of 24 LDCs.[1]

NOTL Hydro believes that this record of improving rates is the best indicator of sound cost management. Looking at costs or cost increases on their own lacks the consideration that costs are only one factor that have an impact on rates and these factors need to be looked at in aggregate. Reliability and capital investments have not been sacrificed by NOTL Hydro and rates are falling in comparison to other Ontario LDCs.

[1] Rates were calculated as the Delivery Rate excluding rate riders. Delivery rates capture investments in transmission assets and lowering line losses which increase distribution rates but lower overall rates. Rate riders are excluded as they are not income and vary based on timing of collecting energy costs.

Rates vs. "Expected" Rates

NOTL Hydro also notes that its rates are lower than would otherwise be expected. There is no perfect way to forecast what rates should be for an LDC but, based on its analysis, NOTL Hydro believes the variable with the biggest impact on rates is customer density. Rates and customer density showed the strongest correlation.

Using information from the approved rate decisions on the OEB website, NOTL Hydro has mapped its rates as at December 31,2018 against rates of all LDCs based on customer density for both residential and GS<50 kV customer classes.

Chart 1 – Expected Residential Delivery Rate based on Customer Density

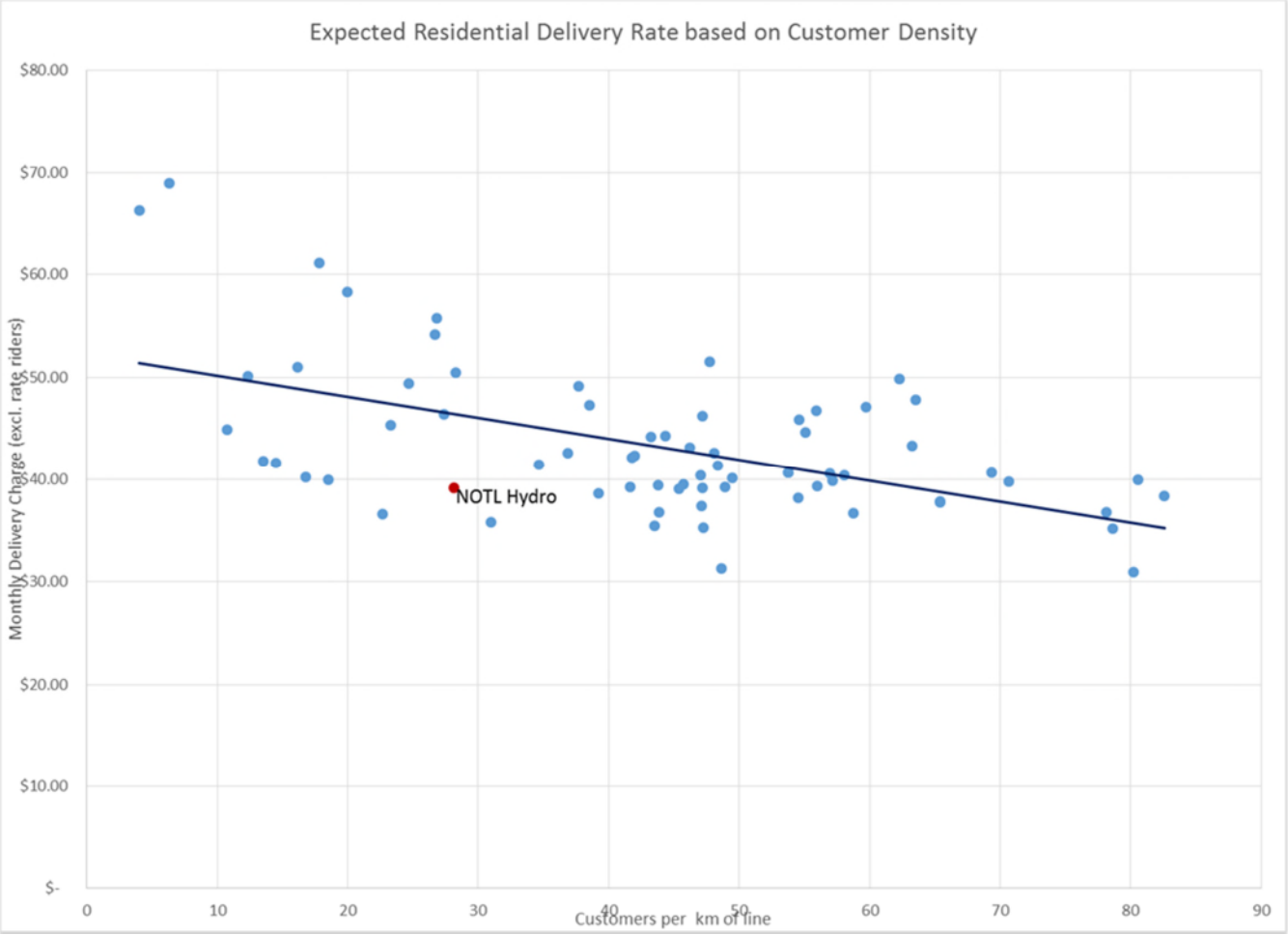
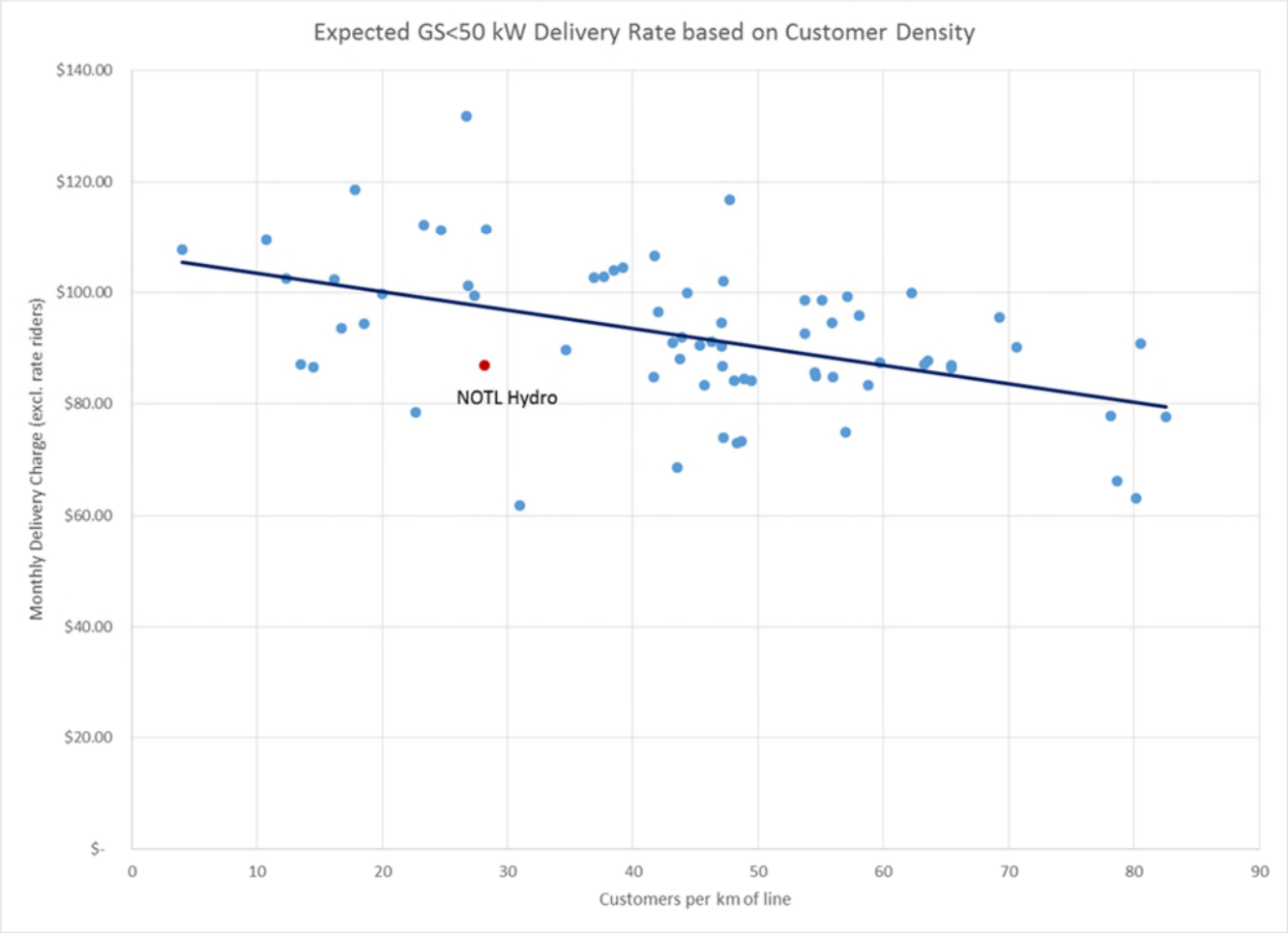


Chart 2 – Expected GS<50 kW Delivery Rate based on Customer Density



In both cases the actual rates are lower than what would be expected based on the rates of other LDCs and their customer densities.

NOTL Hydro believes that this is evidence that it is performing better than what would otherwise be expected. Sound cost management is a part of this performance.

Rate Change

The chart and table below provide the annual changes in NOTL Hydro's Delivery Charge. The total change is shown as well as the change in the Delivery Charge less the rate riders. The rate riders have been excluded as they vary from year-to-year based on the balances in the variance

accounts and are generally for the purpose of matching non-distribution receipts and payments. The one exception to this is the 2015 ICM rate rider. This was included as it will become distribution revenue of NOTL Hydro after this COS.

Chart 3 – NOTL Hydro Annual Delivery Rate Change

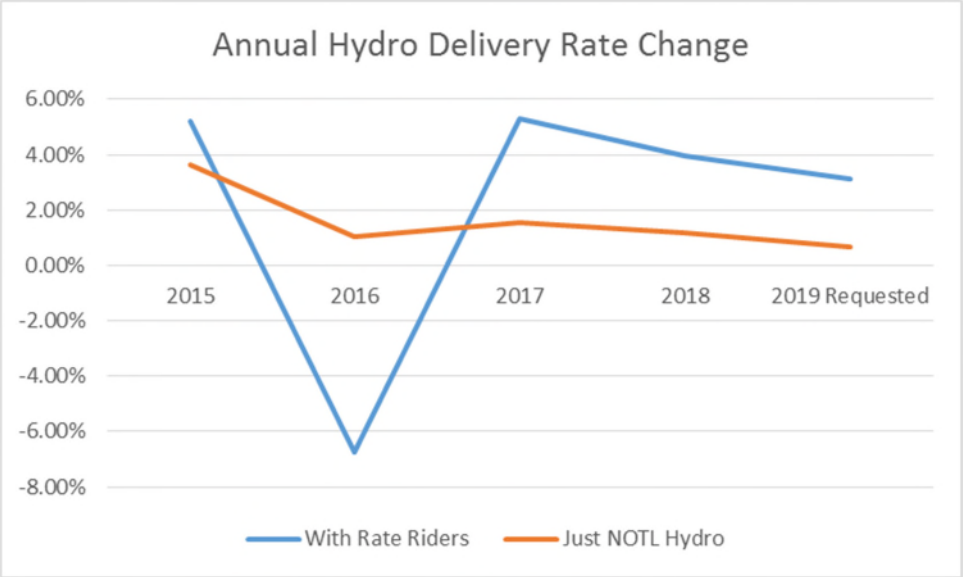


Table 4 – NOTL Hydro Annual Delivery Rate Change

	2015	2016	2017	2018	2019 Requested
With Rate Riders	5.20%	-6.74%	5.28%	3.95%	3.14%
Just NOTL Hydro	3.61%	1.06%	1.55%	1.18%	0.67%

NOTL Hydro's rate increases since 2014 have been lower than the rate of inflation. This is a direct result of the IRM model and to be expected. The only exception was 2015 due to the ICM rate rider. If an LDC has been investing or increasing operating costs beyond what is necessary based on customer growth then it would be expected that a large rate increase would be required with the Cost of Service application. This is not the case for NOTL Hydro. The rate increase being sought is lower than in the IRM years.

PEG Performance

Another illustration of NOTL Hydro's strong performance comes from the annual PEG rating.

Chart 5 – NOTL Hydro PEG Performance

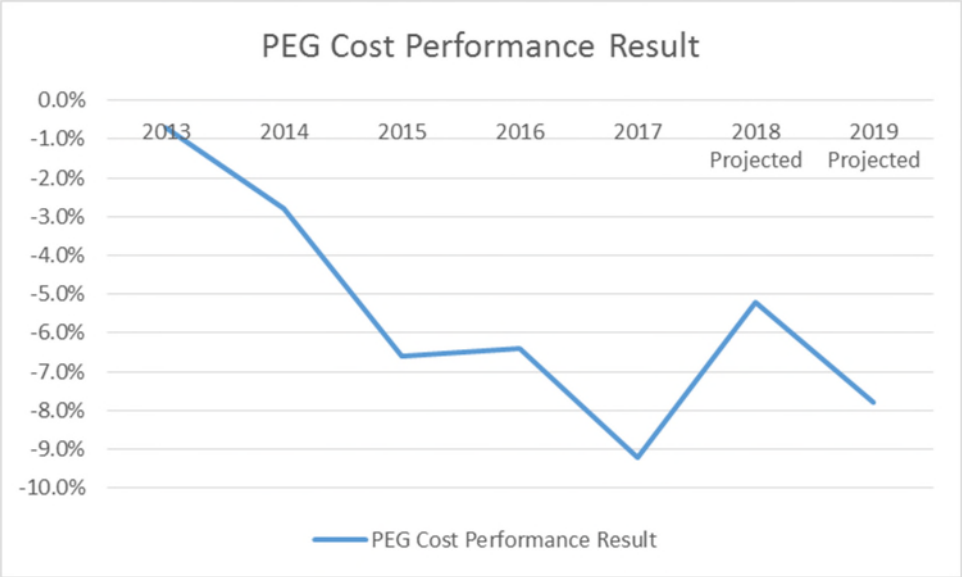
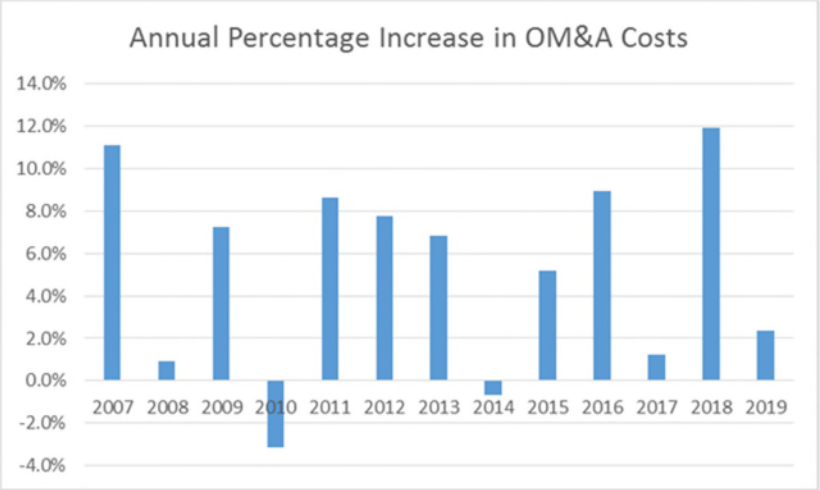


Table 6 - NOTL Hydro PEG Performance

	2013	2014	2015	2016	2017	2018 Projected	2019 Projected
PEG Cost Performance Result	-0.7%	-2.8%	-6.6%	-6.4%	-9.2%	-5.2%	-7.8%

As can be seen in the table and chart above, NOTL Hydro's PEG results demonstrate a significant trend in performance improvement. The performance decline in 2018 is due to a large increase in operating costs in that year. As noted in Table 4.5 on page 6 of Exhibit 4 of the original evidence and in the chart below, NOTL Hydro's operating cost increases are lumpy due to its smaller size. However, it is the trend over multiple years that matter more than one single year.

Chart 7 – Annual Increase in NOTL Hydro OM&A Costs

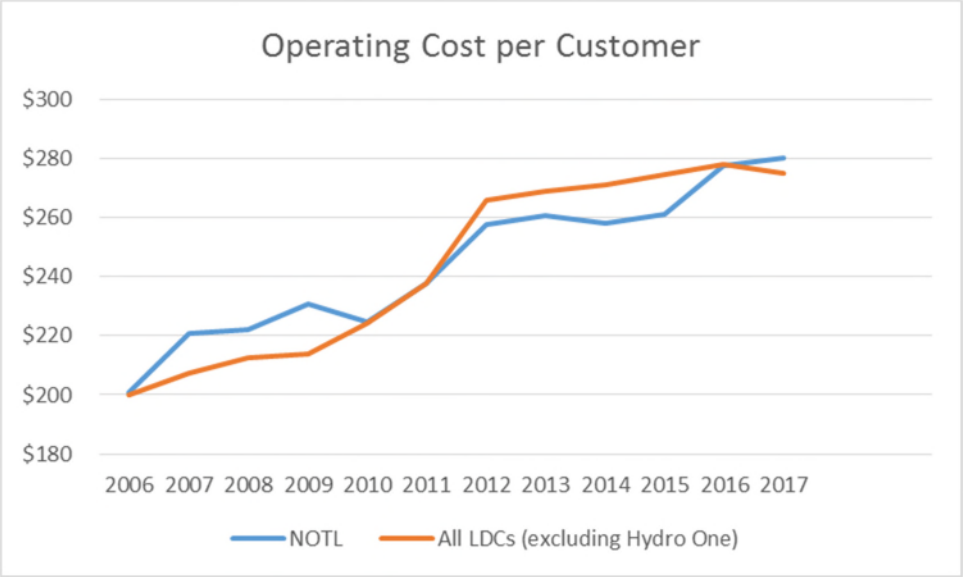


The PEG scores are a validation that NOTL Hydro is getting the mix of managing its growth, capital and operating costs in an appropriate manner. NOTL Hydro has consistently had a PEG rating of 3 but based on the trends it could improve to a 2 rating before the next cost of service application.

OM&A Cost per Customer

NOTL Hydro presented the chart below with 2016 data on page 19 of Exhibit 4 of its original submission. It has now been updated for 2017 full-year actual results. NOTL Hydro continues to track close to the industry average.

Chart 8 – Operating Cost per Customer



NOTL Hydro notes that 30% of its assets are transmission rather than distribution assets. Its costs therefore include the cost of operating and maintaining these assets; a cost many of the other LDCs do not have.

OM&A Cost Drivers

NOTL Hydro's OM&A, as projected for 2019 and used to determine the rates in the above analysis, is $2,964,765. This is an adjusted figure as the OM&A in the original application was $2,974,186. The Board approved OM&A for 2014 was $2,155,262 so there is an increase of $809,503 or 37.56%. It must be noted, though, that the 2014 OM&A approved budget was part of an overall settlement of all of the utility's cost items. NOTL Hydro's actual 2014 OM&A costs were $2,208.203 (approximately 2.5% higher than what was included in the settlement).

NOTL Hydro believes that it will be useful to the Board to collect relevant evidence into one place, and to provide more information about the drivers of the change in OM&A expenses. As described below, there are three main drivers of the increase between 2014 Board approved and 2019 forecast OM&A expenses:

Table 9 – OM&A Cost Drivers

Inflation and growth	$441,679	55%
Accounting standards change	$130,784	16%
New or increased services	$237,040	29%
Total	$809,503	100%

Inflation and Growth

Inflation has been calculated using the OEB approved inflation rates less the stretch factor adjustment. For NOTL Hydro this stretch factor adjustment was a reduction in inflation of 0.30% as NOTL Hydro is ranked in Group 3 as discussed above. An inflation rate of 1.70% was used for 2019.

The PEG report uses five factors to calculate the impact of growth on costs. These are customer growth, load growth, system peak growth, increase in distribution lines and acceleration in customer growth. NOTL Hydro used the first three in their calculation. There has been no noticeable change in either the amount of distribution lines or the rate of customer growth. The PEG elasticity factors used for customer growth was 0.4485, for load growth was 0.1083 and for system peak growth was 0.1623.

Table 10 – Expected Increase in OM&A due to Inflation and Growth

Niagara-on-the-Lake Hydro Inc.
OM&A Analysis
2019 Cost of Service

	Board Approved	Actual				Projected		Variance
	2014 BA	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2019 vs. 2014 BA**
Total OM&A Expenses	2,155,262	2,208,203	2,323,119	2,532,191	2,595,121	2,904,865	2,964,765	809,503
2014 Adjustment: IFRS (President and VP Operations Capitalized Labour)	130,784						0	(130,784)
Adjusted Total	**2,286,047**						**2,964,765**	**678,718**
Growth	**2014**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2019 vs. 2014 BA**
Customers (excludes Street Light and USL)	8,499	8,551	8,839	9,115	9,299	9,444	9,626	1,127
Customer Growth		**0.62%**	**3.36%**	**3.13%**	**2.02%**	**1.55%**	**1.93%**	**13.26%**
kWh Delivered (total excluding losses)	187,976,750	189,355,729	193,845,050	202,468,101	196,959,263	203,217,805	222,679,374	34,702,624
Load Growth		**0.73%**	**2.37%**	**4.45%**	**(2.72%)**	**3.18%**	**9.58%**	**18.46%**
System Peak (MW)	44,925	40,558	43,895	47,702	41,660	52,067	53,377	8,452
System Peak Growth		**(9.72%)**	**8.23%**	**8.67%**	**(12.67%)**	**24.98%**	**2.52%**	**18.81%**
Escalators	2014	2014	2015	2016	2017	2018	2019	**2019 vs. 2014 BA**
Inflation (OEB)		0.00%	1.60%	2.10%	1.90%	1.20%	1.70%	
Stretch Factor (PEG Group 3)		0.00%	0.30%	0.30%	0.30%	0.30%	0.30%	
Sub-Total		0.00%	1.30%	1.80%	1.60%	0.90%	1.40%	
Customer Growth (Growth x PEG Elasticity of 0.4485)		0.28%	1.51%	1.40%	0.91%	0.70%	0.87%	
kWh Growth (Growth x PEG Elasticity of 0.1083)		0.08%	0.26%	0.48%	(0.29%)	0.34%	1.04%	
System Peak (Growth x PEG Elasticity of 0.1623)		(1.58%)	1.34%	1.41%	(2.06%)	4.05%	0.41%	
Total Escalator (lines 20 - 21 - 22 + 24)		**(1.22%)**	**4.40%**	**5.09%**	**0.15%**	**6.00%**	**3.71%**	
Adjusted OM&A - Based on Escalators	2,286,047	2,258,120	2,357,457	2,477,479	2,481,319	2,630,091	2,727,725	**441,679**

As seen, inflation and growth accounts for just over half of NOTL Hydro's OM&A cost increases from 2014 to 2019. The reason that the impact of these factors was shown to be higher in the prefiled evidence (Table 4.6) and related interrogatory responses is that NOTL Hydro's earlier breakdown failed to include the impact of its change in capitalization to align with changes in accounting policy, the impact of which is described below.

Accounting Standards Change

In 2014, NOTL Hydro was using Canadian GAAP as its accounting standard. In line with OEB requirements, NOTL Hydro converted to IFRS and 2019 costs are determined using IFRS. One significant difference between the two standards is the treatment of overhead for capitalization purposes. Canadian GAAP allowed an appropriate amount of senior management time to be included in capital costs while IFRS only allows time that can be directly charged to a project to be included. In 2014, both the President and the VP Operations booked time to capital while in 2019 this will be limited. The reduction in capitalized costs is $130,784. It should be emphasized that these are not new expenditures to NOTL Hydro; just a change in how these costs are accounted for.

New or Increased Services

The responsibilities of a business change over time due to changes in technologies, changes in customer demands and changes in regulations. The result of these changes is normally an increase in responsibilities and very rarely a decrease. In addition, certain costs have risen much faster than the rate of inflation.

Despite the growth in its customer base, NOTL Hydro is not able to include the costs of all of its new responsibilities within an OM&A budget that simply increases with inflation. These additional costs require additional budget (though, as shown above, NOTL Hydro's overall rate increases remain low).

Some of the new or increased services and costs that have increased OM&A are:

Table 11 – New or Increased Services

IT & Cyber security	67,394
Utilismart	56,844
Regulatory costs & survey	36,528
Locates	36,566
Health & Safety Consultant	31,367
Pole rentals	8,341
Total	**$237,040**

IT & Cyber Security

In 2014 and prior, NOTL Hydro had no dedicated IT staff person. Most of the IT requirements were outsourced: the CIS system was maintained by UCS, the G/L was maintained by BDO and the network and firewall was monitored by Skycomp. The Operations Manager managed the remaining day-to-day IT requirements. By 2019 this is no longer sufficient. The online world is changing and the Board has recognized this with their Cyber Security initiative. NOTL Hydro has also recognized this as was evidenced by the IT security audit performed in 2017. As a result, the contract with Skycomp has been significantly enhanced so that greater services are being performed in line with the risks identified by the audit. In addition, one of the existing staff members is being trained in IT services so more of their time is dedicated to IT at NOTL Hydro and less to CDM. CDM charges did not affect OM&A so the result of this change is an increase in OM&A.

Utilismart

NOTL Hydro signed a contract with Utilismart in order to enhance the data available to its larger customers. This will be made available to the customers in early 2019. NOTL Hydro's current customer portal is Customer Connect which is part of the Northstar CIS system. While adequate for residential and small business customers, Customer Connect does not provide the detailed data larger customers will need to manage their costs. Utilismart Settlement Manager provides meter data collection and processing for monthly billing, which determines the weighted average price and net system load for our large user and generation customers. Settlement Manager also validates the data required to settle with the system operators, retailers and other market participants. Large user customers benefit by viewing real time meter data which can help identify when load shifting may reduce their monthly operation costs. Additionally, sample invoices may

be viewed at any time during the month to accrue monthly bills. While this is an expensive new cost, NOTL Hydro believes its customers will appreciate the improved service.

NOTL Hydro notes that some of this increased cost will be offset by the increase in the monthly MicroFIT charge.

Regulatory Costs and Survey

Regulatory costs have increased in three areas since 2014.

Table 12 – Regulatory Costs

OEB charges	9,540
Cost of Service application	13,000
Survey and other	13,988
Total	**$36,528**

OEB charges include the annual charge to NOTL Hydro as a regulated LDC to cover the OEB costs as well as any initiatives for which the OEB deems LDCs should be covering costs. NOTL Hydro has no control over these charges. The annual (over 5 years) as-filed cost of this application is expected to be $13,000 higher than from the 2014 application. NOTL Hydro has made significant efforts to keep the cost of the application down such as not using a third party to prepare any of the evidence, particularly the Distribution System Plan. It now appears, however, that application costs may exceed the forecast amount because the case is proceeding to a full hearing before the OEB.

In 2013, NOTL Hydro conducted its own survey using its website and online survey tools. Requirements are now significantly different with the required use of a third party and statistically significant telephone surveys. This substantially increases the cost. NOTL Hydro tries to manage this cost by conducting the survey jointly with other members of CHEC. Based on quotes received for an individual survey this group approach saves around $5,000.

Locates

NOTL Hydro's locate costs have increased by $36,566 or 49% since 2014. With public initiatives such as Ontario One Call, the awareness of the need for locates has increased substantially over

the past few years. NOTL Hydro supports these initiatives as safety must always be a top priority but notes that there is a cost to this increased awareness. NOTL Hydro notes that it has been able to negotiate so that the price per locate has only increased by 1% over the five years so the cost increase is driven by increased demand from third parties. NOTL Hydro has little control over most of this demand.

Health and Safety Consultant

In 2014 and prior, NOTL Hydro had no dedicated safety staff person. The role was jointly lead by the President and Operations Manager. This leadership was successful and NOTL Hydro was the first Ontario LDC to achieve the ZeroQuest Sustainability level in 2012. Given the importance of safety as its #1 core value, NOTL Hydro felt it would benefit from a third party service to help it continue to improve. This service is now being provided by a retired line supervisor from a larger LDC who is onsite 2-3 days a month. NOTL Hydro considers the added emphasis on safety facilitated by having a third party to be critical.

Pole Rentals

Pole rental costs will be increasing as a result of the Board decision on a province wide rate. NOTL Hydro rents the use of some poles from Bell Canada. NOTL Hydro notes that its own revenue will be increasing and that this is reflected in Other Revenue.

Cost Management

There is an expectation that LDCs will manage their costs appropriately. NOTL Hydro believes it has done so based on its rate management and other new or increased cost that it has absorbed through productivity improvements. Some of the examples of new services or increased costs that have been absorbed include:

- Postage costs have increased by 34%. This is due to the increases in postage rates and the increase in customers. NOTL Hydro tries to get customers to sign up for e-billing

which reduces postage costs but must still provide the mailing option. Over 20% of NOTL Hydro's customers are now on e-billing.

- NOTL Hydro outsourced its bill printing. This saved costs as gave NOTL Hydro access to group postage rates which offset the third party charges. The increase in postage costs would have been even higher without this action.
- NOTL Hydro has 5 net metering customers across 3 rate classes. Each of this is very difficult to implement due to the very different structure of net metering as compared to the traditional monthly bill.
- NOTL Hydro now has 4 ICI customers. It provides regular notices to these customers about potential high peak days. NOTL Hydro had no ICI customers in 2014.
- The net book value of NOTL Hydro's assets has increased 30% since 2014. This is not captured by the PEG analysis which only looks at distribution lines. These assets all need to be maintained.
- Included in the increase in assets is the installation of a number of smart switches, reclosures and tripsavers. NOTL Hydro has upgraded its SCADA system due to these devices and the changes to its transmission stations.
- As NOTL Hydro owns its transmission stations it is subject to a number of regulatory requirements that have grown since 2014. These include:
    - A Certificate of Approval is required from the Ministry of Environment showing monthly inspections of the containment pits around the transformers.
    - NOTL Hydro participates in the annual IESO load shedding test.
    - NOTL Hydro has an obligation to respond to the IESO within 15 minutes with a live operator for any switching requests.
- NOTL Hydro's postretirements actuarial costs have gone from a small annual credit in 2014 to a $29k annual cost due to changes in the age of its workforce.
- In 2014, one of the four linemen was an apprentice. This individual is now a full journeyman lineman. The incremental cost, aside from cost of living increases, is $25k. Apprentices start at 55% of journeyman pay and work up to the 100%.
- The OEB RRR requirements have increased substantially since 2014. A much greater proportion of the time of the business analyst is now devoted to RRR reporting.
- Starting in 2014, NOTL Hydro implemented File Nexus. This system, which is integrated with the Northstar CIS system, saves pdf copies of all bills and correspondence. NOTL Hydro has removed over a dozen filing cabinets since this system implementation.

- The disconnection ban means customer service staff must chase payments which is very time consuming.
- The Ontario Electricity Support Program (OESP) requires daily monitoring for new sign-ups and for notification letters to be sent when the OESP is ending. The programming for this also has to be maintained on the CIS system. The OESP was not in place in 2014.
- The Fair Hydro Plan requires a calculation of the savings arising from the plan to be displayed on the bill. This requires significant ongoing maintenance as essentially doubles the work whenever there is a rate change. The Fair Hydro Plan was not in place in 2014.

