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**BY E-MAIL**

March 4, 2019

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

**Re: Niagara-on-the-Lake Hydro Inc. (NOTL Hydro)**
**2019 Cost of Service Appliaction**
**OEB File Number EB-2018-0056**
**OEB Staff Submission on the Unsettled Issues**

In accordance with Procedural Order No. 4, please find attached OEB staff's submission on the unsettled issues for NOTL Hydro's 2019 cost of service application.

NOTL Hydro and all intervenors have been copied on this filing.

Yours truly,

*Original Signed By*

Tina Li
Project Advisor, Major Applications

Encl.

# 2019 ELECTRICITY DISTRIBUTION RATES

# Niagara-on-the-Lake Hydro Inc.

# EB-2018-0056

# OEB STAFF SUBMISSION

# March 4, 2019

## Introduction

Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) filed a complete application with the Ontario Energy Board (OEB) on August 23, 2018 under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to the rates that NOTL Hydro charges for electricity distribution to be effective May 1, 2019. The OEB issued an approved issue list for this proceeding on December 6, 2018.

The OEB held a settlement conference on December 10 and 11, 2018. NOTL Hydro filed a partial settlement proposal on January 10, 2019. The parties to the partial settlement proposal are NOTL Hydro and the two approved intervenors in the proceeding: School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC). Pursuant to the partial settlement proposal, NOTL Hydro subsequently filed updated evidence regarding the unsettled issues and provided responses to the interrogatories asked by OEB staff and intervenors on the updated evidence. The OEB accepted the partial settlement proposal in the decision issued on February 8, 2019. NOTL Hydro filed its Argument in Chief for the unsettled issues on February 19, 2019.

The unsettled issues are listed below:

- Issue 1.1 Capital: The issue was partially settled. The unsettled issue relates to the prudence of NOTL Hydro's underground conversion project/program since its last rebasing (impacting 2019 opening rate base) and its proposed test year expenditures for the underground conversion program (impacting 2019 net additions and rate base).
- Issue 1.2 Operations, Maintenance & Administration (OM&A): The issue was not part of the settlement accepted by the OEB. The parties agree that all issues relating to OM&A expenses should be determined by the OEB.
- Issue 2.1 & 2.2 Revenue Requirement: The issue was partially settled. The unsettled issue relates to the cost of long-term debt.
- Issue 3.2 Cost Allocation: The issue was partially settled. The unsettled relates to whether to include the Incremental Capital Module (ICM) revenue in distribution revenue at current rates in the cost allocation model.
- Issue 4.2 Deferral and Variance Accounts (DVAs): The issue was partially settled. The unsettled issue was the disposition period of Group 2 DVAs and the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA).
- Issue 5.3 Transmission Gross Load Billing: The issue was not part of the settlement accepted by the OEB. The parties agreed that all issues related to this item should be determined by the OEB.

Before specifically addressing the unsettled issues in its Argument in Chief, NOTL Hydro submitted that the proposed rate increases are reasonable and appropriate in the context of the relatively low level of its current rates.[1] NOTL Hydro stated that it has gone from having one of the highest rates in the province (4th highest residential rate of 111 electricity distributors in 1994) to one of the lowest (17th lowest residential rate of 71 electricity distributors in the province by 2018).[2]

OEB staff notes that the key principles of the *Renewed Regulatory Framework* (RRF) include the expectation for continuous improvement. *The Handbook for Utility Rate Applications* also states that one of the OEB's key considerations is a utility's performance assessments, which analyze the level of continuous improvement and a utility's ability to plan and execute plans.[3] OEB staff, therefore, submits that NOTL Hydro's current rates as compared to its historical rates may be an indicator of its past performance but does not, by itself, justify NOTL Hydro's request for the rate increase in this next rate-setting period.

OEB staff will discuss the above unsettled issues separately.

**Issue 1.1 Capital - The Underground Conversion Project/Program**

**Background**

NOTL Hydro proposed to continue its underground voltage conversion program which consists of continuing to convert the oldest segment of the existing 4 kV distribution system to underground and also converting the supply to 27.6 kV.[4] NOTL Hydro stated that the voltage conversion program is to be completed by the end of 2034.[5] The settlement proposal noted that the parties have not agreed on the prudence of NOTL Hydro's underground conversion project/program since its last rebasing (impacting 2019 opening rate base) and its proposed test year expenditures for the underground conversion program (impacting 2019 net additions and rate base).

To support the underground conversion program, which was started in 1987, NOTL Hydro noted a number of benefits to reliability, safety and the environment. In addition, NOTL Hydro's application stated that "…[a] Town bylaw prohibits the installation of new overhead plant as a means of preserving the heritage nature of the Olde Town".[6] The

[1] Argument in Chief, Page 5
[2] Argument in Chief, Page 4
[3] The Handbook for Utility Rate Applications, October 13, 2016, Page 10
[4] NOTL Hydro's Consolidated Distribution System Plan, Page 56
[5] NOTL Hydro's Response to VECC's Supplement Interrogatory 2.0-VECC-53
[6] Consolidated Distribution System Plan, Pages 38, 43 and 57

same by-law was referenced in NOTL Hydro's 2009 and 2014 cost of service rate applications.[7]

NOTL Hydro clarified in the updated evidence that the town by-law was indeed a legacy by-law of NOTL Hydro Electric Commission[8] that was passed in 1989 instead of a by-law of the town. NOTL Hydro stated that the by-law was adopted by NOTL Hydro as a company policy when NOTL Hydro was incorporated in 2000.[9]

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

- The underground conversion in Olde Town of $215k
- The Virgil project of $125k that is not voltage conversion
- The general underground work of $120k including moving distribution lines for reasons other than voltage conversion; replacing pad-mount transformer or conduit, capital repairs etc.

NOTL Hydro stated that the Virgil project is not a voltage conversion project because the overhead lines along Hwy 55 through downtown Virgil are already 27.6 kV and it has scheduled the Virgil project in 2019 and 2020 along with the Niagara Region's roadworks in 2020 to reduce customer disruptions.

NOTL Hydro submitted[10] that its underground voltage conversion program is appropriate and necessary and the implementation of the program is conducted in a measured and reasonable manner. NOTL Hydro submitted that there should be no issue as to the prudence of amounts already spent, and the forecast costs for 2019 and beyond are appropriate and reasonable.

**OEB Staff Submission**

OEB staff submits that the underground conversion program in Olde town is reasonable for the following three reasons:

- NOTL Hydro noted the benefits of undergrounding in the application: reliability, safety, and environmental benefits. NOTL Hydro further noted the benefit of lower tree trimming costs and the additional costs of installing the overhead lines in downtown areas. NOTL Hydro noted that the additional costs arising from the extra planning and designing work required to put new higher poles in the same

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[8] The precedent of NOTL Hydro before NOTL Hydro was incorporated in 2000
[9] Exhibit 2, Additional Evidence for Rate Base – Underground Voltage Conversion
[10] Argument in Chief, Page 6

location as the existing poles and the potential hearing cost from the town's rigorous review process for any construction in the Olde town to protect its heritage nature.

