Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

May 22, 2019

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

Dear Ms. Walli:

Re: Hydro One Networks Inc. and Peterborough Distribution Inc. Application under sections 86(1)(c), 86(1)(a), 78, 18, 77(5), and 74 of the *Ontario Energy Board Act, 1998* for the relief necessary to effect Hydro One Networks Inc. and 1937680 Ontario Inc.'s purchase and consolidation of Peterborough Distribution Inc.'s distribution assets and other related approvals
OEB Staff Interrogatories

Ontario Energy Board File Number: EB-2018-0242

In accordance with Procedural Order No. 3, please find attached OEB Staff's Interrogatories for the above proceeding. This document has been forwarded to the Applicants and to all other registered parties to this proceeding.

The Applicants are to file with the OEB complete written responses to interrogatories and serve them on all parties by June 3, 2019.

Yours truly,

Original Signed By

Andrew Bishop
Project Advisor, Supply & Infrastructure

OEB Staff Interrogatories

Application under sections 86(1)(c), 86(1)(a), 78, 18, 77(5), and 74 of the *Ontario Energy Board Act, 1998* for the relief necessary to effect Hydro One Networks Inc. and 1937680 Ontario Inc.'s purchase and consolidation of Peterborough Distribution Inc.'s distribution assets and other related approvals

Hydro One Networks Inc. and Peterborough Distribution Inc.

EB-2018-0242

May 22, 2019

OEB Staff-1

Ref: Exhibit A-5-1

Preamble:

At Exhibit A-5-1 p. 2, the Applicants state:

> Hydro One's purchase of PDI will result in over $9 million of savings in Year 11 (i.e., the first rebasing year), as shown in Table 1 below.

Table 1: Savings Resulting from Hydro One's Acquisition of PDI ($M)

PDI Status Quo Total Cost to Serve	$26.3	*Ex. A, Tab 4, Schedule 1 – Table 4*
Total Residual Cost to Serve	17.0	*Ex. A, Tab 4, Schedule 1 – Table 4*
Ratepayer Savings (Year 11)	**$9.3**	

Questions:

a) Table 1 reports a Total Residual Cost to Serve of $17.0 million. Throughout the original application, the Applicants stated that the Total Residual Cost to Serve would be $16.6 million. Please provide an explanation for the variance.

b) Please confirm that the $9.3 million savings reported in Table 1 does not reflect PDI customers' apportionment of Hydro One Shared Costs.

c) For how many years post-Year 11 are the ratepayer savings demonstrated in Table 1 expected to accrue?

    i. Please provide the estimated savings for each of these years.

OEB Staff-2

Ref: Exhibit A-5-1

Preamble:

At Exhibit A-5-1 p. 2, the Applicants state:

> In Exhibit A, Tab 2, Schedule 1, Table 1 of this MAAD application, Hydro One has provided the forecast incremental OM&A and capital cost to serve the customers of PDI, and commits to tracking the *actual* ***incremental OM&A and capital costs*** to serve PDI customers until the end of the ten year deferral

> period. This tracking will allow the Board to compare the actual incremental costs to serve PDI customers with that forecast in this application. The actual incremental OM&A and capital costs to serve PDI customers will be reflected in Hydro One's revenue requirement upon rebasing of rates at the end of the ten year deferral period. [***Emphasis added***]

Questions:

a) Please fully explain what is meant by "incremental OM&A and capital costs" as referenced by the Applicants at Exhibit A-5-1 p. 2. To clarify, is it the Applicants' intention to only track the incremental costs (or marginal costs) incurred by Hydro One to serve the current PDI service territory following the proposed acquisition?

