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

BY EMAIL

May 29, 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 Orillia Power Distribution Corporation Application under sections 86(2)(b), 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.'s purchase of all issued and outstanding shares of Orillia Power Distribution Corporation.

OEB Staff Interrogatories

Ontario Energy Board File Number: EB-2018-0270

In accordance with Procedural Order No. 5, 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 14, 2019.

Yours truly,

Original Signed By

Andrew Bishop
Project Advisor, Supply & Infrastructure

Ontario

OEB Staff Interrogatories

Application under sections 86(2)(b), 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.'s purchase of all issued and outstanding shares of Orillia Power Distribution Corporation

Hydro One Networks Inc. and Orillia Power Distribution Corporation.

EB-2018-0270

May 29, 2019

OEB Staff-1

Ref: Exhibit A-1-1

Preamble:

At Exhibit A-1-1 p. 3, the Applicants state:

> On August 15, 2016, the City and Orillia Power Corporation (the "Vendor") and HOI (the "Purchaser") entered into a Share Purchase Agreement (the "Agreement"), the effect of which is that the Vendor and the City have agreed to sell, and the Purchaser has agreed to purchase, all of the issued and outstanding shares of OPDC. The purchase price is $41.3 million, comprising a cash payment of approximately $26.4 million for the shares and the assumption of OPDC's short- and long-term debt (including regulatory deferral account balances) of approximately $14.9 million.

-and-

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

> The purchase price is subject to adjustment, within 90 days following closing, for working capital, net fixed assets, regulatory accounts and long term debt, as defined in the Agreement.

Questions:

a) If applicable, what is the expiration date of the Share Purchase Agreement?

b) Acknowledging that the purchase price is subject to adjustment, however, in consideration of the principle of transparency; the valuation upon which the purchase price was based is now approximately 2.5 years old:

   i. On what basis did the Applicants determine it was not necessary to update the valuation before filing this second application requesting OEB approval of the proposed transaction?

   ii. What changes to the underlying inputs that informed the valuation – including, but not limited to, short- and long-term debt and net assets, have occurred since completion of the original valuation?

<u>OEB Staff-2</u>

Ref: Exhibit A-1-1

Preamble:

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

> The Purchaser or its affiliates shall offer all active employees of OPDC continued employment in the City of Orillia for a period of at least one year;

-and-

At Exhibit A-2-1 p. 8, the Applicants state:

> As part of the proposed consolidation, Hydro One will retain local knowledge from existing OPDC staff. This local knowledge, in coordination with Hydro One's regional operations and staff, will allow Hydro One to maintain or improve reliability.

Questions:

a) Please clarify how, from an employment standpoint, current employees of OPDC may be impacted one year following the proposed transaction?

   i. If applicable, how many, and what type of employees will be impacted?

b) How will Hydro One ensure that the local knowledge necessary to ensure reliability levels are maintained/improved if only 9 of the current 15 OPDC direct staff (i.e., direct staff as defined by the Applicants at Exhibit A-2-1 p. 12) will be required following Year 1 of the proposed transaction?

   i. Please discuss how the loss of 6 direct staff, equivalent to 40% of OPDC's current complement, will not result in a disruption to current OPDC service and reliability performance.

   ii. In the event that a major outage occurs in the current OPDC and surrounding Hydro One service areas at the same time, to what degree will the loss of the 6 OPDC direct staff impact service restoration times for both current OPDC and Hydro One customers?

OEB Staff-3

Ref: Exhibit A-2-1

Preamble:

The following table is an extract from Exhibit A-2-1 p. 2 of the application:

Table 1: Projected Cost Savings - $M

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OM&A										
Status Quo Forecast	5.5	5.7	5.8	5.9	6.0	6.1	6.2	6.4	6.5	6.6
Hydro One Forecast	4.1	2.0	2.1	1.7	1.7	1.7	1.8	1.8	1.8	1.9
Projected Savings	**1.4**	**3.7**	**3.7**	**4.2**	**4.3**	**4.4**	**4.4**	**4.6**	**4.7**	**4.7**
Capital										
Status Quo Forecast	3.2	4.3	1.5	1.8	2.8	2.8	2.9	3.0	11.1	3.2
Hydro One Forecast	3.4	2.4	2.4	2.5	2.6	2.8	2.8	2.9	2.9	3.0
Projected Savings	**(0.2)**	**1.9**	**(0.9)**	**(0.7)**	**0.2**	**0.0**	**0.1**	**0.1**	**8.2**	**0.2**

Questions:

a) The table above demonstrates a forecast capital savings of $8.2 million in Year 9 following the acquisition. Please describe the capital expense(s) offset by the acquisition that result(s) in the $8.2 million cost savings.

   i. Please explain how the acquisition can deliver this capital cost reduction in Year 9.

b) The application states that efficiencies gained through the acquisition will reduce OPDC's current OM&A costs by approximately 70% from the status quo scenario by Year 10. Please provide an accounting of each OM&A cost category reduction and its contribution to this forecast 70% reduction.