- The underground conversion has been ongoing for more than 30 years and changing the plan may open up potential challenges for NOTL Hydro.
- OEB staff recognizes that NOTL Hydro's customers do not appear to oppose the underground spending. During NOTL Hydro's open house held on October 19, 2018, no attendees raised an objection to the proposed underground spending. Moreover, the customer engagement report prepared by CGC Communications from the 2018 open houses stated that customers prefer that NOTL Hydro roll out its underground line program in a cautious manner.[11] The report continued to elaborate on this recommendation stating that "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".[12]

OEB staff also recognizes that NOTL is required to perform work in Vigil in conjunction with the Niagara Region's road widening project. NOTL Hydro stated that the Niagara Region is widening Hwy 55 through Virgil so the existing pole line will end up much closer to the road and for safety and aesthetic reasons it makes sense to move the lines underground.[13] NOTL Hydro also stated that the project was discussed at the community meetings held the last two years with no objection.[14] However, OEB staff is not satisfied with the rationale provided by NOTL Hydro to support NOTL Hydro's decision of undergrounding the Virgil project for the following reasons:

- The by-law referenced by NOTL Hydro is not relevant since the existing infrastructure in Virgil is overhead lines that are along Hwy 55 and NOTL Hydro confirmed that there is no current legal requirement for the undergrounding.[15]
- NOTL Hydro budgeted a total of $300k capital expenditure for the Virgil project and allocated $125k to 2019 and $175k to 2020.[16] NOTL Hydro stated that "As the Niagara Region will have much of the road torn apart for it roadworks in 2020, it makes sense to schedule the project then and reduce customer

[11] Exhibit 1, Appendix H, Page 13
[12] *Ibid.*
[13] NOTL Hydro's Response to Staff Supplementary Interrogatory Supp-Staff-2
[14] *Ibid.*
[15] NOTL Hydro's Response to SEC's Supplementary Interrogatory SEC-Supp-35
[16] Exhibit 4, Page 46, Table 2.34

disruptions".[17] As such, OEB staff notes that the $125k capital work budgeted in 2019 may be overstated.

- There is insufficient cost and benefit analysis of underground vs. overhead for the Virgil project.

OEB staff does not have concerns with the nature of the general capital work as it appears to be ongoing capital work related to prior undergrounded infrastructure.

OEB staff submits that a reduction of $95k in the 2019 underground expenditures of $460k would be justified mainly because of the historical underspending.

OEB staff notes that NOTL Hydro has been underspending on the underground conversion project from 2014 to 2018. NOTL Hydro provided the comparison of actual spent and forecast spend regarding the underground conversion project (excluding the general underground work) from 2014 to 2018 in its response to VECC's supplementary interrogatory[18] as shown in the Table 1 below:

**Table 1: The Forecasted Underground Spending vs. the Actual Spending Excluding the General Underground (2014-2018)**

| | The Forecasted Underground Spending in 2014 Cost of Service Application | Actual Spending | Difference $ (Actual - Forecast) | Difference % |
|---|---|---|---|---|
| **2014** | 330,000 | 252,568 | (77,432) | -23% |
| **2015** | 385,000 | 125,460 | (259,540) | -67% |
| **2016** | 400,000 | 313,635 | (86,365) | -22% |
| **2017** | 400,000 | 60,794 | (339,206) | -85% |
| **2018** | 400,000 | 162,078 | (237,922) | -59% |
| **Total** | **1,915,000** | **914,535** | **(1,000,465)** | **-52%** |
| **Average** | **383,000** | **183,000** | **(200,000)** | **-52%** |

NOTL Hydro explained that the actual spending is lower than the forecast spending from 2014 to 2018 mainly due to two reasons[19]:

- The forecast spending in the 2014 cost of service application included senior managements' time while the actual spending did not include the senior managements' time as the time was included and accounted for in the general capital work until 2018.

[17] NOTL Hydro's Response to Staff Supplementary Interrogatory Supp-Staff-2
[18] VECC's Supplementary Interrogatory 2.0-VECC-53
[19] *Ibid.*

- The actual amount of line converted was lower than the projected; hence the change in the expected conclusion of the project from 2028 to 2034.

NOTL Hydro stated in the updated evidence that it capitalized senior managements' time of $130,784 in 2014 based on Canadian General Accepted Accounting Standards (GAAP) while NOTL Hydro's 2019 capital expenditures limit the capitalization of senior managements' time based on the International Financial Reporting Standards (IFRS) (see the OM&A section for detailed analysis). Removing the senior managements' time of $130,784 per year from 2014 to 2018, NOTL Hydro still underspent by $350k (28%) from 2014 to 2018, as shown in the Table 2 below:

**Table 2: The Restated Forecasted Underground Spending vs. the Actual Spending Excluding the General Underground (2014-2018)**

| | The Forecasted Underground Spending in 2014 Cost of Service Application | The Restated Forecasted Underground Spending in 2014 Cost of Service Application (Rounded to '000) | Actual Spent | Difference $ (Actual – Restated Forecast) | Difference % (Actual – Restated Forecast) |
|---|---|---|---|---|---|
| **2014** | 330,000 | 200,000 | 252,568 | 52,568 | 26% |
| **2015** | 385,000 | 255,000 | 125,460 | -129,540 | -51% |
| **2016** | 400,000 | 270,000 | 313,635 | 43,635 | 16% |
| **2017** | 400,000 | 270,000 | 60,794 | -209,206 | -77% |
| **2018** | 400,000 | 270,000 | 162,078 | -107,922 | -40% |
| **Total** | **1,915,000** | **1,265,000** | **914,535** | **-350,465** | **-28%** |
| **Average** | **383,000** | **253,000** | **183,000** | **-70,000** | **-28%** |

Due to the underspending in the underground project (excluding the general underground work), OEB staff notes that the expected completion time for the underground conversion program has been delayed by five years from 2028 that was referenced in the 2014 cost of service application to 2034 in this application. OEB staff notes that there is no information regarding the forecast of the general underground work in 2014 cost of service application.

OEB staff further notes that NOTL Hydro stated in the Distribution System Plan[20] that:

> In recent years, NOTL Hydro has transferred some of this budget from the underground work to smart switches and reclosures. In a survey of customers, it has become clear that they value the increased reliability of these investments over the underground voltage conversion work.

