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BY E-MAIL

July 14, 2017

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

Dear Ms. Walli:

Re: Thunder Bay Hydro Electricity Distribution Inc.
2017 Distribution Rate Application
OEB Staff Submission
OEB File No. EB-2016-0105

In accordance with Procedural Order No. 6, please find attached OEB staff's submission in the above proceeding on the unsettled issues for this application. The attached document has been forwarded to Thunder Bay Hydro Electricity Distribution Inc. and to all other registered parties to this proceeding.

Yours truly,

Original Signed By

Martin Davies
Project Advisor, Major Applications

Encl.

2017 ELECTRICITY DISTRIBUTION RATES

Thunder Bay Hydro Electricity Distribution Inc.

EB-2016-0105

ONTARIO ENERGY BOARD

STAFF SUBMISSION

July 14, 2017

INTRODUCTION

Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay Hydro) filed a complete cost of service application with the Ontario Energy Board (OEB) on September 9, 2016 seeking approval for changes to the rates that Thunder Bay Hydro charges for electricity distribution to be effective May 1, 2017. The OEB issued an approved issues list for this proceeding on February 10, 2017. A settlement conference was held February 14 to February 16, 2017 and Thunder Bay Hydro filed a revised partial settlement proposal setting out an agreement between all of the parties to the proceeding on April 27, 2017. The parties to the partial settlement proposal are Thunder Bay Hydro and the following approved intervenors in the proceeding: Association of Major Power Consumers in Ontario, School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC). On May 4, 2017, the OEB accepted the partial settlement proposal.

The issues that were not settled are listed below:

- Issues 1.1 and 2.1 Capital.
- Issues 1.2 and 2.1 OM&A.
- Issue 2.1 Cost of Capital.

Capital

Background

Thunder Bay Hydro stated that in creating its Distribution System Plan (DSP)[1], it had aligned the objectives and scope of the 2017 - 2021 investment plan directly with the OEB's Renewed Regulatory Framework for Electricity Distributors (RRFE) and Thunder Bay Hydro's core values, to ensure that the OEB's DSP evaluation criteria of efficiency, customer value and reliability are embedded into its future plans[2].

[1] Exhibit 2/Attachment 2-B
[2] Exhibit 1, p. 56

Thunder Bay Hydro further stated that the main drivers in the DSP are voltage conversion, system renewal of overhead lines and underground plant, and investments in grid modernization. Thunder Bay Hydro stated that its capital expenditure plan seeks to minimize the cost of an asset over its life by striking the right balance between capital investments in new infrastructure and ongoing operating and maintenance costs.

Certain aspects of the Thunder Bay Hydro DSP were of good quality, in OEB staff's submission. The DSP was generally clearly written, and the evidence was presented in a way that was helpful to the reader. The DSP was arranged using the OEB Chapter 5 Filing Requirements as a template, which helps the reader understand how the requirements have been addressed.

OEB staff found the Health Index Results Summary 2015[3] useful, as it presented a one page overview of the health index of all the assets by category, and in some cases by sub-category. The figure provides a good indication of Thunder Bay Hydro's current view of asset health, although OEB staff recognizes that the asset condition data is as yet incomplete. OEB Staff also found the discussion of reactive and proactive maintenance logical and helpful[4], and appreciated the description of risk as a combination of probability of failure and consequence of failure, estimated using criticality. However, as detailed later in this submission, it is not clear to OEB staff whether the maintenance and risk mitigation strategy is being effectively applied.