The OM&A budget shows a staffing cost increase of 44%. However, NOTL Hydro's overall staffing costs (OM&A and capital) have only increased by 12%. This is much less than inflation plus growth. It is how these costs are accounted for that is affecting OM&A.

Table 13 – Staffing Costs Allocation

	2014	2019	% Change	Explanation
Total staffing cost	1,822,057	2,042,411	12%	- actual increase in total staffing costs
IFRS	130,784	-	-100%	- as per description above
Capital and third party work	528,634	496,975	-6%	- shift to service work
CDM	114,669	71,259	-38%	- shift to IT services as per above
Total non-operating staffing costs	774,087	572,527	-26%	
Total staffing OM&A	1,047,264	1,474,177	41%	

NOTL Hydro's staff count reduced from a little over 19 in 2014 to 18 in 2019. However, due to IFRS and the shift in their activities to operational from either capital or off-book funded (CDM), the cost of this staff has a much greater impact on operating expenses. NOTL Hydro notes that it has already exceeded its 2020 CDM target.

TAB iii

Rate Application Interrogatories

RESPONSES

2019 Cost of Service Rate Application

Niagara-on-the-Lake Hydro Inc. (NOTL Hydro)

EB-2018-0056

4 | Operations, Maintenance & Administration

INTERROGATORY RESPONSES

4-Staff-39

Ref: Appendix 2-JB Recoverable OM&A Cost Drivers; Exhibit 4, Page 11, Table 4.10

The recoverable OM&A cost drivers table in Appendix 2-JB does not match to Table 4.10 in the Exhibit 4. Staff notes that the table in excel may not have the correct closing balances for the OM&A expenses.

a) Please update the Appendix 2-JB to match with the Table 4.10 in Exhibit 4.

RESPONSE

a) Appendix 2-JB has been updated to match with Table 4.10. The updated schedule is being filed in response to OEB Staff interrogatory #1.

4-Staff-40

Ref: Appendix 2-JC OM&A Programs Table; Exhibit 4, Page 22

Staff notes that the following cell values on the Appendix 2-JC OM&A Programs Table does not agree to the Board approved column on Table 4.20 of Exhibit 4:

- **Cell B35, sub-total for Operation for last rebasing year**
- **Cell B55, sub-total for Administrative and General for last rebasing year**
- **Cell B56, total for last rebasing year**

Staff notes that the values for last rebasing year on Table 4.20 of Exhibit 4 agree to the values approved by the OEB in NOTL Hydro's 2014 CoS application.

a) Please update the Appendix 2-JC to ensure that the values on the Appendix agree to the OEB-approved values.

RESPONSE

a) Appendix 2-JC has been updated to agree with OEB approved values. The updated schedule is being filed in response to OEB Staff interrogatory #1.

4-Staff-41

Ref: Exhibit 4, Page 11 and Page 12; Appendix 2-K Employee Costs

NOTL Hydro explains that one of the OM&A cost driver is the cost for new staff: "In 2016 and 2017 NOTL Hydro hired a new Customer Service Representative and a new Lineman due to the overall growth in the company business."

Table 4.10 on page 10 of Exhibit 4 list the new staff's cost which is separate from the wage increase for a total of $141,321 ($31,780+$67,541+$42,000).

Staff notes from Appendix 2-K Employee Costs that NOTL Hydro's headcount in 2019 has not been increased from 2014 OEB-approved headcount (2014 approved headcount of 19.1 and 2019 forecasted headcount of 18).

a) Please confirm whether or not the new staff (headcounts) hired in 2016 and 2107 were included in the 2014 headcounts and the OM&A expense approved by the OEB?
   i. If so, please explain why the cost of new staff is considered as a cost driver for the OM&A expense increase.
   ii. If not, please reconcile the cost drivers of total wage increase and total new staff costs to the increase of employee costs from 2014 approved to 2019 forecast in Appendix 2-K.

b) Please update the Appendix 2-JB OM&A Cost Drivers and Appendix 2-K Employee Costs as applicable.

RESPONSE

The headcount of 19.1 approved for the 2014 test year included 6 management staff and 13.1 union staff. After the new staff were hired the NOTL staffing consisted of 6 management staff and 12 union staff so the headcount was within that approved for 2014.

Table 4.10 analyzes the changes in operating costs from year to year. Therefore, as the new staff were hired they created an increase in costs compared to the previous year.

The reconciliation requested in a) ii is below:

	Employee Compensation	**Source**
2014 Board Approved	$1,813,931	Per Appendix 2-K
2014 Headcount reduction	(174,519)	Per Appendix 2-K
2014 Actual	1,639,412	Per Appendix 2-K
New hires (2015-2017)	141,321	Per Appendix 2-JB
Wage increases	269,962	Per Appendix 2-JB
Other	(8,284)	
2019 Test Year	$2,042,411	Per Appendix 2-K

The updated Appendix 2-JB is below. The negative new staff cost of $100,000 is lower than the $174,519 in the reconciliation above as one of the staff reductions was a leave related to a CDM staff. CDM costs are not included in OM&A. The settlement is shown as offsetting as the reduction in staff costs could be considered a result of the lower settlement costs.

Recoverable OM&A Cost Driver Table

Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Opening Balance	$2,155,262.00	$2,208,203.00	$2,323,118.84	$2,532,190.98	$2,595,121.03	$2,904,865.12
Continuous Cost Increases						
Wage increase		$42,767	$69,517	$71,121	$42,850	$43,707
Inflation		$11,287	$17,696	$17,315	$9,046	$20,721
New staff	-$100,000		$31,780	$67,541	$42,000	
Locate costs		$26,000				
Cyber security				$25,000	$5,000	
Utilismart contract				$25,000		
CHEC		$22,300	$4,700			
Settlement	$75,445					
Variable Costs						
Capitalized labour		-$82,845	$56,124	$19,736	$73,129	$1,316
Transformer St. Mtce		$15,000	$13,000	-$36,000	$46,000	-$25,000
Tree trimming		$23,500	$0	-$40,000	$45,000	
Underground services		$30,000	-$17,000			
One-time Costs						
Regulatory costs	$52,941	-$42,353				$46,198
Severance		$42,000	-$42,000			
Micro-grid study			$100,000	-$100,000		
Temporary staff		$30,490	-$11,942	-$18,548	$25,000	
Other	$24,555	-$3,230	-$12,803	$31,765	$21,719	-$17,621
Decrease in OM&A offseting increase						
Closing Balance	$2,208,203	$2,323,119	$2,532,191	$2,595,121	$2,904,865	$2,974,186
Summay Integrity Check	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
Difference	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

4-Staff-42

Ref: Exhibit 4, Page 17

In explaining the 2017 to 2018 year-over-year variance for OM&A, NOTL Hydro states that

> **Operation costs are forecast to be flat. The transfer of the cost of VP Operations to administration is being offset by an increase in labour as less allocation to capital work is expected. This is not a change in accounting policy but change in work practice.**

a) Please elaborate on why and how NOTL Hydro considers less allocation to capital work is a change in work practice, not a change in accounting policy.
b) Please provide the quantum of the change of this work practice and the impact of the OM&A expense and capital.

RESPONSE

a) IFRS requires that senior management only capitalize hours directly to projects to which their hours are directly attributable. For 2018, NOTL Hydro reviewed the tasks undertaken by and time spent by the President and VP Operations. This resulted in fewer hours of these two management staff being capitalized and more being expensed as part of OM&A.

b) The quantum of change is summarized in the table below:

	Hours	**$**
Forecast 2018	158	$13,128
2017	1,294	$108,577
Variance	(1,136)	($95,449)

4-Staff-43

Ref: Exhibit 4, Page 18 and Page 19

NOTL Hydro compares its 2016 OM&A per customer to the provincial average excluding Hydro One and states that:

> **According to the OEB's published 2016 Yearbook, the total cost per customer provincial average was $431. However, if Hydro One is removed from this calculation the provincial average becomes $278. NOTL Hydro's total cost per customer average was $278.**

a) Please compare NOTL Hydro's OM&A per customer in 2017 to the provincial average excluding Hydro One that is published from 2017 Electricity Distributors Yearbook.

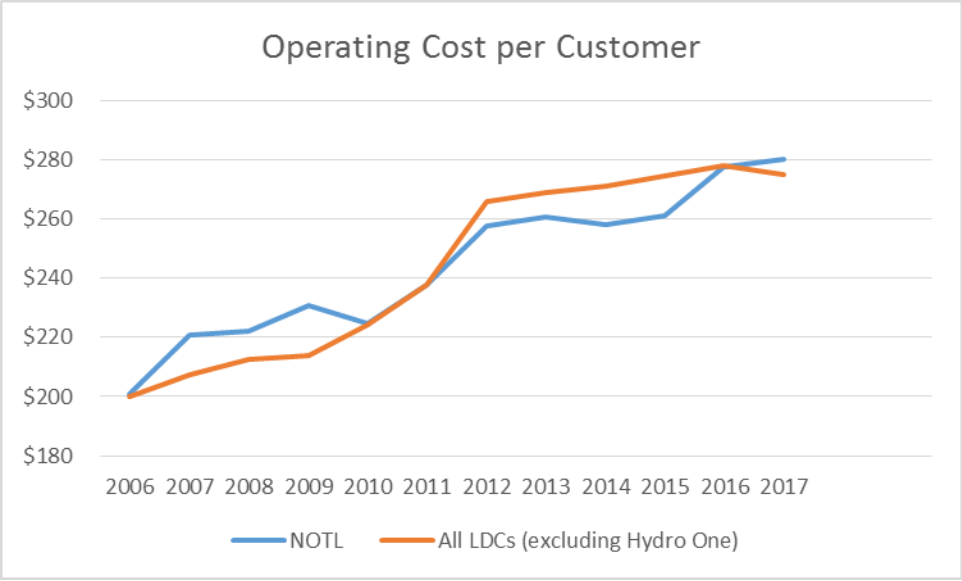
b) Has NOTL Hydro benchmarked itself with the neighbouring distributors with respect to the OM&A expense, similar to the revenue benchmark NOTL has performed and presented in the open houses and AGMs?

i. If so, please provide the benchmark analysis.

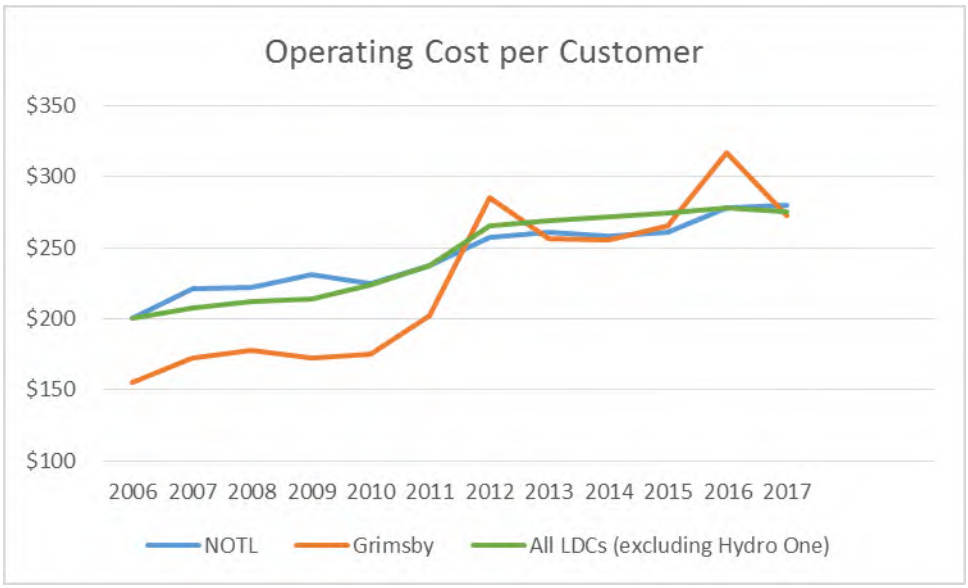
ii. If not, please explain why not.

RESPONSE

a) Please see the chart below



b) As per question 7, NOTL Hydro benchmarks its rates against neighbouring distributors as we believe that is what is important to our customers. NOTL Hydro does not benchmark OM&A against neighbouring distributors as we recognize they can be very different structurally. However, NOTL Hydro did recently compare its OM&A to Grimsby Power as they have a similar number of customers. This analysis is provided below.


Operating Cost per Customer
$350
$300
$250
$200
$150
$100
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

4-Staff-44

Ref: Exhibit 4, Page 23

NOTL Hydro provides the variance analysis for operation costs by program in the table below:

Table 4.21: Operations Program Costs Drivers

Cost	Variance since Board Approved 2014	Variance since 2017	Explanation
Distribution sub-stations	$53,690	$18,984	Increased maintenance at the 2 transmission stations due to age, increased activity and service requirements. Most of this work is contracted to third parties due to need for transmission voltage expertise.
Overhead	$192,432	$69,673	All non-capital service work on overhead lines increasing due to wage increases, increased traffic in Town and shift in focus on customer service from capital work.
Engineering	-$45,671	-$62,067	Transfer of most of non-dedicated VP Operations time to Administration.

a) With respect to the increase of $192,432 in Overhead costs, please provide a further breakdown of the total increase to the increase due to wage increases, the increase due to increased traffic in Town and the increase due to the shift in focus on customer service from capital work.

b) Please confirm whether or not the shift in focus on customer service from capital work means the shift in focus on maintenance service from capital work?

c) Please provide the linkage between "the shift in focus on customer service from capital work" and the overhead capital projects in Exhibit 2.

RESPONSE

a) The breakdown of the overhead by G/L accounts is as follows:

	2014	2019	Change
5020-Overhead Distribution Lines and Feeders - Operation Labour	41,385	138,805	97,420
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	26,958	97,357	70,400
5125-Maintenance of Overhead Conductors and Devices	44,391	60,033	15,642
5130-Maintenance of Overhead Services	23,664	32,693	9,029
	136,397	328,888	192,491

The breakdown by type of costs can be shown as:

Cost type	Cost
Safety consulting	$40,000
Inflation (8%)	10,900
Increased hours (5020,2025)	105,300
Increased Maintenance (5125,5130)	19,200

Subcontracted	17,000
Total	$192,400

- NOTL Hydro did not have a safety consultant in 2014. One was first hired in 2015 and the current consultant provides services 2-3 days a month.
- NOTL Hydro is not able to put a cost to the increased traffic in town. This was an anecdotal observation by staff as to the increase in hours to this type of service.
- The increased hours are for both service work and for safety sessions.

The increased time spent on service work (and safety) is a reflection on the growth of the system in size and complexity and an increase in focus on responding to customer needs.

b & c) Although NOTL Hydro staff are spending more time on service work, the level of capital spending is being maintained. More of the capital work is now either outsourced or focused on investments that do not require the same level of internal labour input such as smart grid devices, underground work and transmission station work.

4-Staff-45

Ref: Exhibit 4, Page 24 and Page 28

NOTL Hydro provides the variance analysis for administration costs by program in the table below:

Table 4.23: Administration Program Costs Drivers

Cost	Variance since Board Approved 2014	Variance since 2017	Explanation
Executive salaries and professional services	$296,103	$161,609	Increased due to addition of VP Operations to Administration, new staff in all three executive roles and less time charged to capital due to focus on other responsibilities.
IT, software, communications	$67,273	$10,986	Increased due to increased cyber-security demands that required new contract with IT provider and more time dedicated by internal staff.

Staff notes that the executive headcount has not been increased over the period of 2014 to 2019 as per Table 4.29 in Exhibit 4 page 28.

a) Please provide a further breakdown of the variance of $296,103 for executive salaries and professional services to the increases due to three reasons provided in Table 4.23.

b) Please explain and reconcile the statement of "the new staff in all three executive roles" with the fact that the executive headcount has not been increased from 2014 to 2019.

RESPONSE

a) Please see the table below for a further breakdown:

	2014	2019	Change
5605-Executive Salaries and Expenses	95,246	431,171	335,925
5610-Management Salaries and Expenses	123,389	15,574	(107,816)
5615-General Administrative Salaries and Expenses	98,614	164,354	65,741
5630-Outside Services Employed	40,800	48,576	7,776
5635-Property Insurance	28,113	21,493	(6,620)
5640-Injuries and Damages	27,719	28,817	1,099
Total			296,105

b) Further to the table above:

- In 2016, the titles of the Manager, Operations and the Director of Corporate Services were changed to Vice President, Operations and Vice President, Finance. At that

time, the allocation of their costs switched from management accounts to the Executive account. In the case of the VP Finance this can be seen in the switching of the costs from 5610 to 5615. In the case of the VP Operations the switch was across functional reporting groupings from Operations to Administration.

- The roles of President, VP Finance and VP Operations are all being provided by different employees in 2019 compared to 2014. It is estimated that the combination of inflation, new hires at higher salaries and the transfer of the non-capitalized cost of the VP Operations have increased costs by around $120k.
- In 2014, a significant amount of the time of the President and the Manager, Operations was booked to capital under CGAAP. Under IFRS, this is no longer allowed and only senior management time working directly on a project can be capitalized. The cost of administration has increased correspondingly and it is estimated that this is over $100k.
- In 2014, General Administrative Salaries and Expenses (Account 5615) were one accounting staff and part of the Business Manager whose time was split between administration and billing and collecting. The Business Manager was replaced by a Business Analyst whose time is 100% administration as deals with regulatory reporting.

4-Staff-46

Ref: Exhibit 4, Page 32

NOTL Hydro provides a breakdown of the 2019 shared services to its sister company ESNI in the table below:

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service-Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$85,676.13	$71,666.78
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$0.00	$0.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll/Solar Panel- Engineering Consulting	Cost-Base	$2,103.03	$1,752.53
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$44,117.04	$40,106.40
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Contractor charges for #Meter Installed	Cost-Base	$12,078.00	$10,980.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$6,516.63	$5,924.21
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00

a) **Please reconcile the mark up on the share services for 2019 to the other revenues in Appendix 2-H for the 2019 test year.**

RESPONSE

a) The table below shows where the mark-up in shared services are reflected in Appendix 2-H. NOTL Hydro acknowledges that the amount of mark-up that should be included in account 4235 in Appendix 2-H should be $4,603.06 ($4,010.64 + $592.42) and that the actual amount reflected for mark-up in Appendix 2-H is $4,112.36, a difference of $490.70. The updated schedule is being filed in response to OEB Staff interrogatory #1.

Year: **2019**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	Other Revenue	Account
From	To			$	$		
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service-Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$85,676.13	$71,666.78	$14,009.36	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$0.00	$0.00	$0.00	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll/Solar Panel- Engineering Consulting	Cost-Base	$2,103.03	$1,752.53	$350.51	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$44,117.04	$40,106.40	$4,010.64	4235
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Contractor charges for #Meter Installed	Cost-Base	$12,078.00	$10,980.00	$1,098.00	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$6,516.63	$5,924.21	$592.42	4235
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00	$0.00	n/a

1

2

4-Staff-47

Ref: Exhibit 4, Page 32

NOTL Hydro forecasts $30,000 for oral hearings and $75,000 for intervenor costs as part of the total cost of $190,000 for preparing the 2019 cost of service application. NOTL Hydro explains that "Interrogatory, settlement and hearing costs have been estimated based on other rate applications".

a) Please provide the rate applications that NOTL Hydro has used for its estimate of the oral hearing and intervenor costs and how the estimates were derived.

b) Given the two intervenors in this case, please confirm whether or not any of the estimated cost for preparing the 2019 cost of service application is to be updated.

i. If so, please provide the updated estimate and the updated appendix.

ii. If not, please explain why not.

RESPONSE

a) NOTL reviewed cost awards for several 2017 and 2018 Cost of Service applications including (CNP, Centre Wellington, and Hawkesbury). Individual intervenor costs in those applications ranged from $8,878 to over $39,000. NOTL Hydro estimated $25,000 per intervenor with an assumption of 3 intervenors to arrive at $75,000. Oral Hearing costs were estimated based on consultations with Tandem Energy Services and their historical experience in these matters.

b) Given that there are 2 intervenors opposed to the 3 that were estimated by NOTL Hydro in the application, NOTL Hydro believes intervenor costs can be reduced to $50,000. The updated schedule is being filed in response to OEB Staff interrogatory #1.

4-Staff-48

Ref: Exhibit 4, Page 51

NOTL Hydro states that "NOTL Hydro had a loss for income tax purposes in the years 2014-2016 so no income tax expense was calculated."

a) Please provide the tax losses for the years 2014-2016 respectively.
b) Please explain if NOTL Hydro has carried back the tax losses from 2014-2016.
c) If the answer to b) is no, please provide NOTL Hydro's plan to carry forward the tax losses from 2014-2016.
d) Please provide the impact of NOTL Hydro's plan in c) to the forecast PILs in 2019 if any.

RESPONSE

a) The losses for the tax years 2014, 2015 and 2016 are $51,083, $383,781 and $18,286 respectively.

b) NOTL Hydro has carried back the losses from 2014 of $51,083 to 2012, the losses from 2015 of $383,781 to 2012 and the losses from 2016 of $18,286 to 2013.

c) Not applicable, losses were fully utilized.

d) Not applicable.

4-Staff-49

Ref: NOTL Hydro 2019 Test Year Income Tax PILs Model; Appendix 2-BA Fixed Asset Continuity Schedule

Staff notes that the total addition on Schedule 8 CCA for the test year in NOTL Hydro's PILs model agrees to the total addition for the test year fixed asset continuity schedule in Appendix 2-BA. However, the addition for Building and Fixture of $52,260 is included as part of the CCA class 47 addition of $4,702,650 on schedule 8 for the test year in the PILs model.

Staff notes that the building and fixture was mapped to the CCA class 1b with the CCA rate of 6% on NOTL Hydro's 2017 tax return.

a) **Please explain why the CCA class of building and fixture for the test year is mapped to Class 47 with the CCA rate of 8% instead of Class 1 with the CCA rate of 6%.**
b) **Please update the PILs model as applicable.**

RESPONSE

a) The amount of $52,260 should be included in Class 1b for the bridge year and $23,150 should be included in Class 1b for the test year

b) An updated PILs model is being filed in response to Staff Interrogatory #1.

4-Staff-50

Ref: NOTL Hydro 2019 Test Year Income Tax PILs Model

Staff notes that the capital addition of the battery for the smart grid project is mapped to CCA Class 43.1 with the rate of 30% on the test year schedule 8.

The Government of Canada website[1] describes the CCA Class 43.1 as follows:

Class 43.1 (30%)

> **Include in Class 43.1 with a CCA rate of 30% electrical vehicle charging stations (EVCSs) set up to supply more than 10 kilowatts but less than 90 kilowatts of continuous power. This is for property acquired for use after March 21, 2016, that has not been used or acquired for use before March 22, 2016.**

a) Please explain the rationale to map the battery to the CCA Class 43.1.
b) Please explain if NOTL Hydro has consulted with any external professionals for its assessment of the CCA class of the battery. i. If so, please provide the correspondence.
c) Please update the PILs model if in any case the assessment for the CCA Class is changed.

RESPONSE

a) On July 26, 2016, the Government proposed amendments to CCA Classes 43.1 and 43.2 to include clean energy capital costs which encompass certain electrical storage property under subparagraph (d)(xviii) of Class 43.1 in Schedule II.

(xviii) fixed location energy storage property that

(A) is used by the taxpayer, or by a lessee of the taxpayer, primarily for the purpose of storing electrical energy

(I) including batteries, compressed air energy storage, flywheels, ancillary equipment (including control and conditioning equipment) and related structures, and (II) not including buildings, pumped hydroelectric storage, hydro electric dams and reservoirs, property used solely for backup electrical energy, batteries used in motor vehicles, fuel cell systems where the hydrogen is produced via steam reformation of methane and property otherwise included in Class 10 or 17, and

(B) either

(I) if the electrical energy to be stored is used in connection with property of the taxpayer or a lessee of the taxpayer, as the case may be, is described in paragraph (c) or would be described in this paragraph if it were read without reference to this subparagraph, or
(II) meets the condition that the efficiency of the electrical energy storage system that includes the property—computed by reference to the quantity of electrical energy supplied to and discharged from the electrical energy storage system—is greater than 50%.

Based on the above, qualifying electrical energy storage property includes batteries, compressed air energy storage, flywheels, ancillary equipment (including control and conditioning equipment) and related structures. In order to be eligible for inclusion in Class 43.1, the electrical energy storage property must meet one of the two additional conditions. First, the electrical energy to be stored by the electrical storage equipment must be used in connection with Class 43.1 property of the taxpayer or a lessee of the taxpayer, as the case may be. Second, where the property is not to be used in connection with Class 43.1 property of the taxpayer or a lessee of the taxpayer, the round trip efficiency of the electrical energy storage system must be greater than 50%.

NOTL Hydro has included the capital addition of the battery for the smart grid project in Class 43.1 as it would qualify under the new subparagraph (d)(xviii). The battery will be a stand-alone unit tied to the NOTL Hydro distribution system. The primary purpose of the battery will be to allow more renewable energy to be stored on the NOTL Hydro distribution system. As the battery will be tied to the distribution system, it is likely not used in connection with other Class 43.1 property. However, the battery meets the second condition as the battery has a round trip efficiency of greater than 50%.

On February 27, 2018, the Government confirmed its intention to proceed with the above tax measure in Budget 2018. As the capital addition relates to 2019, it has been assumed that the proposed legislation will be implemented and the battery will qualify as a Class 43.1 asset.

b) NOTL Hydro has consulted with KPMG LLP for its assessment of the CCA class of the battery.

c) Not applicable

4-Staff-51

Ref: NOTL Hydro LRAMVA Workform, Sheet 5 2015-2020 LRAM, Table 5-b and Table 5-c; 2014 Cost of Service Application (EB-2013-0155) Settlement Agreement, Page 54

NOTL Hydro provides a rate class breakdown of its LRAMVA threshold established in Table 3.2.17 from the 2014 Settlement Agreement.

a) **Please confirm the years in which actual savings were included in the 2014 load forecast.**
b) **Please discuss the appropriateness of including 2011 persistence savings in 2016 and 2017.**

RESPONSE

a) The table below shows the excerpt of the LRAM threshold calculations that were filed as part of the Draft Rate Order supporting NOTL's 2014 Decision and Order (EB-2013-0155). As indicated below, savings from 2011 to 2014 were included in the 2014 load forecast.

Table 3.2.16: Schedule to Achieve 4 Year kWh CDM Target					
4 Year 2011 to 2014 kWh target					
8,270,000					
	2011	2012	2013	2014	Total
2011 Programs	12.4%	12.4%	12.1%	10.0%	46.8%
2012 Programs		10.6%	10.6%	10.5%	31.8%
2013 Programs			7.1%	7.1%	14.3%
2014 Programs				7.1%	7.1%
	12.4%	23.0%	29.8%	34.8%	100.0%
kWh					
2011 Programs	1,022,875	1,022,875	997,755	828,587	3,872,092
2012 Programs		878,526	878,526	870,079	2,627,131
2013 Programs			590,259	590,259	1,180,518
2014 Programs				590,259	590,259
	1,022,875	1,901,401	2,466,540	2,879,184	8,270,000

	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**

b) The rationale for including 2011 persistence savings in 2016 and 2017 is that the conservation programs implemented in 2011-2014 continue to generate savings in 2016 and 2017. The methodology used in NOTL's calculations is consistent with the methodology used and approved in the following 2018 rate cases.
   a. EB-2017-0013
   b. EB-2017-0032
   c. EB-2017-0048

4-Staff-52

Ref: NOTL Hydro LRAMVA Workform, Sheet 3-a Rate Class Allocations and Sheet 5 2015-2020 LRAM

The LRAMVA is the difference between actual savings allocated across customer classes compared to forecast savings by customer class. NOTL Hydro did not provide a summary table as requested in Table 3-a to outline the calculation of the rate class allocations.

a) Please explain how the savings for the commercial and industrial classes were allocated to NOTL Hydro's customer classes.
b) Please show the calculation of 30% of the savings for Save on Energy retrofit program to the streetlighting class in 2015.

RESPONSE

a) In order to calculate the totals from the Retrofit Program, NOTL Hydro totaled the gross savings per project and allocated them according to the rate class of the service address of the project. Net numbers per project were not available due to adjustments from the IESO that we could not identify by project or rate class. The allocation of the gross savings was then applied to the final verified net savings for the Retrofit Program. The remainder of the savings was split up by program by actual participation among rate classes. Projections for future years were based on the average savings by rate classes from historical performance.

b) Below is the calculation of the 30% savings for Save on Energy for streetlights in 2015.

CDM Results | 2015								
		kWh	% by Rate Category					
Residential		325,210	10.91%			NET	Gross	Gross %
	Coupons	108,046			Retrofit Actual	1,703,597	2,349,283	
	BiAnnual Retailer	145,228			Street Light	509,083	702,032	29.88%
	Appliance Retirement	3,267			GS Under 50	330,772	456,139	19.42%
	Home Assistance	2,326			GS Over 50	863,742	1,191,112	50.70%
	HVAC	66,343						
GS<50		402,299	13.50%					
	Retrofit	330,772						
	Small Business Lighting	71,527						
	HPNC	0						
GS>50		1,743,150	58.50%					
	Audit	71,357						
	HPNC	425,850						
	Energy Manager	283,809						
	Retrofit	863,742						
	Ebx	57,642						
	Enabled Savings	40,750						
Street Lighting		509,083	17.08%					
TOTAL		2,979,742	100.00%					

4-Staff-53

Ref: NOTL Hydro LRAMVA Workform, Sheet 6 Carrying Charges

In Table 6 of the LRAMVA workform, NOTL Hydro includes 1.89% interest rate for Q4 2018 to calculate the carrying charge for the LRAMVA.

a) Please update the Q4 2018 interest rate in Table 6 to reflect the OEB's most recently approved prescribed interest rate for deferral and variance accounts.

RESPONSE

a) NOTL Hydro has updated the interest rate in Table 6 for Q4 2018, and Q1 & Q2 2019 to the approved prescribed Q4 interest rate for deferral and variance accounts of 2.17%. The updated LRAMVA model is being filed in response to OEB Staff interrogatory #2.

4-Staff-54

a) Please file a excel copy of the 2017 Final Results Report.
b) Please file a copy of the 2014 Persistence Savings Report.
c) If NOTL Hydro made any changes to the LRAMVA work form as a result of its responses to interrogatories, please file an updated LRAMVA work form. Please confirm any changes to the LRAMVA workform in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".

RESPONSE

a) Attached as appendix 4.STAFF.54.1 2017 Final results Reports

b) Attached as appendix 4.STAFF.54.2 2011-2015 LDC CDM Program Persistence Results Report_Niagara-on-the-Lake

c) Revised LRAMVA workform will be submitted.

4-SEC-27

Please provide revised versions of Appendix 2-JB and 2-JC with an added column showing year-to-date actuals.

RESPONSE

NOTL Hydro does not foresee any material changes to our 2018 forecast as presented in our applications or to Appendix 2-JB.

Below are the year-to-date values for Appendix 2-JC as of September 30, 2018.

