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.

<u>C. ARGUMENT</u>

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]

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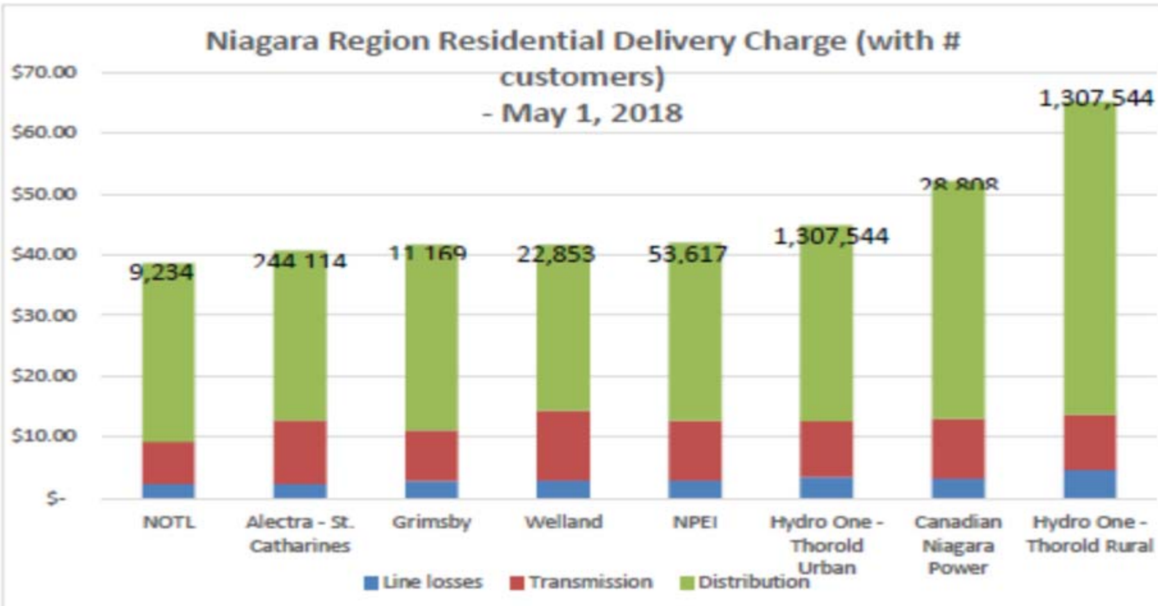
[1] Exhibit 4 – OM&A – Additional Evidence, page 2.
[2] Exhibit 1 – Administrative Documents, page 72.
[3] Scorecard - Niagara-on-the-Lake Hydro Inc, September 2018, filed in response to Staff Interrogatory #1, (Exhibit 1-Staff-4).
[4] Exhibit 1 – Administrative Documents – Appendix 1H – CGC Customer 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.

<u>Table 1 – Niagara Region Delivery Charges</u>



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.

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[8] Exhibit 1 – Administrative Documents, page 81.
[9] See NOTL Hydro 2019 Tariff Schedule and Bill Impact Model 20190111, tab 20.

a. <u>Issue 1.1 – Capital Expenditures – Underground Conversion Program</u>

27. As set out in the Settlement Proposal, most of NOTL Hydro's proposed capital expenditures for 2019 have been resolved (and now approved), along with most of the rate base impact of capital expenditures for the 2014 to 2018 incentive regulation (IR) term.[10]

28. The outstanding issue relates to the costs of NOTL Hydro's underground voltage conversion project/program, both in relation to amounts spent since the 2014 rebasing (impacting 2019 opening rate base) and to the proposed Test Year expenditures (impacting 2019 net additions and rate base).

29. NOTL Hydro submits that its underground voltage conversion program is appropriate and necessary, and that it is being implemented in a measured and reasonable manner. 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.