[20] Consolidated Distribution System Plan, Page 34

OEB staff proposes a 28% reduction ($95k) to the proposed expenditure of $340k for the underground conversion project in Olde town ($215k) and the Virgil Project ($125k). OEB staff notes that the $95k also represents NOTL Hydro's accumulated underspend in the 2014 to 2018 period ($200k X 5 years - $915k in Table 2) as compared to the underground spending budget that was included in the rates in the 2014 cost of service decision. OEB staff notes that NOTL Hydro's actual spending on general underground work in 2018 is $114k and the average spending from 2004 to 2017 is calculated as $178k based on the annual actual spending provided by NOTL Hydro.[21] OEB staff also notes that NOTL Hydro capitalized the senior managements' time into the general underground work prior to 2018. OEB staff is of the view that the proposed $120k in 2019 for general underground work may be appropriate because it appears to mostly related to the prior underground work and capital repairs and given the lack of the evidence to the contrary. Including the forecasted 2019 general underground work of $120k, NOTL Hydro's 2019 total underground expenditure would be $365k ($340k minus $95k plus $120k). OEB staff submits that NOTL Hydro's test year underground expenditure of $365k, which is $95k reduced from the proposed $460k in the application, is in line with the average underground spending including the general underground work from 2014 to 2018[22] in Table 3 below:

**Table 3: Total Actual Underground Expenditures $ (2014 – 2018)**

| in '000 | 2014 | 2015 | 2016 | 2017 | 2018 | Average |
|---|---|---|---|---|---|---|
| **Actual Total Underground* $** | 378 | 258 | 540 | 339 | 276 | **358** |

*Prior to 2018, NOTL Hydro capitalized some of senior managements' time into general underground work.

OEB staff is of the view that $365k would be sufficient to meet NOTL Hydro's needs for its underground conversion project, the Virgil project and general underground capital work. OEB staff does not support the undergrounding of the Vigil project as the rationale of the undergrounding is not sufficient. However, NOTL Hydro may be able to manage the capital expenditure related to the undergrounding of Vigil within the proposed envelop of $365k.

[21] NOTL Hydro's Response to Staff Supplementary Interrogatory Supp-Staff-2

[22] 2014 – 2018 actual underground spending is provided in NOTL Hydro's response to staff supplementary IR: Supp-Staff-2

## Issue 1.2 - OM&A Expenses

## Background

NOTL Hydro proposed $2,974,186 OM&A expense in 2019. The proposed OM&A expense was reduced to $2,964,765[23] after the first round of interrogatories.

NOTL Hydro's historical and proposed OM&A levels[24] are summarized in Table 4 below as are the year-over-year percentage changes:

**Table 4: OM&A Expenses (2014 – 2019)**

| | OM&A Expense $ | Year over Year Change $ | Year over Year Change % |
|---|---|---|---|
| **2014 Last Rebasing Year - OEB Approved** | 2,155,262 | | |
| **2014 Last Rebasing Year - Actuals** | 2,208,203 | 52,941 | 2% |
| **2015 Actuals** | 2,323,119 | 114,916 | 5% |
| **2016 Actuals** | 2,532,191 | 209,072 | 9% |
| **2017 Actuals** | 2,595,121 | 62,930 | 2% |
| **2018 Bridge Year** | 2,838,535 | 243,415 | 9% |
| **2019 Test Year** | 2,964,765 | 126,230 | 4% |
| **Total (2019 vs. 2014 OEB Approved)** | | **809,503** | **38%** |

NOTL Hydro submitted that its proposed 2019 OM&A budget is appropriate for the following five reasons[25]:

- It had provided details with respect to each component of the 2019 OM&A forecast.
- NOTL Hydro's 2018 actual OM&A expense is close to the 2019 forecast. NOTL Hydro provided the 2018 unaudited actual OM&A expense of $2,838,535 in its response to SEC's supplementary interrogatory.[26] The updated figure of $2,838,535 represents a reduction of $66,330 as compared to the original forecasted figure of $2,904,865 for 2018.
- NOTL Hydro identified the cost drivers for the annual variances which substantiate the OM&A cost increase. NOTL Hydro submitted that the

[23] Revenue Requirement Work Form filed on November 20, 2018
[24] Based on the updated Appendix 2-JA, JB and JC filed as part of NOTL Hydro's Response to SEC's supplementary interrogatories
[25] NOTL Hydro's Argument in Chief, February 19, 2019, Pages 10-16
[26] SEC-Supp-38

appropriate starting point for the analysis of the increase in its OM&A expense is 2014 actual OM&A spending instead of 2014 OEB approved OM&A spending. NOTL Hydro noted that the $75,455 reduction of the 2014 OM&A budget in the 2014 cost of service application through an approved settlement proposal was in the context of an overall resolution and does not mean that the specific agreed OM&A budget was reasonable on its own. NOTL Hydro's 2019 OM&A budget is at the level that should be expected. NOTL Hydro, in its updated evidence, identified the cost increase that would be expected as a result of inflation and growth and then identified other discrete items that caused the OM&A to increase. The sum of the following three items add up to the OM&A increase of $809,503 from 2014 OEB approved OM&A to 2019 forecasted OM&A:

    - $441,679 increase due to inflation and growth
    - $130,784 increase due to accounting standards change
    - $237,040 increase due to new or increased services
- NOTL Hydro's OM&A per customer is consistent with other distributors.

NOTL Hydro stated in the updated evidence that it was using Canadian GAAP as its accounting standards in 2014 and booked the President and the VP Operations' time to capital. NOTL Hydro further stated that it limited the capitalization of the President and the VP Operations' time in 2019 to meet the requirement of IFRS. NOTL Hydro quantified the impact of the accounting change to its 2014 OM&A expense as $130,784, i.e. 2014 OM&A was $130,784 less than it would have been under IFRS.

NOTL Hydro calculated the expected OM&A increase from inflation and growth using the following method:

> The 2014 approved OM&A expense of $2,155,262 + the accounting change that was not accounted for in 2014 OM&A of $130,784) x (the annual inflation – stretch factor + the sum of three growth factors[27] used in Pacific Economics Group (PEG)'s benchmarking work

NOTL Hydro explained the $237,040 increase due to the following new or increased services:

- Cost incurred of $67,394 for cyber security audit and enhanced IT services
- A new Utilismart contract of $56,844 in 2019 to enhance the data available to its large customers

[27] These three factors are customer growth, load growth and system peak growth. The PEG group uses five factors in evaluating the impact of growth on OM&A costs. The other two factors are the amount of distribution lines and the rate of customer growth. NOTL Hydro stated that it does not use these two factors because NOTL Hydro has seen no noticeable change in the amount of distribution lines or the rate of customer growth.