Appendix 2-JC
OM&A Programs Table

Programs	2018 YTD at September
Reporting Basis	
Customer Service	
Customer Service, Mailing Costs, Billing and Collections	392,118
Bad Debts	13,500
Monthly Billing (net of savings)	0
Sub-Total	405,618
Operations	
Service Locates	65,780
Municipal Transformer Station -operating and maintenance costs	13,385
Meters maintenance	68,966
Distribution sub-stations and protection and control	111,457
Asset management & maintenance department	0
Overhead lines	237,879
Underground Lines	51,628
24/7 Control room operations and load dispatch activities	39,173
Operations & engineering ,Inspection drafting & design construction services	42,004
Distribution Transformers	26,239
Tree trimming	70,673
Underground conduit	0
Poles Towers & Fixtures	41,944
Fleet costs	0
Sub-Total	769,127
Administrative and General	
Operational Effectiveness & Communication	10,215
Health & Safety Costs	0
Executive, Financial , Legal, Professional and Insurance Services	545,905
Post employment costs	16,740
Procurement and Materials Management	0
Office building & security costs	13,993
IT, software, telecommunications	165,737
Internal Labour & Benefit Costs - attributed to capital work	0
Administrative services recovered from affiliates	0
Collection charges recovered from customers	0
Regulatory & Compliance	57,388
Metering Compliance	0
Smart Meter data management program	0
Capitalization Policy Change (Effective Jan 1 , 2013)	0
ESA Fees	5,202
LEAP	0
Donations	0
Other	43,170
Sub-Total	858,350
Total	**2,033,095**

1

2

4-SEC-28

***[**Ex.4, p.7] In describing the drivers of OM&A, the Applicant states: "No winter disconnections. This lead to more write-offs." Please reconcile this statement with the Applicants actual bad debt expense which appears to have increased by only $2000 in the test year compared to the 2014 Board approved amount.*

RESPONSE

Actual bad debt expenses will vary from year to year for a variety of reasons including any large customer debts (2016 was high due to a grow-op bad debt), timing of the booking of the expense and the general economy. The cost of a program like banning winter disconnections extends to more than bad debts as more resources are also spent chasing payments from customers during the winter season.

NOTL Hydro has determined that the no winter disconnection policy for 2017-2018 led to an additional $5,300 in bad debts. These were booked in 2018. Additional costs for 2018-2019 are unknown but could escalate as customers develop a better understanding of the disconnection ban.

4-SEC-29

[Ex.4, p.7, Table 4.6] Please provide the full derivation of Table 4.6.

RESPONSE

Please see pages 5-7 which provides a full explanation of how all items in Table 4.6 were derived. It has been copied below.

The one exception to the above is the line item "Increase in requirements" for which a narrative description has been provided but no quantification of the estimated impact. Changes in the requirements of electricity distributors have been substantial over the past 5 years and more change is expected in the future with the increase in distributed generation and demands for improved reliability. It is not possible to quantify the impact of each and all these changes on operating costs.

As shown in Table 4.2 below, NOTL Hydro's increase in OM&A spending from its 2014 Cost of Service to the 2019 Test Year is $818,923 or 38% over the 5 years.

Table 4.2: 2014 Board Approved vs. 2019 Test Year OM&A

	Board Approved	2019	Change
Operations	$532,044	$715,973	$183,929
Maintenance	$416,132	$449,790	$33,658
Billing and Collecting	$534,260	$632,867	$98,608
Community Relations	$17,800	$11,485	-$6,315
Administrative and General	$655,026	$1,164,070	$509,044
Total	**$2,155,262**	**$2,974,186**	**$818,923**
%Change (year over year)			38.0%

The 38% increase in OM&A is the result of a combination of inflation, growth and increasing complexity of operations.

Inflation is estimated to be 7% from 2014-2019 using the inflation factors provided each year by the OEB and less the productivity factor of 0.30%. NOTL Hydro has had a PEG rating of 3 in each of these years. For 2019 we have used the average inflation over the past four years as the best estimate.

Table 4.3: Inflation less productivity 2015-2019

Year	2015	2016	2017	2018	2019	Total
Inflation	1.30%	1.80%	1.60%	0.90%	1.40%	7.00%

Growth can be measured in a number of ways. An increase in customers increases operating costs as there are more customers to have service installed, to be billed monthly and to be responded to. During the 2014-2019 period NOTL Hydro increased its customer service staff by one new full-time customer service representative. The increase in customers also leads to an increase in load, increasing demand on NOTL Hydro assets which requires maintenance be increased accordingly. During the 2014-2019 period NOTL Hydro will have installed two new transformers at its transmission station to manage the increasing load and to ensure redundancy of supply. Finally, an increase in assets (net book value) requires increased maintenance. During the 2014-2019 period NOTL Hydro added one new lineman.

Table 4.4: NOTL Hydro Growth Indicators

Measure	2014	2019	% Increase
# Customers	8,574	9,649	12.5%

Load (MWh)	189,356	223,061	17.8%
Assets ($000's)	23,501	30,657	30.5%
Average			20.3%

NOTL Hydro is attributing 20.3% of its increase in OM&A to growth factors note above.

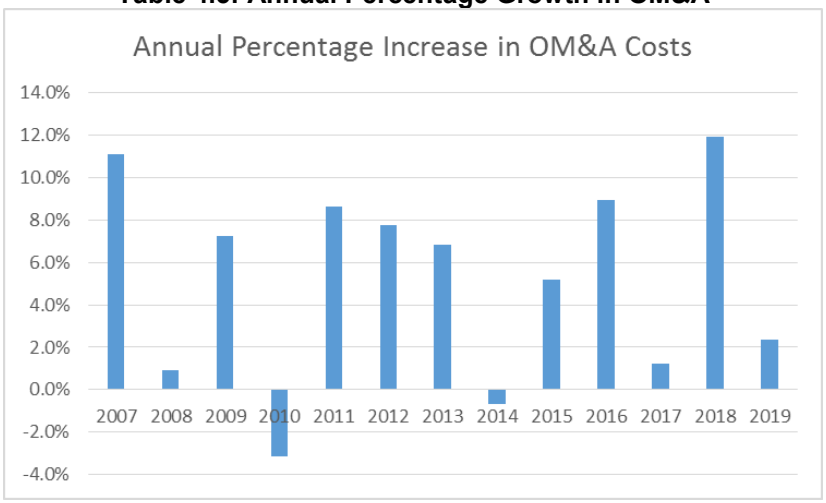
Some of the increase in OM&A is the result of changes in operations or the regulatory environment that increase both revenues and expenses. Just looking at expenses in isolation does not give the full story. Some examples in the case of NOTL Hydro include:

- Pole rental costs are forecast to increase $13.3 thousand from 2017 to 2019 due to the increase in the province-wide pole rental rate. NOTL Hydro has forecast an increase in pole rental revenue of $70 thousand which serves to reduce rates.
- The net increase in the Utilismart service is $29.4 thousand. Some of this will be recovered by the requested increase in the monthly MicroFIT charge which will generate around $8 thousand per year. The rest is increased services to our large customers who will be able to access the data.

Together, these two items represent a $42.7 or 2% increase in OM&A costs.

One of the challenges with OM&A in a smaller LDC is the "lumpiness" of the change. Some years, like 2018, may have several drivers of expense increases while other years, such as 2017 and the 2019 forecast, the changes are quite small. This can be seen in the table below. A longer time horizon yields a different analysis. For instance, from 2006-2019 the average annual increase in OM&A expenses is 5.3%. From 2014-2019 the average annual increase is 5.9%. This would indicate that the higher increases in 2014-2019 is a matter of "timing" and that 3% of the increase from 2014-2019 (5.9% - 5.3% * 5 years = 3%) is a matter of looking at the costs over a short time horizon.

Table 4.5: Annual Percentage Growth in OM&A



The remaining driver of increases in OM&A costs is the increasing complexity of providing electricity distribution services in Ontario. Some of these complexities include:

- Increased expectations by customers. NOTL Hydro introduced its Outage Management System in 2015 so that it can respond to outages without relying solely on customer calls. Like many LDCs, we now have stories of restoring power before a customer is even aware the power is out.
- Net metering. These are much more time consuming to service than a regular customer or a standalone generator due to the complexity of the calculations. NOTL Hydro now has seven net metering customers across all major customer classes (residential, GS<50 kW and GS>50 kW).
- Increased renewable generation. Excluding net metering, these have grown from 117 in 2014 to 153 in 2018; a 31% increase. Renewable generation is increasing costs in another way as NOTL Hydro adapts its asset base and operations in expectation of much more renewable generation in the future.
- Increased regulatory reporting. The volume and complexity of the RRR and other ad hoc reporting to the OEB has grown substantially from 2014 to 2018.
- Increased labour costs. While the inflation estimate above was 7% the cost of labour at NOTL Hydro has gone up a minimum of 11.8% due to the agreements with unionized staff.
- No winter disconnections. This lead to more write-offs. This is somewhat heightened in Niagara-on-the-Lake as there are Niagara College student tenants whose terms end

before the end of the disconnect ban. This also leads to increased costs as more phone calls and other efforts to obtain payments must be undertaken.

- Increased Ministry of Energy programs. New programs such as the OESP and the Affordability Fund all require resources to implement and manage from the context of integrating them within the LDC.

A breakdown of the 2014-2019 increase in OM&A costs would therefore be:

Table 4.6: Breakdown of Increase in OM&A (2014-2019)

Cause	Percentage
Inflation	7%
Growth	20%
Expenses with offsetting revenue	2%
"Timing"	3%
Increase in requirements	6%
Total	**38%**

4-SEC-30

[Ex.4, p.25] Please provide revised versions of Appendix 2-K with an added row showing the amount for each year allocation to capital and OM&A.

RESPONSE

Below is a revised version of Appendix 2-K.

Appendix 2-K
Employee Costs

	Last Rebasing Year (2014 Board Approved)	Last Rebasing Year (2014 Actuals)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	6	5	5	5	6	6	6
Non-Management (union and non-union)	13	10	11	12	12	12	12
Total	19	15	16	17	18	18	18
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 611,906	$ 538,997	$ 530,811	$ 574,605	$ 564,591	$ 652,445	$ 665,494
Non-Management (union and non-union)	$ 874,309	$ 794,717	$ 849,769	$ 841,184	$ 964,936	$ 976,380	$ 995,910
Total	$ 1,486,214	$ 1,333,714	$ 1,380,580	$ 1,415,789	$ 1,529,527	$ 1,628,826	$ 1,661,404
Total Benefits (Current + Accrued)							
Management (including executive)	$ 130,289	$ 123,542	$ 99,963	$ 135,696	$ 131,592	$ 148,231	$ 150,442
Non-Management (union and non-union)	$ 197,428	$ 182,156	$ 160,029	$ 198,649	$ 224,903	$ 227,360	$ 230,565
Total	$ 327,717	$ 305,698	$ 259,992	$ 334,345	$ 356,495	$ 375,592	$ 381,007
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 742,195	$ 662,540	$ 630,774	$ 710,301	$ 696,183	$ 800,676	$ 815,936
Non-Management (union and non-union)	$ 1,071,737	$ 976,873	$ 1,009,798	$ 1,039,833	$ 1,189,839	$ 1,203,741	$ 1,226,475
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411
OM&A	$ 1,017,499	$ 996,664	$ 1,020,261	$ 1,105,954	$ 1,293,811	$ 1,434,069	$ 1,474,177
Capital & Billable	$ 796,432	$ 642,748	$ 620,311	$ 644,180	$ 592,211	$ 570,348	$ 568,235
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411

4.0-VECC-24

Reference: E4/pg. 7

a) Given NOTL's bad debt expense in 2017 was less than in 2014 (17,789 as comparted to 51,789) what evidence does NOTL have that the prohibition on winter disconnection has resulted in more write-offs (bad debt expense).

RESPONSE

Actual bad debt expenses will vary from year to year for a variety of reasons including any large customer debts (2016 was high due to a grow-op bad debt), timing of the booking of the expense and the general economy. The cost of a program like no winter disconnections extends to more than bad debts as more resources are also spent chasing payments from customers during the winter season.

NOTL Hydro has determined that the no winter disconnection policy for 2017-2018 lead to an additional $5,300 in bad debts. These were booked in 2018.

4.0-VECC-25

Reference: E4/Table 4.6/pg.7

a) **Please explain how the calculation of a 20% increase in OM&A attributable to "growth" was derived.**

RESPONSE

Please see response to SEC interrogatory #29 in addition to page 5 of Exhibit 4 as copied below.

Growth can be measured in a number of ways. An increase in customers increases operating costs as there are more customers to have service installed, to be billed monthly and to be responded to. During the 2014-2019 period NOTL Hydro increased its customer service staff by one new full-time customer service representative. The increase in customers also leads to an increase in load, increasing demand on NOTL Hydro assets which requires maintenance be increased accordingly. During the 2014-2019 period NOTL Hydro will have installed two new transformers at its transmission station to manage the increasing load and to ensure redundancy of supply. Finally, an increase in assets (net book value) requires increased maintenance. During the 2014-2019 period NOTL Hydro added one new lineman.

Table 4.4: NOTL Hydro Growth Indicators

Measure	2014	2019	% Increase
# Customers	8,574	9,649	12.5%
Load (MWh)	189,356	223,061	17.8%
Assets ($000's)	23,501	30,657	30.5%
Average			20.3%

NOTL Hydro is attributing 20.3% of its increase in OM&A to growth factors note above.

4.0-VECC-26

Reference: E 4/Table 4.7/pg. 8

a) **In discussing the 19% increase in OM&A per customer NOTL makes the following statement: " *OM&A per customer is expected to rise 19% between 2014 and 2019. This is consistent with the calculation above as the increase in OM&A per customer is the non-growth increase (inflation, offsetting revenues, requirements, etc.*) above."**

It is unclear what this statement is trying to convey. Since 2014 the OM&A increase to 2019 (forecast) has risen by 19.4%. Inflation between that same period would account for approximately 6.6% of that increase (Bank of Canada inflation calculator https://www.bankofcanada.ca/rates/related/inflation-calculator/)

In the result there is 12.8% (13%) increase above inflation during the last rate period. Please explain the factors causing this 13% increase (or 15% if measured from last Board approved) and using the categories shown in Table 4.6

RESPONSE

The statement is trying to convey the following (obviously somewhat unsuccessfully):

The increase in OM&A was 38%. NOTL Hydro had argued that 20% of this increase was due to growth. When you look at the increase in OM&A per customer you are basically eliminating the growth factor. The increase in OM&A per customer of 19% implies that around 19% of the increase in OM&A was due to growth (close enough to 20%) and around 19% was due to other factors.

Based on Table 4.6, the increase in the OM&A per customer would be broken down to:

Cause	Percentage
Inflation	7%
Expenses with offsetting revenue	2%
"Timing"	3%
Increase in requirements	7%
Total	**19%**

Details to the derivation of the "Expenses with offsetting revenue" and "Timing" can be found on page 6 of Exhibit 4. The cost of the "Increase in requirements" is harder to demonstrate but some of the factors have been provided on page 7 of Exhibit 4.

4.0-VECC-27

Reference: E4/pg. 9

a) Please explain why Community Relations should be increase to $11,485 given that in the period 2014 to 2017 the average spending in this category was just $3,800?

RESPONSE

a) NOTL Hydro hosted 4 customer sessions in 2018. 2 for residential, 1 for class A customers, and 1 for small business owners at an overall cost of $13,450. NOTL Hydro also held 2 customer sessions in 2017. NOTL Hydro plans to hold similar events going forward to continue to engage our customers.

4.0-VECC-28

Reference: E4/pg. 16

a) At the above reference NOTL states: "*Billing and Collecting was down $54k or 9.0% as 2015 had the $42k severance payment*." Are severance costs recorded under the ambit of "Billing and Collecting" rather than under accounts related to Administrative and General? If so what other compensation costs are recorded under the accounts for Billing and Collecting?

RESPONSE

Labour costs are allocated to the functional areas including Billing and Collecting. Labour costs are burdened so include all labour related costs such as benefits, vacation, EI, CPP, etc. Where a severance relates to a particular functional area, the associated cost is allocated to that area.

4.0-VECC-29

Reference: E4/Table 4.24 (Appendix 2-K)/pg. 25

a) Please amend Table 4.24 (Appendix 2-k) to show the amount and percentage of employee compensation capitalized in each year.

RESPONSE

a) Below is an amended version of Appendix 2-K

Employee Costs

	Last Rebasing Year (2014 Board Approved)	Last Rebasing Year (2014 Actuals)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	6	5	5	5	6	6	6
Non-Management (union and non-union)	13	10	11	12	12	12	12
Total	19	15	16	17	18	18	18
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 611,906	$ 538,997	$ 530,811	$ 574,605	$ 564,591	$ 652,445	$ 665,494
Non-Management (union and non-union)	$ 874,309	$ 794,717	$ 849,769	$ 841,184	$ 964,936	$ 976,380	$ 995,910
Total	$ 1,486,214	$ 1,333,714	$ 1,380,580	$ 1,415,789	$ 1,529,527	$ 1,628,826	$ 1,661,404
Total Benefits (Current + Accrued)							
Management (including executive)	$ 130,289	$ 123,542	$ 99,963	$ 135,696	$ 131,592	$ 148,231	$ 150,442
Non-Management (union and non-union)	$ 197,428	$ 182,156	$ 160,029	$ 198,649	$ 224,903	$ 227,360	$ 230,565
Total	$ 327,717	$ 305,698	$ 259,992	$ 334,345	$ 356,495	$ 375,592	$ 381,007
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 742,195	$ 662,540	$ 630,774	$ 710,301	$ 696,183	$ 800,676	$ 815,936
Non-Management (union and non-union)	$ 1,071,737	$ 976,873	$ 1,009,798	$ 1,039,833	$ 1,189,839	$ 1,203,741	$ 1,226,475
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411
OM&A	$ 1,017,499	$ 996,664	$ 1,020,261	$ 1,105,954	$ 1,293,811	$ 1,434,069	$ 1,474,177
Capital & Billable	$ 796,432	$ 642,748	$ 620,311	$ 644,180	$ 592,211	$ 570,348	$ 568,235
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411
% OM&A	56.1%	60.8%	62.2%	63.2%	68.6%	71.5%	72.2%
% Capital	43.9%	39.2%	37.8%	36.8%	31.4%	28.5%	27.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

4.0-VECC-30

Reference: E4/pg. 25

a) The average total compensation per employee approved by the Board was $95,470 in 2014. The forecast 2019 average will be $113,467. This increase is significantly above the inflationary increase - 18.4% vs approximately 6.4% inflation. What productivity increases have been achieved which support compensation increases above inflation?

RESPONSE

A common measure of productivity in the industry is customers per employee. From 2014 to 2019 this ratio will increase from 455 to 536. NOTL Hydro is serving 12% more customers with one fewer employee.

Year	Customers	Employees	Customers / Employee
2014 approved	8,647	19	455
2014	8,574	15	572
2015	8,860	16	554
2016	9,134	17	537
2017	9,321	18	518
2018 Bridge	9,469	18	526
2019 Test	9,649	18	536

Please also see SEC Interrogatory #5 for various productivity initiatives.

4.0-VECC-31

Reference: E4/pg. 33

Table 4.32: Services to ESNI Comparisons

Service	2014 OEB Approved	2017 Actual	2019 Proposed
Water heaters rental support	$4,200	$7,505	$2,103
Water and waste water billing	$110,500	$141,808	$141,871
Administration	$5,800	$4,816	$6,517
Board of Directors	-	$8,400	$8,400
Total	$120,500	$162,530	$158,891

a) In 2014 NOTL stated the cost of serving Energy services for water billing was $74,791. In 2019 that cost was 71,666 or 4% decrease in costs. During that same period NOTL's billing and collection costs rose from $559,556 to $597,617 and are projected to increase to $632,867. As Table 4.32 shows shared service costs are in real terms also declining. Water billing costs are in real terms decreasing while those of electricity customers are rising. Please explain why.

RESPONSE

In 2015, the Town of Niagara-on-the-Lake began installing smart meters on all its water accounts. ESNI split its charges that year between water billing and water installs. In 2014 these were combined in the water billing account. The comparison of the water billing costs from 2014 to 2019 should therefore be as follows which shows an increase in costs.

Year	Water Billing Cost	Water Installs Cost	Total
2014	$74,792	-	$74,792
2015	$65,755	$24,190	$89,945
2016	$69,251	$12,574	$81,825
2017	$68,030	$15,850	$81,880
2018	$69,201	$10,980	$80,181
2019	$71,667	$10,980	$82,647

The higher charge in 2015 was for the support provided by ESNI during the installation of most of the water smart meters. Subsequent to that, costs were lower than they otherwise would have been due to savings from the use of smart meters. The full cost of purchasing and installing the water smart meters was the responsibility of the Town of Niagara-on-the-Lake.

It is also noted that a big driver of the increase in the cost of Billing and Collecting in 2019 is the introduction of the Utilismart service for our larger customers. This will provide a level of service and access not available to water customers.

4.0-VECC-32

Reference: E4/pg. 18 Table 4.18 & pg.36

a) Have any one-time regulatory costs been included in Table 4.18 (Appendix 2-JA) in 2018 and 2019? If so please identify the amounts for each year.

b) Please update Table 4.18 to show both 2018 actuals to-date and 2018 forecast to year-end.

RESPONSE

a) The only one-time costs regulatory costs included in table 4.18 relate to the completion of this application ($190,000 / 5) of $38,000 in 2019.

b) Please see below for updated table 4.18

	YTD at Sept 30, 2018	2018 Forecast
OM&A Costs		
O&M Costs	$ 1,170,487	$ 1,762,870
Admin Expenses	$ 848,530	$ 1,141,995
Total Recoverable OM&A	$ 2,019,017	$ 2,904,865
Number of Customers	9,406	9,469
Number of FTEs	17.7	18.1
Customers/FTE	532.42	523.61
OM&A Cost per customer		
O&M Cost per customer	$ 124	$ 186
Admin per customer	$ 90	$ 121
Total OM&A per customer	$ 215	$ 307
OM&A cost per FTE		
O&M per FTE	$ 66,254	$ 97,486
Admin per FTE	$ 48,030	$ 63,152
Total OM&A per FTE	$ 114,284	$ 160,638

4.0-VECC-33

Reference: E4/Table 4.35/pg. 37

a) Please update Table 4.35 to show the amounts expended to-date.

RESPONSE

a) Cost of service expenses invoiced as of September 30, 2018.

Cost of Service Cost Components invoiced as of September 30, 2018	
Application - Consulting (TESI)	$1,601.98
Application - Consulting (CGE)	$13,500.00
Application - Auditor	$0.00
Application - Legal	$7,562.50
Applictation - Other	
Interogatories - Consulting	$0.00
Interogatories - Auditor	$0.00
Interogatories - Legal	$0.00
Settlement - Consulting	$0.00
Settlement - Legal Review	$0.00
Presentation Day	
OEB Customer Session	$0.00
Public Notice	$0.00
Oral Hearings	$0.00
Intervenor Costs	$0.00
Incremental	
Rate Order	$0.00
Total Cost of Service Filing costs	$22,664.48

4.0-VECC-34

Reference: E4/pg.39

a) In each of the years 2014 through 2017 was all of NOTL allocated LEAP funding used?

b) Were any requests denied due to lack of funding?

RESPONSE

a) No

b) No

4.0-VECC-35

Reference: E4/pg.52

a) Please provide the actual taxes (PILs) remitted in each of 2014 through 2017.

RESPONSE

a) The actuals PILS payments in 2014, 2015, and 2016 are nil as NOTL Hydro was in a loss position in those years. The PILS payment made in 2017 was $374,643

4.0-VECC-36

Reference: E4/pg. 36

a) Please explain the increase of $9,540 in Board Assessment costs as between 2018 and 2019.

RESPONSE

a) Currently, NOTL Hydro accounts for OEB Assessments in 2 accounts. Account 5655 Regulatory Expenses and Account 1508 – OEB Cost Assessments. $7,575 of each quarterly invoice is expensed to account 5655 (based on the approved amount in NOTL Hydro's 2014 Cost of Service Application) for a total of $30,300 annually and the remainder is expensed to the 1508 variance account. NOTL Hydro estimates annual assessments to be approximately $39,840 in 2019 with the full amount expensed to account 5655.

	2018F	2019F
OEB Annual Assessment Invoice	$39,231	$39,840
Account 5655 - Regulatory Expenses	$30,300	$39,840
Account 1508 - OEB Costs Assessments	$8,931	$0

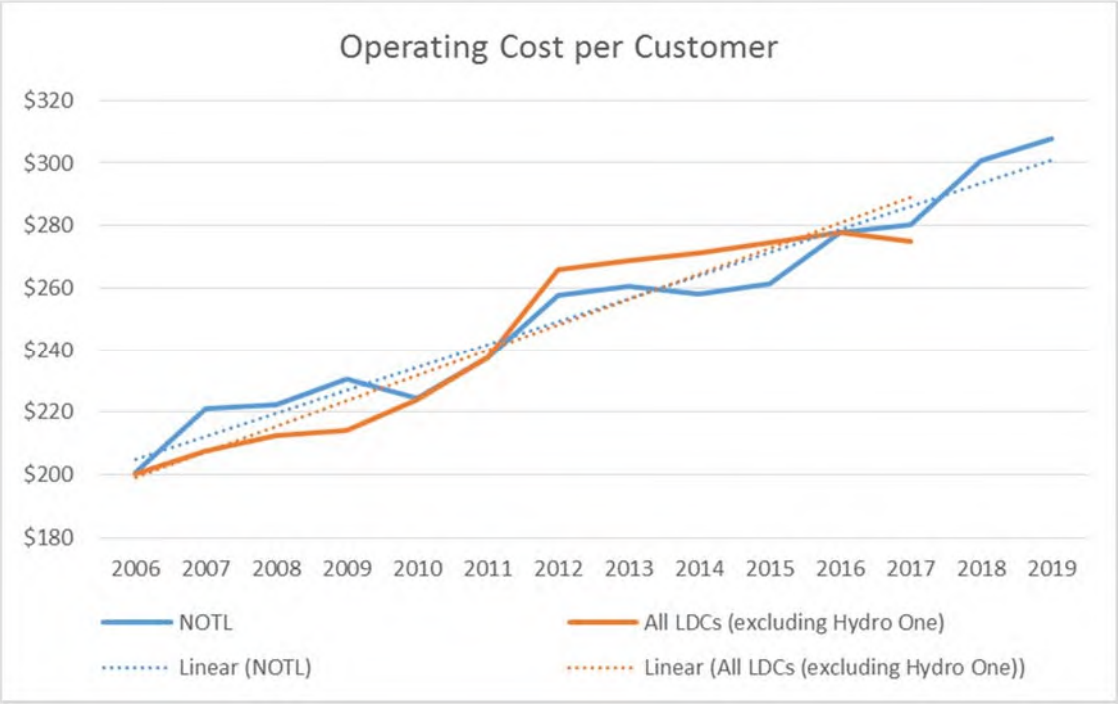
TAB iv

c) No expenditures are planned for underground voltage conversion work on the Niagara Parkway in the Test Year.
d) N/A

SEC-Supp-37
[Ex. 4, Additional Evidence, p.8] Please updated Chart 8 to include the 2018 and forecast 2019 NOTL information.

Response:

See below. As there is no data for other LDCs for 2018 or 2019, trendlines have been added.



SEC-Supp-38
[Ex. 4, Additional Evidence] Please update appendices 2-JA, 2-JB, 2-JC, and 2-K to provide 2018 year-end actuals. Please provide tables in the excel format.

Response:

The updated tables are filed separately as Appendix 1 to the NOTL Hydro Response to the Supplementary SEC Interrogatories. The updated values reflected in Appendix 3 for 2018 represent NOTL Hydro's best estimates based on current available information. These amounts are unaudited.

SEC-Supp-39
[Ex.4, p.7; 4-SEC-29, Ex.4, Additional Evidence, p.8-13] Is NOTL relying on the cost driver evidence in Table 4.6 in the pre-filed evidence or provided in Table 5 of the additional evidence? Please explain.

Response:

NOTL Hydro is assuming the question is referring to Table 9 of the additional evidence (not Table 5 as referenced above).

NOTL Hydro is relying on all of the evidence filed. As OM&A is an unsettled manner proceeding to hearing, NOTL Hydro is providing the additional evidence to assist the intervenors and the Board in understanding the appropriateness of NOTL Hydro's request. The additional evidence is provided as a supplement to the original evidence to provide greater clarification. The only difference is the additional evidence has been updated to reflect any settled matters. NOTL Hydro is hopeful that the provision of the additional evidence, along with the additional interrogatories on that evidence, will ensure that there is a sufficient evidentiary base to support having the unsettled issues determined by way of a written hearing. This would avoid the time and expense of an oral hearing.

Table 4.6 sets out the components of the 38% increase in O&M expenditure from 2014 to 2019. Table 9 in the additional evidence depicts the elements of the increase so that the components add to 100%. The main difference between the two tables is that the originally filed evidence and 4-SEC-29 did not break out or identify the impact of the change in capitalization policy that moved some costs from capital to OM&A in 2017, thereby increasing the administrative and general costs. This item is set out separately in the additional evidence – note that this change simply shifted existing costs; it did not increase overall compensation costs paid by the utility (total compensation costs are discussed at Exhibit 4, pages 24-28).

SEC-Supp-40
[Ex. 4, Additional Evidence, p.6] Please confirm that NOTL stretch factor has remained 0.3% (+/-10%) since its last rebasing application and is forecasted to remain at 0.3% in the test year.

Response:

Confirmed.

SEC-Supp-41
[Ex.4, Additional Evidence, p.9] Please provide a breakdown (and explanation of the calculation) of the actual incremental expenses incurred or forecasted to be incurred since 2014, related specifically for growth, for each of the following:

a. Customer growth
b. System peak and load growth

Response:

The information provided on page 9 of the additional evidence was the calculation of the impact of inflation, customer growth, load growth and system peak growth using the PEG factors. NOTL Hydro is aware that this is a formula commonly used in the Ontario distribution industry as a starting point for analysing OM&A costs. Changes in accounting standards and new or increased services, which would not be captured by the PEG formula, were then added to demonstrate the appropriateness of NOTL Hydro's overall OM&A costs.

At a general level, NOTL Hydro believes that growth in its customer base and load will have added costs over the past 5 years, in terms of items such as billing, customer communications, maintenance and general operations. At the same time, inflation will have increased existing and ongoing costs. NOTL Hydro is not able to breakdown actual incremental costs between load growth or customer growth as that is not how its records and operations are organized or recorded.

SEC-Supp-42
[Ex. 4, Additional Evidence, p.10] Please provide a copy of the live spreadsheet used to calculate table 10.

Response:

A copy of the live spreadsheet is being filed separately as Appendix 2

SEC-Supp-43
[Ex. 4, Additional Evidence, p.15] Please reconcile the 2014 information provided in Table 13 with the information provided in response to 4-SEC-30.

Response:

The main difference between the information in the two tables is that NOTL Hydro separated out the capitalized labour and CDM costs in Table 13 of the additional evidence. There are also some minor changes in the dollars shown because NOTL Hydro used more detailed historical spreadsheets from 2014 to complete the additional evidence, as compared to the more high-level information used to prepare the response to 4-SEC-30.

