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

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Vulnerable Energy Consumers Coalition

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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.

2.0 Underground conversion program

Prior proceedings

2.1 VECC was a party in Niagara-on-the-Lake Hydro (NOTL) previous cost of service application EB-2013-0155. With the exception of relatively minor matters related to smart grid projects the Board approved in that case a complete settlement of the issues. At that time NOTL had outlined an ambitious program to replace existing overhead plant with underground conduit. At that time the nature and status of the undergrounding project was set out in a comprehensive response to an interrogatory by VECC. We think it important the Board consider that response in its entirety as reproduced below[1]:

i. *In 2012 and 2013, NOTL Hydro completed the installation of a major 600 amp feeder 'loop' through the Old Town area at a cost of approximately $400k in each of the two years. With this loop in place, we can now branch off with 200 amp distribution networks to complete the conversion of the Town. Our 5 year plan (2014-2018) is documented in the CDSP in this application. NOTL Hydro generally completes our overhead capital projects 'in-house' and we have determined that our crews can reasonably and efficiently complete approximately $600k/year.* ***The annual amount dedicated to the Old Town conversion project, which is predominantly contracted out, is approximately$400k.***

ii. *The first Old Town conversion project was completed in 1989 with a new 27.6 kV underground supply to a major hotel addition.* ***As our CDSP indicates, we are confident that the Old Town conversion and burial will be completed by 2022.***

iii. *A 500 MCM (600 amp) ring has recently been constructed in the Old Town that links the F2 and F4 feeders with a series of S&C PMH unit switches. The PMH units generally include 2-200 amp fused sections to allow looped distribution supply off the main feeder. The Old Town replacement plan involves the removal of overhead poles, primary and secondary wires and transformers with 2/0 AL (200 amp) 28 kV primary cable, 3/0 AL secondary cable and padmounted transformers. As a majority of Old town customers are already supplied from an underground secondary cable, the conversion project is simplified. Those customers that are not currently supplied with underground cable are offered secondary cabling to their meter base at no charge, during construction only, providing they convert their meter base to accept the underground supply. This is cost beneficial to both the customer and NOTL Hydro as it avoids the need for the installation of a new service pole at their property line.*

iv. ***The Town of NOTL has not contributed to the Old Town underground conversion project (except on an individual customer basis). Since 1989, our predecessor, Niagara-on-the-Lake Hydro Commission and NOTL Hydro have been burying facilities in the Old Town because we believe it benefits our entire community and is the right thing to do****. The historical significance of the Old Town is a key factor in attracting approximately 1 million tourists annually. Would Williamsburg Virginia continue to preserve the Colonial period and be the successful tourist draw if poles and wires donned its main streets?* ***Niagara-on-the-Lake continues to boast the lowest tax mill rate in the Niagara Region, primarily due to tourism revenues. We are proud of our accomplishments to date as completed sections reflect the early 1800's ambiance without overhead poles and wires. Our policy for converting existing overhead customers to an underground supply is outlined in our Conditions of Service sections 3.1.2.1 and 3.2.2.1. In summary, new customers or those upgrading their existing service in designated underground areas are required to accept an underground supply and pay for the additional costs over and above the Basic Service provided.***

[1] Niagara-on-the-Lake Inc. EB-2013-0155, Response to VECC Interrogatories 1.1-VECC-2, February 7, 2014.

To encourage customers to move to an underground supply during our renewal construction projects in designated areas, we offer to install an underground supply cable to the customer's meter base at no cost (during the construction phase only) providing that the customer convert their meter base to accept an underground supply. We justify this expense as we can avoid re-installing a service pole at the customer's property line to maintain the existing overhead service.
(Emphasis added)

2.2 Based on that response and other evidence provided in the prior cost of service proceeding VECC was able to settle the matters of how this expensive capital program would impact future rates. The basis of that resolution was twofold: the first was that the Utility was compelled by the municipality to do the underground work; the second element was an understanding that the work was well defined and would be substantially completed by the time of the next cost of service application, or now. We were wrong on both accounts.

2.3 In this application NOTL explains that the Old (or sometimes referred to as Olde)Town existing 4 kV is being converted to 27.6 kV on a block by block basis and installed underground. The Utility stated in this application that: "***A Town bylaw prohibits the installation of new overhead plant as a means of preserving the heritage nature of the Olde Town***.[2] This statement confirmed VECC understanding from the previous proceeding. However it is untrue and the NOTL has since resiled from that position. Upon enquiry NOTL explained that [T]*he reference to a Town by-law dates back to the 2009 and 2013 Cost of Service applications. However, upon inquiry NOTL Hydro has not been able to ascertain the existence of the actual by-law. NOTL Hydro suspects this may be the local equivalent of an urban myth*."[3] Urban myth indeed.

2.4 At the invitation of VECC NOTL was offered an opportunity to clarify its evidence. I doing so what is revealed is not a Town bylaw. What in fact authorizes the expansive and expensive underground conversion program is an old NOTL Hydro-Electric Commission by-law. These by-laws were the prior form of "direction from the board of directors" when municipal electricity utilities were departments of city governments. Under the 1998 *Electricity Act* local distribution utilities became separate corporate entity with their own independent board of director governance. Since 1998 many utilities have merged or reorganized such that the municipal boundaries and the utility service boundary may no longer match. As it stands today it is our understanding that a municipality does not have the authority, except in very limited circumstances, to order an electricity distribution utility to replace above overhead plant with underground plant or in fact direct any investment of the utility.