30. NOTL Hydro (then the Niagara-on-the-Lake Hydro Electric Commission) commenced its voltage conversion program in 1987. The plan was to convert, over many decades, the existing 4.16 kV system to a 27.6 kV system, because of the many benefits of a higher voltage system (including lower line losses, greater capacity and lower maintenance costs).[11]

31. It is relatively easy to convert rural areas to higher voltage because the required taller poles can be accommodated in areas with lots of space and minimal tree cover.[12] It is less easy to convert developed and established areas. In the case of NOTL Hydro, these areas tend to be big tourist draws as they are heritage areas (Olde Town, Queenston, Virgil), and as older areas they have developed extensive tree canopies. Installing the higher poles for the 27.6 kV lines would extensively damage this tree canopy and disturb the character of the areas. This would not be acceptable to NOTL residents.[13] Recognizing this, in 1989 the NOTL Hydro Electric Commission passed a by-law requiring that the voltage conversion in

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[10] Exhibit N1, Tab 1, Schedule 1, Settlement Proposal, January 10, 2019, at Items 1 and 2, pages 9 to 12.
[11] Exhibit 2 – Additional Evidence – Underground Voltage Conversion, page 2.
[12] *Ibid*.
[13] Exhibit 2 – Additional Evidence – Underground Voltage Conversion, pages 3 and 4.

these areas be by way of underground installations.[14] When NOTL Hydro was created in 2000, the bylaw was adopted as a policy of the new utility.[15]

32. The reasons why the NOTL Hydro Electric Commission required that the voltage conversion program use underground installation in heritage and urban areas continue to be relevant and important today. The Town is a tourist destination, and installing taller replacement poles could damage the tree canopy and character of the neighbourhoods.[16]

33. NOTL Hydro understands that its customers support the underground voltage conversion program.[17] The underground voltage conversion program was not raised as a concern at the October 19, 2018 Open House where the current rate application was presented. While customers did raise some questions about the undergrounding program at the 2018 customer engagement sessions, the overall conclusion was that customers support the approach being taken by NOTL Hydro. The conclusion in the Customer Engagement report from that session states as follows:

> *Most of the downtown of Niagara on the Lake now has underground lines, as does every new housing community. The plan Niagara on the Lake Hydro has put forward to finish the job in the downtown core was seen by customers as being a reasonable cost over the right number of years. Customers are aware of the community being a tourist destination and they are also concerned with reliability. The Niagara on the Lake Hydro plans for underground lines make the most sense to its customers.*[18]

34. In its 2014 cost of service rate application (EB-2013-0155), NOTL Hydro presented its plans for continuing its underground conversion program, and answered interrogatories from participants about the plan.[19] NOTL Hydro's proposed underground conversion program expenditures for the 2014 Test Year were accepted as part of the Board-approved Settlement Proposal in that proceeding.[20]

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[14] Exhibit 2 – Additional Evidence – Underground Voltage Conversion, pages 4 and 5, and Appendices A and B.
[15] Exhibit 2 – Additional Evidence – Underground Voltage Conversion, page 5 and Appendix C.
[16] Exhibit 2 – Additional Evidence – Underground Voltage Conversion, page 6.
[17] Response to Staff Supplementary Interrogatory #1 (Exhibit Supp-Staff-S1).
[18] Exhibit 1 – Administrative Documents – Appendix 1H – CGC Customer Engagement Report NOTL Hydro, May 2018, at page 33.
[19] See, for example, NOTL Hydro's response to Board Staff Interrogatory 5.1-Staff-12 and 1.1-VECC-2 in EB-2013-0155, found at http://www.rds.oeb.ca/HPECMWebDrawer/Record/424731/File/document and http://www.rds.oeb.ca/HPECMWebDrawer/Record/424736/File/document.
[20] EB-2013-0155, Settlement Proposal, filed March 22, 2014, at pages 24 and 25: this document can be found at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/430741/File/document.

35. The actual overall underground conversion program expenditures from 2014 to 2018 were lower than forecast in the EB-2013-0155 proceeding.[21] This is due to slower than expected progress, as well as a change in accounting policy (to IFRS) that resulted in less allocation of overhead costs.[22]

36. NOTL Hydro is not aware of reasons why the amounts spent on the underground conversion program from 2014 to 2018 would not be included in rate base. The expenditures were prudent, and were within the scale, scope and type reviewed and accepted in the EB-2013-0155 cost of service proceeding (for 2014 rates).