For details of the differences, please see the table below:

	Table 13	4-SEC-30	Variance	Notes
IFRS	130,784	-	130,784	Included in Capital & Billable in 4-SEC-30
Capital & Billable	528,634	796,432	(267,798)	4-SEC-30 included both CDM and IFRS payroll in Capital & Billable
CDM	114,669	-	114,669	Included in Capital & Billable in 4-SEC-30
Sub-total non-OM&A	774,087	796,432	(22,345)	Difference between total staffing costs and OM&A related staffing costs
OM&A	1,047,264	1,017,499	29,765	Line by line review of the underlying budget used as the basis for the Board Approved 2014 Cost of Service revealed some items included in services budget were labour related
Total Staffing Costs	1,821,351	1,813,931	7,420	4-SEC-30 did not include some payroll items that were budgeted in services including on-call and step-up pay.

SEC-Supp-44

[Ex. 4, Additional Evidence, p.10] With respect to the accounting change:

a. Please provide the full calculation and derivation of the $130,784.
b. Please provide the 2014 actual total cost for the President and the VP Operations positions, allocated to each of capital & OM&A.
c. Using IFRS accounting rules, please re-allocate the 2014 actual total cost for the President and the VP Operations positions.
d. Please provide the forecast 2019 forecast total costs for the President and the VP Operations positions allocated to each of capital & OM&A.

Response:

a. $130,784 was the amount of payroll for the President and VP Operations that was allocated to the capital expenditures in the underlying budget used to derive NOTL Hydro's approved 2014 cost of service application.
    i. President - 665 hours x $100.07 / hour (all in rate including benefits, vacation etc) = $66,548
    ii. VP Operations - 981 hours x $65.48 / hour (all in rate including benefits, vacation etc) = $64,236

b. The table below includes the breakdown of executive payroll from the Board Approved 2014 Cost of Service. Executive includes the President, VP Operations, and VP Finance. The VP Finance position had minimal time allocated to capital.

2014 Cost of Service	
	Executive Payroll & Benefits
OM&A	$292,297
Billable	$5,875
Capital	$131,311
	$429,484

c. Under IFRS overhead is not an allowable capital expense. The nature of the duties performed by the President and VP Operations at this time would have been overhead in

nature and therefore the full amount allocated to capital would be included in OM&A under IFRS.

d. The table below includes the breakdown of executive payroll from the 2019 Cost of Service Application. Executive includes the President, VP Operations, and VP Finance.

2019 Cost of Service	**Executive Payroll & Benefits**
OM&A	$462,409
Billable	$18,310
Capital	$1,133
	$481,851

SEC-Supp-45
[Ex.5, Additional Evidence, p.1] The evidence states: "In November 2018, the Town of NOTL financial management informed NOTL Hydro verbally that they would be looking to renegotiate the loans due to the rise in interest rates". Please provide greater details regarding the discussion that was held including, but not limited to whom specifically from the Town spoke to whom at NOTL, and on what date.

Response:

The initial discussion was held on November 8, 2018 during a meeting on a different matter. During a break from the main agenda item, the Town's Acting Treasurer, Kyle Freeborn informed NOTL Hydro President Tim Curtis of the Town's desire to renegotiate the loans due to rising interest rates.

SEC-Supp-46
[Ex.5, Additional Evidence, p.1] Please provide a copy of all written communications and a detailed summary (including participants and dates) of all oral communications between the Town and the NOTL, that in whole or in part, discuss its debt arrangements since January 1 2018. [Note: For written communications, please provide copies the actuals communications and do not copy and pasting the text as is done with the email from Mr. Freeborn on p.1-2).

Response:

The only written communication is the e-mail from Kyle Freeborn, a copy of which is attached as Appendix 2 to the responses to the OEB Staff Supplementary Interrogatories. In addition to the oral communication described in the response to SEC-Supp-45, Kyle Freeborn and Tim Curtis discussed the loan terms during a meeting on December 17, 2018. The 3.5% interest rate was proposed during that meeting based upon the due diligence with the schedule A bank as described in SEC-Supp-48. On January 28, 2019, Tim Curtis and Kyle Freeborn discussed finalizing the change in the loan terms. The earliest available date is March 4, 2019 for this to be presented to Town Council for approval. It was agreed that Tim Curtis will prepare the

NOTL Hydro responses to VECC Supplementary Interrogatories on the Updated Evidence

2019 Cost of Service Rate Application

Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) EB-2018-0056

January 30, 2019

4.0-VECC-50
Reference: Exhibit 4 – Additional Evidence OM&A

a) Please explain why NOTL filed new evidence with respect to OM&A costs. Specifically explain what new factors or new facts have changed or become known since the filing of the original evidence and which required this update.

Response:

As OM&A is an unsettled manner, NOTL Hydro is providing the additional evidence to assist the intervenors and the Board in understanding the appropriateness of NOTL Hydro's request. Given that parties have the opportunity to ask interrogatories of the additional evidence, NOTL Hydro believes that any items requiring clarification from the additional evidence can be addressed. NOTL Hydro hopes that by providing additional evidence on unsettled items, it may be possible to avoid the expense and time of an oral hearing, and instead proceed with a written hearing.

2.0-VECC-51
Reference: Exhibit 2 – Additional Evidence

a) Please file the most current Niagara-on-the-Lake Historic Old Town Heritage Conservation District Plan.
b) Please file the District Plan Boundary Map.

Response:

a) What NOTL Hydro believes to be the most current Niagara-on-the-Lake Historic Old Town Heritage Conservation District Plan is attached as Appendix 1.

b) Various district plan maps are attached as Appendix 2.

TAB 5

TAB i

EB-2018-0056

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an application by Niagara-on-the-Lake Hydro Inc. for an order or orders approving electricity distribution rates and other charges commencing as of May 1, 2019.

NIAGARA-ON-THE-LAKE HYDRO
2019 COST OF SERVICE RATES
ARGUMENT-IN-CHIEF

AIRD & BERLIS LLP
Barristers and Solicitors
Brookfield Place
Suite 1800, Box 754
181 Bay Street
Toronto, ON M5J 2T9

David Stevens
Tel (416) 863-1500
Fax (416) 863-1515

Email: dstevens@airdberlis.com

A. OVERVIEW

1. Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) has filed detailed evidence supporting its requirements for the 2019 Test Year. Most aspects of NOTL Hydro's filing were accepted by stakeholders through a Settlement Proposal which was then approved by the OEB.

2. There are six unsettled items in this case, to be addressed in this Argument in Chief. The unsettled items fall into two categories.

3. First, there are three components of revenue requirement at issue. These relate to Operations, Maintenance and Administration (OM&A) expenses, the capital costs (and rate base) related to NOTL Hydro's underground conversion program and NOTL Hydro's cost of long-term debt.

4. NOTL Hydro's evidence for each of these items clearly sets outs why the forecast expenditures are necessary, reasonable and appropriate. This Argument in Chief highlights the key aspects of that evidence. The reasonableness of NOTL Hydro's proposed revenue requirement (inclusive of the unsettled items) is confirmed by the fact that NOTL Hydro's rates remain relatively low (and are lower than its neighbours), and the bills for a typical NOTL Hydro residential customer will only increase by 1.17% if all items are approved as filed.

5. The second category of unsettled items relates to proposals made by NOTL Hydro that will reduce Test Year distribution rates or bill impacts for residential customers. These relate to cost allocation (whether to include ICM revenue in revenue in existing rates), deferral and variance accounts (whether to clear Group 2 accounts and the LRAMVA over two years) and transmission gross load billing (whether to approve the proposal to allocate Hydro One's gross load billing charges to the customer causing such charges). None of these items impact on NOTL Hydro's revenue requirement; instead, each of these represents a scenario where NOTL Hydro has made a proposal to reduce bill impacts for its largest class of customers without unfairly treating other customer classes.

6. NOTL Hydro's customers have clearly indicated their satisfaction with the service they receive. NOTL Hydro requests approval of its proposal for each of the unsettled items, in order to continue to provide safe, reliable, cost-effective service to its customers.

B. BACKGROUND

7. NOTL Hydro filed a cost of service application with the Ontario Energy Board (OEB) on August 23, 2018, seeking approval for changes to the rates that Niagara-on-the-Lake Hydro charges for electricity distribution, to be effective May 1, 2019.

8. NOTL Hydro answered interrogatories from the three participants in the proceeding (Board Staff, SEC and VECC) in November 2018 (with follow-up questions in December 2018), and the parties then participated in a Settlement Conference in December 2018.

9. On January 10, 2019, NOTL Hydro filed a (partial) Settlement Proposal with the OEB. The Settlement Proposal indicated that there are six "Unsettled Items", described as follows:

    i. Rate Base and capital expenditures, specifically the underground conversion program/projects (replacing older overhead distribution lines with a higher voltage underground system);

    ii. OM&A cost forecast of $2,964,765 for the Test Year;

    iii. The cost of NOTL Hydro's long-term debt;

    iv. Cost Allocation and Rate Design, specifically, the proposal to include previous ICM rate rider in revenue at current rates for the purposes of determining the appropriate R/C ratios, which have an impact on rate design;

    v. Whether NOTL Hydro's proposal for gross load billing should be approved; and

    vi. Disposition period of agreed upon Group 2 deferral and variance account balances.

10. The Settlement Proposal indicated that all other issues in the proceeding were resolved between the parties, generally on the basis of NOTL Hydro's as-filed evidence (inclusive of corrections and updates from the interrogatory process).

11. After the Settlement Proposal was filed, the evidentiary record in the proceeding was completed, with the filing of Additional Evidence related to Unsettled Items (i), (ii), (iii) and (vi) above, along with interrogatory responses on the Additional Evidence.

12. On February 8, 2019, the Board issued its Decision on Partial Settlement Agreement and Procedural Order No. 4, accepting the Settlement Proposal and the rates that result, subject to the adjustments arising from the OEB's decision on the unsettled issues.

13. In the February 8, 2019 Decision, the OEB defined the "unsettled issues" as follows:

i. Issue 1.1 Capital: Partial settlement. The unsettled issue relates to the prudence of Niagara-on-the-Lake Hydro's underground conversion project/program since its last rebasing (impacting 2019 opening rate base) and its proposed test year expenditures for the underground conversion program (impacting 2019 net additions and rate base).

ii. Issue 1.2 OM&A: No settlement. The Parties agree that all issues relating to OM&A expenses should be determined by the OEB.

iii. Issue 2.1 & 2.2 Revenue Requirement: Partial settlement. The unsettled issue relates to the cost of long-term debt.

iv. Issue 3.2 Cost Allocation: Partial settlement. There is no agreement on whether to include the Incremental Capital Module revenue in distribution revenue at current rates in the cost allocation model.

v. Issue 4.2 DVAs: Partial settlement. There is no agreement on the disposition period of Group 2 DVAs and the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA).

vi. Issue 5.3 Transmission Gross Load Billing: No settlement. The Parties agree that all issues related to this item should be determined by the OEB.

14. The OEB accepted the parties' request for a written hearing to address the unsettled issues, and provided a schedule for written submissions.

C. ARGUMENT

15. Under the subheadings set out below, NOTL Hydro summarizes the evidence in support of its position on each of the unsettled issues.

16. NOTL Hydro will not anticipate the arguments to be made by other parties on these items; instead, NOTL Hydro will provide its responding submissions after written arguments from the other parties are received.

17. Before specifically addressing the unsettled issues, it is important to provide some context around the overall reasonableness of NOTL Hydro's application.

18. NOTL Hydro's Mission Statement indicates (in part) that "Niagara-on-the-Lake Hydro continuously seeks to provide low cost energy delivery, high reliability and high power

quality." This is obtained by seeking a balance between costs, investments, reliability and power quality.[1]

19. NOTL Hydro has worked hard to improve and maintain its reliability. NOTL Hydro's customers have indicated that this is the most important priority for them.[2] NOTL Hydro's most recent scorecard posted to the OEB website confirms that the utility continues to exceed all operational effectiveness and customer focus targets.[3] In the most recent customer engagement process, NOTL Hydro's customers confirmed their satisfaction, as indicated in the following comment under the "Reliability" heading in the Customer Engagement report: "[a]ll participating customers commented on how the reliability of the system feels like a dream compared to those customers in a more rural setting. They commented on how happy they are with it."[4]

20. NOTL Hydro has succeeded in its goal of low cost energy delivery.[5] NOTL Hydro has gone from having one of the highest rates in the province to one of the lowest. In 1994, NOTL Hydro had the 4th highest residential rate of 111 Ontario electric utilities (LDCs) reporting their rates to the Municipal Electric Association. By 2018, NOTL Hydro had the 17th lowest residential rate of 71 LDCs (lowest quartile), the 23rd lowest GS<50 kW rate of 70 LDCs, the 3rd lowest GS>50 kW rate of 70 LDCs and the lowest Large User rate, based on the forecast consumption of the new Large User, of 24 LDCs.

21. NOTL Hydro believes that this record of improving rates is the best indicator of sound cost management. Importantly, reliability and capital investments have not been sacrificed by NOTL Hydro, and rates are falling in comparison to other Ontario LDCs.[6]

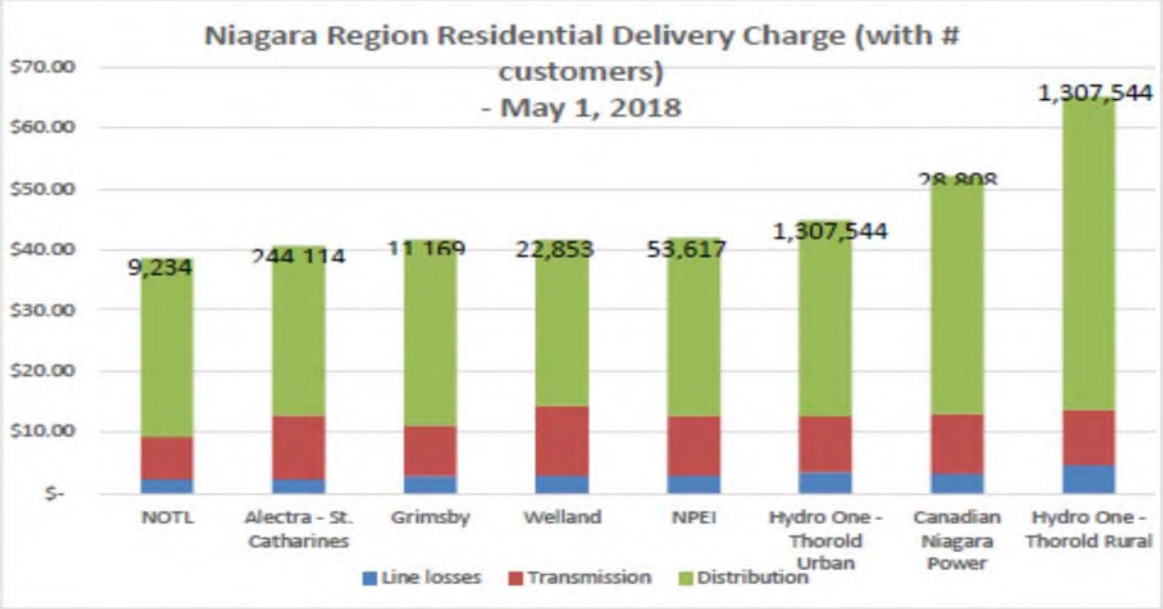
22. Moreover, as explained in NOTL Hydro's Additional Evidence on OM&A expenses, NOTL Hydro's rates are lower than what would be expected based on the customer density in its service territory.[7]

---

[1] Exhibit 4 – OM&A – Additional Evidence, page 2.
[2] Exhibit 1 – Administrative Documents, page 72.
[3] Scorecard - Niagara-on-the-Lake Hydro Inc, September 2018, filed in response to Staff Interrogatory #1, (Exhibit 1-Staff-4).
[4] Exhibit 1 – Administrative Documents – Appendix 1H – CGC Customer Engagement Report NOTL Hydro, May 2018, at page 3; see also page 11 under the "Reliability" heading.
[5] Exhibit 4 – OM&A – Additional Evidence, page 2.
[6] *Ibid*.
[7] Exhibit 4 – OM&A – Additional Evidence, pages 3 and 4.

23. As depicted in Table 1 below, taken from the prefiled evidence[8], NOTL Hydro's distribution rates are lower than others in its region.

Table 1 – Niagara Region Delivery Charges



24. NOTL Hydro's 2019 cost of service application confirms the utility's success in maintaining reasonable rates and strong quality of service.

25. Most of the issues in NOTL Hydro's rate application have been settled and approved. The Settlement Proposal included an updated Bill Impact Model setting out the impacts that will result if the OEB accepts the Partial Settlement Proposal and also accepts NOTL Hydro's position on the Unsettled Items. The total bill impact for a residential customer will be an increase of 1.17%.[9] On a delivery charge basis, the impact will be 3.14%. However, much of that amount (around 2.41% of the 3.14%) relates to rate rider costs for pass-through items unrelated to NOTL Hydro's own cost of service.

26. NOTL Hydro submits that in the context of the relatively low level of its current rates, the rate increases that will result from this application are reasonable and appropriate.

[8] Exhibit 1 – Administrative Documents, page 81.
[9] See NOTL Hydro 2019 Tariff Schedule and Bill Impact Model 20190111, tab 20.

past years, and are necessary for NOTL Hydro to continue its underground conversion program, which is supported by and benefits its ratepayers.

b. Issue 1.2 – OM&A Expenditures

40. NOTL Hydro's 2019 Test Year OM&A forecast is $2,964,765. This is the amount required for NOTL Hydro to continue its safe, reliable and customer-focused operations. Included in NOTL Hydro's OM&A operating costs are required expenditures necessary to maintain and operate NOTL Hydro's distribution system and transmission station assets, the costs associated with metering, billing, collecting from its customers, the costs associated with ensuring all stakeholders' safety (public and employees) and costs to maintain the distribution business service quality and reliability standards set by the regulating bodies.[26]

41. The components of NOTL Hydro's 2019 OM&A forecast are set out in Table 2 below.[27]

Table 2 – NOTL Hydro Forecast 2019 OM&A Expenses

	2019 Test Year
Operations	$ 711,610
Maintenance	$ 449,790
Billing and Collecting	$ 632,867
Community Relations	$ 11,485
Administrative and General	$ 1,159,012
Total	**$ 2,964,765**

42. The reasonableness of NOTL Hydro's 2019 OM&A budget forecast can be confirmed in a variety of ways, including by: (i) looking at the elements of the budget; (ii) comparing the budget to the most recent actual spending; (iii) looking at the details and appropriateness of the various year-over-year cost increases between the last rebasing and 2019; (iv) looking at what would be a reasonable budget, taking into account the budget that existed at the time of the last rebasing, and then considering how that budget would be expected to change over six years; and (v) comparing NOTL Hydro's OM&A per customer to other distributors. Each of these is described below.

[26] Exhibit 4 – OM&A, page 4.
[27] Exhibit 4 – OM&A, Table 4.2 (with updates), page 5.

(i) The evidence supports NOTL Hydro's 2019 OM&A budget forecast

43. NOTL Hydro's prefiled evidence (including Additional Evidence), along with the answers to interrogatories, provide details as to each component of the 2019 OM&A forecast.[28] The evidence sets out the activities and associated costs necessary to support NOTL Hydro's ongoing, reliable and customer-focused operations.

44. NOTL Hydro's evidence also describes its efforts and initiatives to manage and limit OM&A costs over the past five years. For example, NOTL Hydro has installed FileNexus to digitize customer files, outsourced bill printing, implemented an outage management system, outsourced IT services, reduced payroll to biweekly, improved contracts for vegetation management and implemented more rigorous tendering processes.[29]

(ii) NOTL Hydro's actual 2018 OM&A Expenditures are close to the 2019 forecast

45. In NOTL Hydro's submission, the amount actually spent by a utility during years when there is no opportunity to rebase or recover spending beyond that which is implicitly embedded in rates is persuasive evidence of the amounts actually required. One measure of the reasonableness of NOTL Hydro's proposed 2019 OM&A budget is that it is in line with the amounts actually spent in the most recent year. As set out in NOTL Hydro's most recent interrogatory responses, the 2018 full calendar year OM&A expenditures by NOTL Hydro are now estimated (as of February 7, 2019) to be $2,838,535.[30] This total is modestly lower than the as-filed 2018 OM&A forecast ($2,904,865), showing NOTL Hydro's efforts to manage and maintain costs.

46. The drivers of NOTL Hydro's expected OM&A cost increases from 2018 to 2019 are described in the pre-filed evidence. In addition to expected cost increases from inflationary pressures and customer growth, NOTL Hydro also expects discrete cost increases due to higher pole rental fees to Bell Canada (around $8,000), higher billing and collection costs (around $35,000) and higher regulatory costs (around $22,000).[31]

---

[28] The OM&A evidence is found at Exhibit 4 (pre-filed and Additional Evidence), and in the interrogatories on that evidence.
[29] Exhibit 4 – OM&A – pages 13 to 15 and response to SEC Interrogatory #5 (Exhibit 1-SEC-5).
[30] See Appendix 1 to the NOTL Hydro Response to the Supplementary SEC Interrogatories. Note that the 2018 actual results filed are estimated and unaudited – final results may be available in the coming weeks.
[31] Exhibit 4 – OM&A, page 17.

(iii) NOTL Hydro's evidence substantiates the OM&A cost increases since its last rebasing

47. Table 3 below, reproduced from NOTL Hydro's prefiled evidence[32], sets out NOTL Hydro's OM&A expenditures for 2014 to 2019 (note that 2018 and 2019 are presented on a forecast basis, as of the time of filing).

Table 3 – NOTL Hydro OM&A Expenses 2014 to 2019

	Board Approved	2014	2015	2016	2017	2018	2019
Operations	$532,044	$491,400	$548,540	$654,295	$673,867	$679,413	$715,973
Maintenance	$416,132	$412,259	$451,578	$476,273	$414,737	$473,074	$449,790
Billing and Collecting	$534,260	$559,556	$601,150	$547,188	$573,154	$597,617	$632,867
Community Relations	$17,800	$578	$758	$9,700	$4,161	$12,765	$11,485
Administrative and General	$655,026	$744,411	$721,094	$844,735	$929,202	$1,141,995	$1,164,070
Total	**$2,155,262**	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
%Change (year over year)		2.5%	5.2%	9.0%	2.5%	11.9%	2.4%

48. NOTL Hydro's prefiled evidence identifies, on a year-by-year basis, the main drivers of the increase between 2014 Board-approved and 2019 forecast OM&A expenses.[33] The prefiled evidence speaks to the specific year-over-year items that have contributed to the changes in budgets each of these years.[34] The combined impact of these individual items cumulates to the overall change in the OM&A budget level from 2014 to 2019. Review of the details of the individual items confirms the reasonableness of the overall change.

(iv) NOTL Hydro's 2019 OM&A budget forecast is at the level that should be expected

49. In its Additional Evidence, NOTL Hydro sets out a higher-level approach to explain the increases in its OM&A budgets from the last rebasing year. Under this approach, summarized in Table 4 below[35], NOTL Hydro has identified the cost increases that would be expected as a result of inflation and growth, and then has identified other discrete items that have caused its OM&A costs to increase.

---

[32] Exhibit 4 – OM&A, Table 4.1, page 4.
[33] As noted in the OM&A Additional Evidence, it would be more appropriate to use 2014 actual OM&A expenditures as a starting point for evaluating NOTL Hydro's 2019 OM&A budget forecast. That is because the 2014 OEB-approved OM&A budget was part of the settlement of virtually all issues in the EB-2013-0155 proceeding, and it represented a $75,455 reduction from NOTL Hydro's filing (EB-2013-0155, Settlement Proposal, filed March 22, 2014, at pages 9, 26 and 27: this document can be found at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/430741/File/document). It is fair to assume that the budget reduction was agreed in the context of an overall resolution (the settlement was a "package"), and does not necessarily mean that the specific agreed OM&A budget was reasonable on its own. In NOTL Hydro's submission, the appropriate jumping-off point for analysis of increases in its OM&A expenditures from its last rebasing is the actual amount spent by NOTL Hydro in the rebasing year (2014), which amount is approximately $55,000 higher than what was included in the Settlement Proposal.
[34] Exhibit 4 – OM&A, pages 11 to 17.
[35] Exhibit 4 – OM&A – Additional Evidence, Table 9, page 9.

Table 4 – OM&A Cost Drivers

Inflation and growth	$441,679	55%
Accounting standards change	$130,784	16%
New or increased services	$237,040	29%
Total	$809,503	100%

50. As seen in Table 4, inflation and growth can be expected to have caused an increase of around $450,000 in NOTL Hydro's OM&A expenses from 2014 to 2019. The way that this is determined is set out in Table 5 below, reproduced from NOTL Hydro's Additional Evidence[36]. Information about the inputs used is set out in the two paragraphs below.

51. Inflation has been calculated using the OEB approved inflation rates less the stretch factor adjustment. For NOTL Hydro this stretch factor adjustment was a reduction in inflation of 0.30%. An inflation rate of 1.70% was used for 2019.[37]

52. NOTL Hydro has calculated the expected impact of growth on its OM&A expenses with reference to the approach used by the OEB's expert Pacific Economics Group (PEG). As referenced in the OEB's Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, PEG uses five factors to calculate the impact of growth on costs.[38] These are customer growth, load growth, system peak growth, increase in distribution lines and acceleration in customer growth. NOTL Hydro has used the first three of these items in evaluating the impact of growth on OM&A costs.[39] The latter two items were not used because NOTL Hydro has seen no noticeable change in either the amount of distribution lines or the rate of customer growth.

[36] Exhibit 4 – OM&A – Additional Evidence, Table 10, page 9.
[37] Exhibit 4 – OM&A – Additional Evidence, page 9.
[38] EB-2010-0379, Report of the Board titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors", December 4, 2013, page 23.
[39] The PEG elasticity factors used for customer growth was 0.4485, for load growth was 0.1083 and for system peak growth was 0.1623 – see Exhibit 4 – OM&A – Additional Evidence, page 9.

Table 5 – Expected Increase in OM&A due to Inflation and Growth

Niagara-on-the-Lake Hydro Inc.
OM&A Analysis
2019 Cost of Service

	Board Approved 2014 BA	Actual 2014	2015	2016	2017	Projected 2018	2019	Variance 2019 vs. 2014 BA
Total OM&A Expenses	2,155,262	2,208,203	2,323,119	2,532,191	2,595,121	2,904,865	2,964,765	809,503
2014 Adjustment: IFRS (President and VP Operations Capitalized Labour)	130,784						0	(130,784)
Adjusted Total	**2,286,047**						**2,964,765**	**678,718**
Growth	**2014**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2019 vs. 2014 BA**
Customers (excludes Street Light and USL)	8,499	8,551	8,839	9,115	9,299	9,444	9,626	1,127
Customer Growth		**0.62%**	**3.36%**	**3.13%**	**2.02%**	**1.55%**	**1.93%**	**13.26%**
kWh Delivered (total excluding losses)	187,976,750	189,355,729	193,845,050	202,468,101	196,959,263	203,217,805	222,679,374	34,702,624
Load Growth		**0.73%**	**2.37%**	**4.45%**	**(2.72%)**	**3.18%**	**9.58%**	**18.46%**
System Peak (MW)	44,925	40,558	43,895	47,702	41,660	52,067	53,377	8,452
System Peak Growth		**(9.72%)**	**8.23%**	**8.67%**	**(12.67%)**	**24.98%**	**2.52%**	**18.81%**
Escalators	2014	2014	2015	2016	2017	2018	2019	**2019 vs. 2014 BA**
Inflation (OEB)		0.00%	1.60%	2.10%	1.90%	1.20%	1.70%	
Stretch Factor (PEG Group 3)		0.00%	0.30%	0.30%	0.30%	0.30%	0.30%	
Sub-Total		0.00%	1.30%	1.80%	1.60%	0.90%	1.40%	
Customer Growth (Growth x PEG Elasticity of 0.4485)		0.28%	1.51%	1.40%	0.91%	0.70%	0.87%	
kWh Growth (Growth x PEG Elasticity of 0.1083)		0.08%	0.26%	0.48%	(0.29%)	0.34%	1.04%	
System Peak (Growth x PEG Elasticity of 0.1623)		(1.58%)	1.34%	1.41%	(2.06%)	4.05%	0.41%	
Total Escalator (lines 20 - 21 - 22 + 24)		**(1.22%)**	**4.40%**	**5.09%**	**0.15%**	**6.00%**	**3.71%**	
Adjusted OM&A - Based on Escalators	2,286,047	2,258,120	2,357,457	2,477,479	2,481,319	2,630,091	2,727,725	**441,679**

53. A discrete and significant contributor to the change in NOTL Hydro's OM&A expenses arises from the fact that some employee expenses that were capitalized in 2014 are now expensed and included within the OM&A budget.[40] The impact is approximately $130,000.

54. In 2014, NOTL Hydro was using Canadian GAAP as its accounting standard. In line with OEB requirements, NOTL Hydro converted to IFRS and its recent OM&A expenses, including the 2019 forecast costs, are determined using IFRS. One significant difference between the two standards is the treatment of overhead for capitalization purposes. Canadian GAAP allowed an appropriate amount of senior management time to be included in capital costs while IFRS only allows time that can be directly charged to a project to be included. In 2014, both the President and the VP Operations booked time to capital while in 2019 this will be limited. The reduction in capitalized costs, and corresponding addition to OM&A costs, is $130,784.[41]

55. It should be emphasized that these OM&A employee expenses are not new expenditures to

[40] Exhibit 4 – OM&A – Additional Evidence, page 10, and response to Staff Supplementary Interrogatory referencing 4-Staff 42 and 4-VECC-29.
[41] Exhibit 4 – OM&A – Additional Evidence, page 10.

NOTL Hydro; just a change in how these costs are accounted for. As explained in the Additional Evidence, NOTL Hydro's total staffing costs (including amounts that are capitalized) only increased by 12% over the 2014 to 2019 period.[42]

56. A final set of cost pressures for NOTL Hydro comes from new and increased services and costs. The responsibilities of a business change over time due to changes in technologies, changes in customer demands and changes in regulations. The result of these changes is normally an increase in responsibilities and very rarely a decrease. In addition, certain costs have risen much faster than the rate of inflation.

57. Despite the growth in its customer base, NOTL Hydro is not able to include the costs of all of its new responsibilities within an OM&A budget that simply increases with inflation.[43] These additional costs require additional funds (though, as explained above, NOTL Hydro's overall rate increases remain low).

