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May 22, 2019 **VIA E-MAIL**

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Toronto, ON

Dear Ms. Walli:

Re: EB-2018-0242 – Application for approval to amalgamate Peterborough Distribution Inc. and Peterborough Utilities Services Inc. and to sell the amalgamated electricity distribution system to Hydro One Networks Inc.

Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

In accordance with Procedural Order No. 3, please find attached the interrogatories of VECC in the above-noted proceeding. We have also directed a copy of the same to the Applicants.

Yours truly,

Bill Harper
Consultant for VECC/PIAC

Ms. Linda Gibbons, Senior Regulatory Coordinator – Regulatory Affairs Hydro One Networks Inc.
regulatory@HydroOne.com
John Stephenson, President & CEO, Peterborough Distribution Inc.
regulatoryaffairs@peterboroughutilities.ca

REQUESTOR NAME	**VECC**
TO:	**Hydro One Inc. (HOI) / Hydro One Networks Inc. (HONI) & Peterborough Distribution Inc. (PDI)**
DATE:	**May 22, 2019**
CASE NO:	**EB-2018-0242**
APPLICATION NAME	**MADD Application – HOI/HONI Purchase of PDI**

(Numbering follows from VECC IR#1)

VECC-23

Reference: Exhibit A/T5/S1, page 1

Preamble: The Supplemental Evidence states:
"On October 12, 2018 Hydro One filed a MAAD application to purchase PDI and on February 27, 2019 Hydro One updated Exhibit A, Tab 4, Schedule 1 and Attachment 18. Interrogatory responses on the original evidence were filed on February 27, 2019. Included in that Application was an exhibit, "Future Cost Structures" (Exhibit A, Tab 4, Schedule 1), to assist the Board in understanding Hydro One's rate plans for PDI's customers after the deferred rebasing period. 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".

a) Do any of the interrogatory responses provided to date require updating/revision as result of the Supplemental Evidence?

b) If yes, please identify the relevant interrogatory responses and provide the necessary revisions/updates.

VECC-24

Reference: April 26, 2019 Cover Letter to the Supplemental Evidence
OEB Decision and Order, EB-2017-0049, pages 161-165

Preamble: The Cover Letter states:
"This exhibit is being provided to address some of the conclusions reached by the OEB in its Decision and Order on Hydro One's distribution rate application EB-2017-0049".

a) Are the proposals set out in the Supplemental Evidence with the respect to the cost allocation and rate design for acquired utilities at the time of rebasing different from those proposed by Hydro One Networks in EB-2017-0049?

b) If yes, please provide a schedule that: i) specifically indicates those areas where the cost allocation and rate design proposals in the Supplemental Evidence differ from those in EB-2017-0049; and ii) documents the change(s) that have been made.

c) Is it Hydro One Networks' view that the proposals set out in the Supplemental Evidence address the concerns and conclusions of Board regarding its EB-2017-0049 cost allocation and rate design proposals for acquired utilities? If yes, please explain how the Supplemental Evidence specifically addresses the Board's various concerns and conclusions.

VECC-25

Reference: Exhibit A/T5/S1, page 2 (lines 10-14)

Preamble: The Supplemental Evidence states:
"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."

a) In order to allow for such a comparison, please provide a schedule that breaks down the Hydro One Forecast OM&A (per Exhibit A, Tab 2, Schedule 1, Table 1) by USOA account – at the same level of detail as used in Hydro One's cost allocation model (Tab I3).

b) In order to allow for such a comparison, please provide a schedule that breaks down the Hydro One Forecast Capital Expenditures (per Exhibit A, Tab 2, Schedule 1, Table 1) by USOA account – at the same level of detail as used in Hydro One's cost allocation model (Tab I3).

VECC-26

Reference: Exhibit A/T5/S1, page 3 (lines 6-20) and page 7 (lines 23-24)
EB-2017-0049, Exhibit C1/Tab 1/Schedule 1, page 2, Table 1

Preamble: The Supplemental Evidence states: "The OEB's cost allocation model uses fixed assets as the primary allocator for the costs of operating and maintaining distribution assets and since Hydro One proposes to use the principles embedded within the cost allocation model to allocate all other OM&A costs (e.g., customer, and administration and general costs), Hydro One will only track PDI's incremental OM&A costs until the time that PDI is harmonized into Hydro One's rate structure."

It also states: "Hydro One cannot track, on an actual basis, either during the deferral period or after, the costs associated with certain Hydro One resources that PDI customers will enjoy the benefit of (i.e., those resources that are also required by and paid for by legacy customers). These costs, referred to as Shared Costs in Exhibit A, Tab 4, Schedule 1 (page 6 of 12) of this Application, include 17 costs that cannot be directly associated with serving a specific group of customers."

The Supplemental Evidence further states: "Included in Shared Costs are the costs associated with upstream distribution facilities used by former PDI customers (i.e. costs formerly captured under LV charges").