Trends in capital expenditures

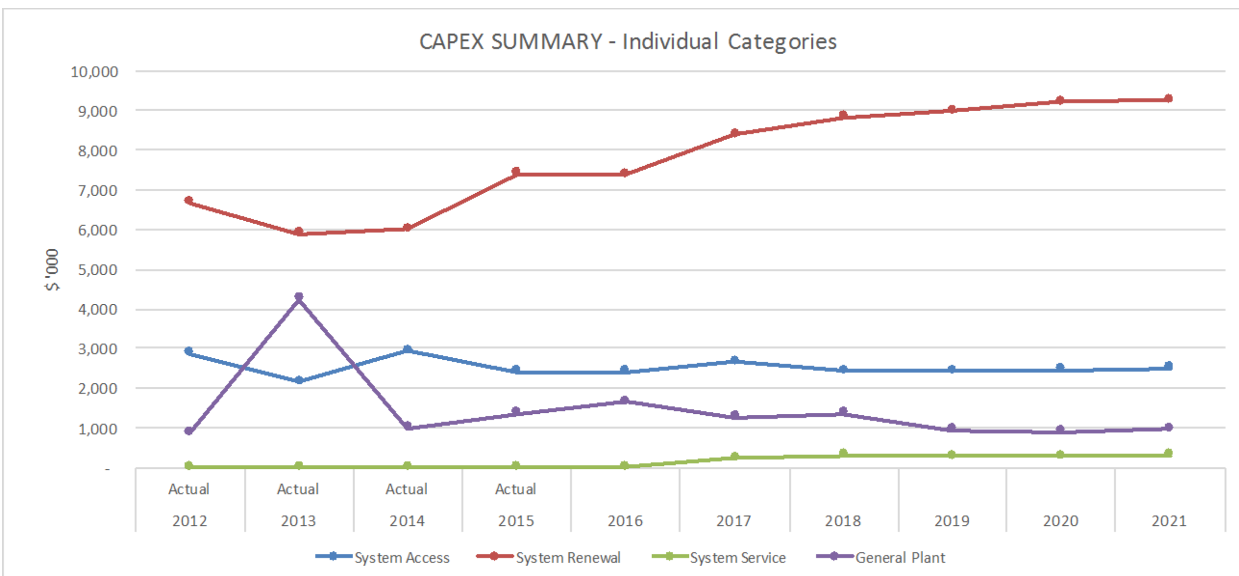
Thunder Bay Hydro's capital expenditures are delineated into four categories: System Renewal, System Access, System Service and General Plant. In the 2017 test year, Thunder Bay Hydro planned for an increase in capital spending in comparison to the 2016 bridge year primarily due to increases in the System Renewal investment category. As outlined in Thunder Bay Hydro's DSP, System Renewal projects represent investments required due to assets reaching the end of their Typical Useful Life and having a poor health index as represented in the Kinectrics Asset Condition Assessment

[3] Exhibit 2, Attachment 2-B, p.62, Figure 5.3.1.2
[4] Exhibit 2, Attachment 2-B, p.63

(ACA) report[5]. The results of this report resulted in a shift in infrastructure investment for Thunder Bay Hydro, which begins in 2017.

The overall levels of forecast capital expenditures are shown below[6]:

Category	Historic Actual Expenditures				Bridge Year	Forecast Expenditures				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Actual	Actual	Actual	Actual						
	$ '000	$ '000	$ '000	$ '000	$ '000					
System Access	2,864	2,154	2,937	2,412	2,398	2,662	2,422	2,432	2,445	2,505
System Renewal	6,664	5,888	5,994	7,413	7,388	8,380	8,818	8,976	9,217	9,261
System Service	-	-	-	-	1	230	300	280	280	300
General Plant	877	4,246	989	1,345	1,664	1,253	1,360	946	901	969
Total Capital Expenditure	10,405	12,287	9,920	11,171	11,451	12,526	12,900	12,634	12,842	13,036



These tables demonstrate the very significant component of the capital program that is represented by system renewal investments, specifically $8.4 million out of a total budget of roughly $12.5 million, or around two-thirds of the total budget.

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[5] Exhibit 2, Attachment 2-B, Appendix C of the DSP

[6] Exhibit K2.1

OEB Staff Submission

Before discussing OEB staff's concerns with the system renewal expenditures, the other categories will be briefly reviewed.

System Access

Thunder Bay Hydro stated that it did not expect to see any material changes in the System Access category in 2017 as compared to 2016 expenditures. As can be seen on the previous page, the system access category expenditures drop from $2.7 million in 2017 to a level in the $2.4 to $2.5 million range in the 2018 to 2021 period. This level of expenditure is reasonably consistent with historic levels in the 2012 to 2015 period which range from $2.2 million to $2.9 million. Thunder Bay Hydro stated that the System Access category is primarily influenced by customer preferences (such as its mandatory obligation to connect and responses to third party asset relocate requests[7]), and can be difficult to forecast and budget. As a result, it has used historical figures and consultations with the City of Thunder Bay to determine budgets, but in many cases connections are requested and executed within the same year, resulting in large fluctuations year over year[8]. OEB staff accepts Thunder Bay Hydro's forecasts in this category.

System Service

OEB staff notes that this is the smallest category of expenditures with only $230,375 forecast for the 2017 test year or around two percent of the total capital budget. This category is forecast to be in the $280,000 to $300,000 range in the 2018 to 2021 period. Thunder Bay Hydro stated that this expenditure is for distribution automation expenditures intended to enhance Thunder Bay Hydro's ability to provide improved reliability to Small Commercial and Large User customers. This project also includes investments in improved SCADA infrastructure and was developed in response to customer preferences as received from feedback in the 2016 DSP customer engagement survey[9].

[7] Argument-in-Chief, p. 15
[8] Exhibit 1, p. 58
[9] Exhibit 1, p. 57

OEB staff does not oppose this expenditure, and notes that there were no system service expenditures in the 2012 to 2016 period, and the current period expenditures are minor.