OEB Staff-4

Ref: Exhibit A-2-1

Preamble:

At Exhibit A-2-1 p. 3, the Applicants state:

> Hydro One's 2017 OM&A cost to serve customers in its high density residential rate class (UR) is $179/customer, compared to OPDC's cost of $352/customer.

Questions:

a) Please confirm if Hydro One's 2017 OM&A cost to serve of $179/customer includes Hydro One Shared Costs as described at Exhibit A-4-1 p. 6 of the application.

   i. If applicable, please provide an estimation of Hydro One's 2017 OM&A cost to serve its high density residential rate class inclusive of Shared Costs.

b) Please provide Hydro One's most recent per customer OM&A cost to serve its high density residential rate class.

   i. Please demonstrate the OM&A cost to serve with and without Shared Costs.

c) Please provide OPDC's most recent per customer OM&A cost to serve.

d) Please provide a forecast of OM&A costs to serve, inclusive of Shared Costs, for current OPDC customers following the rebasing deferral period.

   i. Please fully describe the methodology used by the Applicants to determine and assign Shared Costs to current OPDC customers following the rebasing deferral period.

OEB Staff-5

Ref: Exhibit A-2-1

Preamble:

At Exhibit A-2-1 p. 7, the Applicants state:

> Beginning in year six through to year ten, rates for the former customers of OPDC will be set using the Price Cap adjustment mechanism, as outlined in the Board's Report: "Rate Making Associated with Distributor Consolidation" issued

> March 26, 2015 ("Amended Report"). At the commencement of year six, Hydro One will apply the OEB's Price Cap Index formula utilizing the former OPDC's efficiency cohort factor (0.3%). This will be anchored to then current OPDC Base Distribution Delivery Rates, and applied annually.

Questions:

a) The Applicants propose that rates for former customers of OPDC will be set in accordance with the Price Cap adjustment mechanism during Years 6 to 10 of the rebasing deferral period. OPDC's current rates have been set in accordance with the Annual IR Index option.

   Table 1, on page 15, of the OEB issued *Handbook to Electricity Distributor and Transmitter Consolidations* prescribes that a distributor whose rates are set in accordance with the Annual IR Index must continue on the Annual IR Index method until the end of the rebasing deferral period.

   Do the Applicants accept that, if the acquisition is approved, the rates of former customers of OPDC will be set in accordance with the Annual IR Index option?

b) If applicable, please describe how projected cost efficiencies and/or customer bill impacts demonstrated in the application are impacted by the need to set rates in accordance with the Annual IR Index option as opposed to using the Price Cap adjustment mechanism.

<u>OEB Staff-6</u>

Ref: Exhibit A-5-1

Preamble:

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

> Hydro One's purchase of OPDC will result in over $6.5 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 OPDC ($M)

OPDC Status Quo Total Cost to Serve	$14.4	*Ex. A, Tab 4, Schedule 1 – Table 4*
Total Residual Cost to Serve	7.9	*Ex. A, Tab 4, Schedule 1 – Table 4*
Ratepayer Savings (Year 11)	**$6.5**	

Questions:

a) Please confirm that the $6.5 million savings reported in Table 1 does not reflect OPDC customers' apportionment of Hydro One Shared Costs.

b) 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-7

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 OPDC, and commits to tracking the *actual* ***incremental OM&A and capital costs*** to serve OPDC customers until the end of the ten year deferral period. This tracking will allow the Board to compare the actual incremental costs to serve OPDC customers with that forecast in this application. The actual incremental OM&A and capital costs to serve OPDC 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 OPDC 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 OPDC service territory without the need for added 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 OPDC versus those that are not?

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

<u>OEB Staff-8</u>

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 OPDC customers are charged only their costs to serve is to introduce new rate classes for them.

-and-

[1] EB-2017-0049
[2] EB-2013-0196/EB-2013-0187/EB-2013-0198 (Norfolk), EB-2014-0244 (Haldimand), and EB-2014-0213 (Woodstock).