- Increased regulatory costs and survey cost of $36,528
- Increased locates cost of $36,566 from the public initiatives such as Ontario One call
- A part-time health and safety consultant of $31,367
- Pole rental cost of $8,341, which is offset by the pole rental revenues in other revenues

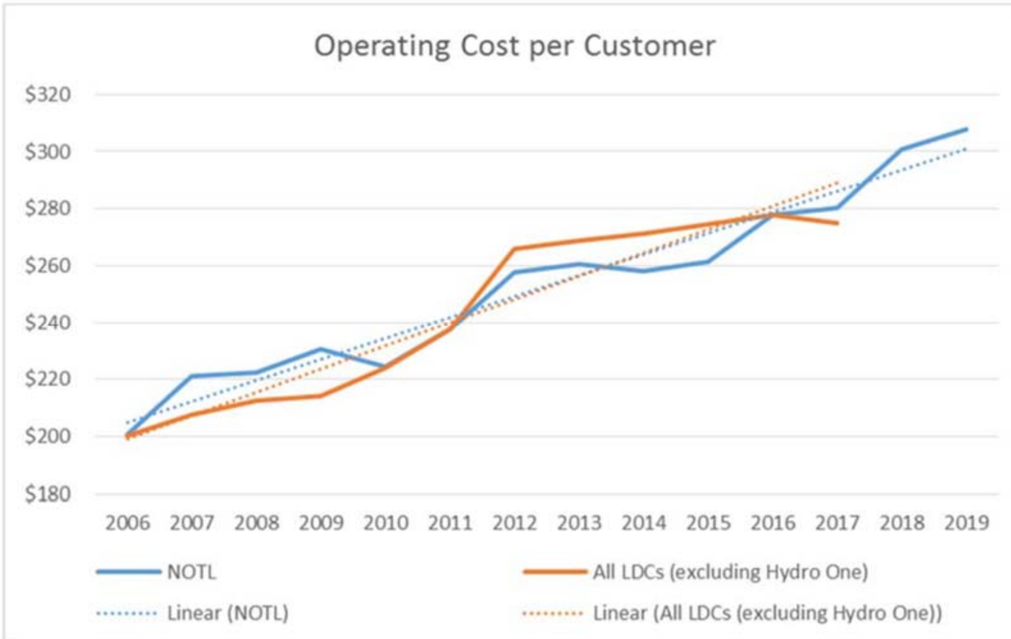
**OEB Staff Submission**

OEB staff submits that NOTL Hydro proposed OM&A level in 2019 of $2,964,765 has not been fully supported for the following reasons:

- The method used by NOTL Hydro to calculate the expected OM&A level in 2019 appears to be flawed. NOTL Hydro adjusted the 2014 approved OM&A expense by the accounting change for the capitalization of senior managements' time in 2014 and then applied the sum of annual inflation and growth factors to the figure to arrive at the expected OM&A ongoing expense in 2019. OEB staff submits that NOTL Hydro should have not added the accounting change to the 2014 approved OM&A figure to calculate the expected OM&A expense from the inflation and growth. OEB staff notes that the accounting change of $130,784 was not approved in the 2014 cost of service rate application and hence should not be used as a base line for the inflation and growth calculation.

- OEB staff acknowledges the unavailability of data for a comparison of NOTL Hydro's OM&A per customer in 2018 and 2019 to the industry. However, NOTL Hydro's OM&A expense per customer in 2017, 2018 and 2019 is trending up and higher than the trend line for the industry average excluding Hydro One.[28] OEB staff notes that NOTL Hydro's 2017, 2018 and 2019 OM&A expense per customer are $278, $307 and $308 respectively.[29] The OM&A expense per customer in 2017 is greater than the industry's average OM&A expense excluding Hydro One in 2017 while NOTL Hydro's OM&A per customer from 2011 to 2016 has been lower than the industry average.[30] In addition, NOTL Hydro's OM&A per customer in 2018 and 2019 is higher than the 2017 figure and higher than the trend line for the industry average, as shown in the graph[31] below:

[28] SEC-Supp-37
[29] Exhibit 4, Page 8, Table 4.7; NOTL Hydro updated the 2018 OM&A expense in the Argument in Chief. Using the updated 2018 OM&A figure, the 2018 OM&A per customer would be $300.
[30] Exhibit 4, Page 19, Chart 4.19
[31] SEC-Supp-37




- OEB staff is of the view that NOTL Hydro does not have an outcome-based action plan to improve its cost efficiency in the next five years. NOTL Hydro has remained in cohort 3 (the middle cohort) of PEG's benchmarking analysis from 2012 to 2017. NOTL Hydro forecasted its PEG cost performance for 2018 and 2019 as -5.2% and -7.8% respectively.[32] OEB staff notes that NOTL's actual 2017 PEG performance is -9.2%, which shows an improvement of cost efficiency as compared to 2016 performance of -6.4%. If NOTL Hydro maintained the trend of the 2017 performance, the expected performance in 2018 and 2019 would put NOTL Hydro in cohort 2 which is the group with the actual costs more than 10% lower than the expected costs. However, NOTL Hydro still remains in cohort group 3 in 2018 and 2019 based on its forecasted performance. The *Handbook for Utility Rate Applications* expects utilities to "identify performance improvement targets that will lead to improvement in its scorecard performance over the term of the rate-setting plan".[33] NOTL Hydro appeared not planning its performance improvement using an outcomes-based approach which emphasizes results instead of activities. NOTL Hydro's plan in the next five years is focused on actions rather than outcomes. This is shown in the  evidence presented by NOTL Hydro:

[32] Exhibit 4, Additional Evidence, Page 6
[33] The Handbook for Utility Rate Applications, October 13, 2016, Page 17

- o NOTL Hydro stated in the application that “It is hoped that this performance improvement will continue over the next five years with the continued application of NOTL Hydro’s values and that NOTL Hydro may even move into the Group 2 stretch cohort”.[34]
- o In its response to a staff interrogatory asking for any initiative taken to improve the cohort group, NOTL Hydro stated that “NOTL Hydro does not undertake any initiatives specific to improving its cohort assignment. However, NOTL Hydro believes that all its initiatives, because they are based on NOTL Hydro’s values, including focus on health & safety, customer needs and financial prudence, will ultimately lead to a move to a Group 2 cohort”.[35]
- o NOTL Hydro stated in its additional evidence for OM&A that “NOTL Hydro has consistently had a PEG rating of 3 but based on the trends it could improve to a 2 rating before the next cost of service application”.[36]

OEB staff submits that the appropriate level for 2019 OM&A expense for NOTL Hydro should reflect a reduction from a 38% increase as compared to 2014 OEB approved OM&A expense of $2,155,262 to a 28% increase as compared to 2014 OEB approved OM&A expense. This represents a reduction of $215,526, rounding to $215,000. The resultant OM&A level for 2019 is therefore $2,749,765.