General Plant

OEB staff notes that this category of expenditure is roughly $1.2 million in the test year, to rise to $1.4 million in 2018 and to be in the $900,000 to $1.0 million range in the three later years. The 2015 and 2016 actual levels were $1.3 million in 2015 and $1.5 million in 2016. Thunder Bay Hydro stated that the reason for the decrease in this category in 2017 was due to the SCADA upgrade implementation project completion in 2016[10].

Thunder Bay Hydro noted that its proposed expenditures in this category in the test year are less than what was actually spent in both 2015 and 2016 and further stated that the amount was generally consistent with other years, reflecting a levelized approach to making general plant investments including fleet replacements, IT equipment and software, and tools and equipment.[11]The table below summarizes these expenditures for the 2012 to 2021 period:

General Plant ($000):			
			Source:
2012	877		E2, p.34 Table 2-11
2013	4246		E2, p.34 Table 2-11
2014	989		E2, p.34 Table 2-11
2015	1345		E2, p.34 Table 2-11
2016	1538		Exhibit J2.1
Avg.	1187.25		Excludes 2013
2017	1253		Argument-in-Chief, p.11
2018	1360		E1, pp. 57-58 Table 1-25
2019	946		E1, pp. 57-58 Table 1-25
2020	901		E1, pp. 57-58 Table 1-25
2021	969		E1, pp. 57-58 Table 1-25
Avg.	1085.8		

[10] Exhibit 1, p. 57
[11] Argument-in-Chief, p. 11

OEB staff accepts Thunder Bay Hydro's test year forecast in this category as it is less than what was actually spent in 2015 and 2016. In addition, OEB staff notes that, as is shown in the above table, the average level of actual expenditures in this category for the 2012 to 2016 period when the 2013 outlier is removed, is also approximately $1.2 million while the average expenditures for the forecast period are about $1.1 million, which supports Thunder Bay Hydro's argument that it is using a levelized approach to making these investments

System Renewal

In the System Renewal category, Thunder Bay Hydro proposed capital expenditures for the 2017 test year that include $5.5M in major projects for voltage conversion, an additional $1.7M in wood pole replacements and $1.1M to replace underground cables, transformers and switches. The 2017 system renewal capital budget is about 17% higher than the 2016 budget. The four year historical average capital spending in this category is about $6.5M, and the forecast expenditures for the six years 2016 – 2021 is an average of $8.6M. This is approximately a 30% increase. Using the actual numbers for 2016 provided during the hearing still results in an increase of over 30% in this category.

Thunder Bay Hydro explained in the DSP that historically, the focus of investment was the decommissioning of aged 4kV substations assets in conjunction with aged wood poles connected to the substation. The strategy was to convert the 4kV network to 25kV through an accelerated wood pole renewal plan resulting in a decommissioning schedule whereby all 4kV power transformers would be removed from service over a 10 year period[12].

However, from the detailed analysis of the 4kV substation assets in the ACA, Thunder Bay Hydro learned that the these assets are in much better health than previously assumed, and the Flagged for Action Plan produced by Kinetrics identified only one substation asset that should be addressed within the next five years[13]. Thunder Bay Hydro stated that this realization prompted a significant change in the previous

[12] Exhibit 2, Attachment 2-B p.69
[13] Ibid pp. 70 - 73

philosophy of accelerated renewal of the 4kV network, and Thunder Bay Hydro has begun to revise its 4kV renewal program to allow for the stations to remain in service longer.

Thunder Bay Hydro decided to shift to a more balanced System Renewal plan, which it defined as one which accounts for renewal of assets on 4kV as well as 12kV and 25kV, and of both overhead and underground classifications[14]. This approach resulted in an increase from historical levels of investment in underground infrastructure and 25kV pole replacements to begin in 2017. Thunder Bay Hydro anticipates becoming aligned with the renewal levels suggested by Kinectrics by the 2019 fiscal year. Once these levels of asset replacement have been reached, Thunder Bay Hydro expects that expenditures in the System Renewal category will remain static from 2019 to 2021[15].

OEB staff does not disagree with the philosophy described in the DSP regarding System Renewal investments. However, OEB staff submits that a detailed review of the evidence regarding System Renewal projects proposed for 2017 and subsequent years does not support the proposed increase in investment in this category.

An examination of the material capital projects and programs chart in the DSP[16] shows a total of over $5.2 million to be spent in 2017 on projects described as voltage conversion. OEB staff found it difficult to get a clear understanding of the need for the voltage conversion expenditures in 2017, and the reasons for the prioritization of the projects. With the exception of one transformer at the Hardisty substation, none of the substation assets are flagged for action within five years. When questioned about the need for the projects given the relatively good condition of the substation assets, the Thunder Bay Hydro witnesses explained that voltage conversion projects may be driven by the age and condition of the poles and transformers in the area of the substation[17]. However, in OEB staff's submission, the evidence on the record does not support this explanation.