Ref: Appendix A

Preamble:

At page 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: Exhibit A-4-1

Preamble:

At Exhibit A-4-1 p. 12, the Applicants state:

> With respect to former OPDC customers, Hydro One anticipates transitioning those customers to one of its proposed new Acquired Rate Classes or to a new rate class to be proposed after the deferred rebasing period has elapsed.

-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) The Applicants' statements at Exhibit A-5-1 p. 4 and at Exhibit A-4-1 p. 12 (as referenced in the preamble above) appear to be inconsistent. Please clarify the Applicants' intent as it relates to post rebasing deferral period rate setting. That is, with respect to current OPDC customers, will an attempt be made to transition these customers into an existing Acquired Rate Class or is it the Applicants' intention to introduce new rate classes?

b) If the Applicants' intention is to create new OPDC-specific rate classes, 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.

c) 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 OPDC service territory.

   i. Based on the Applicants' response to part c), please comment on the reasonableness of the OM&A cost to serve comparison referred to by OEB staff in OEB Staff-4 above.

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

<u>OEB Staff-9</u>

Ref: Exhibit A-4-1

Preamble:

At Exhibit A-4-1 p. 8, 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 OPDC customers

> would be between, (a) the Residual Cost to Serve scenario plus [Low Voltage] charges (totaling $7.9M); and (b) the Year 11 revenue requirement under the OPDC Status Quo scenario plus Year 11 [Low Voltage] charges (totaling $14.4M).

-and-

Ref: Exhibit A-4-1

Preamble:

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

> If the transaction is approved, the underlying cost structures for serving the former OPDC customers will be reduced by an estimated annual amount of $7.5M to a revenue requirement of $6.9M[3] under the Residual Cost to Serve scenario. The $6.9M Residual revenue requirement does not reflect OPDC customers paying their full share of the costs for services that Hydro One would be providing to OPDC 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 OPDC 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:

[3] The Residual Cost to Serve of $6.9 million does not include the Applicants’ cost estimate of Low Voltage charges to former OPDC customers.

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 OPDC rate classes reflect the fixed assets specifically used in OPDC's service area.
2. Ensure that the OPDC rate classes are appropriately allocated Shared Costs, which includes a share of upstream distribution assets required to provide service to OPDC'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 OPDC rate classes that will be less than what the cost-to-serve the OPDC customers would be if OPDC 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 OPDC customers following harmonization will be no greater than approximately $6.5 million. The $6.5 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 OPDC rate classes reflect the fixed assets specifically used in the current OPDC 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 OPDC 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 OPDC 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 OPDC 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 b) is greater than $14.4 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 b), legacy Hydro One customers would not be subsidizing any costs that should be allocated to current OPDC 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-10</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 OPDC 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 OPDC customers in a Year 11 rebasing will: (a) result in an allocation of costs to OPDC customers that reflects the cost to serve them; (b) ***result in rates that collect costs from OPDC 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 OPDC and Hydro One legacy customers. **[*Emphasis added*]**

-and-

Ref: Decision and Order on EB-2016-0276

Preamble:

At page 12 of the Decision and Order on EB-2016-0276, the OEB states:

> ***One of the key considerations in the no harm test is protecting customers with respect to the prices they pay for electricity service**.* Although the Handbook states that "rate setting" following a consolidation will not be considered as part of a section 86 application, that does not mean the OEB will not consider the costs that acquired customers will have to pay following an acquisition (both in the short term and the long term). ***Indeed the Handbook is clear that the underlying cost structures and the rate implications of those cost structures will be a key consideration.*** **[*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-9, is likely to impact the post-rebasing deferral period electricity bills of current OPDC 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 OPDC customer post-rebasing deferral period. The intent of the NPRDPR is to enable a legitimate forecast comparison between the typical OPDC 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 OPDC customer types:

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

Specifically, for each of the three 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 OPDC 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-9.