OEB staff submits that the 10% reduction of the OM&A increase or $215,000 is derived from the three components, each of which is explained in Table 5 below:

**Table 5: OM&A Expense, Cost Drivers and % and $ Disallowed (Staff Proposal)**

| **OM&A Expense and Cost Drivers**<br><br>**(Higher-Level Approach)** | **OM&A Expense or Cost Drivers** | **Composite %** | **% Increase as compared to 2014 OEB Approved**<br><br>**(Composite % x 37.6%)** | **% disallowance proposed by OEB staff** | **$ disallowance proposed by OEB staff** |
|---|---|---|---|---|---|
| **2014 OM&A Expense – OEB Approved** | **$2,155,262** | | | | |
| **Inflation and Growth** | $441,679 | 55% | 20.5% | 2.4% out of 20.5% | |

[34] Exhibit 1, Page 20
[35] 1-Staff-9
[36] Exhibit 4, OM&A, Additional Evidence, Page 7

| | | | | | |
|---|---|---|---|---|---|
| **Accounting Standards Change** | $130,784 | 16% | 6.1% | All of the 6.1% | |
| **New or Increased Services** | $237,040 | 29% | 11.0% | 1.5% out of 11% | |
| **Total OM&A Increase $** | **$809,503** | **100%** | **37.6%** | **10%** | **$215,526, Rounded to $215,000** |
| **2019 OM&A Expense** | **$2,964,765** | | | | **$2,749,765** |

As per the table above, OEB staff is of the view that 2.4% of the 20.5% OM&A increase due to inflation and growth should be disallowed because it is not related to inflation and growth. OEB staff notes that NOTL Hydro applied the inflation and growth factors on the adjusted 2014 OM&A expense (i.e. 2014 OEB approved OM&A expense plus the $130,784 accounting standards change) instead of applying the inflation and growth factors to the 2014 OEB approved OM&A expense. OEB staff notes that the $130,784 accounting standards change was not approved by the OEB in the 2014 decision and hence it is not appropriate for NOTL Hydro to apply the inflation and growth factors to the $130,784. The impact of adding the $130,784 to the starting point for the inflation and growth calculation is 2.4% of the OM&A increase.

OEB staff is of the view that the OM&A increase due to the accounting standards change of $130,784 (6.1% of the OM&A increase) should not be allowed for the following reasons:

- NOTL Hydro's 2014 cost of service application was based on Canadian GAAP. NOTL Hydro adopted the IFRS as the accounting standard on January 1, 2015. However, NOTL Hydro stated in the 2014 application that "pursuant to the Board letter July 17, 2012, NOTL Hydro has applied changes to the depreciation expense and capitalization policies effective January 1, 2013, consistent with the Board's regulatory accounting policy direction in that letter. These changes are reflected in NOTL Hydro's 2013 Bridge Year and 2014 Test Year results".[37]

- The OEB's letter[38] required that all electricity distributors implement accounting changes for capitalization policy and depreciation policy to be consistent with the OEB's regulatory accounting policies as set out for modified IFRS as contained in

[37] EB-2013-0155 Application, Exhibit 1, Tab 5, Schedule 17
[38] The OEB's letter issued on July 17, 2012 to all Electricity Distributors

the 2009 Report of the Board[39], the Kinectrics Report, and the Revised 2012 Accounting Procedures Handbook for Electricity Distributors. OEB staff further notes that the OEB issued another letter[40] pursuant to the 2009 Report of the Board requiring full compliance with the IFRS requirement (e.g. International Accounting Standard (IAS) 16). One important requirement of the IAS 16 is that the company is to capitalize the direct attributable costs related to the assets.

- NOTL Hydro did not, in its 2014 cost of service application, identify the change of capitalization policy regarding the executives' salaries and benefits to align with the IFRS requirement that only direct attributable costs are to be capitalized into assets. OEB staff is of the view that NOTL Hydro should have identified the $130,784 OM&A increase that was related to the executives' salaries and benefits during the process of changing the capitalization policy and should have presented this item in its 2014 cost of service application. The impact, if presented, would have been included in the Account 1576, Accounting Changes under CGAAP, and would have been recovered from ratepayers in the 2014 cost of service application. As a result, the proposed OM&A expense in this application would have been reduced by the cost of the accounting changes and the associated inflation and growth.

OEB staff submits that a reduction of 1.5% out of the 11% proposed OM&A increase due to new and increased services would be appropriate because OEB staff is of the view that NOTL Hydro should be able to address new initiatives, such as the cyber security and increased locate costs due to the Ontario One call initiative, within its existing budget. In February 2016, the OEB issued a letter[41] to all electricity distributors regarding the cyber security framework initiative stating the OEB's expectation that the cyber security framework be established in a cost-efficient manner and the OEB also stated in a notice in December 2017 for the same initiative that "the transmitters and distributors should have already incorporated cyber security into their business and asset planning".[42]

OEB staff therefore submits that a reduction of $215,000 to the total proposed OM&A expense of $2,964,765 in 2019 is warranted. OEB staff notes that the resultant OM&A expense of $2,749,765 in 2019 represents a 28% increase of the OM&A expense from 2014 OEB approved to 2019 as compared to the original 38% increase proposed in the application. OEB staff is of the view that the reduced OM&A level represents a

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[39] Transition to International Financial Reporting Standards, EB-2008-0408
[40] The OEB's letter issued February 24, 2010 to all Electricity Distributors re "Accounting for Overhead Cost Associated with Capital Work"
[41] EB-2016-0032, Letter to All Electricity Distributors, February 11, 2016
[42] EB-2016-0032, Notice of Proposal to Amend a Code, December 20, 2017, Page 13

reasonable increase over the five year period. OEB staff further submits that the reduced OM&A budget would provide additional incentives for NOTL Hydro to develop an outcome-based plan to improve its efficiency (i.e. to improve its OM&A per customer and its cohort group).

### Issue 2.1 & 2.2 Revenue Requirement - Cost of Long-Term Debt

### Background

NOTL Hydro proposed a total cost of long-term debt rate of 3.71% for 2019. There was no agreement on NOTL Hydro's cost of long-term debt in the settlement proposal filed on January 10, 2019. NOTL Hydro updated its cost of long-term debt to 3.95% after the filing of updated evidence. NOTL Hydro filed updated evidence about its cost of long-term debt, applying:

- An updated notional rate associated with a promissory note with the Town of NOTL to reflect the OEB's approved long-term debt rate for 2019 cost of service applications (4.13%)
- A proposed increased interest rate on two loans from the Town of NOTL from 3.0% to 3.5%

As a result of these updates, NOTL Hydro's cost of long-term debt rate increases from 3.71% to 3.95%. The details of NOTL Hydro's long-term debt are in Table 6 below:

**Table 6: NOTL Hydro's Long-term Debt (Original Application vs. Updated Evidence)**

| | | | | | | Original Application | | Updated Evidence[43] | |
|---|---|---|---|---|---|---|---|---|---|
| | **Description** | **Lender** | **Affiliated or 3rd Party?** | **Start Date** | **Term (years)** | **Principal ($)** | **Rate (%)** | **Principal ($)** | **Rate (%)** |
| 1 | Original Promissory Note | Town of NOTL | Affiliated | 1-Jul-00 | Open | 2,098,770 | 4.16 | 2,098,770 | 4.13 |
| 2 | NOTL TS Demand | CIBC | 3rd Party | 27-Oct-05 | 15 | 424,320 | 6.13 | 424,320 | 6.13 |