   By way of example, if Hydro One's staffing levels for certain functions, prior to the acquisition, are adequate enough to absorb the PDI service territory without the need for adding staff, would the incremental costs for that function be considered nil? What methods would Hydro One use to identify those costs that are incremental to PDI versus those that are not?

b) Please confirm if the tracking of PDI's incremental OM&A and capital costs will include the tracking of PDI's Shared Costs.

   i. If Shared Costs will not be tracked, please discuss why the tracking of these costs is not required.

c) If applicable, please discuss why only incremental OM&A and capital costs will be tracked and not the total costs to serve PDI customers until the end of the ten year deferral period.

d) At page 159 of the OEB's Decision and Order on Hydro One's Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022[1], the OEB stated:

   > In approving the acquisition of Norfolk, Haldimand and Woodstock,[2] the OEB directed Hydro One to maintain records of the cost to serve these utilities in order to inform the rate-setting process at the completion of the respective deferral periods. Hydro One has not maintained these records.

   Please articulate why and how the Applicants' decision to track only incremental OM&A and capital costs aligns with the expectations established by the OEB through the aforementioned Decision and Order.

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[1] EB-2017-0049

[2] EB-2013-0196/EB-2013-0187/EB-2013-0198 (Norfolk), EB-2014-0244 (Haldimand), and EB-2014-0213 (Woodstock).

OEB Staff-3

Ref: Exhibit A-5-1

Preamble:

At Exhibit A-5-1 p. 4, the Applicants state:

> Hydro One believes that the best way to ensure that PDI customers are charged only their costs to serve is to introduce new rate classes for them.

-and-

Ref: Appendix A

Preamble:

At p. 6 of Appendix A (the Navigant Report), Navigant states:

> To distinguish customers in the acquired utility service territory from legacy customers, Hydro One proposed to create unique customer classes for customers from the acquired utility…To the extent that the cost to serve the acquired utility customer classes is different from the cost to serve Hydro One's legacy customer classes, this is a valid justification for creating unique classes for customers from the acquired utility.

-and-

Ref: Decision and Order on EB-2017-0049

Preamble:

At pp. 159-165 of the Decision and Order on EB-2017-0049, the OEB states, among other things:

> The OEB denies Hydro One's rates proposals with respect to the Acquired Utilities for the following reasons.
>
> 1) Hydro One's proposal contains simplistically derived and questionable estimates of revenue requirement comparisons to demonstrate adherence to the no harm requirement.

Questions:

a) Please provide a description of each new rate class the Applicants anticipate creating.

  i. For what time period following the acquisition do the Applicants anticipate the acquired rate classes being in effect? That is, when will rate harmonization take place? Alternatively, is it the expectation of the Applicants that these new rate classes will continue in perpetuity? Please justify the planned approach to future rate setting.

b) Please describe the assessment used by the Applicants to determine that, based on its unique characteristics, it is warranted that new rate classes be created for the current PDI service territory.

c) Please provide the results of the assessment used by the Applicants to determine that new rate classes for PDI are warranted. When responding, please clearly identify the sufficient differences that exist between the current PDI service territory and other Hydro One service areas that justify the new rate classes.

<u>OEB Staff-4</u>

Ref: Exhibit A-4-1

Preamble:

At Exhibit A-4-1 p. 7, the Applicants state:

> Hydro One proposes within the harmonization and rebasing application following the deferral period, that it would ensure that the total cost, including a portion of Hydro One's Shared Costs, to be collected from the former PDI customers would be between, (a) the Residual Cost to Serve scenario plus [Low Voltage] charges (totaling $16.6M); and (b) the Year 11 revenue requirement under the PDI Status Quo scenario plus Year 11 [Low Voltage] charges (totaling $26.3M).