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 OPDC 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 OPDC 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 OPDC 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-9, calculate the typical monthly bill for each of the three customer types shown in Attachment 7.

b) Please provide the resultant revenue to cost ratios for each of the three 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	1.0561					
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	42	0.082	$ 3.37			
Distribution Pass Through Charges			**$ 3.94**			
Total: Distribution			**$ 26.52**			
TX - Network ($/kWh)	792	$0.0073	$ 5.78			
TX - Connection ($/kWh)	792	$0.0061	$ 4.83			
Total: Transmission			**$ 10.60**			
WMSC ($/kWh)	792	$0.0036	$ 2.85			
RRRP ($/kWh)	792	$0.0003	$ 0.24			
SSA ($)	1	$0.25	$ 0.25			
Total: Regulatory			**$ 3.34**			
Total Bill (Before Taxes)			$ 101.95			
HST		13%	$ 13.25	13%		
OREC		-8%	$ (8.16)	-8%		
Total Bill (Including HST and OREC)			**$ 107.05**			

OEB Staff-11

Ref: Exhibit A-4-1

Questions:

a) Please provide a table which compares indicative Hydro One and OPDC monthly electricity bills:
   i. Today (e.g. 2019)
   ii. In Year 10 with the proposed consolidation
   iii. In Year 10 without the proposed consolidation
   iv. In Year 11 with the proposed consolidation
   v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, and General Service greater than 50 kW.

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, please ensure that they do.

c) Please also explain how costs have been allocated to OPDC customers in the response to part a) iv) above.

OEB Staff-12

Ref: Exhibit A-4-1

Questions:

a) Please provide a table which estimates Hydro One and OPDC revenue requirements and revenue requirements per customer:
   i. Today (e.g. 2019)
   ii. In Year 10 with the proposed consolidation
   iii. In Year 10 without the proposed consolidation
   iv. In Year 11 with the proposed consolidation, including all costs that are expected to be allocated to OPDC
   v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, General Service greater than 50 kW and total of all customer types (i.e. total revenue requirement).

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, pleas ensure that they do.

<u>OEB Staff-13</u>

Ref: Exhibit A-2-1

Preamble:

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

> All other OPDC tariffs will remain as approved in OPDC's last rate order; with the exception of Specific Service Charges ("SSCs") which Hydro One is seeking approval to amend to align with the SSCs as approved, or will be approved, by the OEB for Hydro One Distribution.

Questions:

a) Please prepare a table which compares the current OPDC Specific Service Charges with those that "…Hydro One is seeking approval to amend to align with the SSCs as approved, or will be approved, by the OEB for Hydro One Distribution"; please explain any differences.

b) Please identify any material differences in the current Conditions of Service of OPDC and Hydro One (as proposed at EB-2017-0049).

<u>OEB Staff-14</u>

Ref: Exhibit A-2-1

Preamble:

At Exhibit A-2-1, p. 20, the Applicants state:

> All of the above incremental costs will be financed through productivity gains associated with the transaction, will not be included in Hydro One's revenue requirement, and thus will not be funded by ratepayers.

Questions:

a) Please state how the Applicants will ensure that the transaction and transition costs will not be included in its ratepayer funded revenue requirement.

b) Please confirm how these costs will be financed if anticipated productivity gains are not fully realized.

OEB Staff-15

Ref: Exhibit A-1-1, Section 5.0 Other Approvals and Considerations
Ref: Exhibit A-2-1, Section 3.0 Other Related Matters

Preamble:

Hydro One is applying for approval to continue to track costs in the regulatory asset accounts currently approved by the OEB for OPDC and seek disposition of their balances at a future date.

Questions:

a) Does Hydro One have an anticipated timeline in mind for when the IESO settlement processes will be harmonized and Hydro One will receive a single, consolidated monthly IESO invoice that includes OPDC's costs?

b) Please confirm that Hydro One intends to maintain a separate set of Group 1 regulatory deferral and variance accounts (DVAs) for the OPDC rate zone until the next rebasing application and that the balances accumulated in those accounts will be disposed to OPDC customers only.

c) How does Hydro One intend to settle with the IESO during:
    i. The period prior to IESO invoice harmonization?
    ii. The period subsequent to IESO invoice harmonization?

d) For the year in which IESO invoice harmonization takes place, please confirm that Hydro One's intent is to submit disposition requests for the OPDC rate zone's Group 1 DVA balances that accumulated prior to IESO invoice harmonization, as well as a request for the disposition of Group 1 DVA balances that accumulated subsequent to IESO invoice harmonization. If this is not the case, please explain how Hydro One intends to dispose of Group 1 DVA balances for the year in which IESO invoice harmonization occurs.

e) In the event that the IESO invoice is harmonized, but the Group 1 DVAs continue to be maintained separately, how does Hydro One propose to allocate the IESO charges to the respective regulatory accounts of the OPDC rate zone?

Does Hydro One have intentions to request the alignment of the effective rate year of the OPDC rate zone with that of Hydro One's prior to rebasing? If so, when does it expect to do so? If not, why not?