[2] EB-2018-0056, Exhibit B, Appendix B, Consolidated Distribution System Plan (DSP) pg. 38 of 63
[3] 2.0-VECC-7

Cost of converting to underground service

2.5 Also conveyed to the Board in the prior cost of service application was that the amount dedicated to the Old Town conversion program would be in the order of be $400k per year over a five year period. The entire project was to be completed by 2022. No explanation is given in this application as to why the date for completion of this project is now **2034**.[4]

2.6 NOTL did not spend the forecasted $400k per year on the program. It spent something less. How much less is not exactly clear. In its DSP NOTL provides the following amounts as being spent on the program:[5]

Table 22: Underground Voltage Projects (2014-2017)

Description of Project	Street range	Year	Capex
Old Town Rebuild Phase 3	Johnson St, Simcoe to Dorchester	2014	$ 332,974
Old Town Rebuild Phase 4	Johnson St, Dorchester to Palatine	2015	$ 186,316
Old Town Rebuild Phase 5	Niagara Blvd, Lansdowne and Orchard	2016	$ 462,077
Old Town Rebuild Phase 6 part 1	Gage, Simcoe to Dorchester	2017	$ 256,601
Old Town Rebuild Phase 6 part 2	Johnson, Palatine to Nassau	2018	$ 275,000

(Emphasis in original)

But in response to a supplementary (post ADR) interrogatory a different amount was suggested which is shown below[6].

Year	EB-2013-0155 Forecast Spend	EB-2013-0155 Planned Area	Actual Area	Actual Spend
2014	$330,000	Johnson – Simcoe to Dorchester	Simcoe - Centre to Prideaux	$252,568
2015	$385,000	Johnson – Dorchester to Palatine	Anne – Mississauga to Victoria	$125,460
2016	$400,000	Niagara Blvd – Orchard to Lansdowne	Niagara Blvd and Orchard – Lansdowne to Palatine	$313,635
2017	$400,000	Gage – Simcoe to Dorchester; Dorchester – Gage to Centre	Niagara Blvd and Orchard – Lansdowne to Palatine	$60,794
2018	$400,000	Centre – Simcoe to Dorchester	Johnson – Palatine to Nassau	$162,078

2.7 Either way the amount spent is less than was contemplated under the prior distribution plan reviewed by the Board.

[4] ibid
[5] Ibid
[6] 2.0-VECC-53 Supplementary

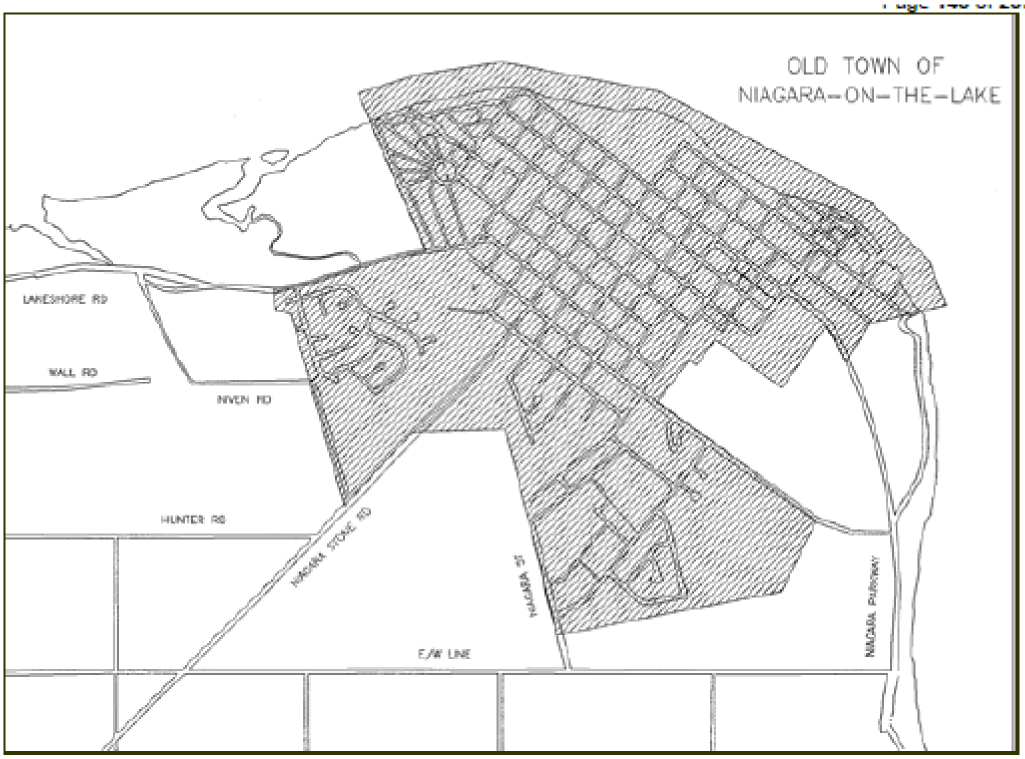
How much conversion is required?