In EB-2017-0049, Hydro One broke its OM&A expenditures down into five major categories: i) Sustainment, ii) Development, iii) Operations, iv) Customer Care, v) Common Corporate and vi) Property Taxes and Rights Payments.

a) Other than the inclusion of "the costs associated with upstream distribution facilities", are the "Shared Costs" referred to in the Supplemental Evidence synonymous with the "Common Corporate Costs" as defined in EB-2017-0049?

b) If not, specifically what are the differences and, in particular, do Shared Costs include costs other than those considered to be Common Corporate Costs per EB-2017-0049?

c) It is noted that, in Hydro One's cost allocation model, Customer Care costs are not allocated based on fixed assets. Do the incremental costs that Hydro One has identified as being associated with PDI include any Customer Care costs (e.g. LEAP, incremental meter reading and billing costs, etc.) or are Customer Care costs all considered to be a Shared Cost?

d) If all Customer Care costs are not considered to be Shared Costs, please separately identify: i) the incremental Customer Care costs included in the PDI's Year 11 Residual Cost to Serve and what activities the costs are associated with and ii) the Customer Care activities (if any) that are considered to be part of Shared Costs.

e) Do the incremental costs that Hydro One has identified as being associated with PDI include Property Taxes and Rights Payments attributable to PDI's service area?

VECC-27

Reference: Exhibit A/T5/S1, page 4 (lines 3-9)
EB-2017-0049, Exhibit G1/Tab 2/Schedule 1, pages 3-4

Preamble: The Supplemental Evidence states: "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".
In EB-2017-0049 Hydro One proposed: "For a small number of customers (i.e., USL, Street Lights, Sentinel Lights and Large Users), Hydro One proposes that they be merged into existing Hydro One rate classes".

a) Is Hydro One now proposing that there would be new separate rate classes for all of PDI's existing customer classes, including its current USL, Street Lights, Sentinel Lights and Large Use classes?

VECC-28

Reference: Exhibit A/T5/S1, page 5 (lines 12-14)
EB-2017-0049, VECC's Final Submissions

Preamble: The Supplemental Evidence states: "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." (emphasis added)

a) In Hydro One's view, is there any possibility that the cost allocation methodology used at the time of rebasing will result in an allocation of cost to customers that is more than what the cost-to-serve the PDI customers would be if PDI is not acquired"?

b) If Hydro One is of the view that there is no possibility of such a result, please explain why?

c) If Hydro One is of the view there is no possibility of such a result, please reconcile this view with the cost allocation results for acquired utilities in EB-2017-0049 where the allocated costs were higher (per VECC's Final Submissions, page 76) that the stand-alone costs to serve the acquired utilities.

VECC-29

Reference: Exhibit A/T5/S1, page 6 (lines 14-17)

Preamble: The Supplemental Evidence states: "This is effectively a direct allocation of locally-used fixed assets to PDI customers. In other words, the adjustment factor ensures a more accurate reflection of the fixed assets, and associated costs, required to serve PDI customers."

a) Does Hydro One accept that the OM&A costs attributed to the local assets used to serve PDI customers using the cost allocation model will differ from the incremental OM&A costs related to the same assets as tracked by Hydro One?

b) Based on the cost allocation proposed for the acquired utilities in EB-2017-0049, what were i) the incremental OM&A costs included in the Residual Cost and ii) the equivalent OM&A costs allocated to the fixed local assets attributed to the acquired utilities via Hydro One cost allocation model for the same rate year?

VECC-30

Reference: Exhibit A/T5/S1, pages 7-8
Exhibit I/Tab 1/Schedule 7 d)

a) Based on EB-2017-0049, what were: i) the total cost allocated to the acquired utilities customers via Hydro One's cost allocation model and ii) the Residual costs attributed to the acquired utilities customers. Please include the relevant EB-2017-0049 references for the values provided.

b) Based on the ratio of these values please estimate the total allocated costs for

PDI customers in year 11 based on PDI's forecast Residual Cost to Serve.

VECC-31

Reference: Exhibit A/T5/S1, page 8 (lines 18-22)
Exhibit I/T1/S 8
Exhibit A/T1/S1/Appendix A, page 8

Preamble: The Supplemental Evidence states: Hydro One fully anticipates that it will be possible to set rates for the PDI rate classes that result in an R/C ratio that both falls within the Board's approved ranges and results in an allocation of savings to both legacy and PDI customers. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One is committing to charge PDI customers no more than the higher goal post amount of $26.3M 21 and no less than their residual cost to serve of $17.0M." (emphasis added)

a) In Hydro One's view, is there any possibility that it will not be able to set rates for the PDI rate classes that result in an R/C ratio that both falls within the Board's approved ranges and results in an allocation of savings to both legacy and PDI customers? If not, please explain why.

b) Please confirm that, in accordance with the response to Staff IR #8 and lines 20-22, if achieving both objectives is not possible then Hydro One would set the rates for PDI customers such that the cost to be borne would not exceed $26.3 M (the forecast standalone cost to serve) – even if the R/C ratio results fell outside the Board's approved revenue to cost ranges. If not confirmed, how would Hydro One set the rates for PDI customers in such circumstances?

c) Navigant's review and endorsement of Hydro One's rate design proposals appears to be predicated on Hydro One recognizing and adhering to the Board's approved revenue to cost ranges. Please reconcile this premise with the response to part (b).