[43] Exhibit 5 Cost of Capital, Cost of Long-Term Debt, Additional Evidence

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Installment Loan | | | | | | | | |
| 3 | Infrastructure Ontario Loan | Infrastructure Ontario | 3rd Party | 15-Feb-11 | 15 | 716,667 | 4.27 | 716,667 | 4.27 |
| 4 | Town loan - transformer | Town of NOTL | Affiliated | 1-Feb-15 | 10 | 1,954,706 | 3.00 | 1,954,706 | 3.50 |
| 5 | Town loan - capital projects | Town of NOTL | Affiliated | 1-Oct-15 | 10 | 1,430,402 | 3.00 | 1,430,402 | 3.50 |
| | | | | | | **Long-term debt rate %** | **3.71** | **Updated rate %** | **3.95** |

All of NOTL Hydro's five long-term loans have fixed rates. Of NOTL's five long-term loans, three are from the town (affiliated party) and the other two are from third party (CIBC and Infrastructure Ontario). NOTL Hydro stated that the third party loans were negotiated many years ago and the associated interest rates have formed part of NOTL Hydro's cost of capital since before the 2014 to 2018 term.[44]

NOTL Hydro updated the interest rates for three affiliated loans. NOTL Hydro updated the notional rate on the promissory note with the town from 4.16% to 4.13% to reflect the OEB's deemed long-term debt rate for 2019 rate applications. NOTL Hydro stated that the promissory note was renewed in August 2018 with the interest rate of 7.25%[45] NOTL Hydro updated the interest rates of two loans with the town from 3% to 3.5% because the town has informed NOTL Hydro that it wishes to exercise its option to renegotiate the two demand loans with a new interest rate of 3.5%. NOTL Hydro explained in its response to supplementary interrogatories that the town is expected to confirm the new arrangements at a council meeting on March 4, 2019 for the effective date of March 1, 2019.[46]

**OEB Staff Submission**

OEB staff submits that NOTL Hydro's updated cost of long-term debt of 3.95% for 2019 is appropriate because OEB staff is of the view that NOTL Hydro has met the requirement of establishing the need and prudence of its actual and forecasted debt including the cost of such debt, as outlined in Report of the Board on the Cost of Capital for Ontario's Regulated Utilities issued on December 11, 2009 (2009 Report).[47] Below

[44] NOTL Hydro's Argument in Chief, Page 17
[45] NOTL Hydro's Argument in Chief, Page 18
[46] NOTL Hydro's Response to Supplementary IRs: Supp-Staff-6 and SEC-Supp-49
[47] EB-2009-0084

is OEB staff's analysis regarding NOTL Hydro's five long-term debt instruments for 2019.

The 2009 Report makes it clear that, while the weighted average cost of debt is based on the actual (embedded) cost of debt for the portfolio of debt instruments of a regulated utility, the OEB's deemed long-term debt rate will act as the ceiling on the allowed interest rate for debt under certain circumstances. These circumstances include affiliated debt (to ensure that the arrangement appears to be "at arm's length") and for debt without a specific term (or maturity). Variable rate debt or new debt for which no reasonable forecast may be available also falls under these criteria.

OEB staff submits that the cost of long-term debt regarding the two third party loans is appropriate. OEB staff notes that NOTL Hydro obtained a $2.4 million loan from CIBC in 2005 to finance the purchase of one transformer from Hydro One. The loan is for a 15-year period with a swap option for an effective all in fixed rate of 6.13%. NOTL Hydro obtained a $1.5 million loan from Infrastructure Ontario in 2011 to fund smart meters. The loan is for a 15-year period with a fixed interest rate of 4.27%. OEB staff notes that both loans existed at the time of NOTL Hydro's 2014 cost of service rate application with the same terms and interest rates and the OEB accepted them in the decision which approved the settlement proposal. OEB staff does not oppose the use of the actual interest rates since the OEB has already approved the rates, and the transactions were at arm's length and with specific terms and maturity.

OEB staff is of the view that cost of long-term debt regarding the promissory note with the town is appropriate. OEB staff notes that NOTL Hydro renewed the promissory note with the town in August 2018 with the same interest rate of 7.25%. NOTL Hydro applied the deemed long-term debt rate of 4.13% for 2019 rate applications to this promissory note. OEB staff submits that this is in accordance with the requirement set out in the 2009 Report.[48]

With respect to the two demand loans with the town, OEB staff is of the view that NOTL Hydro has established the need and prudence of these two loans for the following reasons:

- NOTL Hydro obtained both loans from the town in 2015 with a 10-year term and 3% interest rate. Both loans are demand loans callable by the town and were

[48] Page 53 of the 2009 Report states that "For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario *Business Corporations Act, 1990*) with a fixed rate, the deemed long-term debt rate at the time of issuance will be used as a ceiling on the rate allowed for that debt".

obtained to fund the transformer which was approved by the OEB in NOTL Hydro's 2015 Price Cap IR application to fund ongoing capital expenditures.

- NOTL Hydro, in response to the supplementary interrogatory[49], stated that it has undertaken the due diligence in early December by contacting a schedule A bank for the interest rate of an equivalent loan. The effective rate for the loan quoted by the bank is 3.48% which is approximately the 3.5% offered by the town. In addition, NOTL Hydro stated that the loans from the town do not include financial covenants and are not secured. As a result, its borrowing capacity with financial institutions is not affected.[50]

- The renewed interest rate of 3.5% for NOTL Hydro's two town loans are lower than the deemed long-term debt rate of 4.13%, which is in accordance with the requirement outlined in the 2009 Report.[51]

**Issue 3.2 Cost Allocation - Include or Exclude the ICM revenue in Distribution Revenue at Current Rates**

**Background**

NOTL Hydro proposes to include ICM revenue in its determination of revenue at existing rates for the purpose of cost allocation and the resulting revenue to cost ratios. In the settlement proposal, NOTL Hydro stated that it did so "because the project associated with the ICM will be included in 2019 base rates." [52] Also, it "believes that this approach is a fair way to assess rate impacts from its updated revenue requirement".[53] Intervenors stated that they "are not aware of any other LDC who in its rebasing application after an ICM has applied ICM riders to base rates for the revenue at existing rates calculation".[54]

Subsequent to the 2014 cost of service application, revenue from base rates for each rate class has been adjusted only by across-the-board adjustments under price cap IR.[55] NOTL Hydro's ICM rate rider revenues were set in its 2015 Price Cap IR

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[49] NOTL Hydro's Response to SEC's Supplementary Interrogatory SEC-Supp-48
[50] NOTL Hydro's Argument in Chief, Page 18
[51] Page 54 of the 2009 Report states 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".