2.8 Over the next 5 years the Utility is once again forecasting an annual spend in the range of $400k per years as set out below[7]:

Table 30: Underground Voltage Projects (2019-2023)

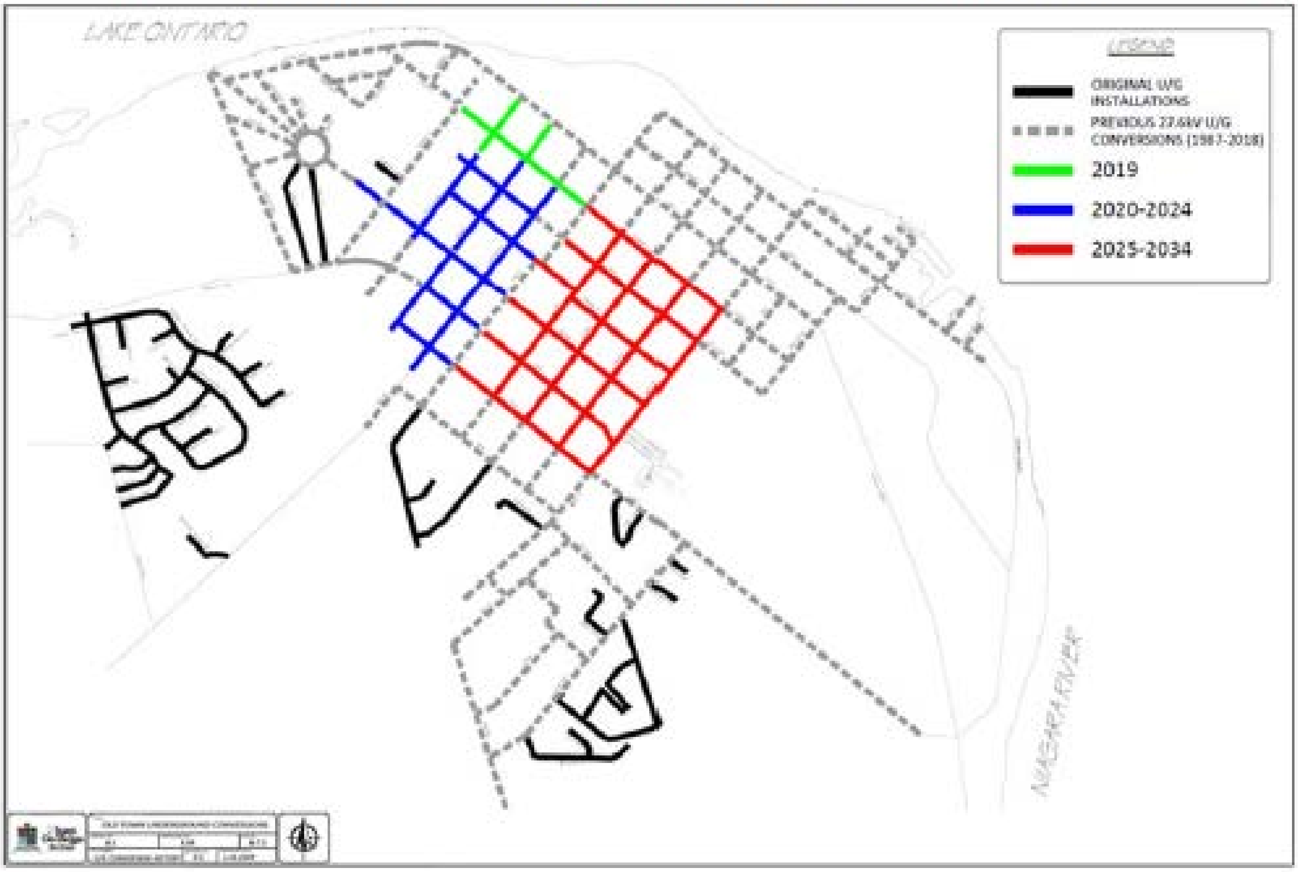
Description of Project	Street range	Year	Capex
Old Town Rebuild Phase 7	F1 Old King 4 kV	2019	$ 335,000
Niagara Stone Road, Road widening	Creek Road to Penner	2020	$ 300,000
Old Town Rebuild Phase 8	F1 Old King 4 kV	2020	$ 425,000
Old Town Rebuild Phase 9	F1 Old King 4 kV	2021	$ 425,000
Old Town Rebuild Phase 10	F1 Old King 4 kV	2022	$ 425,000
Old Town Rebuild Phase 11	F1 Old King 4 kV	2023	$ 434,000

2.9 Since the project is now project to not be completed until 2034 the question unanswered is how much above ground is being replaced and at what total cost? As shown by the map below the Old Town is significantly larger than the main tourist area of Niagara-on-the-Lake. The maps below show both the Old Town area and the current timeline for conversion of this area to underground service.[8]



[7] Exhibit 2,Appendix 2B, Consolidated Distribution Plan August 2018, pg.55 of 63
[8] 2.0-VECC-7

Map 2.2 Past and Future Underground Voltage Conversion in NOTL Olde Town



2.10 We note that while both of these maps are largely coincidental with the Historic Old Town Heritage Conservation District Plan of 2016. However we also note that Historic Plan makes no mention of a requirement (or desirability) to bury electricity plant[9].

