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BY E-MAIL

January 23, 2017

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Canadian Niagara Power Inc.
Application for Rates
Board File Number EB-2016-0061

Please find attached OEB staff's submission on the unsettled issues for this application.

Original Signed By

Martin Davies
Project Advisor, Rates
Major Applications

2017 ELECTRICITY DISTRIBUTION RATES

Canadian Niagara Power Inc.

EB-2016-0061

ONTARIO ENERGY BOARD

STAFF SUBMISSION

January 23, 2017

INTRODUCTION

Canadian Niagara Power Inc. (Canadian Niagara Power) filed a complete cost of service application with the Ontario Energy Board (OEB) on July 13, 2016 seeking approval for changes to the rates that Canadian Niagara Power charges for electricity distribution to be effective January 1, 2017. The OEB issued an approved issues list for this proceeding on November 11, 2016. A settlement conference was held on November 8 and 9, 2016 and Canadian Niagara Power filed a partial settlement proposal setting out an agreement between all of the parties to the proceeding on December 1, 2016. The parties to the partial settlement proposal are Canadian Niagara Power and the following approved intervenors in the proceeding: Energy Probe Research Foundation (EP), School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC). On January 5, 2017, the OEB accepted the partial settlement proposal.

The issues that were not settled are listed below:

- Issue 1.2 OM&A.

- Issue 2.1.1 Cost of Capital, partially settled, unsettled was the issue as to whether and how expected changes in the cost of long-term debt in 2018 should be reflected in rates.

- Issue 4.1 Accounting Standards and related areas, partially settled, unsettled was the discrete issue of the appropriate accounting for Pension and OPEB costs in rates (cash vs. accrual).

- Issue 4.2 Deferral and Variance Accounts, partially settled, unsettled were the issues of whether a variance account related to pension and OPEBs is appropriate and whether a variance account for future changes to the cost of long-term debt should be established.

- Issue 4.2.1 Effective Date, no settlement, the issue of whether or not rates should be effective January 1, 2017.

OEB staff's submission will discuss the above unsettled issues under the following four categories, which encompass all of the unsettled issues noted above, specifically:

1. Appropriate Accounting for Pension and OPEB Costs
2. Treatment of Expected Changes in the Cost of Long-Term Debt for 2018
3. OM&A Expenses
4. Effective Date

Appropriate Accounting for Pension and OPEB Costs

Background

In May 2015, the OEB initiated a consultation (EB-2015-0040) on rate-regulated utility pensions and other post-employment benefits (OPEBs) in the electricity and natural gas sectors. Applicants have been asked to provide information on the accounting method used by the applicant in this area. In response to an OEB staff interrogatory, Canadian Niagara Power stated that it used the accrual method of accounting for pensions and OPEBs since it had started to recover these amounts in rates.[1]

Canadian Niagara Power submitted that the OEB should reject what it characterized as the intervenors' position that it should be required to switch from the accrual to cash methodology for three reasons:

The first is that this is a generic issue currently under review by the OEB. Canadian Niagara Power noted that both itself and SEC are participants in that proceeding and have filed written submissions. Canadian Niagara Power submitted that by raising the issue of cash versus accrual accounting in this proceeding, intervenors are requesting that two different OEB panels adjudicate the same issue and, as such, it would be redundant and inappropriate for the OEB in this proceeding to decide on the issues, especially since the generic proceeding is well underway and is a fulsome consultation involving numerous parties on this complex issue. For these reasons, Canadian Niagara Power requested the OEB in this proceeding to abstain from deciding on this issue.

[1] 4-Staff-67

Canadian Niagara Power's second argument in support of its position is that the OEB had approved its use of the accrual method in its last cost of service rate application. Canadian Niagara Power observed that the intervenors were now proposing that it change from an accrual to cash methodology despite the fact that no direction has come from the OEB to suggest that Canadian Niagara Power should depart from the OEB approved status quo.

Third, Canadian Niagara Power submitted that the onus should be on the intervenors to justify why Canadian Niagara Power should be required to change from the accrual to the cash methodology. The Applicant noted that intervenors have not provided evidence to support their position.