VECC-32

Reference: Exhibit A/T5/S1, pages 8-9
Exhibit I/T4/S21 b)

a) Please confirm that the rate design proposals set out on pages 8-9 (in particular the commitment to charge PDI customers no more than the standalone cost to serve) only apply to the rebasing that will occur at the end of the 10-year deferral period and not to any subsequent rebasing applications. If not confirmed, please reconcile with the response to VECC 21 b).

b) If confirmed, what assurance does the Board and PDI customers have that the no-harm test (per PDI customers) will continue to be met in future rebasing applications?

VECC-33

Reference: Exhibit A/T5/S1, pages 10-11

Preamble: The Supplemental Evidence states: "In the Table 2 illustration, the cost allocation model has allocated $45M to the acquired utility ($30M in residual costs to serve plus $15M in Shared Costs)".

a) In the illustrative example set out in Table 2, for those activities captured under Residual Costs, the cost allocation model is assumed to allocate costs equivalent to the Residual Costs (i.e., $30 M). Please confirm that this is simply an assumption made for purposes of the illustrative example and that, for those activities captured by the Residual Costs, the dollars allocated to the Acquired Utility by the cost allocation model could be more or less than the calculated Residual Costs. If not confirmed please explain why.

b) If confirmed, would it be reasonable to also include in the third row of Table 2 the impact of the cost allocation model treatment of Residual Costs and re-label the row – "Impact of Cost Allocation Model Treatment of Shared Costs and Residual Costs"?

c) Please confirm that the fourth row in Table 2 (Post-Consolidation Cost Allocation) is meant to reflect the cost allocation model results when applied to the consolidated utility. If not confirmed, please explain why.

d) Please confirm that the sixth row in Table 2 (Post-Consolidation Rates Revenue Requirement) is meant to reflect the results after the Status Quo Revenue Requirements for the Hydro One Legacy customers (collectively) and the Acquired Utility have been adjusted such that the R/C ratios for each class fall within the Board approved ranges. If not confirmed, please explain why.

e) Please confirm that the adjustment referred to part (d) is not an adjustment to the allocated costs as suggested by rows 4-6 in Table 2. Rather row 5 is really just the difference between the allocated costs and the revenue requirement after the adjustment referred in part (d) has been made. If not confirmed please explain why.

VECC-34

Reference: Exhibit A/T5/S1, pages 9-12

Preamble: Assume the following cost allocation results at the time of rebasing:

Illustrative Cost Allocation Exercise ($M)			
	Hydro One Legacy	Acquired Utility	Combined
Status Quo Revenue Requirement to be Collected from Customers	$1,000	$40	$1,040
Post Consolidation Cost to Serve	$1,000	$30	$1,030
Impact of Cost Allocation Model Treatment of Shared Costs	($15)	$15	-
Post-Consolidation Cost Allocation	$985	$45	$1,030
Impact of Setting R/C Ratio Within Board Approved Range on Rates Revenue Requirement	$3	($3)	-
Post-Consolidation Rates Revenue Requirement based on Board Approved Ranges	$988	$42	$1,030
Adjustment to Ensure No-Harm to Acquired Utility/Legacy Customers	$2	($2)	-
Post Consolidation Rates Revenue Requirement	$990	$40	$1,030
Consolidation Benefits	($10)	-	($10)

a) Hydro One Legacy is made up of a number of customer classes. Please explain how the initial adjustment to address the Impact of Setting R/C Ratio Within Board Approved Range on Rates Revenue Requirement would be allocated amongst Hydro One's Legacy customer classes (e.g., would it be allocated to just those Legacy customer classes with R./C ratios of less than 100%?).

b) How would Hydro One assign the subsequent adjustment required to Ensure No-Harm to Acquired Utility/Legacy Customers would be allocated amongst Hydro One's Legacy customer classes (i.e., would it be assigned to all Legacy customer classes or just to those with R/C ratios of less than 100%)?

c) If the response to part (b) is just those classes with R/C ratios below 100%, how can Hydro One ensure that all Legacy classes are actually benefitting from the acquisition?

d) If the response to part (b) is all customer classes, how can Hydro One ensure that the final R/C ratios will continue to all be within the Board's approved ranges?

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