37. NOTL Hydro estimates that it has completed around two thirds of its underground voltage conversion program, and it aims to complete all the required work by 2034.[23] A map is included in the Additional Evidence showing areas of focus in the coming years.[24]

38. NOTL Hydro's planned capital expenditures in 2019 for underground capital work is $460,000. Of this amount, $215,000 relates to the ongoing underground conversion program, to continue to complete required work in the urban areas of NOTL Hydro's service territory. An additional amount ($125,000) relates to the "Virgil Project", which will see existing overhead lines along Hwy 55 through the downtown Virgil area converted to underground lines at the same time as the Niagara Region is widening Hwy 55 through the area. This is being done for safety and aesthetic reasons, as is typical in urban areas. The balance of the planned expenditure ($220,000) relates to general underground capital work that is not related to the voltage conversion program or the Virgil Project. This general underground work includes items such as moving distribution lines for reasons other than voltage conversion, replacing transformers and circuitry work.[25]

39. NOTL Hydro's proposed 2019 underground conversion program expenditures are reasonable and appropriate, as are the proposed expenditures for other underground capital work in the Test Year. The expenditures are consistent with (or lower than) the level from

[21] An explanation of the amounts forecast versus amounts spent for the underground conversion program is set out in response to VECC Supplementary Interrogatory 53 (Exhibit 2.0-VECC-53). The actual amounts spent are set out in response to Staff Supplementary Interrogatory #2d (Exhibit Supp-Staff-2d).
[22] See response to VECC Supplementary Interrogatory 53(b) and (c) (Exhibit 2.0-VECC-53).
[23] Exhibit 2 – Additional Evidence – Underground Voltage Conversion, page 8.
[24] Exhibit 2 – Additional Evidence – Underground Voltage Conversion, pages 7, Map 2.2.
[25] See response to Staff Supplementary Interrogatory #2d (Exhibit Supp-Staff-2d).

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.

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[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	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**

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**

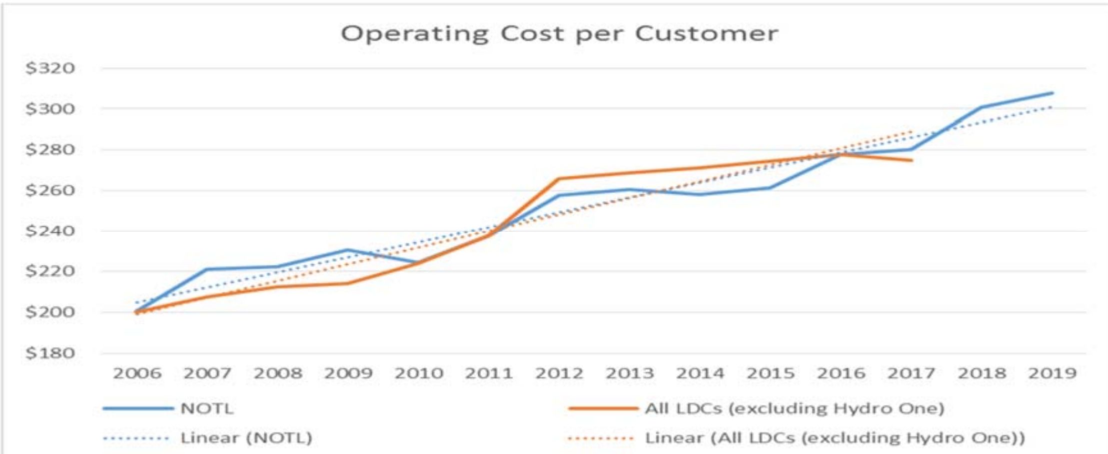
(v) NOTL Hydro's OM&A Cost per Customer is consistent with other distributors

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.

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[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.