[14] Exhibit 1, p. 58
[15] Ibid
[16] Exhibit 2 Attachment 2-B, p.143
[17] Transcript Vol. 2 p. 44 L1 to p. 45 L7

The project summaries provided in the DSP[18] do not provide a clear explanation of why these projects are all needed in 2017. The project summaries are very similar for each project. In the section labelled "Analysis of Project Benefits and Timing"[19], each summary states "While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2017 may cause the risk of failure to increase dramatically and will reduce some of the project benefits." However, none of the project summaries explain why the risk of failure would "increase dramatically" with delay.

The Project Alternatives sections state that the alternative of delaying a project to a later date would postpone the removal of the relevant sub-station, thus increasing maintenance costs for a number of years. This explanation would appear to suggest that it is the sub-station assets that are driving the need for the project, not the associated poles and conductors, although Thunder Bay Hydro acknowledged that no substation assets (with one exception) are flagged for action within five years. Indeed, many of the sub-station assets are listed as having 20 years or more of remaining useful life[20].

The project summaries do mention the risk of lengthy unplanned outages from failed poles, but the emphasis is on the need to retire the sub-station. Indeed the section of the project summaries providing "Information on the condition of the assets relative to their typical life cycle and performance record"[21] states "Numerous assets involved with these projects are not being replaced due to their performance, but rather as part of the process of uprating to 25kV, which results in the need for a higher standard of pole, framing and transformer." OEB staff suggests that Thunder Bay Hydro's previous strategy of accelerating decommissioning of 4kV substations is still a driver behind these projects.

As an example of the importance of pole replacement in the choice of voltage conversion projects, Ms. Bailey referred to the Black-Bay Dewe voltage conversion project summary at the "Project Summary" section[22], which refers to the replacement of end of life 4kV distribution assets and the replacement of 144 poles. However, that same paragraph

[18] Exhibit 2/Attachment 2-B, Appendix J
[19] Exhibit 2 Attachment 2-B Appendix J, Section 5.4.5.2 SR-C5 of each summary
[20] Exhibit 2 Attachment 2-B, page 70 to 73
[21] Exhibit 2 Attachment 2-B Appendix J Section 5.4.5.2 SR C1.2 of each summary
[22] Exhibit 2 Attachment 2B, Appendix J13

states “This project has been prioritized due to the removal of the Grenville substation, which is 47 years of age and has been identified as having a low interconnectivity and no back up transformation should the substation transformer fail”. This wording suggests to staff that the replacement of poles is not the primary driver for this project. The Grenville transformer is in very good condition and has 20 or more years of useful life, according to the ACA[23].

OEB staff submits that the urgency and customer benefit of the capital spending in 2017 on voltage conversion projects has not been demonstrated, particularly given the new information from the ACA. OEB staff recognizes the benefits of moving to a 25kV system and retiring 4kV substations with poor condition assets and low interconnectivity. OEB staff also acknowledges that some projects may be at a stage of work that makes delay very difficult. OEB staff is not recommending that the OEB deny all the capital spending proposed for 2017 on voltage conversion projects. However, Thunder Bay Hydro’s residential and small commercial customers expressed a strong preference for cost control[24]. OEB staff submits that Thunder Bay Hydro has not demonstrated why the voltage conversion projects could not be paced more slowly to recognize customer concerns regarding costs.

OEB staff submits that the increase in capital spending in system renewal might be justified if Thunder Bay Hydro was addressing a problem with reliability that was affecting customers. However, the utility’s reliability, while variable, is generally improving[25]. In addition, it is not clear that deteriorated equipment is a major cause of outage frequency or duration. Thunder Bay Hydro acknowledged that their data on outage causes was not yet consistent or precise[26], so the attribution of outages to defective equipment as opposed to adverse weather or tree contacts cannot be relied upon.

OEB staff submits that the evidence demonstrates that weather and vegetation contacts are the predominant drivers of variability in reliability for Thunder Bay Hydro. This is understandable, given the geographic location of the utility and its forested service

[23] Exhibit 2 Attachment 2B, page 70.
[24] Exhibit 2 Attachment 2B page 23, Interrogatory response 2 Staff 27
[25] Exhibit 2 Attachment 2B page 14, 42-43, Appendix D page 4; Exhibit J2.2,Transcript Vol. 2 p. 61 L10-14, p.62 L3-9
[26] Transcript Vol 2 p. 62 L25 to p. 63 L16, p. 64 L17-25, p. 110 L14 to p. 111 L3.

area[27]. OEB staff submits that while age and condition of a pole will be a factor in whether that pole falls, the more important determinant is that pole's exposure to severe weather and tree contacts. If poles survive to an older age, it is likely that the location in which they stand is less subject to weather stress, and that the annual probability of failure may be less than a new pole in an exposed area. OEB staff submits that while maintaining reliability of the system is important, the ramp up in system renewal spending is not justified by data demonstrating a real risk of an increase in equipment caused outages.