OEB Staff Submission

OEB staff notes that beginning with the Ontario Power Generation Inc. (OPG) Decision in 2014[2] the OEB has generally allowed applicants to recover their cash requirements for pension and OPEBs rather than the accrual amount, where the difference between the two approaches is material, pending the outcome of the pension and OPEBs generic consultation[3]. The difference between the two approaches is tracked in a variance account in case the OEB decides that the accrual method is the appropriate rate-setting methodology.

In order to make a determination of the materiality of this differential, OEB staff asked Canadian Niagara Power to provide the amount of pension and OPEBs costs included in rates versus the amounts actually paid.[4] In its response to this interrogatory, Canadian Niagara Power provided a table which showed that the difference between the two approaches was material in the 2017 Test year.

[2] EB-2013-0321 *Decision With Reasons* November 20, 2014, p. 87.
[3] Toronto Hydro-Electric System Limited (EB-2014-0116), Entegrus Powerlines Inc. (EB-2015-0061), Waterloo North Hydro Inc. (EB-2015-0108), Kingston Hydro Corporation (EB-2015-0083) and Guelph Hydro Electric Systems Limited (EB-2015-0073)
[4] 4-Staff-68

Pensions	2009 to 2011	2012	2013	2014	2015	2016	2017
Amounts included in rates (000's)							
OM&A	$ 934	$ 276	$ 344	$ 284	$ 245	$ 97	$ 211
Allocated out to related parties through shared service agreements	$ 199	$ 92	$ 98	$ 98	$ 108	$ 44	$ 86
Capital	$ 470	$ 141	$ 176	$ 138	$ 154	$ 63	$ 133
Total	$ 1,602	$ 509	$ 618	$ 520	$ 507	$ 204	$ 431
Paid contribution / benefit amounts (cash)	$ 2,578	$ 1,111	$ 1,126	$ 1,120	$ 626	$ -	$ -
Net excess (deficit) amount included in rates relative to amounts actually paid	$ (976)	$ (602)	$ (508)	$ (600)	$ (119)	$ 204	$ 431

OPEBs	2009 to 2011	2012	2013	2014	2015	2016	2017
Amounts included in rates (000's)							
OM&A	$ 695	$ 251	$ 251	$ 257	$ 286	$ 295	$ 276
Allocated out to related parties through shared service agreements	$ 148	$ 84	$ 72	$ 89	$ 126	$ 133	$ 113
Capital	$ 350	$ 128	$ 129	$ 125	$ 180	$ 193	$ 174
Total	$ 1,193	$ 463	$ 452	$ 471	$ 592	$ 621	$ 563
Paid contribution / benefit amounts (cash)	$ 762	$ 310	$ 317	$ 291	$ 295	$ 290	$ 306
Net excess amount included in rates relative to amounts actually paid	$ 431	$ 153	$ 135	$ 180	$ 297	$ 331	$ 257

OEB staff notes that Canadian Niagara Power has a materiality threshold of $100,000[5] and that the net excess amounts proposed for recovery in rates in 2017 are significantly above this materiality threshold. For pensions, the net excess amount included in rates relative to the amounts actually paid is $431,000 and for OPEBs, it is $257,000.

OEB staff submits that given the approach of the OEB towards pension and OPEB costs that began with the referenced OPG Decision of 2014, the OEB should not allow Canadian Niagara Power to include in rates on a final basis the accrual accounting number. The OEB has taken a similar approach to that of the OPG decision in subsequent rate cases, including in rates as an interim measure the cash number when it is materially lower than the accrual accounting number (see footnote 3 on previous page for the relevant cases). However, OEB staff notes that many distributors remain on accrual accounting for pension and OPEBs costs. As such, it is OEB staff's view that it is

[5] E1/T5/S1, p.1

reasonable to allow Canadian Niagara Power to continue with recovery in rates of the accrual accounting number. The result of the consultation is not known, but information on the public record of the consultation has identified significant complexities with converting to a cash basis of recovery as a permanent measure. At the same time, staff submits that it is necessary to establish a variance account that tracks the difference between the accrual amount and the forecast cash contributions for the test period. In this manner, a future OEB panel on Canadian Niagara Power's next cost-based rate case will have the ability to apply the outcome of the generic consultation, whether that is for Canadian Niagara Power to remain on accrual permanently, convert to the cash method or adopt some other approach.