Table 10 – NOTL Hydro 2019 Cost of Capital

Particulars	Updated Evidence Capitalization Ratio		Cost Rate	Return
Debt				
Long-term Debt	56.00%	$17,102,870	3.95%	$675,563
Short-term Debt	4.00%	$1,221,634	2.82%	$34,450
Total Debt	60.00%	$18,324,504	3.87%	$710,013
Equity				
Common Equity	40.00%	$12,216,336	8.98%	$1,097,027
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,216,336	8.98%	$1,097,027
Total	100.00%	$28,384,663	5.92%	$1,807,040

67. NOTL Hydro has a relatively low level of actual debt, in order to maintain financial flexibility into the future. This means that NOTL Hydro uses a deemed capital structure, including 56% long-term debt.[52] As can be seen in the Table 2 above, NOTL Hydro calculates its cost of long-term debt by applying the average cost rate of its actual long-term debt (Table 1) to the deemed level of long-term debt.

68. The interest rates/costs associated with each component of NOTL Hydro's actual long-term debt are reasonable and appropriate. The overall cost rate that applies (3.95%) is lower than the OEB's deemed rate for long-term debt (4.13%).

69. The third party loans from CIBC and Infrastructure Ontario were negotiated many years ago, and the associated costs (interest rates) have formed part of NOTL Hydro's cost of capital since before the 2014 to 2018 IR term. The costs (interest rates) associated with these loans represent market costs from the relevant times.[53]

70. NOTL Hydro's Additional Evidence explains the benefits of its loans from the Town, as compared to loans from a financial institution.[54] These loans do not include financial covenants and the loans are unsecured. These are important to NOTL Hydro as this means

[52] Exhibit 5 – Cost of Long-term Debt, pages 3, 4, 13 and 14.
[53] Exhibit 5– Cost of Long-term Debt, pages 10 to 12.
[54] Exhibit 5 – Additional Evidence – Cost of Long-term Debt, page 2.

its borrowing capacity with financial institutions is not affected. As a small company, NOTL Hydro believes it is very important to maintain this financing flexibility so that if new debt is needed, as will be the case in 2019 with the new transformer, it can be obtained on favourable terms.

71. The promissory note from the Town was established as part of the creation of NOTL Hydro in 2000. The promissory note was renewed in July 2008[55] and August 2018[56]. As of December 31, 2017, the principal balance remaining was $2,098,770. This is being repaid with monthly installments of $41,695.55. The interest rate associated with the promissory note is 7.25%.[57]

72. Consistent with the Board-approach used in NOTL Hydro's 2014 to 2018 IR term[58], for ratemaking purposes NOTL Hydro has notionally reduced the interest rate associated with the promissory note to the current OEB deemed long-term debt rate of 4.13%. This approach is consistent with the OEB's Report on the Cost of Capital for Ontario's Regulated Utilities, which indicates that the cost of existing affiliate debt that is not callable on demand will use the Board's deemed rate at the time the debt was issued as a proxy or a ceiling.[59]

73. NOTL Hydro's Additional Evidence explains that the Town has exercised its option to renegotiate the two existing demand loans.[60] The parties have agreed to a new interest rate of 3.5%, which is competitive with what would be offered by financial institutions.[61] NOTL Hydro's evidence is that the Town is expected to confirm the new arrangements at a council meeting on March 4, 2019, to be effective as March 1, 2019.[62]

74. NOTL Hydro's proposed treatment of the updated cost/interest rate associated with the two demand loans is consistent with the OEB's Report on the Cost of Capital for Ontario's

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[55] The promissory note is filed as Appendix 5A.
[56] See response to SEC Interrogatory #31 (Exhibit 5-SEC-31).
[57] Exhibit 5– Cost of Long-term Debt, page 10 and Exhibit 5 – Additional Evidence – Cost of Long-term Debt, page 2.
[58] EB-2013-0155, Settlement Proposal, filed March 22, 2014, pages 24 and 25: this document can be found at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/430741/File/document.
[59] EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, pages 51 to 54 and 59.
[60] Exhibit 5 – Additional Evidence – Cost of Long-term Debt, pages 2 and 3.
[61] Response to Supplementary Staff Interrogatory #5(Exhibit Supp-Staff-5) and response to SEC Supplementary Interrogatory #48 (Exhibit SEC-Supp-48).
[62] Response to Supplementary Staff Interrogatory #6 (Exhibit Supp-Staff-6) and response to SEC Supplementary Interrogatory #49 (Exhibit SEC-Supp-49).