2.11 However, the Old Town is not, as we understand it, the full extent of the underground project. An examination of the Utility's Condition of Service shows that there are a number of areas in which this program is being implemented. NOTL has various provisions in its existing and proposed Conditions of Service with respect of the incremental costs of connecting underground service.[10] Under section 3 of the Conditions of Service customers in areas designated for underground must pay for the incremental cost of underground connections. According to the Conditions of Service[11]:

Customers in designated U/G areas that make application for a new service Connection will be required to install U/G service cable. Similarly, Customers that make application to upgrade or alter

[9] See 2.0-VECC-51, Appendix 1

[10] As per Exhibit 1, page 15 see http://www.notlhydro.com/wp-content/uploads/2017/09/ConditionsOfService.pdf

[11] Ibid, Proposed Conditions of Service. Pg. 36 and Appendix 4

existing O/H service Connections are required to convert to an U/G cable Connection. ***NOTL Hydro will typically install and maintain service conductors for the standard service. The Customer will be required to pay 100% of the actual cost for the U/G service less the standard allowance for an O/H service****.*

That is, residential (and other classes) are required to pay any incremental costs for underground versus over ground connection

2.12 A It is important to note that only one of those areas – designated “Niagara Urban Area” is with respect to the Old Town. Three other areas: Virgil Downtown, Niagara Parkway, and the Queenston Urban Area are in separate parts of the service territory. It is unclear to us whether these areas are subject to underground conversion. If not it is perplexing why there are set out in separate appendixes of the Utility’s conditions of service. We invite the Utility to clarify this point in its reply argument as it appears to us that the question is not what utility plant is planned to be buried, but rather what part of NOTL’s service territory <u>is not part</u> of this project.

2.13 Finally, it is important to put into perspective the cost of this program to the total capital expenditure budget of the Utility. As shown in Appendix 2-AB NOTL is proposing a significant increase in capital spending over the next five years as compared to the last. The relative increase in the capital expenditure budget can be assessed from the abridged Table Appendix 2-AB shown below.[12] At $400-500k per annum the underground conversion makes up a substantial portion of the Utility’s annual capital budget.

											Forecast Period (planned)				
	2014		2015		2016		2017		2018		2019	2020	2021	2022	2023
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual					
	$ '000		$ '000		$ '000		$ '000		$ '000		$ '000				
System Access	100	955	100	983	100	1,830	100	550	100	2,604	836	851	842	854	873
System Renewal	970	874	4,030	542	1,030	710	935	692	1,030	1,474	1,097	1,160	935	935	969
System Service	95	40	55	2,658	55	229	55	207	55	125	3,832	98	100	130	106
General Plant	120	113	65	66	65	107	160	155	65	499	84	72	149	134	535
TOTAL EXPENDITURE	**1,285**	**1,982**	**4,250**	**4,250**	**1,250**	**2,876**	**1,250**	**1,603**	**1,250**	**4,701**	**5,849**	**2,181**	**2,027**	**2,053**	**2,483**
Capital Contributions	0	-708	0	-601	0	-1,603	0	-320	0	-1,984	-787	-656	-667	-679	-694
Net Capital Expenditures	**1,285**	**1,274**	**4,250**	**3,649**	**1,250**	**1,273**	**1,250**	**1,283**	**1,250**	**2,717**	**5,061**	**1,524**	**1,359**	**1,374**	**1,789**
System O&M	948	904	963	1,000	979	1,131	994	1,089	1,010	1,152	1,161	1,179	1,197	1,214	1,233

[12] This table is an abridged form of Table 2.32 at Exhibit 2, page 45. In order to fit page size we have removed the variance columns from the original.

Customer Engagement

2.14 NOTL has made much of its customer engagement. Yet none of that engagement examines the issue of underground policy/plan. This in spite of the fact that is unusual to replace above overhead with underground plant. Niagara-on-the-Lake is not in the midst of a new development where the developer is required by a municipal plan to put its plant below ground. Only a small part of the town has “historic” features (or tourist traffic) and the overhead system has existed for the better part of 75 years. As far as we can see there were no specific questions in the customer engagement on the conversion program. If there were there are no comparative costs or reliability analysis from which a ratepayer might make an informed opinion. In fact the Utility itself does not appear to understand the cost (or future year cost consequences) of this policy.

2.15 The Ontario Energy Board has gone to great lengths to encourage utilities to engage with their customers. Customer engagement evidence is a standard filing requirement in cost of service applications. At times we have been skeptical of the meaningfulness of these customer surveys. Often they seem to be nothing other than expensive exercises in managing customer expectations or in selling customers on the utility’s points of view. This is a glaring example such as case. In our view the Board risks raising customer cynicism rather than confidence if it allows a utility to avoid real engagement on an important issue which has material cost consequences and for which there are real options and tradeoffs for customers to consider.

2.16 In place of real engagement NOTL has offered up platitudes which speak – not to electricity service – but to the economic welfare of the community. On the face of it such arguments can seem compelling. The problem is that they presuppose the interests of the Town are coincidental with the interest of the electricity ratepayers. It appears to us that both the management of the this Utility and its Board of Directors is conflating the interests of its ratepayers with the interest of the Town of Niagara-on-the-Lake.

2.17 It may be true that the business interests that benefit from the tourism industry are content to pay the incremental costs of Utility to bury distribution plant. Even though, we might add, there is no clear evidence that this will improve tourism or reliability of the system. And if such evidence did exist it is also not clear that all the ratepayers of NOTL would prefer to see enhanced tourism in an already crowded summer town. But the Utility is not a tool of the Town’s or the community’s economic interest. It is in the business of delivering electricity safely and reliably at the most reasonable price. If the Town or its business interest wish to enhance those interests through conversion of the overhead system they can do so if they contribute to the incremental costs of that program.

2.18 The customers VECC tries to represents are much more likely to work in the hotels of Niagara-on-the-Lake than own them. They are much more likely to live in the outlining community and not be beneficiaries of this program. If there is an objective of enhancing the aesthetics of the Town then the Town should pay for that. Yet no contributions are forthcoming from that source.