58. Some of the new or increased services and costs that have increased OM&A are set out in Table 6 below, reproduced from the Additional Evidence.[44] Details of each of the items in Table 6 are set out in the Additional Evidence.[45]

Table 6 – New or Increased Services in addition to inflationary pressures

IT & Cyber security	67,394
Utilismart	56,844
Regulatory costs & survey	36,528
Locates	36,566
Health & Safety Consultant	31,367
Pole rentals	8,341
Total	**$237,040**

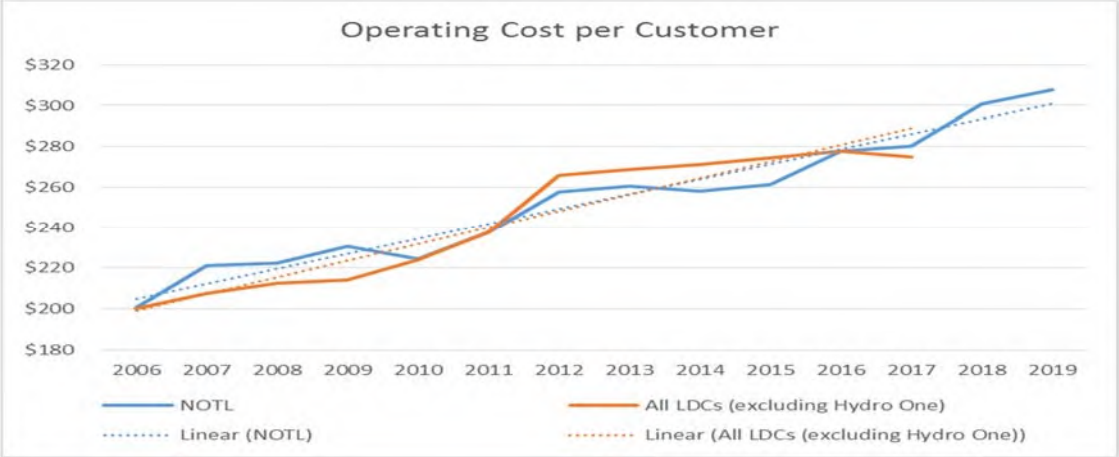
(v) NOTL Hydro's OM&A Cost per Customer is consistent with other distributors

59. A further way to confirm the reasonableness of NOTL Hydro's proposed 2019 OM&A budget is look at the utility's OM&A cost per customer.

[42] Exhibit 4 – OM&A – Additional Evidence, page 15.
[43] Exhibit 4 – OM&A – Additional Evidence, page 10.
[44] Exhibit 4 – OM&A – Additional Evidence, Table 11, page 11.
[45] Exhibit 4 – OM&A – Additional Evidence, page 11 to 13.

60. NOTL Hydro's prefiled evidence sets out the derivation of the utility's OM&A cost per customer from 2014 to 2019. Table 7 below, taken from the most recent interrogatory responses[46], depicts how NOTL Hydro has remained competitive with other Ontario distributors in the years from 2014 to 2019.

Table 7 – Operating Cost per Customer



61. When comparing NOTL Hydro's OM&A costs to other distributors, it is important to note that 30% of NOTL Hydro's assets are transmission rather than distribution assets. Its costs therefore include the cost of operating and maintaining these assets; a cost many of the other LDCs do not have.[47]

62. NOTL Hydro's OM&A cost reasonableness is confirmed by its annual PEG rating, which shows that NOTL Hydro's cost benchmarking continues to show good results, with the utility being placed in the middle cohort of Ontario's distributors.[48] In fact, as can be seen in the Table 8 below (reproduced from NOTL Hydro's Additional Evidence[49]), NOTL Hydro's cost benchmarking performance shows an improving trend since 2013.

[46] Exhibit 4 – OM&A – Additional Evidence, Chart 8, page 8.
[47] Exhibit 4 – OM&A – Additional Evidence, page 8.
[48] Exhibit 4 – OM&A – Additional Evidence, pages 6 to 7.
[49] Exhibit 4 – OM&A – Additional Evidence, Table 6, page 6. The PEG results for 2013 to 2017 are taken from PEG's August 2018 Benchmarking Report, Table A (filed at https://www.oeb.ca/sites/default/files/PEG-benchmarking-report-20180823-revised.pdf); the PEG results for 2018 and 2019 are projections calculated by NOTL Hydro, using the same approach as PEG.

Table 8 - NOTL Hydro PEG Performance

	2013	2014	2015	2016	2017	2018 Projected	2019 Projected
PEG Cost Performance Result	-0.7%	-2.8%	-6.6%	-6.4%	-9.2%	-5.2%	-7.8%

63. Taken together, the evidence in this case clearly supports NOTL Hydro's 2019 OM&A budget forecast.

64. Assuming approval of the as-filed OM&A budget forecast, NOTL Hydro's rates will remain low (as described earlier), and the utility will be able to continue to provide safe, reliable, responsive, cost-effective service to its customers.

c. Issues 2.1 and 2.2 – Cost of Long Term Debt

65. NOTL Hydro's long-term debt in 2019 consists of two third-party loans (from CIBC and Infrastructure Canada), as well as three debt instruments from the Town of Niagara-on-the-Lake (two demand loans and a promissory note).

66. NOTL Hydro filed Additional Evidence that sets out the updated 2019 costs of long-term debt, including the impact of updated rates for its demand loans with the Town.[50] The tables set out below, reproduced from the Additional Evidence[51], show NOTL Hydro's updated cost of long-term debt instruments and updated cost of capital:

Table 9: 2019 Cost of NOTL Hydro Debt Instruments

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Calculated Interest ($)
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.13%	$ 86,679.19
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 30,601.68
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.50%	$ 68,414.72
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.50%	$ 50,064.06
						$ 6,624,865	**3.95%**	**$ 261,770.46**

[50] Exhibit 5 – Additional Evidence – Cost of Long-term Debt.
[51] Exhibit 5 – Additional Evidence – Cost of Long-term Debt, page 2.

88. With the proposed CHP plant to be installed by its Large User, Hydro One will again be applying "gross load billing" for NOTL Hydro. In this case though, only the one customer will be benefiting from the generation and that is the Large Use customer. Without the proposed inclusion of the transmission standby charge (transmission gross load billing), other customers will be paying higher retail transmission service charges than if this customer did not generate any power.

89. NOTL Hydro's proposed transmission standby charge is a note to its GS > 50 kW and Large Use customers Retail Transmission Rate - Line and Transformation Connection Service Rate charges that reads:

> *The Billing Demand for Line and Transformation Connection Services and Low Voltage Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss adjusted demand supplied from the distribution system plus (b) the demand that is supplied by embedded generation installed after October 1998, which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for nonrenewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.*

90. NOTL Hydro notes that this same tariff has been approved for Entegrus Powerlines Inc.[70] and asserts that it is appropriate to be approved in this proceeding, in order to insulate NOTL Hydro's ratepayers from cost consequences of behind-the-meter activities of the new Large User.

D. REQUESTED RELIEF

91. NOTL Hydro respectfully requests OEB approval of the following items:

    i. The as-filed cost of the underground capital expenditures for 2019, and the inclusion into rate base of all amounts spent on the underground conversion program during the 2014 to 2018 term;

    ii. The as-filed OM&A budget for 2019;

    iii. The as-filed updated cost of long-term debt for 2019;

    iv. The determination of 2019 rates using a cost allocation approach that includes 2018 ICM revenues in revenue at existing rates;

[70] This can be seen at pages 4 and 13 of the most recent Rate Order for Entegrus – Main Rate Zone, issued on December 13, 2018 (EB-2018-0024).

v. The clearance of Group 2 Deferral and Variance Accounts and the LRAMVA over two years; and

vi. The proposed transmission standby charge for the Large User rate class.

All of which is respectfully submitted this 19th day of February 2019.



David Stevens
Aird & Berlis LLP
Counsel to NOTL Hydro

TAB ii

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY E-MAIL

March 4, 2019

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

Dear Ms. Walli:

Re: Niagara-on-the-Lake Hydro Inc. (NOTL Hydro)
2019 Cost of Service Appliaction
OEB File Number EB-2018-0056
OEB Staff Submission on the Unsettled Issues

In accordance with Procedural Order No. 4, please find attached OEB staff's submission on the unsettled issues for NOTL Hydro's 2019 cost of service application.

NOTL Hydro and all intervenors have been copied on this filing.

Yours truly,

Original Signed By

Tina Li
Project Advisor, Major Applications

Encl.

2019 ELECTRICITY DISTRIBUTION RATES

Niagara-on-the-Lake Hydro Inc.

EB-2018-0056

OEB STAFF SUBMISSION

March 4, 2019

Introduction

Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) filed a complete application with the Ontario Energy Board (OEB) on August 23, 2018 under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to the rates that NOTL Hydro charges for electricity distribution to be effective May 1, 2019. The OEB issued an approved issue list for this proceeding on December 6, 2018.

The OEB held a settlement conference on December 10 and 11, 2018. NOTL Hydro filed a partial settlement proposal on January 10, 2019. The parties to the partial settlement proposal are NOTL Hydro and the two approved intervenors in the proceeding: School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC). Pursuant to the partial settlement proposal, NOTL Hydro subsequently filed updated evidence regarding the unsettled issues and provided responses to the interrogatories asked by OEB staff and intervenors on the updated evidence. The OEB accepted the partial settlement proposal in the decision issued on February 8, 2019. NOTL Hydro filed its Argument in Chief for the unsettled issues on February 19, 2019.

The unsettled issues are listed below:

- Issue 1.1 Capital: The issue was partially settled. The unsettled issue relates to the prudence of NOTL Hydro's underground conversion project/program since its last rebasing (impacting 2019 opening rate base) and its proposed test year expenditures for the underground conversion program (impacting 2019 net additions and rate base).
- Issue 1.2 Operations, Maintenance & Administration (OM&A): The issue was not part of the settlement accepted by the OEB. The parties agree that all issues relating to OM&A expenses should be determined by the OEB.
- Issue 2.1 & 2.2 Revenue Requirement: The issue was partially settled. The unsettled issue relates to the cost of long-term debt.
- Issue 3.2 Cost Allocation: The issue was partially settled. The unsettled relates to whether to include the Incremental Capital Module (ICM) revenue in distribution revenue at current rates in the cost allocation model.
- Issue 4.2 Deferral and Variance Accounts (DVAs): The issue was partially settled. The unsettled issue was the disposition period of Group 2 DVAs and the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA).
- Issue 5.3 Transmission Gross Load Billing: The issue was not part of the settlement accepted by the OEB. The parties agreed that all issues related to this item should be determined by the OEB.

Before specifically addressing the unsettled issues in its Argument in Chief, NOTL Hydro submitted that the proposed rate increases are reasonable and appropriate in the context of the relatively low level of its current rates.[1] NOTL Hydro stated that it has gone from having one of the highest rates in the province (4th highest residential rate of 111 electricity distributors in 1994) to one of the lowest (17th lowest residential rate of 71 electricity distributors in the province by 2018).[2]

OEB staff notes that the key principles of the *Renewed Regulatory Framework* (RRF) include the expectation for continuous improvement. *The Handbook for Utility Rate Applications* also states that one of the OEB's key considerations is a utility's performance assessments, which analyze the level of continuous improvement and a utility's ability to plan and execute plans.[3] OEB staff, therefore, submits that NOTL Hydro's current rates as compared to its historical rates may be an indicator of its past performance but does not, by itself, justify NOTL Hydro's request for the rate increase in this next rate-setting period.

OEB staff will discuss the above unsettled issues separately.

Issue 1.1 Capital - The Underground Conversion Project/Program

Background

NOTL Hydro proposed to continue its underground voltage conversion program which consists of continuing to convert the oldest segment of the existing 4 kV distribution system to underground and also converting the supply to 27.6 kV.[4] NOTL Hydro stated that the voltage conversion program is to be completed by the end of 2034.[5] The settlement proposal noted that the parties have not agreed on the prudence of NOTL Hydro's underground conversion project/program since its last rebasing (impacting 2019 opening rate base) and its proposed test year expenditures for the underground conversion program (impacting 2019 net additions and rate base).

To support the underground conversion program, which was started in 1987, NOTL Hydro noted a number of benefits to reliability, safety and the environment. In addition, NOTL Hydro's application stated that "…[a] Town bylaw prohibits the installation of new overhead plant as a means of preserving the heritage nature of the Olde Town".[6] The

[1] Argument in Chief, Page 5
[2] Argument in Chief, Page 4
[3] The Handbook for Utility Rate Applications, October 13, 2016, Page 10
[4] NOTL Hydro's Consolidated Distribution System Plan, Page 56
[5] NOTL Hydro's Response to VECC's Supplement Interrogatory 2.0-VECC-53
[6] Consolidated Distribution System Plan, Pages 38, 43 and 57

Issue 1.2 - OM&A Expenses

Background

NOTL Hydro proposed $2,974,186 OM&A expense in 2019. The proposed OM&A expense was reduced to $2,964,765[23] after the first round of interrogatories.

NOTL Hydro's historical and proposed OM&A levels[24] are summarized in Table 4 below as are the year-over-year percentage changes:

Table 4: OM&A Expenses (2014 – 2019)

	OM&A Expense $	Year over Year Change $	Year over Year Change %
2014 Last Rebasing Year - OEB Approved	2,155,262		
2014 Last Rebasing Year - Actuals	2,208,203	52,941	2%
2015 Actuals	2,323,119	114,916	5%
2016 Actuals	2,532,191	209,072	9%
2017 Actuals	2,595,121	62,930	2%
2018 Bridge Year	2,838,535	243,415	9%
2019 Test Year	2,964,765	126,230	4%
Total (2019 vs. 2014 OEB Approved)		**809,503**	**38%**

NOTL Hydro submitted that its proposed 2019 OM&A budget is appropriate for the following five reasons[25]:

- It had provided details with respect to each component of the 2019 OM&A forecast.
- NOTL Hydro's 2018 actual OM&A expense is close to the 2019 forecast. NOTL Hydro provided the 2018 unaudited actual OM&A expense of $2,838,535 in its response to SEC's supplementary interrogatory.[26] The updated figure of $2,838,535 represents a reduction of $66,330 as compared to the original forecasted figure of $2,904,865 for 2018.
- NOTL Hydro identified the cost drivers for the annual variances which substantiate the OM&A cost increase. NOTL Hydro submitted that the

[23] Revenue Requirement Work Form filed on November 20, 2018
[24] Based on the updated Appendix 2-JA, JB and JC filed as part of NOTL Hydro's Response to SEC's supplementary interrogatories
[25] NOTL Hydro's Argument in Chief, February 19, 2019, Pages 10-16
[26] SEC-Supp-38

appropriate starting point for the analysis of the increase in its OM&A expense is 2014 actual OM&A spending instead of 2014 OEB approved OM&A spending. NOTL Hydro noted that the $75,455 reduction of the 2014 OM&A budget in the 2014 cost of service application through an approved settlement proposal was in the context of an overall resolution and does not mean that the specific agreed OM&A budget was reasonable on its own. NOTL Hydro's 2019 OM&A budget is at the level that should be expected. NOTL Hydro, in its updated evidence, identified the cost increase that would be expected as a result of inflation and growth and then identified other discrete items that caused the OM&A to increase. The sum of the following three items add up to the OM&A increase of $809,503 from 2014 OEB approved OM&A to 2019 forecasted OM&A:

    - $441,679 increase due to inflation and growth
    - $130,784 increase due to accounting standards change
    - $237,040 increase due to new or increased services
- NOTL Hydro's OM&A per customer is consistent with other distributors.

NOTL Hydro stated in the updated evidence that it was using Canadian GAAP as its accounting standards in 2014 and booked the President and the VP Operations' time to capital. NOTL Hydro further stated that it limited the capitalization of the President and the VP Operations' time in 2019 to meet the requirement of IFRS. NOTL Hydro quantified the impact of the accounting change to its 2014 OM&A expense as $130,784, i.e. 2014 OM&A was $130,784 less than it would have been under IFRS.

NOTL Hydro calculated the expected OM&A increase from inflation and growth using the following method:

> The 2014 approved OM&A expense of $2,155,262 + the accounting change that was not accounted for in 2014 OM&A of $130,784) x (the annual inflation – stretch factor + the sum of three growth factors[27] used in Pacific Economics Group (PEG)'s benchmarking work

NOTL Hydro explained the $237,040 increase due to the following new or increased services:

- Cost incurred of $67,394 for cyber security audit and enhanced IT services
- A new Utilismart contract of $56,844 in 2019 to enhance the data available to its large customers

[27] These three factors are customer growth, load growth and system peak growth. The PEG group uses five factors in evaluating the impact of growth on OM&A costs. The other two factors are the amount of distribution lines and the rate of customer growth. NOTL Hydro stated that it does not use these two factors because NOTL Hydro has seen no noticeable change in the amount of distribution lines or the rate of customer growth.

- Increased regulatory costs and survey cost of $36,528
- Increased locates cost of $36,566 from the public initiatives such as Ontario One call
- A part-time health and safety consultant of $31,367
- Pole rental cost of $8,341, which is offset by the pole rental revenues in other revenues

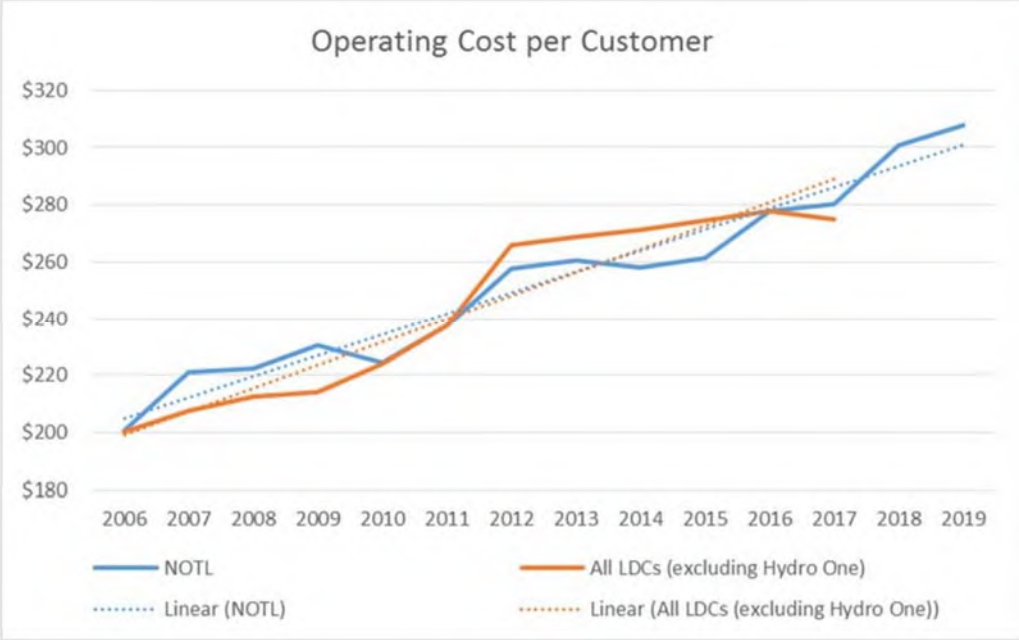
OEB Staff Submission

OEB staff submits that NOTL Hydro proposed OM&A level in 2019 of $2,964,765 has not been fully supported for the following reasons:

- The method used by NOTL Hydro to calculate the expected OM&A level in 2019 appears to be flawed. NOTL Hydro adjusted the 2014 approved OM&A expense by the accounting change for the capitalization of senior managements' time in 2014 and then applied the sum of annual inflation and growth factors to the figure to arrive at the expected OM&A ongoing expense in 2019. OEB staff submits that NOTL Hydro should have not added the accounting change to the 2014 approved OM&A figure to calculate the expected OM&A expense from the inflation and growth. OEB staff notes that the accounting change of $130,784 was not approved in the 2014 cost of service rate application and hence should not be used as a base line for the inflation and growth calculation.

- OEB staff acknowledges the unavailability of data for a comparison of NOTL Hydro's OM&A per customer in 2018 and 2019 to the industry. However, NOTL Hydro's OM&A expense per customer in 2017, 2018 and 2019 is trending up and higher than the trend line for the industry average excluding Hydro One.[28] OEB staff notes that NOTL Hydro's 2017, 2018 and 2019 OM&A expense per customer are $278, $307 and $308 respectively.[29] The OM&A expense per customer in 2017 is greater than the industry's average OM&A expense excluding Hydro One in 2017 while NOTL Hydro's OM&A per customer from 2011 to 2016 has been lower than the industry average.[30] In addition, NOTL Hydro's OM&A per customer in 2018 and 2019 is higher than the 2017 figure and higher than the trend line for the industry average, as shown in the graph[31] below:

[28] SEC-Supp-37
[29] Exhibit 4, Page 8, Table 4.7; NOTL Hydro updated the 2018 OM&A expense in the Argument in Chief. Using the updated 2018 OM&A figure, the 2018 OM&A per customer would be $300.
[30] Exhibit 4, Page 19, Chart 4.19
[31] SEC-Supp-37



- OEB staff is of the view that NOTL Hydro does not have an outcome-based action plan to improve its cost efficiency in the next five years. NOTL Hydro has remained in cohort 3 (the middle cohort) of PEG's benchmarking analysis from 2012 to 2017. NOTL Hydro forecasted its PEG cost performance for 2018 and 2019 as -5.2% and -7.8% respectively.[32] OEB staff notes that NOTL's actual 2017 PEG performance is -9.2%, which shows an improvement of cost efficiency as compared to 2016 performance of -6.4%. If NOTL Hydro maintained the trend of the 2017 performance, the expected performance in 2018 and 2019 would put NOTL Hydro in cohort 2 which is the group with the actual costs more than 10% lower than the expected costs. However, NOTL Hydro still remains in cohort group 3 in 2018 and 2019 based on its forecasted performance. The *Handbook for Utility Rate Applications* expects utilities to "identify performance improvement targets that will lead to improvement in its scorecard performance over the term of the rate-setting plan".[33] NOTL Hydro appeared not planning its performance improvement using an outcomes-based approach which emphasizes results instead of activities. NOTL Hydro's plan in the next five years is focused on actions rather than outcomes. This is shown in the evidence presented by NOTL Hydro:

[32] Exhibit 4, Additional Evidence, Page 6
[33] The Handbook for Utility Rate Applications, October 13, 2016, Page 17

- NOTL Hydro stated in the application that "It is hoped that this performance improvement will continue over the next five years with the continued application of NOTL Hydro's values and that NOTL Hydro may even move into the Group 2 stretch cohort".[34]
- In its response to a staff interrogatory asking for any initiative taken to improve the cohort group, NOTL Hydro stated that "NOTL Hydro does not undertake any initiatives specific to improving its cohort assignment. However, NOTL Hydro believes that all its initiatives, because they are based on NOTL Hydro's values, including focus on health & safety, customer needs and financial prudence, will ultimately lead to a move to a Group 2 cohort".[35]
- NOTL Hydro stated in its additional evidence for OM&A that "NOTL Hydro has consistently had a PEG rating of 3 but based on the trends it could improve to a 2 rating before the next cost of service application".[36]

OEB staff submits that the appropriate level for 2019 OM&A expense for NOTL Hydro should reflect a reduction from a 38% increase as compared to 2014 OEB approved OM&A expense of $2,155,262 to a 28% increase as compared to 2014 OEB approved OM&A expense. This represents a reduction of $215,526, rounding to $215,000. The resultant OM&A level for 2019 is therefore $2,749,765.

OEB staff submits that the 10% reduction of the OM&A increase or $215,000 is derived from the three components, each of which is explained in Table 5 below:

Table 5: OM&A Expense, Cost Drivers and % and $ Disallowed (Staff Proposal)

OM&A Expense and Cost Drivers **(Higher-Level Approach)**	**OM&A Expense or Cost Drivers**	**Composite %**	**% Increase as compared to 2014 OEB Approved** **(Composite % x 37.6%)**	**% disallowance proposed by OEB staff**	**$ disallowance proposed by OEB staff**
2014 OM&A Expense – OEB Approved	**$2,155,262**				
Inflation and Growth	$441,679	55%	20.5%	2.4% out of 20.5%	

[34] Exhibit 1, Page 20
[35] 1-Staff-9
[36] Exhibit 4, OM&A, Additional Evidence, Page 7

Accounting Standards Change	$130,784	16%	6.1%	All of the 6.1%	
New or Increased Services	$237,040	29%	11.0%	1.5% out of 11%	
Total OM&A Increase $	**$809,503**	**100%**	**37.6%**	**10%**	**$215,526, Rounded to $215,000**
2019 OM&A Expense	**$2,964,765**				**$2,749,765**

As per the table above, OEB staff is of the view that 2.4% of the 20.5% OM&A increase due to inflation and growth should be disallowed because it is not related to inflation and growth. OEB staff notes that NOTL Hydro applied the inflation and growth factors on the adjusted 2014 OM&A expense (i.e. 2014 OEB approved OM&A expense plus the $130,784 accounting standards change) instead of applying the inflation and growth factors to the 2014 OEB approved OM&A expense. OEB staff notes that the $130,784 accounting standards change was not approved by the OEB in the 2014 decision and hence it is not appropriate for NOTL Hydro to apply the inflation and growth factors to the $130,784. The impact of adding the $130,784 to the starting point for the inflation and growth calculation is 2.4% of the OM&A increase.

OEB staff is of the view that the OM&A increase due to the accounting standards change of $130,784 (6.1% of the OM&A increase) should not be allowed for the following reasons:

- NOTL Hydro's 2014 cost of service application was based on Canadian GAAP. NOTL Hydro adopted the IFRS as the accounting standard on January 1, 2015. However, NOTL Hydro stated in the 2014 application that "pursuant to the Board letter July 17, 2012, NOTL Hydro has applied changes to the depreciation expense and capitalization policies effective January 1, 2013, consistent with the Board's regulatory accounting policy direction in that letter. These changes are reflected in NOTL Hydro's 2013 Bridge Year and 2014 Test Year results".[37]

- The OEB's letter[38] required that all electricity distributors implement accounting changes for capitalization policy and depreciation policy to be consistent with the OEB's regulatory accounting policies as set out for modified IFRS as contained in

[37] EB-2013-0155 Application, Exhibit 1, Tab 5, Schedule 17
[38] The OEB's letter issued on July 17, 2012 to all Electricity Distributors

the 2009 Report of the Board[39], the Kinectrics Report, and the Revised 2012 Accounting Procedures Handbook for Electricity Distributors. OEB staff further notes that the OEB issued another letter[40] pursuant to the 2009 Report of the Board requiring full compliance with the IFRS requirement (e.g. International Accounting Standard (IAS) 16). One important requirement of the IAS 16 is that the company is to capitalize the direct attributable costs related to the assets.

- NOTL Hydro did not, in its 2014 cost of service application, identify the change of capitalization policy regarding the executives' salaries and benefits to align with the IFRS requirement that only direct attributable costs are to be capitalized into assets. OEB staff is of the view that NOTL Hydro should have identified the $130,784 OM&A increase that was related to the executives' salaries and benefits during the process of changing the capitalization policy and should have presented this item in its 2014 cost of service application. The impact, if presented, would have been included in the Account 1576, Accounting Changes under CGAAP, and would have been recovered from ratepayers in the 2014 cost of service application. As a result, the proposed OM&A expense in this application would have been reduced by the cost of the accounting changes and the associated inflation and growth.

OEB staff submits that a reduction of 1.5% out of the 11% proposed OM&A increase due to new and increased services would be appropriate because OEB staff is of the view that NOTL Hydro should be able to address new initiatives, such as the cyber security and increased locate costs due to the Ontario One call initiative, within its existing budget. In February 2016, the OEB issued a letter[41] to all electricity distributors regarding the cyber security framework initiative stating the OEB's expectation that the cyber security framework be established in a cost-efficient manner and the OEB also stated in a notice in December 2017 for the same initiative that "the transmitters and distributors should have already incorporated cyber security into their business and asset planning".[42]

OEB staff therefore submits that a reduction of $215,000 to the total proposed OM&A expense of $2,964,765 in 2019 is warranted. OEB staff notes that the resultant OM&A expense of $2,749,765 in 2019 represents a 28% increase of the OM&A expense from 2014 OEB approved to 2019 as compared to the original 38% increase proposed in the application. OEB staff is of the view that the reduced OM&A level represents a

[39] Transition to International Financial Reporting Standards, EB-2008-0408
[40] The OEB's letter issued February 24, 2010 to all Electricity Distributors re "Accounting for Overhead Cost Associated with Capital Work"
[41] EB-2016-0032, Letter to All Electricity Distributors, February 11, 2016
[42] EB-2016-0032, Notice of Proposal to Amend a Code, December 20, 2017, Page 13

reasonable increase over the five year period. OEB staff further submits that the reduced OM&A budget would provide additional incentives for NOTL Hydro to develop an outcome-based plan to improve its efficiency (i.e. to improve its OM&A per customer and its cohort group).

Issue 2.1 & 2.2 Revenue Requirement - Cost of Long-Term Debt

Background

NOTL Hydro proposed a total cost of long-term debt rate of 3.71% for 2019. There was no agreement on NOTL Hydro's cost of long-term debt in the settlement proposal filed on January 10, 2019. NOTL Hydro updated its cost of long-term debt to 3.95% after the filing of updated evidence. NOTL Hydro filed updated evidence about its cost of long-term debt, applying:

- An updated notional rate associated with a promissory note with the Town of NOTL to reflect the OEB's approved long-term debt rate for 2019 cost of service applications (4.13%)
- A proposed increased interest rate on two loans from the Town of NOTL from 3.0% to 3.5%

As a result of these updates, NOTL Hydro's cost of long-term debt rate increases from 3.71% to 3.95%. The details of NOTL Hydro's long-term debt are in Table 6 below:

Table 6: NOTL Hydro's Long-term Debt
(Original Application vs. Updated Evidence)

						Original Application		Updated Evidence[43]	
	Description	Lender	Affiliated or 3rd Party?	Start Date	Term (years)	Principal ($)	Rate (%)	Principal ($)	Rate (%)
1	Original Promissory Note	Town of NOTL	Affiliated	1-Jul-00	Open	2,098,770	4.16	2,098,770	4.13
2	NOTL TS Demand	CIBC	3rd Party	27-Oct-05	15	424,320	6.13	424,320	6.13

[43] Exhibit 5 Cost of Capital, Cost of Long-Term Debt, Additional Evidence

TAB iii

EB-2018-0056

ONTARIO ENERGY BOARD

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 or Orders approving or fixing just and reasonable distribution rates effective May 1, 2019.

FINAL ARGUMENT OF THE SCHOOL ENERGY COALITION

Overview

1. Niagara-on-the-Lake Hydro Inc. ("NOTL") has filed an application for approval of distribution rates effective May 1, 2019. Most of the application was settled by way of a Settlement Proposal which has subsequently been approved by the Board. A number of aspects of the application were unable to be resolved by way of settlement.

2. The unsettled aspects of the application can be placed into three broad categories. First, the proposed costs related to the underground conversion/rebuild program and the test year Operations, Maintenance, and Administration ("OM&A") budget. Second, NOTL's long-term debt, specifically those entered into with its shareholder. Lastly, matters of Board policy, such as the treatment of the ICM rate rider in the Cost Allocation Model, gross load billing of retail transmission rates, and the disposition period of Group 2 deferral and variance accounts.

3. This is the Final Argument of the School Energy Coalition ("SEC") on these unsettled matters.

Underground Conversion/Rebuild Program

4. The only outstanding item related to NOTL's capital spending relates to costs related to its underground conversion/rebuild program. NOTL has spent $915K on this program since 2014, with an additional $460,000 proposed for the test year.[1] With agreement of the intervenors, NOTL filed additional evidence on the program.[2]

[1] Interrogatory Response Supp-Staff-2(d). SEC notes that historic numbers do not appear to match those in 2-SEC-18, where the total amount between 2014 and 2018 is $1.29M.