Regulated Utilities. That Report indicates that for debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt (though it is clear that if the actual rate is lower, then the actual rate should be used).[63] In this instance, NOTL Hydro is valuing the two demand loans at their actual cost (3.5%), which is lower than the OEB's 2019 deemed rate for long-term debt.

d. <u>Issue 3.2 Cost Allocation: Inclusion of ICM Revenues in Existing Rates</u>

75. NOTL Hydro's filing calculated proposed 2019 rates by including Incremental Capital Module (ICM) revenue in distribution revenue at current rates in the cost allocation model.

76. NOTL Hydro believes this is an appropriate approach in the circumstances of this case. The ICM revenues relate to a new transformer asset. The costs for that asset will continue to be recovered from customers from 2019 and beyond. The only difference will be that from and after 2019, revenues associated with the ICM asset will be recovered through rates rather than through a rate rider.

77. NOTL Hydro submits that the ICM rate rider is different in character from other rate riders, which are intended to recover temporary or changing costs from ratepayers in addition to the costs being recovered through distribution rates. The ICM revenues recover costs for one or more assets which will become part of the cost base covered by distribution rates upon rebasing. It is appropriate and logical, therefore, for the ICM revenues to be treated as part of the pre-rebasing revenues for cost allocation purposes.

78. Set out below is a table filed by NOTL Hydro in response to a request from intervenors[64], setting out the impact of either including, or not including, ICM revenues in revenue at exiting rates for cost allocation purposes.

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[63] EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, page 54.
[64] Filed as IRR_SUPP_Impact of Including ICM.

Table 11 – Impact of Including/Not Including ICM Revenues in Revenues at Existing Rates

Niagara-on-the-Lake Hydro Inc.
Impact of Including ICM in Distribution Revenue at Current Rates

	Rates including ICM in Distribution Revenue at Current Rates (as filed in the Settlement Proposal)		Rates Excluding ICM from Distribution Revenue at Current Rates		Variance		Units (Variable Rate)	Estimated Consumption (includes losses)	Impact of Including ICM in Distribution Revenue at Current Rates[1]
	Fixed Rate	Variable Rate	Fixed Rate	Variable Rate	Fixed Rate	Variable Rate			
Residential	$ 30.47	$ -	$ 30.97	$ -	$ (0.50)	$ -	kWh	778	$ (0.50)
GS < 50	$ 39.41	$ 0.0133	$ 39.41	$ 0.0131	$ -	$ 0.0002	kWh	2,000	$ 0.40
GS > 50	$ 281.65	$ 2.6169	$ 281.65	$ 2.4248	$ -	$ 0.1921	kW	135	$ 25.93
Unmetered	$ 21.20	$ 0.0072	$ 21.20	$ 0.0080	$ -	$ (0.0008)	kWh	800	$ (0.64)
Street lights	$ 7.85	$ 7.3887	$ 7.85	$ 7.3887	$ -	$ -	kW	29	$ -
Large User	$ 2,829.49	$ 2.6169	$ 3,790.12	$ 2.4248	$ (960.63)	$ 0.1921	kW	5,000	$ (0.13)

1. Impact is before tax and does not include the 8% OREC rebate.

79. As can be seen, NOTL Hydro's proposal results in a monthly fixed distribution rate for residential customers that is $0.50 lower than would be the case where ICM revenue was considered in revenues at existing rates. The corresponding impact is that rates for GS>50kw customers will be higher. NOTL Hydro submits this approach is reasonable and appropriate, particularly in light of the fact that NOTL Hydro's rates for GS>50kw customers are among the lowest in Ontario.

e. <u>Issue 4.2 DVAs: Disposition period of Group 2 DVAs and LRAMVA</u>

80. As explained in NOTL Hydro's Additional Evidence on Exhibit 9, subsequent to the filing of its original evidence NOTL Hydro determined that there was an error in the spreadsheets supplied by the OEB used to calculate rate riders. After this was corrected, the impact of some rate riders went from being negligible, as communicated to customers at the rate application open house, to having a significant impact.[65]