2.19 It is widely accepted that underground plant is substantially more expensive to both to install and to maintain. And it is uncommon to see extensive underground plant except in three circumstances – replacement in crowded urban areas (e.g. downtown Toronto) or where in the case of new green field development under the authority of the *Planning Act* the original electricity plant is mandated to be installed underground. The third circumstance encountered, as it has recently in the Alectra Utilities ICM application, is where the plant is mandated to be moved to a particular location by the road authority under the auspices of the *Public Service Works on Highwa*y Act ("PSHA)[13].

2.20 It is very unusual, and we would suggest, for the Board to approve other cases. Where it does the proponent utility will provide extensive evidence supporting the change in type of plant. In these cases the applicable legislation contemplates a sharing of the costs of moving or changing plant.

Conclusions

2.21 So what is there to do about all of this? Arguably the Board might disallow portions of the underground plant proposed to be put into the rate base. It could do so based on the simple construct that it was misled in the past as to both the authority and the breadth of this program. In response NOTL might suggest it has undergone significant reorganization of its management since the lost cost of service since there appears to be some "confusion" as to what has been said in the past and what is to be done going forward with respect to this policy. However we believe the Board should not accept excuse of management or get itself involved in the politic as between the Utility and its municipal owner. Simply put the Board is not in the business of enhancing the tourist attractiveness of Niagara-on-the-Lake.

2.22 NOTL is now well engaged into a policy to replace less expensive overhead plant with much more expensive underground. How much more expensive we don't know because they have never done a comprehensive plan to understand the costs. The Board could, if it is swayed by our arguments put a hold on the whole matter. It could, in addition to consider disallowance of some portion of the existing underground plant and remove costs from the calculation of rate base as they are related to underground conversion program.

2.23 Or it could take a less severe approach. It could require the Utility develop a comprehensive plan for its next cost of service application. It could require that that plan be properly stakeholdered. It could in the interim allow the Utility to continue with its conversion but only in the old town area.

2.24 If the Board were to choose this path it could, in our submission, compensate ratepayers for the higher costs incurred to date and continuing being incurred under the existing capital program through an adjustment to the OM&A budget. In doing so it would consider the extra

[13] See for example Alectra Utilities Corporation EB-2018-0016 - Exhibit 1, Tab 1, Schedule 1, page 8

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]:

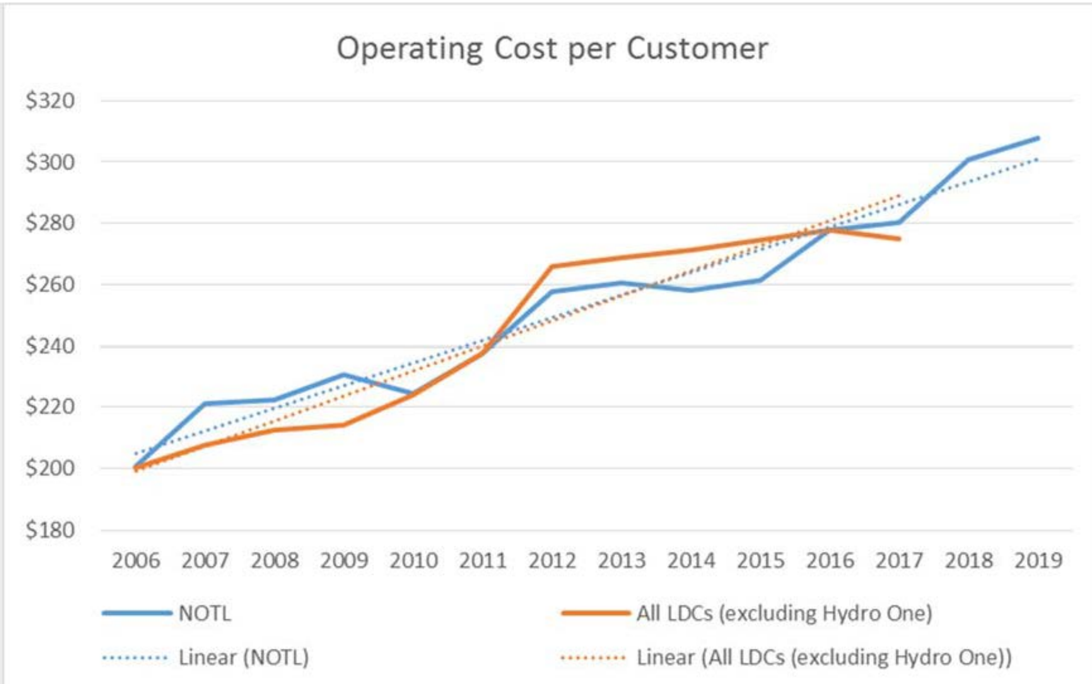
Table 4.6: Breakdown of Increase in OM&A (2014-2019)

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)

4. Cost of Long-term Debt

4.1 Subsequent to the settlement conference negotiations NOTL sought to update is proposal for the cost of long-term debt for 2019. The updated post settlement conference proposed 3.95% calculation is shown below[20].