OEB staff acknowledges that Thunder Bay Hydro is striving to implement best management practices, and is moving in the right direction by adopting a more condition-based asset management strategy. This strategy should help the utility to prioritize the order in which assets should be replaced and direct its capital spending to the most pressing concerns.

However, Thunder Bay Hydro will need more complete and reliable data on outage causes before it can optimize asset management practices to improve the resilience of the system. Once Thunder Bay Hydro has collected sufficient data, the utility can use it in capital planning processes, track the corresponding performance results, for example, trends in corrective maintenance[28], and refine the planning process as needed. OEB staff submits that this will help Thunder Bay Hydro target and pace capital investments over the course of time.

Conclusion

OEB staff submits that the DSP filed by Thunder Bay Hydro is responsive to the OEB's filing requirements and in general was clearly written. Some of the projects and proposed expenditures are well supported.

OEB staff supports Thunder Bay Hydro's move towards a more condition-based asset management strategy through the engagement of Kinectrics to produce the ACA. It appears to OEB staff that the utility is striving to implement best asset management practices, and this new approach should support system reliability and

[27] Transcript Vol 2 p. 61 L15 to p. 62 L2, p. 63 L14-16.
[28] Transcript Vol 2 p. 133 L24 to p. 134 L2.

resilience. However, Thunder Bay Hydro has only just started building an asset condition database, and even a perfectly designed asset management process cannot produce good outcomes without sufficient empirical data. OEB staff recommends that Thunder Bay Hydro collect asset removal and other data as recommended by Mr. Tsimberg[29], so that the results of the next ACA are more credible and useful in targeting capital investment.

That said, OEB staff submits that the evidence in this application does not support the total proposed spending in the system renewal category. In OEB staff's submission, the evidence shows that expenditures in this area could be reduced without a noticeable reduction in reliability or any other detriment to customers. Thunder Bay Hydro's customers are concerned about increasing costs and rates. In OEB staff's view, the evidence presented by Thunder Bay Hydro has not demonstrated the customer benefit of the significant increase in capital spending proposed for the test year in the system renewal category.

OEB staff submits that while many of the capital investments proposed for 2017 will provide customer benefit in the longer term, the pace at which Thunder Bay Hydro proposes to move forward with system renewal projects is not justified. OEB staff recommends that the OEB allow an increase in spending in this category consistent with the rate of inflation of 1.9%[30].

The actual 2016 spending in the system renewal category was $7,184,000[31]. An increase of 1.9% would yield an investment level of $7,320,496. Staff therefore recommends a reduction of $1,059,500 in the proposed capital expenditures for 2017, from $12,256,000 to $11,466,500.

[29] Y. Tsimberg: *Independent Assessment of Thunder Bay Hydro Electricity Distribution Inc. System Renewal Capital Requirements* (May 11, 2017) page 7, Transcript, Vol. 2 p. 113 L17 to p. 114 L21
[30] Ontario Energy Board, Inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2017, October 27, 2016
[31] Exhibit J2.1 Filed June 29, 2017

OM&A

Background

Thunder Bay Hydro's historic and proposed OM&A levels are summarized in the table below[32] as are the percentage changes over both one-year and two-year time periods:

	OM&A ($)	Chg ($)	Yr over Yr Chg (%)	Act 2 Year Chg (%)
2013 BA	14,300,000			
2013 A	13,232,884	- 1,067,116	-7.46	
2014 A	13,822,518	589,634	4.46	
2015 A	14,244,004	421,486	3.05	7.64
2016 A	15,430,638	1,186,634	8.33	11.63
2017 T	15,680,655	250,017	1.62	10.09

BA = OEB Approved
A = Actual
T = Test Year

Thunder Bay Hydro stated that it has demonstrated an emphasis on operational effectiveness and achieving sustainable cost savings for rate payers, but submitted that despite these best efforts, costs are still increasing and ROE has been steadily decreasing. Thunder Bay Hydro argued that the OEB should approve the requested OM&A expenditures in the 2017 test year as they reflected a measured and balanced approach to minimizing rates in accordance with the Rate Minimization Model, while doing what is needed to respond to new obligations mandated by government and the OEB and to address specific operational risks facing the utility in the near-term.

OEB Staff Submission

OEB staff submits that there is a variety of evidence on the record in this proceeding that would support the view that Thunder Bay Hydro's costs are too high and that its proposed 2017 Test year OM&A recovery should be reduced.