As such, OEB staff does not agree with the submission of Canadian Niagara Power that the OEB should abstain from making a decision on this matter, even if it is an interim measure. Canadian Niagara Power's base rates for the next five years are being set in this application and OEB staff is of the view that it would not be appropriate for the OEB panel to abstain from making a decision that will affect rates for the next five years. Given the potential for a material over recovery of pension and OPEBs expenditures that is forecast by Canadian Niagara Power, a variance account is necessary to protect customers.

Furthermore, the fact that the OEB approved Canadian Niagara Power's use of the accrual method in its previous cost of service case, and that intervenors did not oppose it at that time, does not restrict the position that may be taken by any party in a subsequent cost of service application.

With respect to the proposed variance account, Canadian Niagara Power argued that while there was some discussion at the oral hearing about a variance account being used in regard to cash versus accrual accounting, the intervenors provided little information on the specifics of what the variance account would record and the mechanics of the account. Canadian Niagara Power concluded that in the absence of such details, it was unable to comment on this matter.

OEB staff notes that the OEB has established variance accounts for OPG and other distributors over the past 24 months in circumstances where the cash number is embedded in rates with the difference being tracked in the variance account. OEB staff sees no reason why the same approach to the mechanics cannot be followed in the event the OEB accepts OEB staff's proposal to allow the accrual number in rates as opposed to the cash number, as an interim measure.

Treatment of Expected Changes in the Cost of Long-Term Debt for 2018

Background

Canadian Niagara Power's application provided information on its outstanding debt instruments, which showed that on August 14, 2018 $30,000,000 of Senior Unsecured Notes with a coupon rate of 7.092% will mature. The settlement proposal noted that the parties had not agreed on whether it is appropriate to recognize and if so how to recognize in revenue requirement or rates any differential between Canadian Niagara Power's cost of long term debt and current market rates for long term debt, or any change in the cost of long-term debt in 2018.

Canadian Niagara Power submitted that it would be inappropriate for the OEB to consider potential changes to its cost of long-term debt beyond the 2017 Test year since it filed its cost of service rate application on a single test year basis, not on a Custom IR basis and, as such, any potential reduction in actual cost of capital in future years should not be reflected in 2017 rates.

OEB Staff Submission

OEB staff notes that rates in this application are being set for the 2017 test year and this potential reduction in the long-term debt cost is to occur in 2018. For this reason, OEB staff submits that it is inappropriate to directly recognize in rates any differential between Canadian Niagara Power's cost of long term debt and current market rates for long term debt, or any change in the cost of long-term debt in 2018. As such, OEB staff is also of the view that the related proposal for a variance account to record these amounts is unnecessary.

OEB staff takes this position on the basis that selecting individual items of this kind from outside the test year and seeking adjustments for them is "cherry-picking" and if accepted opens the door to the possibility of additional adjustments of this kind being proposed by either applicants, intervenors or both in future applications related to non-test year anticipated changes. Such changes may either have the effect of decreasing rates, as is likely here, or increasing rates if a distributor was to seek adjustments of this kind for significant cost shifts outside the test year.

OEB staff further notes that the OEB Rate Handbook[6] summarizes the OEB's cost of capital policy in stating that "(t)he general expectation is that the cost of capital parameters will remain unchanged throughout the rate-setting term, typically five years." Any adjustment made to this application to recognize expected changes in the cost of long-term debt in 2018 is a move away from this expectation and may represent the first step towards a year-by-year examination of cost of capital rates in non-test years for cost of service applications. Such an approach would be contradictory with the approach outlined in the Handbook. In this context, OEB staff also notes that when the OEB revised its cost of capital approach in 2009, which resulted in an increase in the allowed rate of return on equity, distributors were only able to effect the increase by filing a cost of service application, rather than "cherry-picking" this cost for updating.[7]

OM&A Expenses

Background

Canadian Niagara Power's historic and proposed OM&A levels are summarized in the table below[8] as are the percentage changes over both a one-year and two-year time periods:

[6] Ontario Energy Board *Handbook to Utility Rate Applications* App. 3, p. iii

[7] Ontario Energy Board EB-2009-0084 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities,* December 11, 2009, p. 61.

