PUBLIC INTEREST ADVOCACY CENTRE
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May 29, 2019 **VIA E-MAIL**

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

Dear Ms. Walli:

Re: EB-2018-0270 – Hydro One's application for approval to purchase all issued and outstanding shares of Orillia Power Distribution
Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

In accordance with Procedural Order No. 5, please find attached the interrogatories of VECC in the above-noted proceeding.

Yours truly,

Bill Harper
Consultant for VECC/PIAC

For interrogatory clarifications please contact Bill Harper at 905-883-1727 or bharper.consultant@bell.net

REQUESTOR NAME	**VECC**
TO:	**Hydro One Inc. (HOI) / Hydro One Networks Inc. (HONI) & Orillia Power Distribution Corp. (OPDC)**
DATE:	**May 29, 2019**
CASE NO:	**EB-2018-0270**
APPLICATION NAME	**MADD Application – HOI Purchase of OPDC**

VECC-1

Reference: Exhibit A/Tab 1/Schedule 1, page 4 (line 3) and page 8 (lines 8-9)
Attachment 5 (Share Purchase Agreement), Schedule 6.2
EB-2016-0276, Exhibit I, Tab 3, Schedule 2

a) Is the list of community events/programs that OPDC supported in 2017 and 2018 that targeted residential, GS<50 and GS>50 customers as well as students and the general public similar to that provided in EB-2016-0276, Exhibit I, Tab 3, Schedule 2? If not please provide an updated list reflecting the community events/programs supported in the past two years.

b) Will all of the community event/programs OPDC supported in 2017 and 2018 be covered by the types of community events that HON proposes to sponsor (per Schedule 6.2)? If not, which ones would not be included?

VECC-2

Reference: Exhibit A/Tab 1/Schedule 1, page 5 (lines 8-17)
Attachment 5

a) Is the Share Purchase Agreement the same as that filed in EB-2016-0276.

b) If not, please provide a schedule indicating the changes made.

VECC-3

Reference: Exhibit A/Tab 1/Schedule 1, pages 6-7

a) On pages 6-7 the Application outlines a number of approvals that are being requested for actions to be taken by either OPDC or Hydro One. Please provide a timeline that, starting with the closing date of the transaction, sets out when each of these actions is expected to occur.

VECC-4

Reference: Exhibit A/Tab 1/Schedule 1, page 8 (lines 5-7)
EB-2016-0276, Exhibit I, Tab 3, Schedule 3, part (b)

a) Is the response provided to EB-2016-0276, Exhibit I, Tab 3, Schedule 3, part (b) regarding future CDM programs still applicable? If not, please provide an updated response.

VECC-5

Reference: Exhibit A/Tab 2/Schedule 1, page 18 (lines 21-28) and
page 19 (lines 17-20)
EB-2016-0276, Exhibit I, Tab 3, Schedule 4

a) Are the responses provided to EB-2016-0276, Exhibit I, Tab 3, Schedule 3, parts (b) and (c) regarding LEAP funding also applicable for the years 2017 and 2018? If not, please provide a revised response.

VECC-6

Reference: Exhibit A/Tab 1/Schedule 1, page 7 (lines 9-11)
Exhibit A/Tab 2/Schedule 1, page 21 (lines 17-25) and
Page 22 (lines 6-7)
Exhibit A, Attachments 12-17
EB-2016-0276, Exhibit I, Tab 3, Schedule 5, parts (a) – (d)

a) Please provide copies of the 2018 financial statements for OPDC, Hydro One Inc. and Hydro One Networks Inc.

b) Please provide an updated response to EB-2016-0276, Exhibit I, Tab 3, Schedule 5, part (a) as of December 31, 2018 and reconcile the balances with those in OPDC 2018 financial statements (per the response to part (a)).

c) Are the responses to EB-2016-0276, Exhibit I, Tab 3, Schedule 5, parts (b) – (d) still applicable? If not, please provide revised responses.

d) At what point in time will Hydro One cease making separate additions to OPDC's regulatory accounts and what is the basis for choosing this point in time?

VECC-7

Reference: Exhibit A/Tab 2/Schedule 1, page 2, Table 1
EB-2016-0276, Exhibit A/Tab 2/Schedule 1, page 2, Table 1

a) Please explain the material increase in forecast OM&A costs under the Status Quo forecast as between the EB-2016-0276 Application and the current Application (i.e., ten-year total increases from $52.6 M to $60.7 M).

b) More specifically, please explain the increase in forecast OM&A costs for year 1 under the Status Quo from $4.8 M to $5.5 M.

c) Given the response to part (a), please explain why the forecast OM&A under the Hydro One forecast has decreased slightly as between the EB-2016-0276 Application and the current Application (i.e., ten-year total decreases from $20.7 M to $20.6 M).

d) In the current Application, please provide the reasons for the significant increase in forecast capital spending in year 9 of the Status Quo forecast and why there is no similar increase in the Hydro One forecast.