[32] EB-2016-0105 Exhibit 4/p.7 Table 4-1 except 2016 Actual which is from Argument-in-Chief, p. 15 and 2017 test year which is from EB-2016-0105 Exhibit J3.4 filed July 6, 2017.

i) *OEB Total Cost Benchmarking*

OEB staff notes that the cost benchmarking results filed by Thunder Bay Hydro using the OEB model suggests that Thunder Bay Hydro's total costs are about 10% above predicted total costs[33]. These results placed Thunder Bay Hydro in Stretch Factor Cohort 3, although they also showed it slipping into Cohort 4 during the 2016 bridge year when the differential reached 11 percent. Thunder Bay Hydro commented on this result as follows:

> The increase in costs is consistent with ongoing operating activities and Asset Management Plan, to replace, refurbish and modernize our aging distribution system and to connect all new customers. With continued dedication to finding efficiencies in operating and performing work Thunder Bay Hydro has managed to minimize the cost affecting the customer.[34]

ii) "Aiken Model" Results Presented by SEC

SEC presented OM&A calculations during its cross examination which also suggested that Thunder Bay Hydro's costs were too high[35]. This model, as stated by Mr. Shepherd, is known as the Aiken model and has been used in other proceedings before the OEB[36]. The model compares the changes in total OM&A that have occurred since the applicant's last cost of service applications, adjusted to remove one-time costs[37] against the level of cost increase that would be expected considering the escalators of inflation, base productivity, stretch factor and customer growth.

When this analysis is undertaken using Thunder Bay Hydro's 2013 actual OM&A level as a starting point, it produces an expected level of 2017 test year OM&A of $1,208,798 lower than the adjusted 2017 test year requested level of $15,390,872, or an eight percent reduction. When the same analysis is undertaken using 2014's higher starting point, this analysis still produces an expected 2017 test year OM&A of $816,631 lower, or a five percent reduction.

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[33] EB-2016-0105 Exhibit 1/p.32
[34] EB-2016-0105 Exhibit 1/p.32
[35] Transcript, Vol. 3, p.93 L12 to p. 99 L8
[36] School Energy Coalition Cross Examination Materials EB-2016-0105 Thunder Bay Hydro, p.62
[37] For Thunder Bay Hydro monthly billing costs of $118,000 and OEB Assessment costs of $339,000

iii) *Comparative Level of Test Year OM&A Increase Proposed*

If the increase in OM&A between 2013 actuals and 2015 actuals is compared to that between 2015 actuals and the 2017 test year, the increase in the latter period considerably exceeds that of the former period. In this context, OEB staff notes that the two year increase from the 2015 actual to the 2017 test year is 10.1%, as compared to only 7.6% for the 2013 actual to 2015 actual period. If this two-year growth rate was applied to the 2015 actual, the 2017 test year OM&A would be reduced to $15.3 million from $15.7 million.

iv) Overstatement of 2013 Test Year OM&A Compared to 2013 Actual

The overstatement of Thunder Bay Hydro's 2013 test year forecast as compared to the actual was considerable at $1,067,116 or 7.5%. OEB staff notes that if the 2017 test year forecast and 2017 actual level was to show the same differential, this would reduce the 2017 test year OM&A from $15.7 million to $14.5 million, a reduction of $1.2 million. Thunder Bay Hydro attempted to explain this discrepancy both within the evidence and during cross-examination.[38]

During cross-examination by Mr. Shepherd, who was attempting to clarify the reasons for this differential, Ms. Speziale referenced three items. The first of these was the completion of an actuarial valuation in January 2014, which resulted in costs being substantially lower than budgeted of which $190,000 impacted OM&A. Second, $350,000 related to the 2013 budget amount for overhead and underground maintenance costs being weather normalized. Finally there were supervisory and engineering allocation errors that were corrected in the amount of $182,000. Ms. Speziale concluded that the foregoing addressed $722,000 of the $892,000. It is also not clear how the $892,000 relates to the total $1,067,116 differential.

OEB staff is unclear as to the nature of some of these adjustments and why they could not have been anticipated. In addition, the amounts referenced by Ms. Speziale only appear to address $722,000 of the $1,067,116 differential.

[38] Transcript, Vol. 3, p. 87 L3 to P.93 L11

OEB staff submits that these explanations were not very clear and did not make a compelling case as to which of these factors could not have been foreseen at the time the application was filed and why.

v) Lack of OM&A Savings Being Generated by Increased Total Expenditures

OEB staff submits that for all the increases in capital and OM&A spending that have taken place in the previous five years and are being planned for the next five years very little in the way of efficiency savings have been achieved on a comparative basis. OEB staff asked Thunder Bay Hydro through an interrogatory to quantify the expected annual operational savings that would result from eight cost savings sources including such items as continued asset condition assessment, distribution automation, voltage conversion work and other similar programs.[39] The realized efficiencies identified ranged from $24,607 in 2017 up to $29,910 in 2021.