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**

4.2 This compares to the original filing proposal for a long-term debt rate of 3.71% as shown below[21].

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note	Calculated Interest ($) (Note 1)	Actual Interest
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.16%	$ 87,308.82	$ 140,354.6
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-	15	$ -	6.03%	$ -	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81	$ 18,898.02
Infrastructure Ontario Loan	Infrastructure	Third-Party	Fixed Rate	15-Feb-	15	$ 716,667	4.27%	$ 30,601.68	$ 28,551.00
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.00%	$ 58,641.19	$ 54,628.35
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.00%	$ 42,912.05	$ 40,289.76
						$ 6,624,865	3.71%	$ 245,474.5	$ 282,721.8

4.3 The two loans which have changed from 3.0% to 3.5% are with the affiliate Town of Niagara-on-the-Lake. The difference in interest costs is about $23.5k

4.4 As we have observed in our discussion on the underground plant conversion there appears to be less than arms-length relationship between the Utility and its affiliate and owner the Town of Niagara-on-the-Lake. And while it is hard not to applaud the fact that the affiliated debt is not, as is often the case in these circumstances, simply the Board's deemed affiliate rate (4.13%) we remain concerned. There is no apparent reason for the change in debt rates from 3.00% to 3.50% and the timing of the change is worrisome.

[20] Exhibit 5, page 9, August 2018
[21] Exhibit 5 – Additional Evidence, page 3 January 2019

4.5 Our first point is that according to the updated evidence that while there is intent to raise the interest rate on the debts instruments no documentation to that affect has been offered. Second we note that the verbal discussions around the increase in the debt rate was on December 19, 2018.[22] Coincidentally the settlement conference was competed the week of December 10th.

4.6 No evidence has been provided which substantiates the increase costs in this non-arm's length transaction. While the proposed rates are still below the Board's (in our view rather high) affiliated debt ceiling we believe the Board should not make the proposed adjustment until signed loan agreements are proffered.

4.7 It is important, in our view in considering this issue, it is important to keep in perspective that under the current rates and the existing long-term debt rates NOTL has maintained healthy returns[23] to its affiliate.

	2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Forecast
Actual ROE	10.85%	8.90%	7.44%	9.81%	9.99%

5.0 Allocation of revenues related to Incremental Capital Modules (ICM)

Background

5.1 The purpose of the Board's Cost Allocation Model ("CAM") is to help determine whether or not each customer class is paying its fair share of a distributor's overall revenue requirement. To do so the CAM allocates the revenue requirement (i.e., the cost to provide service) to each of the customer classes using methodologies established by the Board[24]. These costs are then compared with the revenues received from each customer class by calculating a revenue to cost ratio ("RCR").

5.2 The Board has established RCR ranges for each customer class (around 100%) within which the class is viewed as paying its fair share of costs[25]. In instances where a class' RCR falls outside the range it is the Board's policy to have the RCR for class adjusted in order that it be within the policy range. It should be noted that this adjustment is often done over more than one year in order to address concerns regarding year over year bill impacts.

[22] The Applicant did not provide the actual email but rather an extraction and the date of sending.
[23] 5-SEC-32
[24] RP-2005-0317; EB-2007-0067; EB-2010-0219 and EB-2012-0383
[25] Filing Requirements For Electricity Distribution Rate Applications for 2019 Rate Applications, Chapter 2, page 48

It should also be noted that, since rates overall must recover the total approved revenue requirement, adjusting the RCR for one customer class will necessitate adjusting the RCR values for other customer classes in order to maintain revenue neutrality.

5.3 The customer class revenues to be used in the determination of the RCRs are based on the revenues for the test period using currently approved distribution rates. The revenues at current rates for each class are then adjusted by a common percentage in order to ensure that revenues and the revenue requirement balance overall. This percentage is referred as the “D-factor” and effectively produces the revenue that would be received from each customer class assuming the rates for all classes were adjusted by the same percentage in order to recover the approved revenue requirement. In the case of NOTL this factor is 1.01 based on NOTL’s proposal as set out in the results of the CAM filed[26] in conjunction with the Settlement Agreement. A copy of the relevant portion of the CAM is set out below.

		1	2	3	6	7	9
	Total	Residential	GS <50	GS >50kW	Large User	Street Light	Unmetered Scattered Load
Distribution Revenue at Existing Rates	$5,493,786	$2,923,268	$1,178,755	$977,428	$124,034	$281,952	$8,350
Miscellaneous Revenue (mi)	$482,447	$304,688	$86,399	$63,359	$10,309	$16,937	$756
	Miscellaneous Revenue Input equals Output						
Total Revenue at Existing Rates	**$5,976,234**	**$3,227,956**	**$1,265,154**	**$1,040,787**	**$134,343**	**$298,889**	**$9,106**
Factor required to recover deficiency (1 + D)	1.0100						
Distribution Revenue at Status Quo Rates	$5,548,687	$2,952,482	$1,190,535	$987,196	$125,273	$284,769	$8,433
Miscellaneous Revenue (mi)	$482,447	$304,688	$86,399	$63,359	$10,309	$16,937	$756
Total Revenue at Status Quo Rates	**$6,031,135**	**$3,257,170**	**$1,276,933**	**$1,050,555**	**$135,582**	**$301,706**	**$9,189**

Unsettled Issue

5.4 The unsettled issues arises from the fact that in its determination of revenue at current rates for purposes of the CAM NOTL has included not only the revenues from the approved 2018 base distribution rates[27] but also the revenues from the Incremental Capital Module (“ICM”) rate rider approved by the OEB in EB-2014-0097 to recover the cost of a new transformer at NOTL’s transformation station. This approach differs from what has typically been used by utilities that had an approved ICM rate rider at the time of rebasing. At the time of rebasing all of the following utilities used their base distribution rates (excluding the ICM rate rider) to determine revenue at current (existing) rates in their CAM:

- Kingston (EB-2015-0083)
- Centre Wellington (EB-2012-0113)
- InnPower (EB-2016-0085)
- Festival (EB-2014-0073)
- Power Stream (EB-2016-0003)
- Toronto Hydro (EB-2014-0116)
- Wellington North (EB-2015-0110)
- Oakville (EB-2013-0159)

[26] Update version filed February 11, 2019
[27] That is the approved monthly service charge and volumetric distribution rate for each class

5.5 In all of the cases cited above the ICM rate riders were established by allocating the revenues attributable to the ICM based on the current distribution revenues by class[28], consistent with the Board's ICM Rate Generator Model[29]. This is essentially the same approach as used by the CAM to establish the "D-factor". As a result, the inclusion or exclusion of the ICM rate rider in the determination of revenues at existing rates would have had little to no impact on the determination of each customer class' revenues at status quo rates as calculated in the CAM.