[8] Sources: 2013BA E4/T1/S1/p. 1/T4.1.1, remainder Canadian Niagara Power Inc. Hearing Materials Filed: January 3, 2017, Tab 4 OM&A Annual Comparison.

	OM&A ($)	Chg ($)	Yr over Yr Chg (%)	Act 2 Year Chg (%)
2013 BA	9,835,961			
2013 A	8,864,063	- 971,898	-9.88	
2014 A	9,434,813	570,750	6.44	
2015 A	9,518,933	84,120	0.89	7.39
2016 B	10,160,816	641,883	6.74	7.69
2017 T	10,574,723	413,907	4.07	11.09

BA=Board Approved
A=Actual
B=Bridge
T=Test

Canadian Niagara Power submitted that its proposed 2017 OM&A budget was appropriate as it had provided detailed explanations for all of its material OM&A programs, cost drivers and annual variances since 2013 in accordance with the OEB's filing requirements.

Canadian Niagara Power further noted that it had also provided summaries that highlighted: (1) the fact that its OM&A programs satisfy the RRFE objectives and provide value to ratepayers, and (2) that Canadian Niagara Power has undertaken and will continue to undertake numerous programs that improve its productivity.

Canadian Niagara Power stated that it had also demonstrated that although it appeared to be relatively unproductive based on PEG's econometric model, when adjusted to address the impacts of Canadian Niagara Power's atypically high Other Revenues, it was actually a reasonably productive utility. Canadian Niagara Power is in the OEB's incentive rate-setting Group 4 for 2015 and 2016 which means that it has a 0.45 stretch factor, within an overall range from 0 to 0.60, establishing it as a higher than average cost performer. Canadian Niagara Power acknowledged during cross-examination that it is a relatively high cost and high rate distributor.[9]

[9] Transcript Vol. 1, p. 139 L19 to L22.

OEB Staff Submission

OEB staff notes that there are several issues with regard to Canadian Niagara Power's OM&A levels summarized in the table above. These are: (1) the 10% disparity between the 2013 OEB approved level and the lower amount actually spent, (2) the 11% increase in 2017 proposed relative to the 2015 actual level and (3) concerns that Canadian Niagara Power is a high cost utility.

Disparity Between the OEB Approved Level and the Lower Amount Actually Spent

OEB staff notes that while Canadian Niagara Power provided explanations for the significant 10% discrepancy between the 2013 OEB approved level of OM&A expenses and the actual amount incurred[10] the fact remains that the higher amount was used in 2012 to set Canadian Niagara Power's rates for the next four years. As shown in the above table, Canadian Niagara Power's actual OM&A expenses were only forecast to exceed the 2013 OEB approved level in the 2016 Bridge Year. However, during cross-examination by Mr. Aiken on January 4, 2017, Mr. King stated that Canadian Niagara Power's current 2016 OM&A full year forecast is somewhere between $9.7 to $9.9[11] million which means that the 2013 OEB approved level may not be exceeded until the 2017 test year. OEB staff is of the view that the magnitude of the difference between Canadian Niagara Power's forecast OM&A which was approved based on the 2013 application and the actual levels for the following years supports concerns that the proposed 2017 test year level may also be overstated.

Increase in 2017 Proposed Relative to the 2015 Actual Level

OEB staff notes that although the 2015 actual level of OM&A of $9,518,933 is still over three percent lower than the 2013 OEB approved level for this two-year period, Canadian Niagara Power is asking for an increase in the 2017 test year that if granted by the OEB would allow for an 11% increase over the 2015 to 2017 two-year period. When the significantly lower 2013 actual level is compared to the 2015 actual level, OM&A

[10] E 4/T2/S2/p. 9
[11] Transcript Vol. 1, p. 170 L18-L25

expenses still only show a 7.4% two-year increase which is approximately a third lower than the overall 11% increase being requested by Canadian Niagara Power.

OEB staff submits that the changes in actual OM&A levels in the 2013 to 2015 period when compared to the significantly higher 2015 to 2017 forecast change also support the view that the OM&A level requested by Canadian Niagara Power in the 2017 test year may be too high.