On a more general basis covering a longer time period of roughly ten years, Mr. Wilson also identified $1.2 million of efficiency savings during cross examination. However, it did not appear to be entirely clear exactly what this amount represented, or how significant it was relative to the magnitude of the expenditures being incurred[40]:

MR. SHEPHERD: So this is 1.2 million of total efficiency savings over the period from, what, 2013 until the next rebasing? Like nine years, ten years?

MR. WILSON: I wouldn't categorize it completely like that, but I say there's certainly a bridge over between the two.

MR. SHEPHERD: So you got $150 million of OM&A in that period or so and your efficiency saving are 1.2?

MR. WILSON: Right. So if you go back and look at my testimony, I call it a sample list. So I didn't -- I didn't

[39] EB-2016-0105 Responses to Interrogatories 2-Staff-26a
[40] Transcript Vol. 3, p.86 L16 to p. 87 L2

glean out every single item from within the application itself.

MR. SHEPHERD: All right, okay. I honestly don't understand what the $1.2 million means, but I don't want to spend time on it.

Thunder Bay Hydro, in its Argument-in-Chief, provided a clarification of the derivation of this amount which included an itemized breakdown of $1,079,484 million in annual savings for ratepayers, with the balance being one-time savings.[41] The largest of these savings in the amount of $570,000 is stated as having been achieved for the following reasons[42]:

> Attaining collective bargaining settlements below Thunder Bay Hydro's cohort average from 2013 to 2017, reducing wage schedules for new non-trades/technical positions, and the elimination of post retirement employer paid life insurance and eligible employee sick leave payout have resulted in a test year OM&A budget that is **$570,000 lower** than it would have been had management settled for industry average wage increases. This has been achieved without resorting to other non-wage improvements that have been seen in the industry. This is a good outcome for ratepayers, given the important role of wages and benefits as an OM&A cost driver year-over-year.

OEB staff notes that while the above number is referenced in Mr. Wilson's opening statement[43] during the oral hearing, Thunder Bay Hydro has provided no references in its Argument-in-Chief as to where it appears in the evidentiary record, nor where a breakdown of its calculation is provided along with related explanations. OEB staff submits that in the absence of such supporting calculations and explanations, limited weight should be placed upon this number by the OEB. OEB staff further submits that if Thunder Bay Hydro believes this information is on the record, it should provide specific references in its reply submission as to where it can be found.

vi) Level of Increase in Compensation Costs

OEB staff does not have concerns with the nature of the programs that Thunder Bay Hydro has proposed to undertake or continue such as the proactive replacement program to phase-out porcelain insulators that have known manufacturing defects and are prone to fail and the achievement of a planned seven year tree trimming and

[41] EB-2016-0105 Argument-In-Chief July 5, 2017, pp. 15 to 18
[42] EB-2016-0105 Argument-In-Chief July 5, 2017, pp. 15-16
[43] Transcript, Vol. 2, p. 14

vegetation management cycle. However, OEB staff has concerns with the level of the costs proposed overall and will focus its submission on Thunder Bay Hydro's compensation strategy to supplement the information noted above and below regarding the broader OM&A envelope. OEB staff is particularly concerned that the increase in the overall level of costs is driven by headcount increases and corresponding rising compensation costs.

OEB staff has concerns as to the level of compensation cost increases that have occurred since 2013, particularly the proposed increase in the test year of 6.6%, which compares to increases in the three previous years ranging from 1.83% in 2015 to 2.51% in 2014.

OEB staff notes that in its Argument-in-Chief, Thunder Bay Hydro states that "most of these incremental OM&A cost pressures identified by Mr. Mace are attributable to Thunder Bay Hydro taking steps to meet the RRFE outcome known as "public policy responsiveness and delivering on obligations mandated by government and the OEB".[44] However, in cross examination, OEB staff presented these test year increases to Thunder Bay Hydro and requested further explanations of them,[45] Mr. Mace responded as follows[46]:

MS. LEA: And would the union agreement be part of the test year increase?

MR. MACE: Well, there would be an increase in each year, so it wouldn't account for a large portion of the variance.

I can tell you that the 2016 bridge year for management also reflects vacancies.

MS. LEA: Okay. So the 8.21 increase in non-management, as we have defined it for the test year, is there an explanation for that that you have not yet provided?

[44] Argument-in-Chief, p.18
[45] Transcript, Vol. 3, p. 157 L12 to p. 161 L14 and Exhibit K3.3
[46] Transcript, Vol. 3, p.160 L25 to p. 161 L13

MR. MACE: For the non-management?

MS. LEA: Um-hmm, in the test year, 2017.