5.6 However, in NOTL's circumstance a different allocator was used to establish customer class responsibility of the ICM revenue requirement. In its IRM Application (EB-2014-0097) NOTL had proposed and the Board accepted that the Transformation Coincident Peak 4 (TCP4) allocator from the cost allocation study filed in NOTL's last cost of service application (EB-2013-0155) should be used to allocate the incremental revenue requirement associated with the ICM to customer classes. This resulted in a different revenue allocation than if the ICM revenues were allocated to customer classes in proportion to each class' revenues at existing rates.

5.7 The result is that, for purposes of the current Application, treating ICM rate riders as part of the existing currently approved rates for NOTL results in different allocation of the revenues at status quo rates to customer classes than if the revenues at current rates had been establish using just the base distribution rates. The difference can be seen from the following table[30] which reflects the results of an alternative CAM where revenues at existing rates do not include the revenues from the ICM rate rider which leads to a different "D-factor".

			1	2	3	6	7	9
Rate Base Assets		Total	Residential	GS <50	GS >50kW	Large User	Street Light	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$5,296,856	$2,871,539	$1,128,516	$903,489	$103,136	$281,952	$8,224
mi	Miscellaneous Revenue (mi)	$482,447	$304,688	$86,399	$63,359	$10,309	$16,937	$756
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	**$5,779,304**	**$3,176,227**	**$1,214,915**	**$966,848**	**$113,445**	**$298,889**	**$8,980**
	Factor required to recover deficiency (1 + D)	1.0475						
	Distribution Revenue at Status Quo Rates	$5,548,687	$3,008,062	$1,182,170	$946,444	$108,039	$295,357	$8,615
	Miscellaneous Revenue (mi)	$482,447	$304,688	$86,399	$63,359	$10,309	$16,937	$756
	Total Revenue at Status Quo Rates	**$6,031,135**	**$3,312,750**	**$1,268,568**	**$1,009,804**	**$118,348**	**$312,294**	**$9,371**

5.8 For those customer classes whose proposed RCRs are set based on a percentage of allocated costs (i.e., Large Use and Street Lighting) this difference in revenues will not

[28] This can be confirm by reviewing the OEB Decision that established the ICM rate riders EB-2014-0086 (InnPower); EB-2011-0178 (Kingston); EB-2011-0124 (Festival); EB-2011-0160 (Centre Wellington); EB-2013-0166 (Power Steam); EB-2012-0064 (THESL); EB-2012-0178 (Wellington North) and EB-2010-0104 (Oakville).

[29] Most recent model (Version 4) posted October 3, 2018

[30] Based on the CAM (Excluding ICM) filed February 7, 2019 in response to SEC's additional questions

affect final revenue requirement used to set their 2019 distribution rates. However, for the remaining customer classes it will have an impact on their final revenue requirements.

5.9 While the impact may be minor in NOTL's current circumstance, VECC submits that there is broader policy issue that needs to be addressed. Similar situations are likely to arise in the future and there is no precedent for situations such as that faced by NOTL where a different allocation of the ICM-related revenue requirement was approved by the Board than the default approach in the Board's ICM Rate Generator Model.

5.10 In VECC's view the approach adopted by NOTL is appropriate and should be accepted by the Board for two reasons. The ICM is a mechanism that the Board has introduced to address extraordinary capital spending requirements of distributors that arise during the IRM rate setting period. In order for the associated incremental revenue requirements to be accepted by the Board, the requested ICM claim must be incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates and satisfy the eligibility criteria of materiality, need and prudence. These criteria are similar to those that would be used by the Board, when considering similar capital expenditures in a cost of service based rate application. As a result, once approved, the ICM-related revenue requirement should be considered to be part of a distributor's overall revenue requirement and the revenues generated by the rider should be treated as such for purposes of the CAM.

5.11 Second, the revenues at status quo rates are meant to reflect the situation that would occur if all customer classes receive the same percentage rate increase. Since customers are currently paying the ICM rate rider as part of the "cost" of their distribution service it is logical that the revenues included.

6.0 Disposition of Group 2 Deferral and Variance Accounts

6.1 The Board's Chapter 2 Filing Requirements state that the default disposition period for recovery or refund of DVA balances is one year; if the applicant is proposing an alternative recovery period, an explanation must be provided". In its original Application[31], NOTL proposed a one-year disposition period for all the deferral and variance accounts that it was proposing to clear.