-and-

Ref: Exhibit A-4-1

Preamble:

At Exhibit A-4-1 pp. 5-6, the Applicants state:

> If the transaction is approved, the underlying cost structures for serving the former PDI customers will be reduced by an estimated annual amount of $11.1M to a revenue requirement of $15.2M[3] under the Residual Cost to Serve scenario. However, the $15.2M revenue requirement does not reflect PDI customers paying their full share of the costs for services that Hydro One would be providing to PDI customers. Hydro One considers the costs of the functions, resources and assets used to provide such services to be its “Shared Costs”. More particularly, Hydro One’s Shared Costs reflect, (i) shared facilities used to provide operations and maintenance services (i.e. service centres and maintenance yards), billing and IT system costs, and other miscellaneous general plant; (ii) OM&A costs associated with shared services, such as planning, finance, regulatory, human resources, information technology, customer services and corporate communications; and (iii) asset and related OM&A costs associated with upstream distribution facilities used by former PDI customers (i.e. costs formerly captured under [Low Voltage] charges).

-and-

Ref: Exhibit A-5-1

Preamble:

At Exhibit A-5-1 p. 5, the Applicants state:

> In order to ensure the equitable treatment of both legacy and acquired customers, Hydro One proposes to use the principles underlying the OEB’s cost allocation model to determine the cost allocation to all rate classes. To the extent necessary, the OEB’s cost allocation model will be adjusted to achieve the following objectives:
>
> 1. Ensure that costs allocated to the PDI rate classes reflect the fixed assets specifically used in PDI’s service area.

[3] The Residual Cost to Serve of $15.2 million does not include the Applicants’ cost estimate of Low Voltage charges to former PDI customers.

2. Ensure that the PDI rate classes are appropriately allocated Shared Costs, which includes a share of upstream distribution assets required to provide service to PDI's service area.

Hydro One fully anticipates that the cost allocation process described above, and detailed in the following sections, will result in a fair and reasonable allocation of costs to the PDI rate classes that will be less than what the cost-to-serve the PDI customers would be if PDI is not acquired.

-and-

Ref: Appendix A

Preamble:

At pp.1-2 of Appendix A (the Navigant Report), Navigant states:

> The proposed approach to cost allocation and rate design described in the OPDC Supplemental Evidence and the PDI Supplemental Evidence incorporates changes relative to the approach outlined in the Distribution Rate Cost Allocation Model. However, several elements are the same, and the Distribution Rate Cost Allocation Model provided Navigant with a worked, numerical, example of the approach upon which to perform a detailed review.

-and-

Ref: *Report of the Board on Application of Cost Allocation for Electricity Distributors*

Preamble:

At p. 7 of the OEB's November 28, 2007 *Report of the Board on Application of Cost Allocation for Electricity Distributors*, the OEB states:

> Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one.

Questions:

The Applicants' evidence specifies that the Total Residual Cost to Serve does not include Shared Costs. Further, the Applicants' evidence highlights that the portion of Hydro One's Shared Costs to be collected from current PDI customers following harmonization will be no greater than approximately $9.3 million. The $9.3 million represents the monetary value of the Applicants' estimated efficiency gains resulting from the acquisition. The Applicants also state that they will "use the principles underlying the OEB's cost allocation model" during future rate harmonization processes. The benefit of this approach, as stated by the Applicants, is that it ensures all costs, including Shared Costs, allocated to the PDI rate classes reflect the fixed assets specifically used in the current PDI service territory.

a) Please provide the following with respect to the Applicants' proposed cost allocation methodology:

    i. The Distribution Rate Cost Allocation Model reviewed by Navigant and referenced in their report.

    ii. The Applicants' proposed adjustment factors, the formula and inputs used in their calculation, as well as a description of the rationale that supports their reasonableness.

b) Using the Applicants' proposed Distribution Rate Cost Allocation Model (as referenced in the Navigant Report), please calculate the Total Residual Cost to Serve PDI ensuring that the calculation reflects all applicable costs, including, but not limited to, Low Voltage charges as well as an appropriate allocation of Shared Costs. The result of the calculation should be a reasonable estimate based on sound assumptions of the costs to serve the current PDI service territory following the rebasing deferral period (i.e., post-Year 10).