MR. MACE: So finance clerk, system control operator, a portion of the GIS technician.

MS. LEA: And that's between the increase over 2016?

MR. MACE: '16 to '17, yes.

OEB staff notes that the large test year increase, based on the explanation provided by Mr. Mace is driven by the hiring of additional staff in the test year. OEB staff further notes that during cross-examination, Thunder Bay Hydro confirmed that it had not had a comprehensive study of its compensation levels done, nor was it planning to have one undertaken[47].

Conclusion

OEB staff accepts that the OM&A programs Thunder Bay Hydro is undertaking are appropriate ones and does not recommend that any of these programs be discontinued or that any specific cuts in a particular program be made.

However, OEB staff notes that both the OEB Total Cost Benchmarking approach and the Aiken model presented by SEC suggest that Thunder Bay Hydro's overall costs and those specifically requested for recovery are on the high side. As well, the test year increases proposed, both on a total OM&A and compensation costs basis are significantly higher in the test year than in 2015 and 2016. Furthermore, the test year OM&A in Thunder Bay Hydro's previous cost of service application for 2013 rates was significantly overstated. Finally there does not appear to be any compelling evidence that any significant efficiency savings are being achieved.

On the basis of all of the preceding considerations, OEB staff is of the view that a reduction in the approved level of OM&A would provide Thunder Bay Hydro with a greater incentive to achieve efficiencies and would therefore be appropriate. Based on

[47] Transcript Vol. 3, p. 163 L13 to p. 165 L1

the indicators discussed above, OEB staff submits that a reduction in the range of five percent would be appropriate. As such, OEB staff recommends that the OEB provide Thunder Bay Hydro with an envelope OM&A amount of $15 million for the 2017 test year, representing a cut of $680,655 which is roughly a 4.3% reduction and is significantly higher than the 2015 actual OM&A level of $14.2 million. OEB staff is aware that this amount is also $430,638 below the 2016 actual OM&A level. However, in its Argument-in-Chief, Thunder Bay Hydro notes that in the bridge year there were a series of one-time non-recurring costs totaling approximately $258,000[48] which accounts for the majority of this differential.

Cost of Capital

Background

Thunder Bay Hydro's requested capital structure and capital cost rates are compliant with OEB policies as outlined in the OEB's cost of capital report[49] and incorporate the updated cost of capital parameters issued by the OEB subsequent to the filing of the application.[50]

Thunder Bay Hydro stated that it has also updated its weighted average cost of debt to reflect the lower cost of debt achieved following the issuance of two new promissory notes in 2017[51]. Thunder Bay Hydro submitted that this lower weighted average cost of debt should be used to set rates for 2017 because it reflects the best information available about its actual cost of long-term debt[52].

Thunder Bay Hydro further noted that the OEB had determined[53] that the question as to whether or not it is in compliance with its shareholders' declaration is generally outside the scope of the application. Thunder Bay Hydro submitted that even if this question was

[48] Argument-in-Chief, p.18
[49] EB-2009-0084 Ontario Energy Board *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities,* December 11, 2009.
[50] Ontario Energy Board *Cost of Capital Parameter Updates for 2017 Applications,* October 27, 2016
[51] Undertaking J3.5
[52] Argument-In-Chief, p.3.
[53] Ontario Energy Board *Decision on the Issues List,* February 10, 2017

to be considered in scope for the application, its shareholder, the City of Thunder Bay, had provided a letter[54] confirming the shareholder's view that the application is in compliance with the shareholder declaration as it relates to cost of capital.

OEB Staff Submission

OEB staff submits that Thunder Bay Hydro is in compliance with OEB policies regarding cost of capital and that its proposed parameters are appropriate.

OEB staff notes that Thunder Bay Hydro's proposed update of its cost of debt for its issuance of its new promissory notes are shown as being issued on July 4, 2017[55]. OEB staff notes that the holder of this debt has not been stated and submits that Thunder Bay Hydro should clarify this matter in its reply submission. OEB staff notes that the issuance date of the debt is considerably outside the time frame of the remainder of the 2017 forecast which was prepared in 2016. In addition, the impact of this change is about $96,000[56] which is below Thunder Bay Hydro's materiality threshold of about $119,000[57]. OEB staff has no concerns with this update as it benefits customers. However, OEB staff submits that the acceptance of this update is for this application only, and should not be construed as acceptance of selective updates of this kind in future applications by Thunder Bay Hydro and other utilities.

- All of which is respectfully submitted –

[54] Supplementary Response to 5.0-SEC-32, February 7, 2017.
[55] EB-2016-0105, Exhibit J3.5
[56] EB-2006-0105, Exhibit J3.5 and Response to Interrogatory 5.0-VECC.35, January 30, 2017
[57] Application Exhibit 1/p. 66