6.2 However, during the interrogatory process the associated rate rider calculations were corrected and updated, such that the rate riders increased materially[32]. In its Update Evidence, NOTL is now proposing to spread the recovery of the balances in the Group 2 and LRAM accounts over two years[33]. NOTL's rationale for doing so it that it "believes its customers would benefit from, and prefer, having the impact of the Group 2 and LRAM rate riders spread over two years rather than just one year". NOTL also notes that "both the Group 2 accounts and the LRAM are 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". [34]

6.3 Typically distribution utilities request to extend the recovery period their DVAs as part of a bill impact mitigation plan to address total bill increases that exceed 10%. In NOTL's case the total bill impacts resulting from its proposal range from -7.1% to 4.6% as shown below[35].

Table 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 1.54	5.3%	$ 1.53	4.8%	$ 1.21	3.1%	$ 1.27	1.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 4.20	6.7%	$ 4.10	5.9%	$ 3.26	3.8%	$ 3.42	1.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 92.50	16.5%	$ 161.87	41.0%	$ 142.95	17.3%	$ 157.47	2.0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 1.20	4.7%	$ 0.04	0.1%	$ (0.30)	-0.8%	$ (0.34)	-0.3%
STREET LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ (295.29)	-9.1%	$ (295.45)	-9.0%	$ (298.54)	-8.9%	$ (337.37)	-7.1%
LARGE USER - Non-RPP (Other)	kw	$ 5,302.34	50.0%	$ 7,869.22	175.5%	$ 6,903.72	27.0%	$ (556.15)	-0.2%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 2.89	10.4%	$ 3.10	10.5%	$ 2.94	9.0%	$ 3.09	4.6%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 1.73	6.0%	$ 2.61	8.6%	$ 2.29	6.2%	$ 2.40	1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retail	kwh	$ 4.20	6.7%	$ 6.47	9.9%	$ 5.63	6.8%	$ 5.90	1.8%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ 92.50	16.5%	$ 161.87	41.0%	$ 142.95	17.3%	$ 157.47	2.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (295.29)	-9.1%	$ (283.44)	-8.7%	$ (286.53)	-8.6%	$ (323.80)	-6.4%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 92.50	16.5%	$ 161.87	41.0%	$ 271.60	32.8%	$ 302.85	3.8%

[31] Exhibit 9, page 31
[32] For example, the Residential Rate Riders for Group 2 accounts increased from $0.07/month to $0.86/month (per the DVA Continuity Schedules (Tab 7) filed with the initial Application and the IR responses respectively.
[33] Updated Exhibit 9, page 2 of 3
[34] Updated Exhibit 9, page 2 of 3
[35] Settlement Agreement – Tariff Schedule and Bill Impact Model

6.4 The following table sets out the change in the rate riders for recovery the Group 2 and LRAM balances in one year versus two[36].

Niagara-on-the-Lake Hydro

Rate Rider Impact

Period for Disposition of Group 2 and LRAM

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
Street 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
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

6.5 A comparison of the variances with the total bill changes and associated total bill impacts in the preceding table indicates that the incremental bill impacts of adopting a one-year as opposed to two-year recovery period will be less than 1% for all classes except Street Lighting. However, given that the initial total bill impact for Street Lighting is -7.1% the overall bill impact of adopting a one-year recovery would still be significantly less than 10%. Indeed, VECC estimates that Low Volume Residential customers will continue to be the group with the highest total bill impact percentage (roughly 5.5%) if a one-year recovery period was adopted. However, this is still well below the Board's 10% threshold.

6.6 With respect to NOTL's second rationale, the fact the existing variances were accumulated over a number years also supports a one-year recovery. The reason being that the shorter recovery period is more likely to ensure that the customers paying the rate rider are the same ones that benefitted during the previous years.

6.7 It is VECC's view that, based strictly on the criteria set by the Board, NOTL's there is no reason for NOTL to depart from the one-year default recovery period for the Group 2 and LRAM DVA balances.

[36] Updated Exhibit 9, page 3 of 3

6.8 Having said this, even with a two year recovery period, the percentage increase in the residential base distribution bill (i.e., using the base distribution rates, including the 2018 ICM rate rider) in 2019 is 2% for a typical RPP Residential customer and 7.7% for a low volume customer. In both cases the values are higher than what is like to be the base distribution rate increase in 2020 under IRM. Therefore, from a rate smoothing perspective, the two recovery period does have merit.

7.0 Issue 5.3 Transmission Gross Load Billing

7.1 K NOTL Hydro is applying to have the Retail Transmission Rate – Line and Transformation Connection Service Rates applied to customers that have 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 on a gross load billing basis. NOTL's rationale is that this approach is consistent with the basis on which the IESO bills it for Line Connection and Transformation Connection services[37].

7.2 VECC notes that approved 2019 Uniform Transmission Rates define the billing demand for Line Connection and Transformation Connection services as follows[38]:

"The Billing Demand for Line and Transformation Connection 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 transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998. 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."

7.3 VECC submits that NOTL's proposal to use gross load billing should be accepted by the Board, subject to NOTL adopting: i) the same definition for "renewable energy" as used for purposes of the UTR and ii) gross load billing only being applicable to generation capacity installed after October 30, 1998 consistent with the UTR. In VECC's view it is entirely appropriate for NOTL to establish its billing determinants for Line and Transformation Connection Services using the same approach as the IESO uses for billing these same services to NOTL.

[37] Exhibit 8 – Additional Evidence (November 2018), page 2 of 5
[38] EB-2018-0326, Decision and Interim Rate Order – 2019 Uniform Transmission Rates, Appendix B, page 5

8.0 Reasonably Incurred Costs

8.1 VECC respectfully submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred cost

ALL OF WHICH IS RESPECTFULLY SUBMITTED