81. NOTL Hydro reviewed the impact of these revised rate riders on overall customer bills and believes its customers would benefit from, and prefer, having the impact of the Group 2 deferral and variance accounts (Group 2 DVAs) and LRAM rate riders spread over two years rather than just one year.[66] This is consistent with the approach that has been employed in the past for accounts with relatively large balances, as was the case in 2016

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[65] Exhibit 9 – Additional Evidence – Deferral and Variance Accounts – Group 2 and LRAM Rate Riders, page 2.
[66] *Ibid*.

where the rate rider to recover global adjustment costs for non-RPP General Service > 50 kW customers was spread over two years.[67]

82. The proposed changes to the rate riders are summarized below, including the impact of the rate riders being collected over one and two years.[68]

Table 12 – Rate riders for Group 2 accounts and LRAMVA over 1 and 2 years

LRAM	Rate Rider 1 Year	Rate Rider 2 Years	Variance	LRAM 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
Street Lights	$ 26.3920	$ 13.1960	$ 13.1960	$ 382.68
Unmetered	$ -	$ -	$ -	$ -
Large User	$ -	$ -	$ -	$ -

Group 2	Rate Rider 1 Year	Rate Rider 2 Years	Variance	Group 2 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
Street 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

Group 2 & LRAM	Rate Rider 1 Year	Rate Rider 2 Years	Variance	Group 2 & LRAM Bill Impact
Residential	$ 1.22	$ 0.61	$ 0.61	$ 0.61
GS<50	$ 0.0021	$ 0.0010	$ 0.0011	$ 2.10
GS>50	$ 0.6790	$ 0.3395	$ 0.3395	$ 45.83
Street Lights	$ 26.7705	$ 13.3853	$ 13.3853	$ 388.17
Unmetered	$ 0.0011	$ 0.0005	$ 0.0006	$ 0.41
Large User	$ 0.4104	$ 0.2052	$ 0.2052	$ 1,026.00

[67] Exhibit 9 – Additional Evidence – Deferral and Variance Accounts – Group 2 and LRAM Rate Riders, page 2.
[68] Information taken from Exhibit 9 – Deferral & Variance Accounts – Additional Evidence – page 3. The updated DVA continuity schedule showing NOTL Hydro's proposed 2 year clearance was filed on February 13, 2019.

83. The impacts of the rate riders for the Group 2 DVAs and LRAMVA are significant in relation to the overall bill impacts in this case. As noted earlier, on an overall basis NOTL Hydro's application would increase residential customer bills by $1.27 per month (inclusive of the rate riders). If the Group 2 DVAs and LRAMVA are cleared over one year, that impact will increase by almost 50% ($.061 per month).

84. NOTL Hydro recognizes that spreading the collection period over two years will result in increased interest charges. NOTL Hydro estimates this to be around $5,000. For NOTL Hydro customers, this cost is offset by not having to make half the payment to NOTL Hydro for an extra year.[69]

f. <u>Issue 5.3 Transmission Gross Load Billing</u>

85. NOTL Hydro's proposal for Transmission Gross Load Billing is set out in the Exhibit 8 Rate Design Additional Evidence.

86. As described, NOTL Hydro has applied to have the Retail Transmission Rate – Line and Transformation Connection Service Rates 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 applied on a gross load billing basis consistent with the method charged for Line and Transformation Connection Services by the IESO. Without gross billing of Retail Transmission Rate - Line and Transformation Connection, NOTL Hydro's other customers will be subsidizing the gross load billing transmission costs for any future LDG customers.

87. Hydro One applies "gross load billing" for Line and Transformation Connection Services to NOTL Hydro. Currently, this charge is applied based on the generation from a >2 MW hydro generating plant located within the NOTL Hydro service territory. The generation plant operates under a SOP contract. The cost of this charge is allocated across all NOTL Hydro customers through the retail service transmission charges. In this case this is appropriate as all customers use and benefit from this generation that feeds directly into the NOTL Hydro grid.

[69] Exhibit 9 – Additional Evidence – Deferral and Variance Accounts – Group 2 and LRAM Rate Riders, page 3.

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.

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David Stevens
Aird & Berlis LLP
Counsel to NOTL Hydro