[52] Settlement Agreement, Page 22.
[53] Settlement Agreement, Page 22.
[54] Settlement Agreement, Pages 22-23.
[55] EB-2013-0155.

application.[56] The ICM rate rider was not set as a uniform percentage of fixed and variable rates for all rate classes. Instead, it was applied only to variable charges, and not applied to the Street Lighting rate class. NOTL Hydro proposed to use the TCP4 allocator from the cost allocation model to allocate the incremental revenue requirement, which is consistent with the cost allocation treatment for transformer stations. NOTL Hydro's approved rate riders incorporated this proposal.[57]

OEB staff is of the view that the rate design for the 2015 ICM rate rider would have been different if the rate riders were set in the context of a full cost allocation including all revenues and costs. As a result, the inclusion or exclusion of the ICM rate rider revenues into the current cost allocation model results in different initial revenue to cost ratios for rate design.

**Table 7: The 2019 Distribution Revenue and Revenue-to-Cost Impact of Including or Excluding ICM Rate Rider Revenues in Cost Allocation Model**

| | ICM included | | | ICM excluded | | |
|---|---|---|---|---|---|---|
| | **Revenue at Existing Rates** | **Revenue at Stats Quo Rates** | **Revenue-to-Cost Ratio** | **Revenue at Existing Rates** | **Revenue at Status Quo Rates** | **Revenue-to-Cost Ratio** |
| **Residential** | 2,923,268 | 2,952,907 | 89.80% | 2,871,539 | 3,008,469 | 91.33% |
| **GS < 50** | 1,177,925 | 1,189,868 | 110.64% | 1,127,762 | 1,181,540 | 109.92% |
| **GS > 50** | 977,428 | 987,338 | 118.24% | 903,489 | 946,573 | 113.65% |
| **Unmetered** | 8,350 | 8,434 | 114.03% | 8,224 | 8,616 | 116.28% |
| **Street Light** | 281,952 | 284,810 | 162.62% | 281,952 | 295,397 | 168.33% |
| **Large User** | 124,034 | 125,291 | 80.84% | 103,136 | 108,054 | 70.56% |
| **Total** | 5,492,956 | 5,548,649 | | 5,296,102 | 5,548,649 | |

The resultant rate impact of including ICM revenues in the calculation of distribution revenue on existing rates is in Table 8 below:[58]

**Table 8: The Rate Impact of Including or Excluding ICM Rate Rider Revenues in Cost Allocation Model**

| | ICM included | | ICM excluded | |
|---|---|---|---|---|
| | **Fixed Rate** | **Variable Rate** | **Fixed Charge** | **Variable Rate** |
| **Residential** | $30.47 | - | $30.97 | - |
| **GS < 50** | $39.41 | $0.0133 | $39.41 | $0.0131 |
| **GS > 50** | $281.65 | $2.6169 | $281.65 | $2.4248 |
| **Unmetered** | $21.20 | $0.0072 | $21.20 | $0.0080 |
| **Street Light** | $7.85 | $7.3887 | $7.85 | $7.3887 |
| **Large User** | $2,829.49 | $2.6169 | $3,790.12 | $2.4248 |

[56] EB-2014-0097
[57] EB-2014-0097 Decision and Order, Pages 8-10
[58] Supplementary Interrogatory Response Filed February 7, 2019

## Table 9: Revenue Responsibility by rate class with ICM Rate Rider Revenues included in Cost Allocation Model

| | Fixed Rate | Customers / Connections | Fixed Revenue | Variable Rate | Energy / Demand | Variable Revenue | TOA | Total Revenue* |
|---|---|---|---|---|---|---|---|---|
| **Residential** | $30.47 | 8,152 | $2,980,834 | - | 73,898,698 | - | | $2,980,834 |
| **GS < 50** | $39.41 | 1,342 | $634,501 | $0.0133 | 41,801,817 | $555,964 | | $1,190,465 |
| **GS > 50** | $281.65 | 131 | $442,754 | $2.6169 | 212,284 | $555,716 | $11,086 | $987,384 |
| **Unmetered** | $21.20 | 26 | $6,614 | $0.0072 | 251,508 | $1,811 | | $8,425 |
| **Street Light** | $7.85 | 2,187 | $205,993 | $7.3887 | 2,475 | $18,286 | | $224,280 |
| **Large User** | $2,829.49 | 1 | $33,968 | $2.6169 | 60,000 | $157,068 | $33,600 | $157,436 |
| **Total** | | | $4,304,665 | | | $1,288,846 | $44,686 | $5,548,825 |

*Difference in total revenue from $5,489,649 requirement is due to rounding

## Table 10: Revenue Responsibility by rate class with ICM Rate Rider Revenues excluded in Cost Allocation Model

| | Fixed Rate | Customers / Connections | Fixed Revenue | Variable Rate | Energy / Demand | Variable Revenue | TOA | Total Revenue* |
|---|---|---|---|---|---|---|---|---|
| **Residential** | $30.97 | 8,152 | $3,029,749 | - | 73,898,698 | - | | $3,029,749 |
| **GS < 50** | $39.41 | 1,342 | $634,501 | $0.0131 | 41,801,817 | $547,604 | | $1,182,105 |
| **GS > 50** | $281.65 | 131 | $442,754 | $2.4248 | 212,284 | $514,745 | $11,086 | $946,413 |
| **Unmetered** | $21.20 | 26 | $6,614 | $0.0080 | 251,508 | $2,012 | | $8,626 |
| **Street Light** | $7.85 | 2,187 | $205,993 | $7.3887 | 2,475 | $18,285 | | $224,279 |
| **Large User** | $3,790.12 | 1 | $45,481 | $2.4248 | 60,000 | $145,488 | $33,600 | $157,369 |
| **Total** | | | $4,365,093 | | | $1,288,134 | $44,686 | $5,548,541 |

*Difference in total revenue from $5,489,649 requirement is due to rounding

In recent cases where a utility has had an ICM rate rider, and subsequently rebased either through a cost of service or Custom IR application, the utility has not included ICM rate rider revenue in the revenue to cost calculation in its cost allocation model. These cases include:

- InnPower Corporation, which was approved for an ICM in 2015[59] rates and rebased in 2017[60]
- Wellington North Power Inc., which was approved for an ICM in 2014[61] rates and rebased in 2016[62]
- Alectra Utilities – PowerStream rate zone, which was approved for an ICM in 2014[63] rates and rebased in 2016[64]
- Festival Hydro Inc., which was approved for an ICM in 2013[65] rates and rebased in 2015[66]

[59] EB-2014-0086
[60] EB-2016-0085
[61] EB-2013-0166
[62] EB-2015-0110
[63] EB-2013-0166
[64] EB-2015-0003
[65] EB-2012-0124
[66] EB-2014-0073

- Oakville Hydro Electricity Distribution Inc., which was approved for an ICM in 2011[67] rates and rebased in 2014[68]
- Hydro Hawkesbury Inc., which was approved for an ICM in 2012[69] rates and rebased in 2014[70]

Introduced May 1, 2006, the Smart Meter Funding Adder (SMFA) was created as part of the OEB's Generic Issues Decision[71] to recover the incremental costs associated with the province wide smart meter deployment. Upon rebasing, the associated investment was included in rate base, and the SMFA was discontinued. Utilities did not add SMFA revenue to the base rates in performing the first Cost Allocation study after the completion of the smart meter deployment.