Concern That Canadian Niagara Power is a High Cost Utility

As discussed above, Canadian Niagara Power is in the OEB's incentive rate-setting Group 4 for 2015 and 2016 which means that it has a 0.45 stretch factor, within an overall range from 0 to 0.60, establishing it as a higher than average cost performer. Canadian Niagara Power acknowledged during cross-examination that it is a relatively high cost and high rate distributor.[12]

Canadian Niagara Power was asked through an OEB staff interrogatory[13] to discuss results from the completed version of the OEB's Benchmarking Spreadsheet Forecast Model which showed a growing differential between its Actual and Predicted Total Cost, rising from 13.0% in 2015 to a forecast 16.4% in the 2017 test year (subsequently updated to 15.9%[14]). Canadian Niagara Power's response stated in part that:

> The Model uses a set of statistically significant coefficients to predict a distributor's costs that are based on analysis of Ontario-wide data up to 2012, intended to allow benchmarking of distributors for the purpose of assigning stretch factors to individual LDC's during 4th Generation IR applications.
>
> CNPI's Cost of Service Application on the other hand includes a comprehensive Distribution System Plan, based on a regulatory framework and associated filing requirements that have changed substantially since 2012. Many of the projects and programs justified in CNPI's Application identify primary drivers that are not directly related to coefficients in the Model, including but not limited to, safety, reliability, regulatory requirements and asset end of life. The misalignment between CNPI's cost drivers in a Cost of Service application and the Model coefficients developed for benchmarking in the context of incentive ratemaking results in an increasing differential between Actual and Predicted Total Cost.

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[12] *Ibid,* p. 139 L19 to L22.
[13] 1-Staff-16
[14] Response to Undertakings. J1.3, p. 3.

During the oral hearing, OEB staff sought further clarification as to what Canadian Niagara Power meant by the above-referenced misalignment and whether the cost drivers in question were generic to all distributors or specific to Canadian Niagara Power[15]:

> MS. DJURDJEVIC: Okay. And if I am understanding you correctly, the suggestion is that there are certain cost drivers that are not being picked up in the models or the PEG model.
>
> MR. BEHARRIELL: Yes.
>
> MS. DJURDJEVIC: Now, are you able to tell us what those are and if they are generic or they are specific to CNPI? You may want to do this by way of undertaking, or if you can answer here.
>
> MR. BEHARRIELL: Well, I think we have discussed some generically in the technical conference. You just mentioned a bunch of them, the DSP, the RRFE, things like that. And then I can take you to the cost driver table in tab 5 of our hearing materials, which details cost drivers specific to CNPI. Some of them are specific to CNPI, some of them are not. For example, the one-call initiative would be, you know, equally applicable to, you know, all LDCs in the province, maybe to different degrees, depending on the number of utilities doing underground work in their service area.
>
> I am not saying they would be exactly equally applicable to all LDCs. Some of them, we have added a pole-testing program. I can't speak to whether other LDCs have or have not or when they have since that 2002 to 2012 time period. We have a cost driver for missed metering that again would impact all LDCs, so when you look at our results using the PEG model and you infer any trending from those results, there are cost drivers that are affecting the costs that go into the model that aren't picked up on the inputs and the coefficients.

[15] Transcript V1, p. 137 L9 to p. 138 L10.

OEB staff notes that in the above response, Canadian Niagara Power did not provide a specific example of costs which were clearly unique to it. Subsequently this matter again arose and Canadian Niagara Power's response was to cite unique characteristics of its network as one such example[16]:

> MS. SPOEL: If you want to give a specific example of why your utility faces higher cost situations for the number of customers, that's fine. But it's not off the record.
>
> MR. BEHARRIELL: I can add to Mr. Han's technical analysis. I have a lot of experience in engineering and system planning from my previous role at Algoma Power, and one that strikes me about CNPI and Fort Erie in particular is the number of substations, the amount of 34.a KV line required to bring the transmission voltage to those substations and step it down again. You know, there is historical decisions that go back generations into that system design where utilities in our neighbourhood, like NPEI, like Niagara on the Lake, who historically have had a 25 KV or 276 KV voltage coming from Hydro One and then going to step down stations to 4 KV have been able to eliminate those substations and the costs of, you know, continued capital investment, continued maintenance on those substations, because those voltages, 25 KV, 27.6 KV, are standard distribution voltages. They have just simply -- you know, as the equipment at those voltages over the years has become more available and more cost-effective, they have just simply eliminated old substations and eliminated those costs.
>
> The legacy decisions that have been made on our system, it is just -- it is not possible. We could go to a 34.5 KV distribution voltage, in theory. The costs are much higher at 34.5 KV than they are at the standard distribution voltage classes, 28 KV and less.