[2] Settlement Proposal filed January 10 2019, p.9 ; Exhibit 2 – Additional Evidence - Rate Base, Underground Voltage Conversion

9. NOTL has historically underspent compared to its proposed budget on this program. Between 2014 and 2018 NOTL has spent just under 50% of the amount set out in its previous distribution system plan.[9] On that basis the Board should only approve 50% of the forecast expenditures. This would result in a reduction of $230K.

OM&A

10. ***Summary.*** NOTL is seeking approval of an OM&A budget of $2.96M in 2019. This represents a 38% increase from its 2014 Board approved amount.[10] It represents an average, year-over-year, increase of 7.34%. SEC submits this increase is unreasonable and unsupported by the evidence. As discussed in greater detail below, the Board should reduce the proposed test year OM&A by $374,500.

11. NOTL's argument on the reasonableness of its proposed OM&A budget is based almost entirely on the additional evidence it filed after the settlement conference, which not precipitated by any changes to the forecast or circumstances.[11] The evidence tries to demonstrate that the proposed 2019 OM&A budget is exactly where it should be, based on a formula it has determined that accounts for inflation and growth, then adjusted for changes in accounting standards, and increased to account for new services.

12. What is clear from the approach is NOTL is simply trying to find some methodology that it can use to justify its significant increase in OM&A costs. This high-level envelope justification sets out in the additional evidence and relied upon in its Argument-In-Chief is *entirely different* than the one it provided for in its pre-filed evidence and interrogatory responses.[12]

13. SEC addresses each of these 'buckets' that justify the reasonableness of its test year OM&A budget as set out in the additional evidence and Argument-In-Chief[13]:

[9] 2.0-VECC-53(b)(c)

[10] Appendix 2-JA. At footnote 33 of its Argument-in-Chief: NOTL takes the position that the Board should disregard the 2014 Board-approved amount in favor of 2014 actuals as the Board-approved amount was the result of a settlement which included an agreed upon reduction of $75,455 from the requested amount. SEC disagrees. The Board amount is not just what the Board approved in the approving the settlement, but was more importantly, what NOTL itself agreed to in the settlement represented a reasonable amount.

[11] Interrogatory Response 4-VECC-50

[12] Ex.4, p.7, Table 4.6; Interrogatory Response 4-SEC-29. SEC assumes this was done since the analysis provided in the pre-filed evidence made very little sense. For example, NOTL attributed the 20.3% increase in OM&A to growth. It did so by averaging percentage increase customers, load, and asset value.

[13] Argument-in-Chief, para. 49-58

i. ***Inflation and Growth***. NOTL's approach to the inflation and growth portion of its OM&A increase is to adjust the 2014 Board-approved annual by using the Board's annual inflation factor, minus the company specific stretch factor, plus an amount for growth.[14] This is similar to how the Board has previously approved the total OM&A for a distributor. In the Board's *Decision and Order* in EB-2016-0061, it determined that the appropriate OM&A budget or Canadian Niagara Power's budget is one that, at most, is close to the level of inflation reduced by the stretch factor plus an amount for customer growth. [15] NOTL's treats this as just a small part of the overall increase.

NOTL's proposal for an inflation and growth adjustment goes farther then what the Board approved in the EB-2016-0160 *Decision and Order*. NOTL proposes the OM&A inflation and growth adjustment should include kwh and peak demand growth, using a similar approach to customer growth derived from the PEG benchmarking model. The problem is that the PEG model is based on total cost not OM&A costs. While load and system peak growth do impact costs, there is no evidence that they materially impact OM&A as opposed to capital costs. In fact, the evidence appears to indicate the opposite. For NOTL, it has made significant capital investments related to increases in system peak over the last number of years.[16] Whereas, when asked to point to actual OM&A costs that have increased due to kwh and system peak growth, it could not point to any actual costs.[17] Further, if kwh and system peak growth these were drivers in OM&A costs, then one would expect to see it in the operations and maintenance categories of spending as it would involve increase work on new assets. But the evidence shows the increase in OM&A costs since 2014 have occurred primarily in the administrative and general category.[18] Those categories should not be impacted by increased in kwh or system peak growth, but may be impacted by increasing customer growth.

[14] Exhibit 4 - Additional Evidence – OM&A, p.8-15

[15] *Decision and Order* (CNPI 2017 - EB-2016-0061), December 9 2017, p.5

[16] For example, since the last rebasing NOTL has added a new transformer at its transformer station which was substantial enough in cost that it required an ICM (Exhibit 2, p.51). In addition, NOTL will be installing another 83 MVA transformer (See, Exhibit 2, p.52).

[17] Interrogatory Response SEC-Supp-41

[18] Exhibit 4, p.5

Table 4.2: 2014 Board Approved vs. 2019 Test Year OM&A

	Board Approved	2019	Change
Operations	$532,044	$715,973	$183,929
Maintenance	$416,132	$449,790	$33,658
Billing and Collecting	$534,260	$632,867	$98,608
Community Relations	$17,800	$11,485	-$6,315
Administrative and General	$655,026	$1,164,070	$509,044
Total	**$2,155,262**	**$2,974,186**	**$818,923**
%Change (year over year)			38.0%

ii. ***Accounting Adjustment.*** SEC accepts that the accounting adjustment made to the Board approved amounts that reflects the changes in capitalizing of certain executives due to the transition to IFRS is appropriate.

iii. ***Additional Services***. NOTL argues that even when one includes inflation and growth, the increase still does not account for the new and additional services that it believes it should provide. SEC submits it may be that some additional funding over the inflation and growth amounts are appropriate, but that most of those costs should be included with that budget. Customers expect their utility to offset additional services which it may want with additional efficiencies and productivity improvements. The impact of the measures it had previously taken are unknown. NOTL admittedly could not quantify many of the savings achieved.[19] With respect to test year productivity initiatives, the response to interrogatory 1-SEC-6 appears to indicate that it does not expect to be a focus on any in 2019 due to other matters. For the initiatives it does have, they appear to have a minor impact on its OM&A costs and the savings have not been estimated. In light of these facts, no additional funding should be approved.

14. ***Comparison With Other Utilities.*** Looking at just NOTL in isolation, its OM&A per customer has increased significantly from $262 in 2015 to a forecast of $307 by 2019.[20] While historically NOTL has had below average OM&A costs per customer, it appears that this has taken a turn in the opposite direction. Based on NOTL's own analysis, its OM&A per customer has been below all other LDCs (excluding Hydro One) until 2016, where the trend has shown a flattening of the increase in the sector as a whole.[21] Yet, NOTL's OM&A per customer in 2017 was already higher than the sector. Based on its own forecast for 2018 and 2019 costs, the differential will increase. [22]

[19] Interrogatory Response 1-SEC-5

[20] Appendix 2-L

[21] Interrogatory Response SEC-Sup-37

[22] *Ibid*

15. NOTL places much emphasis on its low rates. SEC does not dispute that it has some of the lowest rates in Ontario, but that should be expected. Unlike most other utilities which have seen declining load and stagnant customer growth of the last few years, NOTL has seen a brisk increase in both.[23] This has allowed it to keep rates low as the increase in costs since the last rebasing year is offset by the increase in load. It is why it is important to look at the PEG total cost benchmarking which accounts for the increase load. The PEG benchmarking evidence reveals that while NOTL has low rates, it is not a top performer, but only a slightly above average one Its cost are only slightly better than the model would expect a utility with its characteristics to have. It is forecast to remain in the test year in the Board's group 3 stretch factor cohort (+/- 10%).[24] The Board's rate-setting approach emphasizes continuous improvement, not regression to the mean.[25]

16. ***2018 Actuals.*** NOTL points to its 2018 actual (unaudited) OM&A spending being close to its 2018 forecast as "persuasive evidence of the amounts actually required."[26] SEC submit it is only evidence that NOTL is able spend to its forecast budget. It does not demonstrate that the forecast budget itself was reasonable. This is especially the case when the 2018 actuals are increased over the previous year's OM&A amount by a staggering 11%.[27] An increase that is far from reasonable.

17. ***SEC Approach.*** SEC submits that determining a reasonable test year OM&A amount is looking at a reasonable aggregate amount. Dissecting each individual line item when the proposed increase is so large, is not helpful since it may be that any given cost item may be reasonable on its own, but added together they clearly are not.

18. A more appropriate methodology to determine the envelope amount is the method the Board used EB-2016-0061, where it approved an amount based on an annual adjustment to the previously Board-approved amount for inflation, productivity (stretch factor), and an amount for customer growth. SEC does accept that the 2014 Board approved year should be adjusted due to the accounting change. With the adjustments shown below, the Board should approve an OM&A budget of $2,590,341, which represents a reduction of $374,424 from the requested amount. SEC submits that this still provides for a significant

[23] Exhibit 3, p.9

[24] Exhibit 4 - Additional Evidence, Table 6

[25] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (October 18, 2012), p.2

[26] Argument-in-Chief, p.45

[27] Revised Appendix 2-JA, Appendix 1 to Supplementary SEC Interrogatories Responses

20% increase without the accounting adjustment, and 13.3% increase with the adjustment, since NOTL's last rebasing proceeding in 2014.

		Board Approved 2014 BA	Actual 2014	2015	2016	2017	Projected 2018	2019
Total OM&A Expenses		2,155,262	2,208,203	2,323,119	2,532,191	2,595,121	2,904,865	2,964,765
2014 Adjustment: IFRS (President and VP Operations Capitalized Labour)		130,784						
Adjusted Total		**2,286,047**						
Growth		**2014**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Customers (excludes Street Light and USL)		8,499	8,551	8,839	9,115	9,299	9,444	9,626
Customer Growth			**0.62%**	**3.36%**	**3.13%**	**2.02%**	**1.55%**	**1.93%**
Escalators		2014	2014	2015	2016	2017	2018	2019
Inflation (OEB)			0.00%	1.60%	2.10%	1.90%	1.20%	1.70%
Base Productivity			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Stretch Factor (PEG Group 3)			0.00%	0.30%	0.30%	0.30%	0.30%	0.30%
Sub-Total			0.00%	1.30%	1.80%	1.60%	0.90%	1.40%
Customer Growth (Growth x PEG Elasticity of 0.4485)	0.4485		0.28%	1.51%	1.40%	0.91%	0.70%	0.87%
Total Escalator (lines 20 - 21 - 22 + 24)			**0.28%**	**2.81%**	**3.20%**	**2.51%**	**1.60%**	**2.27%**
		2014	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Adjusted OM&A - Based on Escalators		2,286,047	2,292,370	2,356,717	2,432,173	2,493,108	2,532,927	***2,590,341***
					Reduction From Proposed			**-374,424**
					% Incease without Accounting Adjusment			**20.19%**
					% Increase with Accounting Adjustment			**13.31%**

Long-Term Debt

19. There are two separate issues related to its proposed NOTL debt costs, i) the original promissory note which was renewed in 2018 and, ii) the proposed changes to two recent promissory notes. Both those notes are held by its shareholder, the Town of Niagara-on-the-Lake ("Town"), and because of that, the Board must consider the affiliate nature of the relationship in determining what reasonable actions NOTL should have taken.

20. As detailed below, the approach NOTL has taken with its affiliate debt is evidence, that with respect to its relationship with its shareholder, it does not properly consider the interest of its consumers. The Ontario Court of Appeal commented in *Toronto Hydro-Electric System Limited v. Ontario Energy Board*, that regulated utilities are not the same as normal companies. Regulated utilities must balance the interests of both shareholders and consumers and when they do not, the Board must step in:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of unregulated companies have a fiduciary obligation to act in the best interests of the company (which is often interpreted to in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility's shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.[28]

[28] *Toronto Hydro-Electric System Limited v. Ontario Energy Board*, 2010 ONCA 284, para 50

TAB iv

PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

Niagara-on-the-Lake (NOTL)
EB-2018-0056
2019 Rates

Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

March 4, 2019

Mark C. Garner on behalf of the
Vulnerable Energy Consumers Coalition

Public Interest Advocacy Centre
613-562-4002
piac@piac.ca

1.0 Summary of the Submissions

1.1 Following the settlement conference of December 10, 2018 six issues remained unsettled. With respect to the establishment of the revenue requirement the first three of these are: (1) the prudence of the underground capital expenditures undertaken in the past and planned for the future; (2) the appropriate level of operating and administration expenses (OM&A); and, (3) the appropriate long-term debt rate to be incorporated into the rate calculation. The remaining three issues are with respect to cost allocation and deferral and variance account (DVA) dispositions; (4) the treatment for the calculation of rates of revenues related to the incremental capital module of the utility; (5) the disposition period of Group 2 Deferral and Variance Accounts ("DVAs") and specifically the balances related to the Lost Revenue Adjustment Mechanism; and (6) the appropriate manner in which to charge the retail transmission rate. Our detailed views on these unresolved issues are set out in the sections below. A summary of our submissions follows.

1.2 It is our submission that the Board should require Niagara-on-the-Lake Hydro (NOTL) to develop a comprehensive plan to support its current policy of replacing above ground plant with underground plant. This plan should include a discussion of the incremental costs of underground plan, a cost comparison of the two options and a discussion of the benefits to ratepayers of replacing above ground plant with buried plant. NOTL should also be required to undertake meaningful customer engagement and stakeholdering which would allow ratepayers a better understanding of the cost and benefit trade-offs of the Utility's plan.

1.3 NOTL should reduce its OM&A budget for the test year, and for the purpose of calculating 2019 rates, by between $400 and $500k. The Board's consideration of the amount of the OM&A reduction should include the reasonableness of the Utility's capital budget plan and specifically the underground replacement project.

1.4 We submit that the Board should reject the cost of capital update of the Utility.

1.5 In our submission the Board should accept NOTL's proposed treatment of the ICM revenues for the purpose of determining revenues at status quo rates in the cost allocation model.

1.6 NOTL's proposal to spread the recovery of the balances in the Group 2 and LRAM accounts over two years does not align with Board policy. However in our view such a proposal will result in more evenly paced rate increases over the next two years and therefore should be given careful consideration by the Board.

1.7 In our submission the Board should accept NOTL's proposal to have the Retail Transmission Rate ("RTR") – Line Transformation Connection Service Rates applied to customers that have load displacement generators ("LDG"), with a generator unit rating 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation on a gross load billing basis. However, the application of gross load billing should be subject to NOTL adopting: 1) the same definition for "renewable energy" as is used for purposes of the Uniform Transmission Rate ("UTR"); and 2) gross load billing should only be applicable to generation capacity installed after October 30, 1998 consistent with the UTR.

costs being incurred in the capital budget of the Utility in how it considers the OM&A budget. We acknowledge this is a rather different approach. But as has been stated by the Board in other decision – "regulation is a form of rough justice" which seeks fair solutions.

2.25 In our submission there is a natural trade-off between the OM&A and capital budget of the Utility. A large portion of OM&A is aimed at maintaining assets. To the extent those assets are put underground they are – at least in the short run- less expensive to maintain. The Board may consider that in arriving at an appropriate reduction to the Utility's OM&A. In our arguments on OM&A were have offered a range of outcomes we think reasonable for the Board to consider.

2.26 In our view it is open to the Board to order a broad spectrum of results. Arguably the applicant has previously misled the regulator. The current management regime tries to address this criticism by distancing itself from the past. We have no sympathy for that approach. Nor are we swayed by implicit argument that the Town's interest are the same as those of the Utility's ratepayers. Believing that would overturn the entire premise of the 1998 Electricity Act's policy of incorporation of municipal utilities. As such the argument of NOTL cannot be left to stand. They are holdovers from another era where Utility governance and municipal council believe they represent the same interest and where electricity rates were factors of economic development and not cost causality.

3.0 Operating, Maintenance and Administration (OM&A) Costs

3.1 NOTL proposes an OM&A increase that it significantly larger than would be expected by inflation and customer growth[14].

Table 4.1: OM&A 2014-2019

	Board Approved	2014	2015	2016	2017	2018	2019
Operations	$532,044	$491,400	$548,540	$654,295	$673,867	$679,413	$715,973
Maintenance	$416,132	$412,259	$451,578	$476,273	$414,737	$473,074	$449,790
Billing and Collecting	$534,260	$559,556	$601,150	$547,188	$573,154	$597,617	$632,867
Community Relations	$17,800	$578	$758	$9,700	$4,161	$12,765	$11,485
Administrative and General	$655,026	$744,411	$721,094	$844,735	$929,202	$1,141,995	$1,164,070
Total	**$2,155,262**	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
%Change (year over year)		2.5%	5.2%	9.0%	2.5%	11.9%	2.4%

3.2 Subsequent to the settlement conference NOTL unexpectedly submitted additional evidence to support its OM&A request. There is nothing new or particularly revealing in this last minute effort to support its proposal. It does provide a detailed accounting of the actual 2018 OM&A costs which one might expect at this late juncture. We do know that the total 2018 actual OM&A costs are $2,838,525.[15]

[14] Exhibit 4, page 4
[15] AIG, page 10

3.3 There has been a 27.5% increase in OM&A since the last Board approved. Other than inflation and customer growth there are no extraordinary events to explain this increase. If one factors in only inflation the $2,155k Board approved OM&A would translate to $2,339 in 2019[16]. Significantly less than the near $3 million requested.

3.4 NOTL has seen customer growth of approximately 13% cumulatively over the 2014-19 period[17]. Even at a generous .50 (rather than the .445% suggested by the Board sponsored PEG studies) the impact of customer growth would add only about $140k to this figure. The question NOTL is then left to explain is the difference between $2,479K adjusted for inflation and customer growth and the $2,974k it is seeking. This $495k above market increase does not factor in any expected gains in productivity over the rate period.

3.5 So what explains the 23% increase above what might be expected from customer growth and inflation? The Utility offered up the following table in explanation[18]:

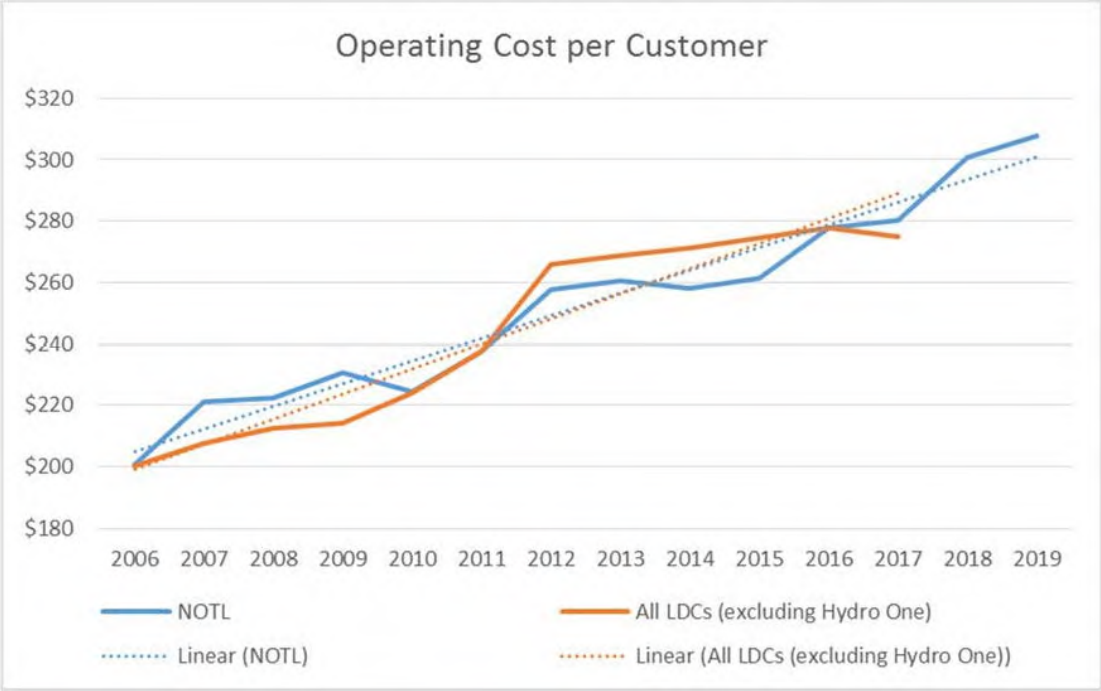
Table 4.6: Breakdown of Increase in OM&A (2014-2019)

Cause	Percentage
Inflation	7%
Growth	20%
Expenses with offsetting revenue	2%
"Timing"	3%
Increase in requirements	6%
Total	**38%**

3.6 The table summarizes the ambiguity of some causes of increase (like "timing") and the generous provisions in others (like growth at 20%). In fact we can find no reasonable explanation for the inordinate increase in OM&A costs in any of the evidence, including the non-solicited evidence filed in anticipation of our arguments. In fact in its argument-in-chief contains both the marginal – that NOTL Hydro also expects discrete cost increases due to higher pole rental fees to Bell Canada (around $8,000), higher billing and collection costs (around $35,000) and higher regulatory costs (around $22,000) and the unexplained including $237k in "new services."

[16] We have used the Bank of Canada inflation calculator to show the inflation impacts.
[17] Exhibit 3, Table 3.5 – Residential, GS<>50
[18] Exhibit 4, page 7

3.7 NOTL has spent considerable effort emphasizing its relative performance to other utilities. Yet the evidence on that front is far from encouraging. The table below shows NOTL's OM&A costs as compared to other (non Hydro One) distribution utilities. However one looks at it the OM&A costs of this Utility are moving in the wrong direction[19].



3.8 The argument presupposes there to be a 55% increase in costs due to inflation and growth is simply unconvincing. The evidence is that at best these factors might represent a reason for closer to 15% - even without considering expected productivity improvements.

3.9 In our discussion of the underground capital program (and in the following discussion on the cost of long-term debt) we have examined the relationship between its affiliate and owner the Town of Niagara-on-the-Lake. We have suggested that there should be greater discipline to separate the interest of one from the other. As we have noted it could be difficult for the Board to make post-facto changes to rate base due to potential excessive spending on underground plant. However, in our view the Board would be well within the bound of reasonableness to adjust the OM&A included in 2019 rates in consideration of the excessive underground capital program. Intuitively one benefit of converting above ground plant to underground is that in the short run there are lower maintenance and reliability related costs. This should translate to lower OM&A needs.

3.10 In our submission the Board should reduce the OM&A request for rate calculation between $400 and $500k for this Utility.

[19] SEC-Supp-37 (Supplementary Interrogatories)

TAB v

EB-2018-0056

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an application by Niagara-on-the-Lake Hydro Inc. for an order or orders approving electricity distribution rates and other charges commencing as of May 1, 2019.

NIAGARA-ON-THE-LAKE HYDRO
2019 COST OF SERVICE RATES
REPLY ARGUMENT

AIRD & BERLIS LLP
Barristers and Solicitors
Brookfield Place
Suite 1800, Box 754
181 Bay Street
Toronto, ON M5J 2T9

David Stevens
Tel (416) 863-1500
Fax (416) 863-1515

Email: dstevens@airdberlis.com

A. INTRODUCTION

1. On February 19, 2018, Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) filed its Argument in Chief summarizing its proposals and evidence in respect of each of the six unsettled items. NOTL Hydro's Argument in Chief details why its proposals are reasonable and appropriate and should be accepted by the Ontario Energy Board (OEB, or the Board). As explained, NOTL Hydro's ratepayers are pleased with the service they receive, and approval of the utility's position will support NOTL Hydro continuing to provide safe, reliable, cost-effective service to its customers.

2. Three parties filed Arguments in response to NOTL Hydro – OEB Staff[1], School Energy Coalition (SEC)[2] and Vulnerable Energy Consumers Coalition (VECC)[3].

3. This Reply Argument sets out NOTL Hydro's response to the arguments advanced by the other parties in this proceeding. In addition to the items set out herein, NOTL Hydro repeats and relies on the positions taken and arguments set out in its Argument in Chief.

4. Before addressing the positions taken by other parties on the six unsettled issues in this proceeding, NOTL Hydro would like to address two high-level items that are included in the submissions from other parties. The unifying theme in these responses, and in NOTL Hydro's Application as a whole, is that NOTL Hydro has been even-handed and responsive to the expectations and needs of its ratepayers and the reasonable requests in this Application exemplify that commitment and approach.

5. The distribution rates to be paid by NOTL Hydro's customers is an important factor that underlies all of the unsettled items in this case. Ratepayers care about safe, reliable service at reasonable costs. NOTL Hydro's objective is to maintain low rates for its customers. As noted in Argument in Chief, NOTL Hydro's Mission Statement indicates (in part) that "Niagara-on-the-Lake Hydro continuously seeks to provide low cost energy delivery, high reliability and high power quality." This is a long-term objective, and NOTL Hydro has been successful in delivering on this goal, with significant progress achieved over time. The budgets and proposals included in NOTL Hydro's Application (including the remaining unsettled items)

[1] OEB Staff Submission on the Unsettled Issues, March 4, 2019 (OEB Staff Submission).
[2] Final Argument of the School Energy Coalition, March 4, 2019 (SEC Final Argument).
[3] Submission of the Vulnerable Energy Consumers Coalition, March 4, 2019 (VECC Submission).

further this goal. NOTL Hydro notes that, after adjusting for the ICM, the requested rate increase for its distribution rates is lower than would be received through an IRM.[4] If the OEB grants the relief requested by NOTL Hydro (see Section C of this Reply Argument), then its customers across its rate classes will continue to enjoy among the lowest rates in Niagara, and the province.[5]

6. OEB Staff and SEC give little credit to NOTL Hydro for its relatively low rates, focusing only on what they say is a recent trend showing that some of NOTL Hydro's costs have been increasing.[6] While it is true that some of NOTL Hydro's costs have increased in 2018, there are two key points to keep in mind. First, NOTL Hydro has maintained an overall positive trend of cost efficiency in recent years. A fair review of NOTL Hydro's performance looks at more than one year, and takes account of the fact that a small utility will have some "lumpiness" to its expenditure profile. NOTL Hydro's Additional Evidence on OM&A shows its PEG performance each year from 2014 to 2019[7] – it is clear that NOTL Hydro's cost performance continues to trend positively compared to expectations. This trend is what is important. Second, it should also be recognized that even if costs increase, rates can stay at a reasonable level. Where costs increase, but so too do customer numbers and load, then rates can remain reasonable.

7. The submissions from VECC and SEC question whether NOTL Hydro is preferring the interests of its shareholder (the Town of Niagara-on-the-Lake) over ratepayers.[8] This is unfounded and unfair. NOTL Hydro is directly focused on achieving safe, cost-effective, reliable service for its ratepayers. Ratepayers are not disadvantaged by NOTL Hydro's financing activities with the Town, since ratepayers actually pay less than the OEB's deemed cost of long-term debt for the utility's loans with the Town. Ratepayers are not disadvantaged by NOTL Hydro's practice of replacing overhead lines with underground lines in the "Old Town" and elsewhere. Ratepayers receive more reliable service and the character of their community is improved. And, of course, this is not a situation where the utility is owned by a private shareholder who is the beneficiary of the utility's decisions. NOTL Hydro's ratepayers

[4] Exhibit 4 – OM&A – Additional Evidence, page 5.
[5] Argument in Chief, paras. 18-23.
[6] Staff Submission, page 2; and SEC Final Argument, para. 15.
[7] Exhibit 4 – OM&A – Additional Evidence, page 7. Chart 6 from the Additional Evidence is reproduced below as Table 1.
[8] VECC Submission, para. 2.16; and SEC Final Argument, paras. 20, 21 and 30.

19. NOTL Hydro has explained why its entire proposed budget for its underground conversion program and general underground work is appropriate and necessary.[20]

20. The fact that less has been spent in recent years than had been forecast does not mean that this trend will continue during the next IR term. NOTL Hydro expects that the entire budgeted amount is needed and will be spent.

21. To the extent that the OEB believes that a reduction to the proposed underground conversion program budget is appropriate based on prior actual spending, then NOTL Hydro believes that it is appropriate for the OEB to properly identify what has been the recent actual spending relative to forecast amounts. The OEB Staff Submission concludes that NOTL Hydro underspent by around 28% per year, once the impact of capitalized management time is taken into account.[21] If applied to NOTL Hydro's $340,000 Test Year underground conversion budget at issue in this case, this would translate to a $95,000 reduction.

22. NOTL Hydro questions whether any reduction to this budget is warranted, given that there are clear plans for underground conversion work throughout the upcoming IR term, However, if the Board does believe that reduction is necessary, the detailed approach in the OEB Staff Submission to determine an applicable reduction is more appropriate than the high-level estimate included in the SEC Final Argument.

23. There is one final item related to this unsettled issue to which NOTL Hydro would like to respond,

24. In their submissions, the other parties each take different views about the customer engagement conducted on NOTL Hydro's underground conversion program. OEB Staff note that NOTL Hydro's customers do not appear to oppose the program.[22] SEC indicates that it is not clear if the level of spending takes customers' views into account.[23] VECC states that there has not been sufficient consultation on the costs and benefits of the underground conversion program.[24]

---

[20] See Argument in Chief, para. 38 (and associated references). The plans and associated costs are also addressed in NOTL Hydro's Distribution System Plan (filed at Exhibit 3 – for example, see pages 55-58).
[21] Board Staff Submission, pages 5-7.
[22] Board Staff Submission, page 4.
[23] SEC Final Argument, paras. 7-8.
[24] VECC Submission, paras. 2.14 -2.16.

25. In NOTL Hydro's view, the suggestion that deeper consultation was required is an attempt to create an issue where none exists. NOTL Hydro is a small utility and is in close contact with its customers. NOTL Hydro is aware of and responsive to concerns and questions raised by customers. Customers are not complaining about their rates in general, or about the underground conversion program in particular. This is not a new program that the utility is now considering. It is a long-standing program (over 30 years) that has not attracted complaints and concerns. Additional customer engagement should not be expected to change this.

b. Issue 1.2 – OM&A Expenditures

26. As explained in Argument in Chief, NOTL Hydro's 2019 Test Year OM&A forecast is $2,964,765.[25] This is the amount required for NOTL Hydro to continue its safe, reliable and customer-focused operations. Included in NOTL Hydro's OM&A operating costs are required expenditures necessary to maintain and operate NOTL Hydro's distribution system and transmission station assets, the costs associated with metering, billing, collecting from its customers, the costs associated with ensuring all stakeholders' safety (public and employees) and costs to maintain the distribution business service quality and reliability standards set by the regulating bodies.[26]

27. NOTL Hydro's Argument in Chief details several analyses that confirm the reasonableness of NOTL Hydro's 2019 OM&A budget forecast including: (i) the elements of the budget; (ii) comparing the budget to the most recent actual spending; (iii) the details and appropriateness of the various year-over-year cost increases between the last rebasing and 2019; (iv) expected increase in the budget from the last rebasing; and (v) comparing NOTL Hydro's OM&A per customer to other distributors.[27]

28. The other parties in this proceeding each propose that NOTL Hydro's 2019 OM&A budget should be reduced. Different budget levels and rationale are included by each party.