**OEB Staff Submission**

OEB staff notes that an ICM is analogous to the SMFA, where SMFA revenue was not included as part of distribution revenue in determination of revenue to cost ratios, and it would be appropriate to apply the same treatment to ICMs. In every case examined by OEB staff, utilities have not included ICM revenue in their determination of revenue to cost ratios. In addition, the existing base rates have been set on the basis of allocated costs in the context of a cost of service application.

OEB staff is of the view that including the ICM rate rider revenue in the cost allocation model could be seen as a reasonable proposal in light of the fact that an ICM application is akin to a mini cost of service application. The resulting starting point for revenue to cost ratio adjustments reflects the current revenue that is being collected from each rate class. As a result, the total revenue to be collected from each rate class more closely reflects the current total revenue by class when the ICM revenue is included. However, as outlined above, this is a departure from the OEB's existing practice. Given the modest cost shifting that results from this proposal (less than $50,000 in every rate class), OEB staff submits that a departure is not required in this case.

For these reasons, OEB staff submits that base rates, excluding the ICM rate rider, are the appropriate starting point for the determination of base rates in this proceeding. Therefore, the ICM rate rider should not be included in the base rates for cost allocation purposes.

[67] EB-2010-0104
[68] EB-2013-0159
[69] EB-2011-0173
[70] EB-2013-0139
[71] EB-2005-0529

## Issue 4.2 DVAs - Disposition Period of Group 2 DVAs and the LRAMVA

### Background

Concurrently with this filing of this settlement proposal, NOTL Hydro indicated to parties it would be filing updated evidence proposing to clear the DVAs over a two-year period (the original evidence had proposed a one-year clearance period). The parties did not settle the disposition period for the agreed upon Group 2 DVAs and LRAMVA balances.

In the updated evidence, NOTL Hydro stated that due to an error outside its control the impact of the DVA rate riders communicated to NOTL Hydro's customers at the open house was incorrectly stated to be negligible, when in fact it had a significant impact. As a result, NOTL Hydro proposed the disposition of the Group 2 DVAs and LRAMVA over a two-year period instead of a one-year period in order to reduce the bill impacts. In addition, NOTL Hydro submitted that both the Group 2 DVAs (mainly Account 1508 Deferred IFRS costs and Accounts 1518 and 1548 Retail Settlement Variance Accounts) and the LRAMVA were aggregated over multiple years so there should be no inherent requirement to have them repaid in one year rather than over two or more years.[72]

NOTL Hydro stated in its Argument in Chief that "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% ($0.61 per month)".[73]

### OEB Staff Submission

OEB staff notes that the *2019 Filing Requirements for Electricity Distribution Rate Applications* states that for DVAs "The default disposition period is one year; if the applicant is proposing an alternative recovery period, an explanation must be provided".[74]

OEB staff submits that NOTL Hydro has provided adequate explanation for the two-year disposition request. OEB staff therefore supports the two-year disposition period requested by NOTL Hydro because of the consideration of bill impacts and especially

[72] Exhibit 9, Additional Evidence
[73] Argument in Chief, Page 22
[74] 2019 Filing Requirements for Electricity Distribution Rate Applications, Page 63

given that NOTL Hydro's customers were advised in the open house that the impacts of DVA rate riders would be negligible. OEB staff notes that a longer disposition period would give rise to increased interest charges which NOTL Hydro estimates to be around $5,000. However, OEB staff agrees with NOTL Hydro that the increased interest charges are not significant and so there is value in providing customers with relief by mitigating bill impacts.

**Issue 5.3 Transmission Gross Load Billing**

**Background**

In its additional evidence filed for Exhibit 8 Rate Design, NOTL Hydro stated that

> NOTL Hydro is applying to have the Retail Transmission Rate – Line and transformation Connection Service Rates for Load Displacement Generators ("LDG"), with a generator unit rating 5 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.[75]

NOTL Hydro stated that "The proposed transmission standby charge is a note to our GS > 50 kW and Large Use customers Retail Transmission Rate - Line and Transformation Connection Service Rate charges that reads"[76]:

> 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 non-renewable 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.

[75] Exhibit 8 Rate Design, Additional Evidence
[76] Exhibit 8, Rate Design, Additional Evidence, Page 2

NOTL Hydro stated[77] that the same tariff has been approved for Entegrus Powerlines Inc. (Entegrus).[78]

**OEB Staff Submission**

OEB staff notes that the Entegrus decision[79] referenced by NOTL Hydro arose from a streamlined incentive rate mechanism application and it did not include any discussion of the transmission gross load billing proposal. OEB staff notes that the 2016 to 2019 tariffs[80] of rates and charges for Entegrus' main rate zone contain a note 1 with the same wording regarding the transmission gross load billing proposed by NOTL Hydro. OEB staff further notes that the wording in fact stems from Entegrus' 2016 cost of service application.[81] OEB staff stated in Entegrus' 2016 decision and order that "the issue of gross load billing of transmission charges at the distribution level has not been addressed by the OEB, which might indicate that a conditional approval is appropriate".[82] The OEB stated in the Entegrus 2016 decision and order that "the OEB does not find it necessary to add any conditions to its approval".[83]

OEB staff notes that the OEB approved Entegrus' transmission gross load billing wording in the 2016 decision and the wording has been carried forward in Entegrus' subsequent tariffs from 2017 to 2019. However, OEB staff submits that the wording in Entegrus' tariffs is not adequate to support the same wording in NOTL Hydro's tariff without further considerations. OEB staff submits that NOTL Hydro should continue to charge its Retail Transmission Rate - Line and Transformation Connection Service Rate for the GS >50 kV and Large Use classes as has been done to date. OEB staff is of the view that the OEB should be guided by a more recent decision for Enwin Utilities Ltd. (Enwin Utilities)'s 2018 rates, which states that "the OEB may review this matter further on a generic basis and provide information in due course. EnWin Utilities should continue to use the same approach to the settlement of these activities as it has been using to date".[84]

OEB staff is of the view that the OEB's latest view on this matter is the one established in the EnWin Utilities' decision in which the OEB established an expectation that EnWin

[77] Argument in Chief, Page 23
[78] EB-2018-0024, Rate Order for Entegrus – Main Rate Zone, Pages 4 and 13
[79] EB-2018-0024
[80] EB-2018-0024, Entegrus' Tariff of Rates and Charges for Main Rate Zone issued on December 18, 2018, Page 13
[81] EB-2015-0061,Decision and Order, Page 3
[82] *Ibid.*
[83] *Ibid.*
[84] EB-2017-0037, Decision and Rate Order, March 22, 2018

Utilities should not change its approach to settlement. If NOTL has not used gross load billing as the basis for settlement in the past, then it should not commence to do so at this time.

All of which is respectfully submitted