    i. In response to this question, the Applicants are requested to fully describe the process used by the Applicants to determine the appropriate allocation of Shared Costs to PDI and clearly demonstrate how these Shared Costs are reflected in the allocation model.

c) If the result of the calculation undertaken in response to part a) is greater than $26.3 million, please discuss the implications of the result in terms of the proposed acquisition satisfying the conditions of the "no harm" test.

d) Please confirm, and provide reasoning/evidence, that as a result of the estimate undertaken in response to part a), legacy Hydro One customers would not be subsidizing any costs that should be allocated to current PDI customers post-rebasing deferral period.

e) Please explain and demonstrate how Hydro One's proposed allocation methodology is consistent with the guidance provided by the OEB in its *Report of the Board on Application of Cost Allocation for Electricity Distributors* with respect to moving revenue-to-cost ratios closer to one.

<u>OEB Staff-5</u>

Ref: Exhibit A-5-1

Preamble:

At Exhibit A-5-1 p. 1, the Applicants state:

> The purpose of this Supplemental Evidence is to explain in detail Hydro One's proposed cost allocation and rate design for PDI customers at the end of the rebasing deferral period. The Supplemental Evidence demonstrates that the application of Hydro One's proposed cost allocation and rate design to PDI customers in a Year 11 rebasing will: (a) result in an allocation of costs to PDI customers that reflects the cost to serve them; (b) ***result in rates that collect costs from PDI customers that are less than what those customers would have paid in the absence of the proposed transaction***; and (c) leave Hydro One legacy customers unharmed or slightly better off than they would have been in the absence of the proposed transaction. In fact, the outcome of the cost allocation model and rate design reflects the sharing of cost savings in Year 11 and beyond for the benefit of both PDI and Hydro One legacy customers. **[*Emphasis added*]**

OEB staff's focus is on understanding how the application of the proposed cost allocation, as defined by the Applicants in response to OEB Staff-4, is likely to impact the post-rebasing deferral period electricity bills of current PDI customers.

To illustrate post-rebasing deferral period impacts, the Applicants are requested to create what OEB staff refers to as a Notional Post-Rebasing Deferral Period Rate (NPRDPR). The NPRDPR serves a fundamental purpose: it will allow the Applicants to forecast, based on their proposed allocation methodology, the monthly bill of a typical PDI customer post-rebasing deferral period. The intent of the NPRDPR is to enable a legitimate forecast comparison between the typical PDI customer's current and post-acquisition monthly bill. In-turn, a determination on the performance of the proposed transaction against a primary component of the "no harm" test can be made.

Below, OEB staff describes the methodology the Applicants should follow to produce the NPRDPR and subsequent bill comparison.

Computing the NPRDPR and Performing the Comparison

The NPRDPR will be used by the Applicants to demonstrate the bill impacts of the proposed acquisition if the post-rebasing deferral period electricity rate ***came into effect today***.

At Attachment 7 of the original application, the Applicants provided bill impact tables for the following PDI customer types:

1. Residential
2. General Service Less Than 50kW
3. General Service 50 to 4,999 kW
4. Large Use

Specifically, for each of the four customer types listed above, the Applicants are requested to compare the current typical monthly bill with that calculated using the NPRDPR methodology.

Components of the NPRDPR Comparison

The NPRDPR requires the Applicants to quantify both the savings and costs that they reasonably believe will be experienced by PDI customers at the end of the rebasing deferral period. OEB staff's expectation is that the savings and costs used to develop the NPRDPR will be the same as those used by the Applicants to inform their response to OEB Staff-4.

Boxes 1 and 2 demonstrate the inputs the Applicants can use when developing the estimates for the pre- and post-acquisition bill impacts.

Box 1: Current Customer Bill Calculations

- For purposes of illustrating the current typical monthly PDI customer bill, OEB staff expects that the Applicants can rely on the values already provided in the Customer Bill Impacts Tables found at Attachment 7 of the original application.
    - i.e., no additional calculations are likely required given that the columns labelled "Current Rates" and "Current Charges ($)" in these tables already demonstrate the typical inputs into the PDI customer's monthly bill.