VECC-8

Reference: Exhibit A/Tab 2/Schedule 1, page 2, Table 1
Exhibit A/Tab 2/Schedule 1, page 13, (lines 3-13 and Table 5)
EB-2016-0276, Exhibit I, Tab 3, Schedule 10
Attachment 18

a) What portion of OPDC's actual 2017 OM&A costs ($4.87 M) is labour-related?

b) What were the main non-labour contributors to OPDC's actual 2017 OM&A costs?

c) What portion of the OM&A reduction shown in Table 1 as between the Status Quo and the Hydro One forecast is due to the proposed elimination of 25 local positions (per page 13)?

d) What are the sources for the balance of the assumed OM&A savings in the Hydro One forecast versus the Status Quo forecast? In responding, please be specific as to the non-labour sources for these savings.

e) The response to EB-2016-0276, Exhibit I, Tab 3, Schedule 10, part c) indicated that in the previous Application the Hydro One forecast OM&A included an evaluation of the incremental administrative and support services costs as a result of absorbing OPDC. Was a similar evaluation performed for the current Application? If yes, please provide. If not, why not?

f) Does the Hydro One Forecast OM&A in Table 1 include any allowance for incremental costs associated with administration or support services (e.g. back-office services, customer service, finance, human resources, distribution system planning& design, executive & governance, etc.)? If yes, for what services were incremental costs included, what costs (i.e., dollars) were included in each year for each service and how were they determined? If not, why not?

VECC-9

Reference: Exhibit A/T5/S1, page 2 (lines 7-13)

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 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."

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 (EB-2017-0049, DRO Exhibit 3.1, Tab I3-TB Data).

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 (EB-2017-0049, DRO Exhibit 3.1, Tab I3-TB Data).

VECC-10

Reference: Exhibit A/Tab 2/Schedule 1, page 2 (Table 1)
EB-2016-0276, Exhibit I, Tab 3, Schedule 13

a) Please update the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 13 part (a) to include 2017 and 2018.

b) If the average spending for the 2017-2018 period is materially different from that in the Year 1 Status Quo Forecast, please explain why.

VECC-11

Reference: Exhibit A/Tab 2/Schedule 1, page 3 (lines 1-7)
EB-2017-0049, DRO, Exhibit 3.1

a) Please confirm that the 2017 HONI OM&A costs and customer counts used to derive the $179/customer cost for high density (UR) residential class are forecast values whereas the 2017 OM&A costs and customer counts for OPDC are actual values.

b) Please provide a schedule that compares the HONI's total forecast versus actual 2017 OM&A costs and that also compares the customer/connection counts as used in the Cost Allocation Model submitted with the 2017 DRO (EB-2016-0081) with the actual 2017 customer counts. (Note: Please include the individual forecast and actual customer/connection count for all HONI's customer classes).

c) Footnote #3 states: "For the OPDC residential class … the cost to serve is estimated to be $208/customer". Please provide the calculations supporting this statement.

d) Based on HONI's 2017 DRO (EB-2016-0081), what are the OM&A costs per customer to serve the UG_e and UG_d customer classes?

e) Based on the last Cost Allocation model submitted by OPDC to the Board, what percentage of total OM&A costs were allocated to the Residential, GS<50 and GS>50 customer classes?

f) Based on the HONI's EB-2017-0049 Draft Rate Order Filing, Exhibit 3.1 (i.e., the related cost allocation model), please provide the forecast 2018 customer count, OM&A cost and OM&A costs per customer for the high density (UR) residential class.

g) Based on HONI's EB-2017-0049 DRO, what are the OM&A costs per customer to serve the UG_e and UG_d customer classes?

h) Please provide a schedule that compares the HONI's total forecast versus actual 2018 OM&A costs and that also compares the customer/connection counts as used in the Cost Allocation Model submitted with the EB-2017-0049 DRO with the actual 2018 customer counts. (Note: Please include the individual forecast and actual customer/connection count for all HONI's customer classes).

i) Please provide OPDC's actual 2018 actual OM&A costs, customer count (consistent with the definition used in the OEB Yearbook) and the resulting 2018 OM&A cost per customer.

j) For those areas that HONI has currently designated as "high density", what is the average number of customers per km?

VECC-12

Reference: Exhibit A/Tab 2/Schedule 1, page 3 (line 11) to page 6
EB-2016-0276, Exhibit I, Tab 3, Schedule 16

a) The Application states (page 5) that OPDC's last rate order was approved in EB-2017-0264. Please confirm that a more recent rate order has now been approved by the OEB effective May 1, 2019 (EB-2018-0061).

b) Does this new rate order change OPDC's base distribution rates or the bill impacts in Table 2 attributed to "Change in Distribution Delivery Rates" or "Total Bill"? If yes please provide a revised version of Table 2.

c) Please update Table 3, as required, based on the EB-2018-0061 Decision and Rate Order.

d) Based on the EB-2018-0061 Decision and Rate Order and HONI's current EB-2017-0049 DRO, please update the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 16, part (a).

e) What would have been the impact on OPDC's 2017 revenue from specific service charges if HONI's currently approved charges (per EB-2017-0049) were used instead of OPDC's 2017 approved charges?