29. What is common to each of the arguments presented by other parties is an approach that starts with NOTL Hydro's 2014 Board-approved OM&A budget and then adjusts that number

[25] Argument in Chief, para. 40.
[26] Exhibit 4 – OM&A, page 4.
[27] Argument in Chief, paras. 43-62.

based on inflation, stretch factor and other items.[28] None of the arguments look at the details of any of the proposed OM&A expenditures. Importantly, no objections are raised as to the programs and staff that NOTL Hydro proposes to employ in the coming years. That makes concerns about the overall budget ring somewhat hollow.

30. NOTL Hydro submits that there are several problems with the approach taken by each of the other parties. Therefore, the evaluation approach used by NOTL Hydro in its Argument in Chief should be preferred to the approaches employed by other parties. If the OEB decides to use the approach proposed by any of the other parties, then adjustments should be made to address/correct the issues discussed below.

31. First, contrary to the position taken by OEB Staff[29] and VECC[30], it is entirely appropriate for NOTL Hydro to include the cost of previously capitalized employee expenses in the OM&A budget forecast for 2019.

    i. As detailed in Argument in Chief, during 2014 NOTL Hydro's President and the VP Operations booked time to capital, as appropriate under Canadian GAAP, while in 2019 this will be limited, because IFRS rules are now being applied. The reduction in capitalized costs, and corresponding addition to OM&A costs, is $130,784.41.[31] These are not new costs that the utility should be expected to absorb within an inflation-adjusted budget. They are recategorized costs that are no longer being booked as capital expenses (with a corresponding savings because ratebase impact is reduced).

    ii. Even assuming that OEB Staff is correct that NOTL Hydro should have expensed these costs as part of its 2014 cost of service filing, that does not mean that ratepayers have been harmed. NOTL Hydro has only ever reflected these costs in one place (initially as capitalized expenses and later as OM&A costs). All parties accepted NOTL Hydro's 2014 capital budget forecast, which included these costs. Ratepayers would

[28] As stated in Argument in Chief (para. 49 and footnote 33), an approach that compares the 2019 Test Year OM&A forecast with the budget from the last cost of service year should use NOTL Hydro's 2014 actual OM&A expenditures as a starting point because they represent the actual costs of the relevant year. NOTL Hydro's 2014 actual 2014 OM&A expenditures were around $55,000 higher than the compromise Settlement Proposal budget amount cited by each of the other parties.
[29] OEB Staff Submission, pages 13-14.
[30] The VECC Submission does discuss this discrete expense item.
[31] Argument in Chief, para. 54.

receive a windfall, and the utility would be penalized, if NOTL Hydro is not now permitted to recover these costs within OM&A expenditures.

iii. SEC agrees with NOTL Hydro that the capitalized employee expenses should be included in the 2014 OM&A base amount used to assess 2019 OM&A budget.[32] The point of using an earlier budget to assess a new forecast is to make an "apples to apples" comparison. To do that, the same items should be included in both budgets. The 2019 budget forecast includes the previously capitalized costs noted above – to fairly compare the current budget to the earlier budget requires that these costs be imputed into the prior budget.

32. Second, the adjustment factors used by SEC and VECC in their analyses are understated.

i. NOTL Hydro notes that OEB Staff appears to accept the adjustment factor approach applied by NOTL Hydro (using both customer and load growth as factors influencing expected OM&A costs).[33]

ii. SEC cites the approach taken by the OEB in a recent case which adjusted the prior Board-approved budget by inflation and customer growth with an offset for a stretch factor, and applies a proposed adjustment approach that results in a lower number than NOTL Hydro's 2019 OM&A forecast.[34] NOTL Hydro believes that this approach improperly excludes the impact of load growth, which is a significant driver of OM&A costs, especially for a distributor like NOTL Hydro that has transmission assets.[35]

iii. NOTL Hydro notes that in a recent case where the OEB used a formulaic approach to evaluate Test Year OM&A as compared to prior Board-approved budgets, the OEB also allowed for additional extraordinary expenses to be added to the amount derived using a formula.[36] NOTL Hydro has provided evidence and argument about the extraordinary cost pressures that it faces that are not accommodated in a budget that

[32] SEC Final Argument, paras. 13(ii) and 18.
[33] OEB Staff Submission, page 9 (footnote 27) and page 10 (where OEB Staff object to including the previously capitalized labour in the 2014 OM&A base amount, but do not object to NOTL Hydro's adjustment approach).
[34] SEC Final Argument, paras. 13(i) and 18.
[35] Exhibit 4 – OM&A – Additional Evidence, pages 2 and 8.
[36] See EB-2016-0085 Innpower Corporation, Decision and Order dated March 8, 2018 (at pages 23-25).

simply increases for inflation and growth. These items should be reflected in NOTL Hydro's 2019 Board-approved OM&A budget.

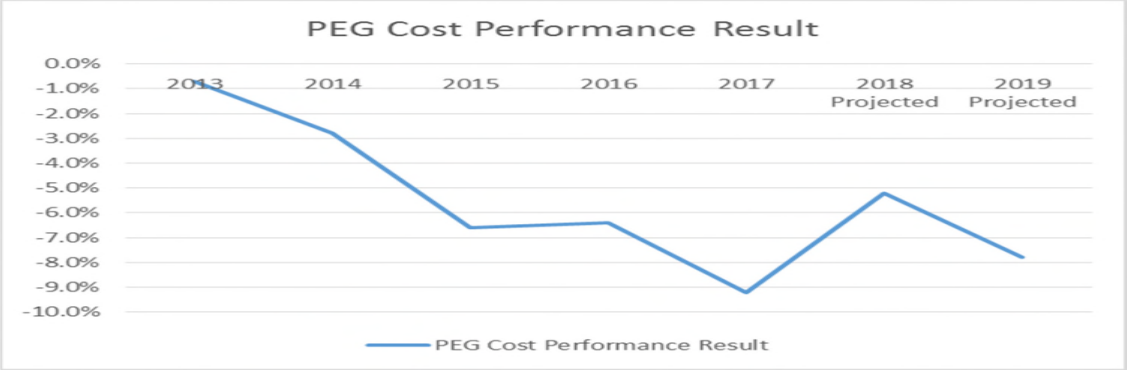
iv. VECC takes a higher-level approach of applying inflation and customer growth to derive a proposed 2019 OM&A budget. It is not entirely clear how its adjustment factors were derived.[37] It is also not clear whether VECC has compounded or combined the effect of the factors it used (which would be appropriate). What is clear is that VECC has not included any impact for load growth, nor any allowance for extraordinary cost pressures.

33. Another common theme in the submissions from other parties is the assertion that NOTL Hydro's OM&A costs per customer are trending negatively, and this supports reducing the proposed Test Year OM&A budget forecast.[38] NOTL Hydro disagrees. As seen in Table 7 of NOTL Hydro's Argument in Chief, the utility's operating cost per customer was virtually the same as the industry average in the last year for which actual data was available. Indeed, NOTL Hydro's actual OM&A cost per customer has never been significantly different from the industry average during any year since 2010. That is a good achievement for a utility that has relatively low customer density[39], and uses 30% of its assets for transmission purposes.[40]

34. NOTL Hydro's actual cost performance is improving when evaluated through the lens of the PEG benchmarking analysis. NOTL Hydro has maintained its ranking within cohort 3 (where its costs are within the expected range[41]) throughout the current IR term. In each year, NOTL Hydro's cost performance has been better than what would be expected. NOTL Hydro's performance has been improving over time (trending positively), using the evaluation method employed by PEG, as seen in Table 1 below, reproduced from NOTL Hydro's Additional Evidence[42]:

[37] VECC Submission, paras. 3.3 and 3.4.
[38] See VECC Submission, para. 3.7; SEC Final Argument, para. 14; and OEB Staff Submission, pages 10-11.
[39] Exhibit 4 – OM&A – Additional Evidence, pages 3-4.
[40] Exhibit 4 – OM&A – Additional Evidence, pages 2 and 8.
[41] Pacific Economics Group (PEG) Report to the Ontario Energy Board titled "Empirical Research in Support of Incentive Rate-Setting: 2017 Benchmarking Update", pages 8-9. PEG Report filed at https://www.oeb.ca/sites/default/files/PEG-benchmarking-report-20180823-revised.pdf
[42] Exhibit 4 – OM&A – Additional Evidence, page 7.

Table 1 – NOTL Hydro PEG Performance



35. NOTL Hydro's evidence is that based on the trends of its costs, it may be able to achieve a rating within cohort 2 of PEG's rankings, which is the group with actual costs more than 10% lower than the expected costs in the not too distant future. Contrary to the submissions of other parties, this demonstrates reasonable performance, and it demonstrates continuous improvement and positive outcomes for ratepayers. None of this is a basis for penalizing NOTL Hydro and reducing its forecast OM&A budget forecast for 2019.

36. VECC submits that reductions to NOTL Hydro's 2019 OM&A budget forecast should be made in recognition of the alleged excessive spending on the underground conversion (capital) program.[43] No specific suggestion is made as to what reduction is appropriate. In response, NOTL Hydro asserts that there is no basis for this proposed adjustment. It has not been established that NOTL Hydro's historic spending on the underground conversion program is "excessive". The spending on that program during the 2014 to 2018 IR term has been lower than forecast and endorsed in the 2014 cost of service proceeding.[44] The activities undertaken were reasonable and appropriate. The approach suggested by VECC amounts to punishment (they call it "rough justice"[45]) for a non-existent crime.

37. As explained in Argument in Chief, a key way to evaluate NOTL Hydro's Test Year OM&A budget forecast is to look at the most recent actual expenditures. The utility is incented to keep OM&A expenditures as low as possible during an IR term, because lower spending directly translates into higher returns for its shareholder. Therefore, actual spending shows what the utility really needs to provide safe, reliable, responsive, cost-effective service to its

[43] VECC Submission, para. 3.9.
[44] This can be seen in Table 1 of the Board Staff Submission, at page 5.
[45] VECC Submission, para. 2.24.

customers. A reduction from OM&A amounts already being spent will cause NOTL Hydro to have to choose between current activities and programs, and reduce services that benefit customers.

38. The OEB agreed in a recent case that looking at the most recent actual OM&A expenditures and adjusting for inflation, growth and stretch factor is an appropriate way to evaluate the forecast Test Year budget.[46] Applying this approach to NOTL Hydro's application results in a forecast 2019 OM&A budget that is very close to the as-filed budget.

39. NOTL Hydro's best evidence of its actual 2018 OM&A expenditures is $2,838,525.[47] That should be the starting point for adjustments to determine a 2019 budget level. As set out in Table 5 of NOTL Hydro's Argument in Chief, the combination of inflation, growth factors and stretch factor from 2018 to 2019 equates to an increase of 3.71%. Applying that escalation factor to 2018 actuals results in a 2019 OM&A budget forecast of $2,943,834. This is very close to NOTL Hydro's filed 2019 OM&A budget forecast of $2,964,765. Even if one was to simply apply an adjustment of 1.7% based on the OEB's 2019 inflation factor to the 2018 actuals, this would result in a 2019 OM&A budget forecast of $2,886,780, which is also close to the as-filed 2019 budget forecast. It is important to highlight that an approved OM&A below the 2018 base spending adjusted to 2019 will not support NOTL Hydro's current and planned operations for 2019[48], and will result in important and beneficial programs and activities being reduced or not pursued.

40. For the reasons described in Argument in Chief, and taking into account NOTL Hydro's response to the positions advanced by other parties, NOTL Hydro repeats its request that the OEB approve the as-filed 2019 OM&A budget forecast. This will support continued safe, reliable and responsive service to NOTL Hydro's customers.

---

[46] EB-2016-0105, Thunder Bay Hydro Electricity Distribution Inc., Decision and Order dated September 21, 2017 (page 5).

[47] SEC suggests that the increase from 2017 to 2018 is unduly high – this argument fails to recognize that a big part of the increase (around $100,000) results from moving costs for the President and VP-Operations from capital to OM&A – these are not new costs in 2018, they are recategorized costs (see 4-SEC-42 and 4-VECC-29).

[48] New expenditures currently planned for NOTL Hydro in 2019 include Cybersecurity and the Utilismart initiative which would provide large customers with better access to their data.

customers will be subsidizing the gross load billing transmission costs for any future LDG customers.[78]

64. No party objects to NOTL Hydro's proposal on any principled basis. Both SEC and VECC agree that there is merit in aligning NOTL Hydro's billing of customers with the way that NOTL Hydro is billed by the IESO.[79] This is different from the Erie-Thames Powerlines Corporation proceeding where a party to be impacted by transmission gross load billing was an active participant.[80]

65. The only concern raised is around whether the OEB plans to look at transmission gross load billing on a generic basis, and whether any change to NOTL Hydro's rates should await that process.[81] NOTL Hydro submits that this is not adequate reason to refrain from approving the proposal. It is not appropriate for NOTL Hydro's other customers to pay costs caused by a Large User where such costs can be directed to the Large User. The fact that NOTL Hydro has not applied this transmission gross load billing before now is simply a reflection of the fact that there has been no customer causing upstream gross load billing costs. Contrary to the OEB Staff Submission[82], that should not prevent the OEB from approving such a charge now. NOTL Hydro submits that approving its current proposal will not impair the OEB's ability to look at the question of transmission gross load billing on a generic basis at a later time. If the OEB directs an approach that is different from what is in place for NOTL Hydro, then NOTL Hydro can implement that different approach at that time.

C. REQUESTED RELIEF

66. In summary, NOTL Hydro respectfully requests OEB approval of the following items:

    i. The as-filed cost of the underground capital expenditures for 2019, and the inclusion into rate base of all amounts spent on the underground conversion program during the 2014 to 2018 term;

    ii. The as-filed OM&A budget for 2019;

[78] Argument in Chief, paras. 85-90.
[79] SEC Final Argument, para. 43; and VECC Submission, para. 7.3.
[80] EB-2017-0038 Erie Thames Powerlines Corporation, 2018 Cost of Service Application – see August 1, 2018 Notice of Appeal from Toyota Motor Manufacturing Inc. which set out the topics of interest to that party.
[81] OEB Staff Submission, pages 24-25; and SEC Final Argument, para. 43.
[82] OEB Staff Submission, page 25.

iii. The as-filed updated cost of long-term debt for 2019;

iv. The determination of 2019 rates using a cost allocation approach that includes 2018 ICM revenues in revenue at existing rates;

v. The clearance of Group 2 Deferral and Variance Accounts and the LRAMVA over two years, with a reduction of $5,000 to the principal balance being recovered (to reflect the difference in interest costs); and

vi. The proposed transmission standby charge for the Large User rate class.

All of which is respectfully submitted this 15th day of March 2019.



David Stevens
Aird & Berlis LLP
Counsel to NOTL Hydro

TAB 6

TAB i



Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION ON MOTION TO REVIEW AND VARY

EB-2016-0005

CITY OF HAMILTON

BEFORE: Cathy Spoel
Presiding Member

Ken Quesnelle
Member and Vice-Chair

Christine Long
Member

March 3, 2016

1 INTRODUCTION AND SUMMARY

Horizon Utilities Corporation (Horizon) is the electricity distributor that serves approximately 245,000 customers in the City of Hamilton (City) and the City of St. Catharines. The City is Horizon's majority shareholder. The City is Horizon's largest customer in the street lighting class. Horizon filed a second year update to its Custom Incentive Regulation (Custom IR) application for approval of distribution rates for 2016 (EB-2015-0075). As a result of the installation of more efficient bulbs in the City's street lights, the electricity demand profile (also known as a load profile) of the street lighting class had changed. In its decision on the application, the Ontario Energy Board (OEB) did not approve Horizon's request to update the load profile of the street lighting class in the cost allocation model, as it found that there is no advantage to selective updating of the load profile for only one rate class.

The City filed a motion to review and vary the OEB's decision in EB-2015-0075 on the basis that the OEB erred in its decision not to approve the updating of the street lighting class load profile in the cost allocation model, and that by doing so it failed to implement provincial government policies on conservation.

The OEB finds the City has not demonstrated any identifiable error in the EB-2015-0075 decision and denies the motion at the threshold stage.

2 BACKGROUND

Horizon, a licensed distributor of electricity, filed a Custom IR application with the OEB on April 17, 2014 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 it charges for electricity distribution, to be effective January 1, 2015 and for each following year through to December 31, 2019. The OEB assigned the application file number EB-2014-0002.

The OEB accepted a partial settlement agreement between Horizon and the intervenors in that proceeding, and held an oral hearing on the issues of rate design and cost allocation. On December 11, 2014, the OEB issued its Decision and Order on the Custom IR application, which stated that "[i]n the event that there is direction from the Board with respect to a new policy concerning the methodology for cost allocation related to street lighting which is applicable to Horizon, the Board is of the view that the Settlement Agreement provides that Horizon will adjust street lighting rates accordingly".[1]

On June 5, 2015, the OEB issued a new cost allocation policy for street lighting, which required the implementation of a street lighting adjustment factor (SLAF) and narrowed the range for the revenue to cost (R/C) ratio for the street lighting class to 80%-120%.[2]

On August 12, 2015, Horizon filed its first annual update to its five-year Custom IR (Annual Update) for rates to be effective January 1, 2016. The OEB assigned the application file number EB-2015-0075. The application included a number of adjustments and changes due to the implementation of the OEB's new policy for street lighting.

In its Annual Update, Horizon requested approval of revisions to its cost allocation model to include the SLAF, an update to the street lighting load profile to reflect the reduction in load due to conversion to light-emitting diodes (LED) and an adjustment to the R/C ratio for the street lighting class to 100%. The OEB issued its decision on Horizon's Annual Update on December 10, 2015. It accepted Horizon's update for the SLAF, and OEB staff's recommendation that implementation of the R/C ratio of 100% for street lighting class should be phased in, starting with a move to 120% for 2016. The OEB did not accept Horizon's proposal to update the street lighting load profile.

[1] EB-2014-0002, Decision and Order, December 11, 2014, p. 13
[2] New Cost Allocation Policy for Street Lighting Class, EB-2012-0383, June 12, 2015

In rejecting Horizon's proposal to update the street lighting load profile, the OEB stated that while the use of up-to-date data is preferable, there is no advantage to selective updating. Until data that is more accurate is available for all rate classes, Horizon must continue to use the existing load profiles for purposes of its cost allocation model.

3 MOTION TO REVIEW AND VARY

On December 22, 2015, the City filed a Motion to Review and Vary (Motion) the OEB's Decision and Order dated December 10, 2015 for EB-2015-0075 (Decision and Order). The OEB has assigned the Motion file number EB-2016-0005. The Motion requested that OEB review and vary the part of the Decision and Order dealing with the load profile used for the street lighting class in Horizon's cost allocation model.

Rule 42.01(a) of the OEB's Rules of Practice and Procedure (Rules) provides the grounds upon which a motion to review and vary may be made to the OEB:

> Every notice of motion made under Rule 40.01, in addition to the requirements under Rule 8.02, shall:
>
> (a) Set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
>
> i. error in fact;
> ii. change in circumstances;
> iii. new facts that have arisen;
> iv. facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

The OEB recognizes that the list of grounds noted above is not an exhaustive list. However, the grounds supporting a motion to review must raise a question as to the correctness of the order or decision.

Under Rule 43.01 of the Rules, the OEB may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits. The purpose of the threshold question is to determine whether the grounds put forward by the moving party raise a question as to the correctness of the order or the decision, and whether there is enough substance to the issues raised that a review could result in the OEB varying, cancelling, or suspending the decision.

In the OEB's view, a motion to review cannot succeed in varying the outcome of the decision if the moving party cannot satisfy these tests, and in that case, there would be no useful purpose in proceeding with the motion to review. The threshold test is not met when a party simply seeks to reargue the case.

3.1 The City's Motion

The City's Motion alleges that as a result of the OEB's Decision and Order, the City and its residents will not benefit from the LED conversion program until Horizon's next rebasing year, which is scheduled for 2020.[3] Further, the City argues that the provincial government's policy on conservation, as set out in the Long-Term Energy Plan, states that the government's agencies are to put conservation first in their planning, approval and procurement processes. The City submits that the OEB erred by failing to implement provincial government policies on conservation and, in particular, the Province's "Conservation First" policy, and that the OEB also erred by failing to comply with directives issued to it by the Minister of Energy with respect to the Province's conservation and demand management policies.

Findings

The OEB finds that the City has not demonstrated any identifiable error in the EB-2015-0075 decision and therefore the OEB finds it appropriate to deny the motion at the threshold stage.

The Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads, states "[d]istributors should update unmetered load and consumption data for billing purposes that reflects energy efficiency improvements or other changes when those changes can be supported by evidence presented by unmetered load customers. It will be the responsibility of the unmetered load customer to provide the information to the distributor. The updated consumption data should be used by distributors for billing unmetered loads once it is validated by the distributor."[4]

[3] EB-2016-0005, Notice of Motion to Review and Vary, 2015, 1222, p. 2
[4] EB-2012-0383, Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads, December 19, 2013, p. 12

In keeping with this requirement, the City has provided Horizon with the updated information for the converted street lights, which will now be used for billing purposes. As a result, the monthly bill to the City from Horizon for electricity will be reduced in a number of ways:

1. As a result of the reduced energy consumption, the commodity charge and all other energy based charges will be reduced.
2. As a result of the reduction in peak kWs, the distribution and transmission charges will be reduced.

In addition to the above, the City's bill has decreased due to the implementation of the SLAF in the cost allocation model and subsequent reduction in the R/C ratio as shown below[5]:

	Revenues collected from the City for the street lighting class	**Reduction in costs paid by the City**	**Costs**	**R/C Ratio**
Implementation of SLAF only	$2.7M		$1.8M	153%
Implementation of SLAF and movement of R/C to 120%	$2.2M	($0.5M)	$1.8M	120%

As the City is being billed using the updated billing determinants and is receiving the benefits of the LED conversion program noted above, the Decision and Order is not contrary to the province's conservation objectives. As all consumers of electricity are encouraged to implement conservation programs, all rate classes' load profiles may change as a result of undertaking such programs. Selective updating would benefit the street lighting rate class but would do so at the expense of other rate classes. This in turn might negate some of the impact of those rate classes' conservation efforts. The OEB does not agree that provincial policies require the OEB to selectively update load profiles of some rate classes to the detriment of others. The OEB is of the view that

[5] EB-2015-0075, 2016 Cost Allocation Model_20151216, Tab O1 Revenue to Cost

provincial government policies on conservation are reflected within the Decision and Order and finds that there is no identifiable error which puts in doubt the correctness of the Decision and Order. The OEB is also of the view that the issue raised is not one that could result in the OEB varying, cancelling or suspending its Decision and Order. As such, the OEB does not find that the threshold test has been met. The Motion is denied.

DATED at Toronto, March 3, 2016

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

TAB ii

Ontario Energy Board

Commission de l'Énergie de l'Ontario



EB-2006-0322
EB-2006-0338
EB-2006-0340

MOTIONS TO REVIEW THE NATURAL GAS ELECTRICITY INTERFACE REVIEW DECISION

DECISION WITH REASONS

May 22, 2007

EB-2006-0322
EB-2006-0338
EB-2006-0340

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

AND IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers) and whether the Board should refrain from regulating the rates for storage of gas;

AND IN THE MATTER OF Rules 42, 44.01 and 45.01 of the Board's *Rules of Practice and Procedur*e.

BEFORE: Pamela Nowina
Vice Chair, Presiding Member

Paul Vlahos
Member

Cathy Spoel
Member

DECISION WITH REASONS

May 22, 2007

EXECUTIVE SUMMARY

In November of 2006 the Board issued a Decision with Reasons in the Natural Gas Electricity Interface Review proceeding (the "NGEIR Decision"). This proceeding was initiated by the Ontario Energy Board in response to issues first raised in the Board's Natural Gas Forum Report issued in 2004. The NGEIR Decision addressed the key issues of natural gas storage rates and services for gas-fired generators, and storage regulation.

In the NGEIR Decision, the Board determined that it would cease regulating the prices charged for certain storage services but that the rates for storage services provided to Union and Enbridge distribution customers will continue to be regulated by the Board.

The Board received three Notices of Motion for review of certain parts of the NGEIR Decision. The Board held an oral hearing to consider the threshold questions that the Board should apply in determining whether the Board should review those parts of the NGEIR Decision and whether the moving parties met the test or tests.

The Board finds that the motions do not pass the threshold tests applied by the Board, except in two areas.

First, the Board finds that the decision to cap the storage available to Union Gas Limited's in-franchise customers at regulated rates to 100 PJ is reviewable.

Second, the Board finds that the decisions regarding additional storage requirements for Union Gas Limited's in-franchise gas-fired generator customers and Enbridge's Rate 316 are reviewable.

TABLE OF CONTENTS

Section A: Introduction **1**
The NGEIR Decision 2
Organization of the Decision 3

Section B: Board Jurisdiction to Hear the Motions **5**

Section C: Threshold Test **16**

Section D: Board Process **19**

Section E: Board Jurisdiction under Section 29 ..... **26**

Section F: Status Quo **34**

Section G: Onus **37**

Section H: Competition in the Secondary Market **38**

Section I: Harm to Ratepayers **42**

Section J: Union's 100 PJ Cap **45**

Section K: Earnings Sharing **50**

Section L: Additional Storage for Generators and Enbridge's Rate 316 ..... **54**

Section M: Aggregate Excess Method of Allocating Storage **59**

Section N: Orders **62**

Section O: Cost Awards **63**

Section A: Introduction

The Board received three Notices of Motion for review of its Decision in the Natural Gas Electricity Interface Review proceeding[1] ("NGEIR"). Motions were filed by the City of Kitchener ("Kitchener") and the Association of Power Producers of Ontario ("APPrO"). There was also a joint notice by the Industrial Gas Users' Association ("IGUA"), the Vulnerable Energy Consumers Coalition ("VECC") and the Consumers Council of Canada ("CCC")

On January 25, 2007, the Board issued a Notice of Hearing and Procedural Order which established a schedule for the filing of factums by the moving parties, any responding parties' factums, and an oral hearing date for hearing the threshold question. On February 8, 2007, factums were filed by Kitchener, APPrO, IGUA, and jointly by CCC and VECC.

Responding factums were filed on February 15, 2007 by Board Staff, Union Gas Limited, Enbridge Gas Distribution Inc., Market Hub Partners Canada Ltd., School Energy Coalition, The Independent Electricity System Operator and BP Canada Energy Company.

In its Procedural Order No.2, the Board indicated that, at the upcoming oral hearing, parties should confine their submissions to the material in their factums and to responding to the factums of other parties. The Board also stated that parties should address only the issues set out in the Board's Procedural Order No. 1, namely:

1) What are the threshold questions that the Board should apply in determining whether the Board should review the NGEIR Decision? and

2) Have the Moving Parties met the test or tests?

[1] EB-2008-0551 (November 7, 2006)

On March 5 and 6, 2007, the Board heard the oral submissions of all the parties with the exception of the Independent System Operator and BP Canada who had advised the Board that they would not be appearing at the oral hearing.

The NGEIR Decision

On November 7, 2006 the Board issued its Decision with Reasons in the Natural Gas Electricity Interface Review proceeding (the "NGEIR Decision"). This proceeding was initiated by the Ontario Energy Board in response to issues first raised in the Board's Natural Gas Forum Report issued in 2004. The 123-page NGEIR Decision addressed the key issues of:

1) Rates and services for gas-fired generators, and

2) Storage regulation.

The parties reached settlements with Enbridge and Union on most of the issues related to rates and services for gas-fired generators. These settlements were approved by the Board. The oral hearing and the NGEIR Decision addressed the broad issue of storage regulation and any issues that were not settled in the settlement negotiations.

The issue concerning storage regulation was whether the Board should refrain from regulating the prices charged for storage services under section 29 (1) of the Ontario Energy Board Act, 1998. The Board found that the storage market is workably competitive and that neither Union nor Enbridge have market power in the storage market. The Board determined that it would cease regulating the prices charged for certain storage services; however, the Board found that rates for storage services provided to Union and Enbridge distribution customers will continue to be regulated by the Board.

The motions requested the following decisions made in the NGEIR Decision be either reviewed and changed; cancelled, or clarified, in a new Board proceeding:

Kitchener

- The aggregate excess methodology for allocating storage space
- The 100 PJ cap on Union's regulated storage

APPrO

- Whether short notice balancing service should be included on the tariffs of Union and Enbridge

IGUA/CCC/VECC

- Parts of the NGEIR Decision pertaining to storage, storage regulation and storage allocation be cancelled
- Review to be heard by a different Board panel

The parties outlined the grounds for the motions which included allegations of errors of fact and in some cases, errors of law.

Organization of the Decision

In this Decision, the Board organized the issues raised by the parties into sections that cover the same or similar topics. In each section following the section on the threshold test, the Board identifies the issue or issues raised, and makes a finding whether the issues are reviewable by applying the threshold test.

The sections of this Decision are:

A. Introduction (this section)
B. Board Jurisdiction to Hear Motions
C. Threshold Test
D. Board Process

E. Board Jurisdiction under Section 29
F. Status Quo
G. Onus
H. Competition in the Secondary Market
I. Harm to Ratepayers
J. Union's 100 PJ Cap
K. Earnings Sharing
L. Additional Deliverability for Generators and Enbridge's Rate 316
M. Aggregate Excess Method of Allocating Storage
N. Orders
O. Cost Awards

The Board has reviewed the factums and arguments of all parties but has chosen to set out or summarize the factums or arguments by parties only to the extent necessary to provide context to its findings.

Section B: Board Jurisdiction to Hear the Motions

Under Rule 45.01, the Board may determine as a threshold question whether the matter should be reviewed before conducting any review on the merits.

In the case of IGUA's motion, which raises questions of law and jurisdiction, counsel for Board Staff argued that the Board should not, and indeed could not, review the NGEIR Decision as these grounds are not specifically enumerated in Rule 44.01 as possible grounds for review. Counsel for Board Staff argued that the Board has no inherent power to review its decisions and the manner in which it exercises such power must fall narrowly within the scope of the *Statutory Powers Procedure Act* (SPPA), which grants the Board this power.

The Board's power to review its decisions arises from Section 21.1(1) of the SPPA which provides that:

> A tribunal may, if it considers it advisable and if its rules made under section 25.1 deal with the matter, review all or any part of its own decision or order, and may confirm, vary, suspend or cancel the decision or order.

Part VII (sections 42 to 45) of the Board's Rules of Practice and Procedure deal with the review of decisions of the Board. Rule 42.01 provides that "any person may bring a motion requesting the Board to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision". Rule 42.03 requires that the notice of motion for a motion under 42.01 shall include the information required under Rule 44. Rule 44.01 provides as follows:

> Every notice of motion made under Rule 42.01, in addition to the requirements of Rule 8.02, shall:
>
> > (a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:

(i) error in fact;

(ii) change in circumstances;

(iii) new facts that have arisen;

(iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time; and

(b) if required, and subject to Rule 42, request a stay of the implementation of the order or decision, or any part pending the determination of the motion.