[16] Transcript Vol. 1, p. 159 L21 to p. 160 L21

Mr. Beharriell in his testimony quoted above appears to be blaming legacy decisions for Canadian Niagara Power's inability to deal with higher cost elements of its network, while neighbouring utilities such as Niagara on the Lake have been more successful in doing so. In this context, Mr. Shepherd raised the issue during his cross-examination as to the time Fortis, Canadian Niagara Power's parent company had owned the various components of the present utility and established that this was a period ranging from 15 to 20 years and in spite of the passage of that considerable period of time, this problem had not been dealt with.[17]

OEB staff notes that Canadian Niagara Power did not provide any evidence of the extent of the impact of the network characteristics factor cited above on the results arising from the OEB model. The uniqueness of this factor is also doubtful as it can be seen as falling under the general category of the need for network modernization - a factor common to many distributors. OEB staff submits that if Canadian Niagara Power believes that there are any other factors on the record of this proceeding which it considers are unique to it and are driving its higher level of costs, it should summarize them in its reply argument, including why it believes they are unique.

In this context, OEB staff further notes that on January 3, 2017, Canadian Niagara Power filed as part of its "Hearing Materials" document Tab 8 "Adjusted PEG Econometric Model." Canadian Niagara Power explained that the most recent version of the OEB's Benchmarking Forecast Model prepared by it had been filed in conjunction with the Technical Conference. At that time, Canadian Niagara Power had updated the inputs for the OEB's revised cost of capital parameters and had also noted an issue associated with the mismatch between costs and revenues associated with Other Revenue accounts. The version of the model filed in Tab 8 provided further updates to the cost of capital inputs as well as an analysis with further details on the Other Revenue issue.

Canadian Niagara Power argued that this version of the model suggested that it should be in the Category 3 Stretch Factor Cohort, rather than Category 4, as is presently the case. It is this analysis that is the basis of Canadian Niagara Power's claim in its submission that it is a relatively productive utility when the Other Revenue matter is taken into account.

[17] Transcript Vol. 1 p. 160 L 22 to p. 161 L12.

OEB staff disagrees with Canadian Niagara Power's claim. OEB staff notes that the analysis provided by Canadian Niagara Power removes Other Revenue Offset amounts from the years 2017 to 2021, but not 2015 or 2016, making the Total Cost numbers for these years inconsistent with those for the following years. Mr. Shepherd discussed this matter in some detail with Canadian Niagara Power during his cross-examination[18] and, related to it, what could be concluded from the modified version of the model. The following exchange between Mr. Shepherd and Mr. Beharriell explains why in OEB staff's view, the version of the benchmarking model filed in Tab 8 is of little use to the OEB in this proceeding[19]:

> MR. SHEPHERD: So your 2017 forward and your 2015 and 2016 in this presentation are not comparable, are they?
>
> MR. BEHARRIELL: Well, and that's why we left the original results of the benchmarking model in, so line G presents the unadjusted results. So if you are trying to look at trending, then the trending is there.
>
> I think you are reading too much into this model. We presented it as, here is an issue that we see with the results of the model, and here is an adjustment, you know, that from a high-level perspective -- and I agree with earlier comments that this might need to be investigated in more detail -- presents, you know, our attempt to adjust the model to show at a high level at a ballpark what that adjustment results in.
>
> MR. SHEPHERD: Can I simplify this?
>
> MR. BEHARRIELL: Sure.
>
> MR. SHEPHERD: Is it fair to say that you can't find in the model, and so you assume it is isn't there -- and I looked too and I can't find it either -- some way that the variation in other revenues related to internal cost sharing is reflected? You can't find that in the model; right?
>
> MR. BEHARRIELL: Right.
>
> MR. SHEPHERD: And you don't know what the impact of not having it

[18] Transcript Vol. 1, p.176, L10 to p. 183 L16
[19] *Ibid,* p. 177 L6 to p. 178 L3.