OEB Staff-16

Ref: *Handbook to Electricity Distributor and Transmitter Consolidations*

Preamble:

The OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* includes a list of filing requirements. Under the filing requirements, Section 2.2.4, (page 6 of the filing requirements), applicants are asked to "provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction.

Question:

a) Please provide pro forma financial statements for Hydro One including those of OPDC, for the first full year following the completion of the proposed transaction.

OEB Staff-17

Ref: Exhibit A-2-1, page 2 Table 1, page 23
Ref: Exhibit A-3-1, page 7 Table 2

Preamble:

Hydro One is requesting approval to utilize US GAAP for accounting purposes in relation to the ongoing business of the former OPDC. OPDC currently uses IFRS for financial accounting purposes. The current distribution rates for the OPDC service territory are underpinned by Modified IFRS (MIFRS) for regulatory accounting purposes and will continue to be during the deferred rebasing period.

Questions:

a) Has Hydro One undertaken any studies or reviews of the types of transactions that will be impacted by the accounting standard transition from IFRS to US GAAP in the former OPDC? If so, please list the areas of accounting that are expected to be impacted. If not, please explain why this hasn't been addressed as of yet and when Hydro One expects to undertake such an exercise.

b) Please quantify the estimated impact on OPDC's revenue requirement during the deferred rebasing period as a result of OPDC changing its accounting standards. Specifically, please separate the components of revenue requirement that are expected to be impacted and show how these calculations are derived. To simplify, OEB staff is seeking the total revenue requirement of OPDC under IFRS versus the total revenue requirement of OPDC under US GAAP, by year, from the date that OPDC is initially acquired to the date when OPDC has its rates rebased (when the deferred rebasing period expires).

c) Please explain how Hydro One intends to account for the differences during the deferred rebasing period to ensure that both the rate payers and/or the utility are kept whole for these differences.

d) If Hydro One's intention in part c) above is to request to have an Accounting Order established to track the revenue requirement differences between MIFRS and US GAAP in the former OPDC service territory as part of this proceeding, please prepare and submit a Draft Accounting Order as an appendix for approval.

e) Please explain and quantify what impact, if any, the change from IFRS to US GAAP has on the amounts forecasted in Table 1: Projected Cost Savings - $M of Exhibit A-2-1. For example, if the Status Quo projections of Table 1 are currently presented under US GAAP standards, present these amounts under IFRS. If they are presented under IFRS, please present these amounts under US GAAP.

f) Please explain and quantify what impact, if any, the change from IFRS to US GAAP has on the amounts forecasted in the proposed ESM calculation under Table 2: Earnings Sharing Mechanism of Exhibit A-3-1 (particularly, on OM&A, depreciation, financing costs, and taxes). For example, if the ESM projections are currently presented under US GAAP standards, present these amounts under IFRS. If they are presented under IFRS, please present these amounts under US GAAP standards.

g) Generally speaking, does US GAAP allow for the capitalization of more overhead costs then is permitted under IFRS? Please explain.

   i. If so, then please explain how ratepayers will be better off under US GAAP when the ratepayers of OPDC will now be required to pay a return on rate base associated with costs that would not have been capitalized under IFRS.

OEB Staff-18

Ref: Attachment 5 (Asset Purchase Agreement)
Ref: Exhibit A-3-1, Table 2

Preamble:

As a result of the sale of its shares, OPDC may be subject to certain incremental tax obligations under the Ontario Electricity Act, and may also be required to revalue its assets to fair-market-value (FMV) as of the date this sale is executed.

Questions:

a) Please explain if the sale of shares by OPDC will trigger its exit from the Ontario Payment in Lieu of Taxes (PILs) regime? If not, please explain why that is the case.

b) Please provide the expected incremental PILs costs that will be incurred as a result of the sale of shares, including but not limited to, any business transfer taxes, recapture, capital gains, or departure taxes, payable upon completion of the proposed sale.

c) Please explain if, subsequent to the proposed sale of the OPDC shares, Hydro One will be assuming obligation for these incremental PILs costs (such as, but not limited to, payment of a departure tax, if any) incurred by OPDC as a result of the sale of its shares. If not, please explain how such costs are going to be addressed and or excluded from the transaction.

d) If Hydro One is assuming the obligation for incremental PILs costs noted above, please confirm that these incremental PILs costs will not be recovered from ratepayers and how Hydro One will ensure that these costs are not included in rates.