Counsel for Board Staff argued that while the grounds for review do not have to be exactly as those described, they must be of the same nature, and that to the extent the grounds for review include other factors such as error of law, mixed error of fact and law, breach of natural justice, or lack of procedural fairness, they are not within the Board's jurisdiction. He argued that Rule 44 should be interpreted as an exhaustive list, and that as section 21.1(1) of the SPPA requires that the tribunal's rules deal with the matter of motions for review, the Board's jurisdiction is limited to the matters specifically set out in its Rules.

In support of this interpretation of the Rule 44.01, Counsel relied on the fact that an earlier version of the Board's rules specifically allowed grounds which no longer appear in Rule 44.01. Therefore, it must be assumed that the current Rules are not intended to allow motions for review based on those grounds. The relevant section of the earlier version of the Rules read as follows:

63.01 Every notice of motion made under Rule 62.01, in addition to the requirements of Rule 8.02, shall:

> (a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
>
> (i) error of law or jurisdiction, including a breach of natural justice;
>
> (ii) error in fact;
>
> (iii) a change in circumstances;
>
> (iv) new facts that have arisen;
>
> (v) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time;
>
> (vi) an important matter of principle that has been raised by the order or decision;
>
> (b) request a delay in the implementation of the order or decision, or any part pending the determination of the motion, if required, …

Counsel for Board Staff argued that the "presumption of purposeful change" rule of statutory interpretation should be applied to the Board's Rules. This rule applies generally to legislative instruments and is based on the presumption that legislative bodies do not go to the bother and expense of making changes to legislative instruments unless there is a specific reason to do so. Applied to Rule 44, this means that the Board should be presumed to have intended to eliminate the possibility of motions for review based on grounds which are no longer enumerated. He further argued that because the SPPA requires the Board's Rules "to deal with the matter", the

Board can only deal with them in the manner allowed for by its Rules, and any deviation from the Rules will cause the Board to go beyond its power to review granted by Section 21.1(1) of the SPPA.

In general Union and Enbridge supported the argument made by counsel for Board Staff.

Other parties made several arguments to counter those put forward by counsel for Board Staff. These included:

- as the Board's rules are not statutes or regulations but deal with procedural matters the rules of statutory interpretation such as the presumption of purposeful change have little if any application

- to the extent rules of statutory interpretation apply, section 2 of the SPPA specifically requires that the Act and any rules made under it be liberally construed:

  > This Act, and any rule made by a tribunal under subsection 17.1(4) or section 25.1, shall be liberally construed to secure the just, most expeditious and cost-effective determination of every proceeding on its merits

- that the *Interpretation Act* requires that the word "may" be construed as permissive, whereas "shall" is imperative, so the list of grounds in Rule 44 should be considered as examples. In support of this argument, counsel for CCC referred to Sullivan and Dreiger on the Construction of Statutes, Fourth Edition, Butterworths, pp 175*ff* which cites the Supreme Court of Canada decision in *National Bank of Greece (Canada) v. Katsikonouris* (1990), 74 D.L.R. (4th) 197

- that the Ontario Court of Appeal decision in *Russell v. Toronto(City)* (2000), 52 O.R. (3d) 9 provides that a tribunal (in that case the Ontario Municipal Board) cannot use its own policy or practice to restrict the range of matters which it will consider on a motion to review

- that the *Russell* decision gives tribunals a broad jurisdiction to review in contradistinction to the narrow right of appeal to the Divisional Court.

Findings

In the Board's view, in addition to the specific sections of the SPPA and the Board's Rules dealing with motions to review, it is helpful to look at the overall scheme of the SPPA and the Rules to determine the scope of the Board's jurisdiction to review a decision.

Originally, the SPPA was enacted to ensure that decision making bodies such as the Board provided certain procedural rights to parties that were affected by those decisions. These basic requirements apply regardless of whether a tribunal has enacted rules of practice and procedure. They include such requirements as:

- Parties must be given reasonable notice of the hearing (s 6)

- Hearings must be open to the public, except where intimate personal or financial matters may be disclosed (s 9)

- The right to counsel (s 10)

- The right to call and examine witnesses and present evidence and submissions and to conduct cross-examinations of witnesses at the hearing reasonably required for a full and fair disclosure of all matters relevant to the issues in the proceeding (s 10.1)

- That decisions be given in writing with reasons if requested by a party (s 17 (1))

- That parties receive notice of the decision (s 18)

- That the tribunal compile a record of the proceeding (s 20).

In addition to these requirements there are several practices and procedures that tribunals are allowed to adopt, if provision is made for them in an individual tribunal's rules. These include:

- Alternative dispute resolution. Section 4.8 provides that a tribunal may direct parties to participate in ADR if "it has made rules under section 25.1 respecting the use of ADR mechanisms…"

- Prehearing conferences. Section 5.3 provides that "if the tribunal's rules under section 25.1 deal with prehearing conferences, the tribunal may direct parties to participate in a pre-hearing conference…"

- Disclosure of documents. Section 5.4 provides that "if the tribunal's rules made under section 25.1 deal with disclosure, the tribunal may,…, make orders for (a) the exchange of documents, …"

- Written hearings. Section 5.1 (1) provides that "a tribunal whose rules made under section 25.1 deal with written hearings may hold a written hearing in a proceeding."

- Electronic hearings. Section 5.2 provides that "a tribunal whose rules made under section 25.1 deal with electronic hearings may hold an electronic hearing in a proceeding."

- Motions to review. Section 21.1(1) provides that "a tribunal may, if it considers it advisable and if its rules made under section 25.1 deal with the matter, review all or any part of its own decision or order, and may confirm, vary, suspend or cancel the decision or order."

Beyond stating that a tribunal's rules have to "deal with" each of these procedures in order for the tribunal to avail itself of them, there are no restrictions on the way in which they do so. In this regard nothing distinguishes motions to review from the other "optional" procedural matters listed above. A tribunal is free to create whatever procedures it thinks appropriate to handle them, provided they are consistent with the SPPA.

The Board notes that there are situations where the SPPA does not give tribunals full discretion in developing their rules to deal with "optional" procedural powers. For example, section 4.5(3) allows tribunals or their staff to make a decision not to process a document relating to the commencement of a proceeding. This section not only requires a tribunal to have "made rules under section 25.1 respecting the making of such decisions" but also requires that "those rules shall set out … any of the grounds referred to in subsection 1 upon which the tribunal or its administrative staff may decide not to process the documents relating to the commencement of the proceeding;…" While a tribunal can prescribe the grounds for such a decision in its rules, the grounds must come from a predetermined list found in the SPPA. In that case, it is clear that only certain grounds are permitted, and a tribunal must restrict itself to those grounds enumerated in its rules.

The SPPA could put similar restrictions on the development of a tribunal's rules dealing with motions to review, but it does not.

While the Court of Appeal's decision in *Russell v. Toronto* dealt with motions to review under the *Ontario Municipal Board Act* rather than under the SPPA, the power granted to review decisions is effectively the same, so the principles enunciated in the *Russell* decision are applicable to the Board. The Court of Appeal found that the OMB could not

use its own policies and guidelines to restrict the scope of the power to review which was granted to it by statute. The Board therefore finds that it cannot use its Rules to limit the scope of the authority given to it by the SPPA.

The SPPA allows each tribunal to make its own Rules, so as to allow it to deal more effectively with the specific needs of its proceedings. The SPPA does not give the Board the authority to limit the substantive matters within the Board's purview.

The provisions of the SPPA dealing with the making of rules, give tribunals a very wide latitude to meet their own needs, both in the context of creating rules and in each individual proceeding:

> 25.0.1 A tribunal has the power to determine its own procedure and practices and may for that purpose,
>
> (a) make orders with respect to the procedures and practices that apply in any particular proceeding; and
>
> (b) establish rules under section 25.1

> 25.1 (1) A tribunal may make rules governing the practice and procedure before it.
>
> (2) The rules may be of general or particular application.
>
> (3) The rules shall be consistent with this Act and with the other Acts to which they relate.
>
> (4) The tribunal shall make the rules available to the public in English and in French.
>
> (5) Rules adopted under this section are not regulations as defined in the *Regulations Act*.
>
> (6) The power conferred by this section is in addition to any other power to adopt rules that the tribunal may have under another Act.

In the Board's view these sections of the SPPA give the Board very broad latitude to determine the procedure best suited to it from time to time. While consistency with the Act is required, the Rules are not regulations, and can be amended from time to time by the Board to suit its evolving needs.

The Board finds that there is nothing in the SPPA to suggest that rules dealing with motions to review should be interpreted or applied any differently from other provisions of the Board's Rules.

The Board's Rules

In addition to Section 2 of the SPPA which provides for a liberal interpretation of the Act and the Rules, the Board's Rules include the following provisions as a guide to their interpretation.

> 1.03 The Board may dispense with, amend, vary or supplement, with or without a hearing, all or any part of any rule at any time, if it is satisfied that the circumstances of the proceeding so require, or it is in the public interest to do so.
>
> 2.01 These Rules shall be liberally construed in the public interest to secure the most just, expeditious and cost-effective determination of every proceeding before the Board.
>
> 2.02 Where procedures are not provided for in these Rules, the Board may do whatever is necessary and permitted by law to enable it to effectively and completely adjudicate on the matter before it.

As these provisions are of general application to all of the Board's Rules of Practice and Procedure, the Board finds that each of its individual rules should be read as if the above rules 1.03, 2.01 were part of them, except of course where restricted by the SPPA or another Act. Therefore, the Rules which "deal with the matter" of motions to

review, i.e. Rules 42 to 45, should be read in conjunction with Rules 1.03 and 2.01. Similarly, the rules dealing with alternative dispute resolution, written hearings and so on include Rules 1.03 and 2.01.

The Board finds that it should interpret the words “may include” in Rule 44.01 as giving a list of examples of grounds for review for the following reasons:

- It is the usual interpretation of the phrase;
- It is consistent with section 2 of the SPPA which requires a liberal interpretation of the Rules;
- It is consistent with Rule 1.03 of the Board’s rules which allows the Board to amend, vary or supplement the rules in an appropriate case; and
- If the SPPA had intended to require that the power to review be restricted to specific grounds it would have required the rules to include those grounds and would have required the use of the word “shall”.

With respect to the application of the principle of presumption of purposeful change urged by counsel for Board Staff, the Board notes that at the same time that its rules were amended to remove certain grounds of appeal from Rule 44.01, Rule 1.03 was also amended. The previous version of Rule 1.03 (then 4.04) read as follows:

> The Board may dispense with, amend, vary, or supplement, with or without a hearing, all or any part of any Rule, at any time by making a procedural order, if it is satisfied that the special circumstances of the proceeding so require, or it is in the public interest to do so.

When compared with the current Rule 1.03, it is apparent that the old rule was more restrictive – amendments had to be made by procedural order, and the circumstances of the proceeding had to be “special”. Given the need for a procedural order, it is reasonable to interpret the old rule as applying only to the sorts of matters dealt with in procedural orders, the conduct of the proceeding and not to other provisions of the rules. No such restriction applies in the current Rule 1.03.

The Board finds that to the extent the Rules were amended to remove specific grounds from the list for motions to review, the contemporaneous amendments to Rule 1.03 give the Board the necessary discretion to supplement this list in an appropriate case. The Board presumably was aware of that at the time of the amendments.

The Board therefore finds that it has the jurisdiction to consider the IGUA motion to review even though the grounds are errors of mixed fact and law which do not fall squarely within the list of enumerated grounds in Rule 44.01.

Even if this interpretation of Rule 44.01 is incorrect, the Board can apply Rule 1.03 to supplement Rule 44.01 to allow the grounds specified by IGUA. Given the number of motions for review, the timing involved, the nature of the hearing and the nature of the alleged errors, the Board concludes that it is in the public interest to avoid splitting this case into Motions reviewed by some parties and appealed by others.

This panel is also aware that Appeals to the Divisional Court can only be based on matters of law including jurisdiction. If the position advanced by counsel for the Board staff was accepted, errors of mixed fact and law could not be effectively reviewed or appealed by any body. This, the Board believes is not consistent with Section 2 of the SPPA.

Section C: Threshold Test

Section 45.01 of the Board's Rules provides that:

> In respect of a motion brought under Rule 42.01, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

Parties were asked by the panel to provide submissions on the appropriate test for the Board to apply in making a determination under Rule 45.01.

Board Staff argued that the issue raised by a moving party had to raise a question as to the correctness of the decision and had to be sufficiently serious in nature that it is capable of affecting the outcome. Board Staff argued that to qualify, the error must be clearly extricable from the record, and cannot turn on an interpretation of conflicting evidence. They also argued that it's not sufficient for the applicants to say they disagree with the Board's decision and that, in their view, the Board got it wrong and that the applicants have an argument that should be reheard.

Enbridge submitted that the threshold test is not met when a party simply seeks to reargue the case that the already been determined by the Board. Enbridge argued that something new is required before the Board will exercise its discretion and allow a review motion to proceed.

Union agreed with Board Staff counsel's analysis of the scope and grounds for review.

IGUA argued that to succeed on the threshold issue, the moving parties must identify arguable errors in the decision which, if ultimately found to be errors at the hearing on the merits will affect the result of the decision. IGUA argued that the phrase "arguable errors" meant that the onus is on the moving parties to demonstrate that there is some reasonable prospect of success on the errors that are alleged.

CCC and VECC argued that the moving parties are required to demonstrate, first, that the issues are serious and go to the correctness of the NGEIR decision, and , second, that they have an arguable case on one or more of these issues. They argued that the moving parties are not required to demonstrate, at the threshold stage, that they will be successful in persuading the Board of the correctness of their position on all the issues.

MHP argued that the threshold question relates to whether there are identifiable errors of fact or law on the face of the decision, which give rise to a substantial doubt as to the correctness of the decision, and that the issue is not whether a different panel might arrive at a different decision, but whether the hearing panel itself committed serious errors that cast doubt on the correctness of the decision. MHP submitted that a review panel should be loathe to interfere with the hearing panel's findings of fact and the conclusions drawn there from except in the clearest possible circumstances.

Kitchener argued that jurisdictional or other threshold questions should be addressed on the assumption that the record in NGEIR establishes the facts asserted.

School Energy Coalition argued that an application for reconsideration should only be denied a hearing on the merits in circumstances where the appeal is an abuse of the Board's process, is vexatious or otherwise lacking objectively reasonable grounds.

Findings

It appears to the Board that all the grounds for review raised by the various applicants allege errors of fact or law in the decision, and that there are no issues relating to new evidence or changes in circumstances. The parties' submissions addressed the matter of alleged error.

In determining the appropriate threshold test pursuant to Rule 45.01, it is useful to look at the wording of Rule 44. Rule 44.01(a) provides that:

> Every notice of motion… shall set out the grounds for the motion that raise a question as to the correctness of the order or decision…

Therefore, the grounds must "raise a question as to the correctness of the order or decision". In the panel's view, the purpose of the threshold test is to determine whether the grounds raise such a question. This panel must also decide whether there is enough substance to the issues raised such that a review based on those issues could result in the Board deciding that the decision should be varied, cancelled or suspended.

With respect to the question of the correctness of the decision, the Board agrees with the parties who argued that there must be an identifiable error in the decision and that a review is not an opportunity for a party to reargue the case.

In demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature. It is not enough to argue that conflicting evidence should have been interpreted differently.

The applicant must also be able to demonstrate that the alleged error is material and relevant to the outcome of the decision, and that if the error is corrected, the reviewing panel would change the outcome of the decision.

In the Board's view, a motion to review cannot succeed in varying the outcome of the decision if the moving party cannot satisfy these tests, and in that case, there would be no useful purpose in proceeding with the motion to review.

TAB iii

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2016-0105

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

Application for electricity distribution rates beginning May 1, 2017

BEFORE: Allison Duff
Presiding Member

Paul Pastirik
Member

September 21, 2017

TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY 1

2. THE PROCESS 2

3. DECISION ON THE UNSETTLED ISSUES 4

3.1 OM&A 4

3.2 CUSTOMER ENGAGEMENT 6

3.3 CAPITAL EXPENDITURES AND RATE BASE 7

3.4 COST OF CAPITAL 14

3.5 RENEWABLE GENERATION CONNECTION FUNDING ADDER 15

3.6 EFFECTIVE DATE 16

4 IMPLEMENTATION 18

5 ORDER 19

SCHEDULE A 21

1. INTRODUCTION AND SUMMARY

Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay Hydro) filed an application with the Ontario Energy Board (OEB) to change its electricity distribution rates effective May 1, 2017. Under section 78 of the Ontario Energy Board Act, 1998 (OEB Act), a distributor must apply to the OEB to change the rates it charges its customers.

Thunder Bay Hydro provides electricity distribution services to over 50,000 customers in the City of Thunder Bay and the Fort William First Nation.

Thunder Bay Hydro asked the OEB to approve its rates for five years using the Price-Cap Incentive rate-setting option. With this option, the approved 2017 rates are adjusted mechanistically each year for four years through a price cap adjustment based on inflation, industry productivity and the OEB's assessment of Thunder Bay Hydro's efficiency.

On April 27, 2017, Thunder Bay Hydro filed a partial settlement proposal with the OEB on behalf of the parties to the settlement. The OEB accepted the partial settlement proposal (see Schedule A attached) and held an oral hearing regarding the unsettled issues.

This Decision addresses the unsettled issues. The OEB approves Thunder Bay Hydro's proposed cost of capital of 4.67%, operating expenses of $15.210 million which is a reduction of $0.471 million from the proposed expenses and a capital budget of $11.526 million which is a reduction of $1.0 million from the proposed capital budget.

2. THE PROCESS

The OEB's policy for rate setting is set out in the "*Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach"* (RRFE, now referred to as the RRF). The RRF provides the distributor with performance-based rate application options that support the cost effective planning and efficient operation of a distribution network.

Thunder Bay Hydro filed an application on September 9, 2016 for 2017 rates under the Price-Cap Incentive rate-setting option of the RRF. The OEB issued a Notice of Application on November 9, 2016, inviting parties to apply for intervenor status. The Association of Major Power Consumers in Ontario (AMPCO), the School Energy Coalition (SEC) and the Vulnerable Energy Consumers Coalition (VECC) (collectively the intervenors) applied for, and were granted, intervenor status. OEB staff also participated in this proceeding.

On November 23, 2016, the OEB held a community meeting in the City of Thunder Bay. The OEB and Thunder Bay Hydro made presentations at the meeting, and there were two customer presentations at the meeting as well. A summary of the community meeting was added to the record of the proceeding. The comments during the community meeting focused on the costs of monthly billing, general concerns regarding affordability and rising electricity rates, as well as provincial energy policy. Specifically with respect to Thunder Bay Hydro, customers voiced concerns about the requested rate increase, citing increasingly unaffordable electricity bills.

The OEB issued Procedural Order No.1 on December 5, 2016. This order established, among other things, the timetable for a written interrogatory discovery process, the filing of a proposed issues list and a settlement conference.

A settlement conference was held from February 14, 2017 to February 16, 2017, which was attended by Thunder Bay and the intervenors. A partial settlement proposal was filed on April 27, 2017. OEB staff, which was not a party to the partial settlement proposal, filed a submission in support of it. The partial settlement proposal was approved by the OEB. The remaining unsettled issues were:

- Issues 1.1 and 2.1 Capital
- Issues 1.2 and 2.1 Operations, Maintenance & Administrative Expenses (OM&A)
- Issue 2.1 Cost of Capital

An oral hearing began on April 20, 2017, but was adjourned pending the filing of supplementary evidence by Thunder Bay Hydro related to the unsettled issues. After additional discovery on the supplementary evidence was completed, the oral hearing resumed on June 29, 2017 and June 30, 2017. All parties filed written submissions on the unsettled issues.

3. DECISION ON THE UNSETTLED ISSUES

3.1 OM&A

Background

Thunder Bay Hydro proposed an OM&A budget for 2017 of $15,680,655. A table with year over year OM&A comparisons follows.

Table 1: OM&A 2013 - 2017

Year	OM&A	$ Change	% Change
2013 OEB approved	$14,300,000		
2013 Actual	$13,232,884	($1,067,116)	(7.46%)
2014 Actual	$13,822,518	$589,634	4.46
2015 Actual	$14,244,004	$421,486	3.05
2016 Actual	$15,430,638	$1,186,634	8.33
2017 Proposed	$15,680,655	$250,017	1.62

OEB staff and intervenors argued for reductions from the original budget resulting in recommended OM&A levels ranging from $14.5[1] to $15 million[2], as compared to the proposed test year level of $15.681 million.

Findings

The OEB approves a 2017 OM&A budget of $15.210 million, a reduction of $0.471 million from Thunder Bay Hydro's proposed budget. The OEB makes this reduction after considering the actual 2016 OM&A costs net of one-time costs and the proposed 2017 OM&A increase.

The OEB assessed the reasonableness of the proposed 2017 OM&A expense using two methods:

[1] EB-2016-0105, School Energy Coalition July 13, 2017, p. 19
[2] EB-2016-0105, Ontario Energy Board Staff Submission, July 14, 2017, pp. 19-20

- Calculating the increase over the actual OM&A spend in 2016, net of one-time, non-recurring costs
- Applying an annual inflationary increase to the total OM&A spend in 2013 (adjusted for certain costs related to 2013) and adding other costs incremental to inflation

In this application, Thunder Bay Hydro requested an increase in OM&A costs of $0.250 million over its 2016 actual spend, an increase of 1.62%. While 1.62% seems reasonable as it is below the 2017 approved inflation rate of 1.9%, the OEB finds that the proposed budget must be considered in the context of the increase that occurred in 2016. From 2015 to 2016, OM&A costs increased by $1.186 million or 8.3%. The OEB finds 8.3% to be a significant increase in one year and worthy of further review.

In approving the 2017 budget, the OEB has first considered the one-time items that resulted in the significant increase in the 2016 OM&A. The OEB has determined from the evidence that the total of one-time costs that would not carry on into 2017 was approximately $0.471 million. These costs are outlined in the following table:

Table 2: OEB-Determined 2016 One-Time Costs

	$
Legal Costs related to load transfer	50,000
Renovations to operating centre	168,000
Supervisory Control and Data Acquisition (SCADA) training	40,000
Fire retardant clothing	116,000
Start of monthly billing process	65,000
Collective Bargaining costs	12,000
Electrical Safety Authority (ESA) public safety survey	20,000
Total	**471,000**

Accordingly, the OEB considers $14.960 million to be the appropriate 2016 cost base for costs that will recur in 2017. The OEB finds Thunder Bay Hydro's proposed 2017 OM&A increase of $0.250 million to be reasonable and approves a total 2017 OM&A budget of $15.210 million.

In approving the 2017 budget, the OEB has also assessed the total OM&A increase from 2013 to 2017. The OEB reviewed the total increase as a secondary check of the actual five year spend. In 2013, Thunder Bay Hydro proposed a budget of $14.7 million and the OEB approved $14.3 million, yet the actual spend was lower still at $13.2 million. The company explained that after the 2013 budget was prepared it needed to make some corrections and new information became available.

Starting from the actual spend in 2013 of $13.2 million, the OEB finds it appropriate to add certain costs related to 2013 given the explanations provided by Thunder Bay Hydro as shown in the following table:

Table 3: OEB Adjustments to 2013 Actual OM&A

	$
2013 Actual OM&A	13,232,884
Change in affiliate costs	175,000
Correction of supervisory classification costs	182,000
Pension evaluation costs	190,000
2013 OEB Adjusted OM&A amount	13,779,884

Applying an annual inflation rate of 1.9% from 2013 to 2017 to the 2013 OEB-adjusted OM&A amount of $13.780 million in Table 3, Thunder Bay Hydro's 2017 budget would approximate $14.857 million.

The OEB agrees with SEC's submission that two costs were incremental to inflation, which were the OEB fee assessment cost increase of $118,000 and the move to monthly billing of $221,000. Adding these two increases to the inflation-based estimate, the result is a total 2017 OM&A amount of $15.196 million. The OEB notes that this inflationary-based calculation approximates the OEB's approved 2017 budget of $15.210 million.

For these reasons, the OEB approves for rate-setting purposes an OM&A budget of $15.210 million for 2017.

3.2 Customer Engagement

"Customer feedback and preferences" were unsettled sub-issues under Capital and OM&A on the OEB-approved issues list for this proceeding. The topic of customer engagement was explored extensively during the oral hearing. Thunder Bay Hydro's witnesses provided oral testimony regarding the customer engagement process that included a customer survey and community meetings.

SEC submitted that Thunder Bay Hydro appears to have provided information to its customers in a manner that was misleading. As a result, SEC submitted that for the purpose of Thunder Bay Hydro's 2017 rate order only, the OEB should closely supervise the communications from Thunder Bay Hydro to its customers explaining the drivers and impacts of the 2017 rate increase.

TAB 7

TAB i

Ontario Energy Board

EB-2010-0379

Report of the Board

Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors

Issued on November 21, 2013 and as corrected on December 4, 2013

3 Benchmarking

The Board's regulatory oversight of electricity distributors is supported by benchmarking analysis. Since 2008 benchmarking, based on operations, maintenance and administration ("OM&A") cost data, has provided the basis for the annual assignment of stretch factors to distributors.

In its RRF Report, the Board concluded that benchmarking will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including total cost benchmarking for the 2014 rate year. Future work will involve comprehensive benchmarking (i.e., model(s) that combine standards for customer service, including distribution system reliability, and cost performance).

The Board has determined that PEG's econometric model will be used for benchmarking distributor cost performance and, as previously noted, for informing the Board's annual assignment of stretch factors to distributors. The Board may explore other methodologies (e.g., Data Envelopment Analysis) and other alternative approaches proposed in consultations to benchmarking performance in the future. The alternatives proposed are outlined in Appendix A.

PEG's model controls for the impact of various factors beyond management control on a distributor's total costs. These factors, determined by PEG's analysis to be statistically significant drivers of total costs, include:

- the number of customers served;
- kWh deliveries;
- system capacity peak demand;
- average circuit km of line; and
- share of customers served that were added over the last 10 years.

Furthermore, PEG's model employs a well-established estimation procedure, does not rely on peer grouping, and does not assume constant returns to scale.

This benchmarking model will be used to predict each distributor's total costs, and the distributor's actual total costs will be compared to the econometrically derived predicted value.

With respect to data issues, staff and stakeholders developed and proposed certain adjustments to the benchmarking data set to make distributors more comparable. Specifically, adjustments were proposed in relation to high voltage ("HV") equipment and low voltage ("LV") services. This work was carried out as planned subsequent to the issues identified at the end of the 3rd Generation IR consultations. Many stakeholders expressed concern over the proposed adjustments and asked the Board for an opportunity to refine them (i.e., the definitions of the proposed adjustments and/or the data) stating that further analysis is needed. VECC, Hydro One Networks Inc., and the Cornerstone Hydro Electric Concepts Association, made specific recommendations on what adjustments should be made. In its Draft Report, the Board directed staff to consult further with distributors on the LV and HV adjustments. The recommendations offered in written comment were to provide a basis for this consultation. Staff facilitated an industry workshop on October 7, 2013 to achieve stakeholder agreement on how to determine LV costs for each distributor that should be included in total cost benchmarking. Board staff enlisted the help of representatives with specific expertise from the industry to plan and lead the workshop. The Board accepts the resultant agreement that is posted on the Board's website and thanks workshop participants for their time and advice.

The Board acknowledges the concerns raised by some workshop participants that a host distributor's costs to own, operate, maintain and refurbish sub-transmission and LV facilities used by embedded distributors have not been fully reflected in the agreed upon LV adjustments. The LV workshop summary alludes to this issue vis-à-vis common sub-transmission line charges. Specifically, workshop participants advised that some of

these charges should be included, but since data is not available to help determine how much to include, participants agreed to exclude the charges completely. The Board notes that the broader issue of how to better estimate LV adjustments so that a host distributor's overall total costs are not overstated needs to be addressed in future benchmarking studies.

Unless otherwise determined by the Board, all distributors[21] will be included in the Board's total cost benchmarking analyses. The concern over outliers is restricted to the estimation of Industry TFP for the purpose of setting rates.

[21] Four distributors are excluded from PEG's analysis because their RRR data is not available: Attawapiskat First Nation; Fort Albany First Nation; Kashechewan First Nation; and Hydro One Remote Communities Inc.

TAB ii

PRODUCTIVITY AND BENCHMARKING RESEARCH IN SUPPORT OF INCENTIVE RATE SETTING IN ONTARIO:

FINAL REPORT TO THE ONTARIO ENERGY BOARD

November 2013

(Issued on November 21, 2013 and as corrected on December 19, 2013 and January 24, 2014)



Pacific Economics Group Research, LLC

trend, and therefore the rate adjustment mechanism, that will apply during an IR term. Doing so would mean increasing future customer rates to pay for costs that have already been recovered in previous customer rates.

Third, it is not clear that the negative 2002-2012 TFP trend is in fact industry-wide rather than the experience of a relatively small number of distributors. The RRFE will have multiple ratemaking options available to distributors. As previously noted, one of these options is designed to be "custom" to distributors with especially rapid capital investment needs. Although it is not clear which distributors will elect to file custom IR proposals, it is conceivable that distributors with historically high capital spending could depress industry-wide TFP trends, and thereby reduce the X factor in Price Cap IR, and later choose to opt out of this ratemaking approach precisely because of their atypical capital requirements. This would lead to higher price adjustments under Price Cap IR than are warranted for distributors with more typical capital requirements. Because of these concerns, PEG recommends that the productivity factor in Price Cap IR be set to zero.

Benchmarking

PEG developed an econometric model to benchmark distributors' total cost performance. PEG's recommended model finds that there is a statistically significant relationship between a distributor's total costs and five business condition variables: 1) the number of customers served; 2) kWh deliveries; 3) system peak capacity; 4) the average km of distribution over the sample period; and 5) the percent of customers added in the last 10 years.

PEG used the cost model to generate econometric evaluations of the cost performance of distributors by inserting values for each distributor's business condition variables into the cost model that is "fitted" with the estimated coefficients for the business condition variables. This process yields a value for the predicted (or expected) costs for each distributor in the sample given the exact business condition variables faced by that distributor. The model also generates confidence intervals around that cost prediction.

PEG believes that the empirical research used to develop its recommendations can provide a solid foundation for future incentive rate-setting in Ontario. PEG has estimated TFP trends and benchmarked the total costs of electricity distributors in Ontario. Our TFP

and benchmarking studies can be updated and refined over time to accommodate new data from the industry or consider different business condition variables, including measures of service reliability such as SAIDI and SAIFI. Overall, PEG believes the methodologies used strike a reasonable balance between rigor, objectivity and feasibility (given the data constraints), while simultaneously developing empirical techniques that can provide a foundation for effective IR applications for Ontario in the future.

Overview of this Report

This report is structured as follows. After this introduction, Chapter Two details the basic indexing logic that underpins the calibration of X factors. Chapter Three presents PEG's input price research, which is necessary to estimate industry TFP trends. Chapter Four discusses data sources and issues associated with available data. Chapter Five estimates historical TFP growth for the Ontario electricity distribution industry for the 2002-2012 period. Chapter Six presents PEG's econometric research on the cost performance of Ontario electricity distributors. Chapter Seven presents concluding remarks.

There are also two appendices. Appendix One presents a mathematical decomposition of TFP growth into its various components. Appendix Two presents some technical details of PEG's econometric modeling.