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in the model is; do you?
       MR. BEHARRIELL:  Correct.
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OEB staff concludes that Canadian Niagara Power has failed to provide any clearly unique utility specific examples to justify its position that it has higher cost factors than other distributors. The absence of the identification of such factors goes against its argument in favour of an OM&A increase which over a two-year period from 2015 to 2017 is considerably higher than the inflation rate. OEB staff further submits that the analysis provided by Canadian Niagara Power does not support its view that the adjustments it has made for Other Revenues change the appearance of it being a relatively inefficient utility to being a reasonably efficient one.

In addition, it is OEB staff's view that cost control and productivity improvements need to be demonstrated in all cost-based applications (not just Custom IR). Incentives are inherent in the IRM mechanism, so efficiency measures should have been taking place over the previous IR years. Cost of service is not a catch-up and that the equivalent of an "IRM adjustment" should not be considered the "floor" or the starting point for the test year. For a utility such as Canadian Niagara Power whose total cost performance is not improving over time, OEB staff is of the view that the OEB should take this into consideration when setting the base for the next incentive rate-setting period.

On this basis, OEB staff submits that a significant reduction by the OEB in the 2017 Test year approved OM&A level from that sought in the application would be justified both in light of the over forecast of OM&A requirements in Canadian Niagara Power's previous 2013 cost of service application and also to provide an additional incentive to encourage Canadian Niagara Power to work to achieve additional cost efficiencies in the next five years.

In this context, OEB staff also notes the anticipated reduction in Canadian Niagara Power's long-term debt costs in 2018 would provide a potential disincentive to efficiency that would potentially be further enhanced the higher the level of test year OM&A expenses approved by the OEB as a result of the present application.

OEB staff recommends that as a starting point, the allowed increase in OM&A for 2017 be reduced from the 11.1% increase relative to the 2015 actual level which is proposed in the application to 7.4%, which is the two year increase on an actual basis between

2013 and 2015. Further, OEB staff is of the view that Canadian Niagara Power is a high cost utility that has not justified in this context its entire increase relative to the year in which it was last before the OEB (2013). Therefore, a further disallowance is justified. If the OEB were to allow an increase only for inflation dating back to 2013 actuals, the overall reduction to the 2017 test year would be approximately $1,000,000. OEB staff is of the view however that the utility has justified some of the increases to certain OM&A programs such as the pole testing and emerald ash borer programs as well as those related to mandated programs such as the Ontario One Call System and MIST metering programs.

OEB staff therefore recommends that the OEB could set the 2017 OM&A envelope halfway between the amount that arises with only a 7.4% increased from 2015, and the amount that would result from only an inflationary increase from 2013 actuals. This approach would disallow a total of approximately $700,000 or 6.5% of Canadian Niagara Power's test year OM&A budget. OEB staff is of the view that given the evidence in this case, this is a reasonable outcome. OEB staff notes that this would produce an allowed OM&A level of $9.9 million which is the upper end of Canadian Niagara Power's current 2016 forecast and slightly higher than the 2013 OEB approved level.

OEB staff believes that its proposed level of allowed test year OM&A would be more representative of the actual level of increase in Canadian Niagara Power's OM&A in recent years and would provide an additional incentive for Canadian Niagara Power to increase its efficiency. OEB staff further notes in this context that for each one percent drop in the refinancing rate for the debt maturing in 2018 (current rate 7.092%), Canadian Niagara Power will save $300,000 in interest costs.

Effective Date

Background

Canadian Niagara Power submitted that it had met all deadlines prescribed and ordered by the OEB and, as such, the effective date should be January 1, 2017.

The partial settlement proposal noted that it was not likely the OEB would release a decision on the unsettled issues prior to the proposed January 1, 2017 implementation date for all proposed rates and this did not happen. It further noted that Canadian Niagara Power had in its application requested an order making its current rates interim as of January 1, 2017. The OEB issued an Interim Rate Order on December 13, 2016. The partial settlement proposal stated that the issue of the appropriateness of a January 1, 2017 effective date for rates remained an unsettled issue.

OEB Staff Submission

OEB staff submits that the effective date for rates of January 1, 2017 is appropriate as Canadian Niagara Power has met all deadlines established during the application process in a timely fashion.

- All of which is respectfully submitted –