e) Please explain if OPDC will be required to revalue its assets to FMV for tax reporting purposes as a result the sale of its shares to Hydro One? If not, please explain why.

f) Please confirm whether or not Hydro One intends to pass on to ratepayers the additional Capital Cost Allowance (CCA) deductions that will become available to them as a result of the revaluation of OPDC's assets to FMV noted above. If so, what is Hydro One's expectations with respect to how those future tax deductions should be applied in rates?

g) Please confirm whether or not the PILs costs, including but not limited to the departure tax, associated with the sale of shares by OPDC are reflected in Table 2 of Exhibit A-3-1 (Earnings Sharing Mechanism) and provide justification for this treatment.

h) Please confirm whether or not the utilization of the additional CCA deductions from the revaluation of OPDC's assets are reflected in Table 2 of Exhibit A-3-1 (Earnings Sharing Mechanism) and justification for this treatment.

OEB Staff-19

Ref: Exhibit A-2-1, Table 1 Projected Costs Savings; Page 19 Incremental Transaction and Integration Costs

Questions:

a) Please provide a more detailed breakdown for how the Status Quo Forecast and Hydro One Forecast was quantified in Table 1 of Exhibit A-2-1, showing the supporting calculations for the differences in OM&A and capital under both scenarios, as well as any key assumptions or figures used in those calculations.

    i. Please ensure that the more detailed Exhibit A-2-1 Table 1 requested in part a) above also separately presents the timeline and any underlying calculations supporting the incremental transaction costs ($0.2M) and integration costs ($9.0M).

OEB Staff-20

Ref: Exhibit A-3-1, Table 1; Table 2
Ref: Exhibit A-2-1, Table 1

Preamble:

Hydro One has proposed to adjust the forecast OM&A expenses by a risk factor of 20% to account for the fact that it is assuming all operational risks during the 10-year deferred rebasing period, including:

- The risk that the OM&A forecast is not achieved
- The risk that assets are not in the condition anticipated
- The risk that the anticipated load and customer load profiles do not materialize

Questions:

a) Please confirm that the OM&A and capital expenditure forecast in Table 1 of Exhibit A-2-1 represents the best estimate of Hydro One's costs and savings during the deferred rebasing period.

b) Please confirm that, under the currently proposed ESM mechanism, Hydro One's shareholders will accrue the potential benefits of:

- The OM&A forecast used being overstated
- The assets being in better condition than anticipated
- The anticipated load and customer load profiles used resulting in a revenue forecast that is understated.

c) Please comment on the appropriateness of an asymmetrical risk-based adjustment to earnings sharing if, presuming the forecast represents the best estimate of future OM&A and capital expenditures, Hydro One's shareholders also accrue the potential benefits of any favourable variances in the assumptions used in the ESM calculation.

d) Please present the amounts in Table 2 of Exhibit A-3-1 on the basis that no risk factor adjustment is applied to the ESM calculation.

OEB Staff-21

Ref: Exhibit A-3-1, Table 1 (ESM Components); Table 2 (ESM)

Questions:

a) In Table 1, Hydro One has indicated that the starting point for calculating OPDC's forecast rate base was OPDC's 2017 audited Financial Statements.

Please update the starting point for calculating OPDC's forecast rate base using OPDC's 2018 audited financial statements.

b) Please provide summary continuity schedules, beginning with the most recently available actual fiscal year (OPDCs 2018 audited financial statements), for each of the components presented in lines 1 to 7 of Table 2 of Exhibit A-3-1. Please ensure all key underlying assumptions are disclosed and supporting calculations are provided that were used in deriving these projections. Please include, at a minimum, the following information for each ESM component to support its associated summary schedule(s):

i. Rate Base: segregate the Property, Plant and Equipment (PP&E), capital contributions, and working capital components in the continuity schedule and explain the methodology behind the growth rates applied to each component

ii. Revenue: indicate the inflation rate used, the growth rate used for customer load, and any key assumptions made in changes to the forecasted customer load profiles.

iii. Depreciation: provide the weighted average depreciation rates (or by asset class if practicable) applied to PP&E each year, the average remaining useful lives (or by asset class if practicable) of PP&E each year, and any key assumptions made or processes undertaken by Hydro One to determine the remaining useful lives of the acquired assets.

iv. Financing Costs: disclose the current cost of short-term and long-term debt for Hydro One.

v. Taxes: provide a reconciliation between the combined provincial and federal statutory tax rates (26.5%) and the actual effective tax rates used.