- The Applicants may elect to update the values in these tables for items such as current time-of-use electricity prices. If updates to values are made, OEB staff requests that the Applicants fully explain the rationale for the change.

Box 2: NPRDPR Calculations

- The NPRDPR represents the Current Typical Monthly Bill (inclusive of Low Voltage charges), adjusted to reflect the financial impacts of acquisition-related efficiencies (e.g., OM&A cost reductions) and Hydro One loss factors ***as well as*** an appropriate allocation of Hydro One Shared Costs to each customer group.

  Importantly, the calculation of the NPRDPR should ***not*** include any acquisition related short-term customer benefit such as the Applicants' proposed guaranteed earnings sharing mechanism or the 1% distribution rate discount.

- For demonstrative purposes, the Residential bill impacts table provided at Attachment 7, page 1 of the original application, has been recreated below to illustrate how the results of the NPRDPR analysis can be presented. When responding, the Applicants may choose to revise the tables as appropriate to clearly demonstrate how the NPRDPR monthly bill calculation reflects both the savings and costs experienced by PDI customers as a result of the acquisition.
  - Below, within the reproduced Attachment 7 table, OEB staff have highlighted in green the values that are likely to change as a result of this comparative exercise. Cells highlighted in grey represent values that OEB staff do not anticipate the comparison will impact. Note that these are assumptions only and the Applicants should update NPRDPR values as necessary to ensure an accurate comparison of pre- and post-rebasing deferral period bill impacts is created.

Questions:

a) Applying the same cost allocation approach created in response to OEB Staff-4, calculate the typical monthly bill for each of the four customer types shown in Attachment 7.

b) Please provide the resultant revenue to cost ratios for each of the four customer types/rate classes.

Example Comparison Reporting Table

	Residential					
	Volume	Current Rates	Current Charges ($)	Rates as per NPRDPR	Charges per NPRDPR ($)	% Change
Monthly Consumption (kWh)	750			750	750	
Total Loss Factors	1.0548					
TOU - Off Peak Consumption	488	$0.065	$ 31.69	$0.065	$ 31.69	
TOU - Mid Peak Consumption	128	$0.094	$ 11.99	$0.094	$ 11.99	
TOU - On Peak Consumption	135	$0.132	$ 17.82	$0.132	$ 17.82	
Total: Commodity			**$ 61.49**		**$ 61.49**	
DX Fixed Charge	1	$18.9800	$ 18.98			
DX Fixed Charge Rate Riders	1	$0.0000	$ -			
DX Vol. Charge ($/kWh)	750	$0.0047	$ 3.53			
DX Low Voltage Charge ($/kWh)	750	$0.0010	$ 0.75			
DX Vol. Rate Riders ($/kWh)	750	-$0.0009	$ (0.68)			
Distribution Rates Only			**$ 22.58**			
Smart Meter Entity Charge	1	$0.57	$ 0.57	$0.57	$ 0.57	
Cost of Losses	41	0.082	$ 3.37			
Distribution Pass Through Charges			**$ 3.94**			
Total: Distribution			**$ 26.52**			
TX - Network ($/kWh)	791	$0.0073	$ 5.78			
TX - Connection ($/kWh)	791	$0.0061	$ 4.83			
Total: Transmission			**$ 10.60**			
WMSC ($/kWh)	791	$0.0036	$ 2.85			
RRRP ($/kWh)	791	$0.0003	$ 0.24			
SSA ($)	1	$0.25	$ 0.25			
Total: Regulatory			**$ 3.34**			
Total Bill (Before Taxes)			$ 101.95			
HST		13%	$ 13.25			
OREC		-8%	$ (8.16)			
Total Bill (Including HST and OREC)			**$ 107.05**			