VECC-13

Reference: Exhibit A/Tab 2/Schedule 1, pages 8-11
EB-2016-0276, Exhibit I, Tab 3, Schedule 17
OEB Electricity Reporting and Record Keeping Requirements (RRR)

a) If available, please update Table 4 to include 2018 (either all or as much of the year as information for both utilities is available).

b) With respect to Table 4, please provide the contribution to the reliability metrics for HONI and OPDC for the following cause codes for the years 2016-2018:

- Scheduled Outages
- Tree Contacts
- Defective Equipment

c) Please update the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 17, part c) to include 2016 to 2018.

VECC-14

Reference: Exhibit A/Tab 2/Schedule 1, page 11 (lines 25) to page 12 (line 2)
EB-2016-0276, Exhibit I, Tab 3, Schedule 14

a) With respect to the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 14, part c), please indicate where in HON's EB-2017-0049 Application the details regarding the capital costs for the new operations centre in Orillia can be found.

VECC-15

Reference: Exhibit A/Tab 2/Schedule 1, pages 17-19

a) Does OPDC currently have a local office/location where customer can pay their bills in person (i.e., not a drop-off box but a location staffed by OPDC)?

b) If yes, will a similar location/service exist after the integration of OPDC?

VECC-16

Reference: Exhibit A/Tab 2/Schedule 1, page 23 (lines 1-22)

a) Will utilizing US GAAP alter any of the depreciation rates or recorded asset values in OPDC's financial statements or have any other "cost" implications?

b) If yes, please describe the impacts and whether HON will be requesting any new deferral/variance accounts to record these impacts until the time of the rebasing.

VECC-17

Reference: Exhibit A/Tab 3/Schedule 1, pages 1-7
Attachment 18
EB-2016-0276, Exhibit A/Tab 3/Schedule 3, page 7 (Table 6)

a) Please explain the following changes in the forecast for 2025 from the EB-2016-0276 Application (Table 6) to the current application (Table 2 on page 7):
   i. Rate Base – increases from $45.4 M to $47.9 M
   ii. Revenue – increases from $9.2 M to $9.3 M
   iii. OM&A – decreases from $2.237 M to $2.075 M.

b) Please provide a schedule that sets out the calculation of the OM&A values included in Table 2 (including the risk factor adjustment) and reconcile with the Hydro One Forecast OM&A costs in Table 1 (Exhibit A, Tab 2 Schedule 1).

c) Attachment 18 states that the Hydro One Residual scenario is calculated based on the same model used by Hydro One in the calculation of the ESM. Given this statement please explain the following variances between the 2029 values in the ESM calculation (page 7, Table 2) and Attachment 18:
   - Rate Base - $54.722 M vs. $51.215 M
   - Cost of Debt (Interest) - $1.944 M vs. $1.329 M

d) With respect to Table 1 (page 5), please explain how the working capital component of the rate base was determined and, in particular the basis for the assumptions made regarding the cost of power.

e) With respect to Table 1, please explain more fully the basis for the depreciation rates that will applied to the acquired assets during the 10-year deferral period. In particular, does Hydro One plan on specifically reviewing the useful life of the acquired assets and resetting the depreciation rates accordingly?
   i. If yes, does Hydro One plan on establishing a deferral/variance account to capture any differences in depreciation charges for these assets until the time of rebasing?
   ii. How can the ESM values in Table 2 be “locked in” at this point in time if the depreciation rates are yet to be determined?
   iii. If the depreciation rates for the acquired assets have already been set, how do they compare with OPDC’s current rates? If there is a difference, does Hydro One plan on establishing a deferral/variance account to capture the differences in depreciation charges for these assets until the time of rebasing? If not, why not?

VECC-18

Reference: Exhibit A/Tab 3/Schedule 1, pages 3-6
EB-2016-0276, Exhibit I, Tab 4, Schedule 16

a) Please provide a schedule that sets out the load and customer count forecasts (by customer class) as used in EB-2016-0276 and in the current Application to project the revenues used in the calculation of the ESM. (Note: For the starting

year, please use the last year for which actual values were available in EB-2016-0276. For both the EB-2016-0276 and current Application, please report actual values where applicable.)

VECC-19

Reference: Exhibit A/Tab 4/Schedule 1, page 7 (lines 14-22)

Preamble: The referenced portion of the Application lists a number of factors that are likely to be taken into account by both Hydro One and a future OEB Panel in determining the methodology to be used to establish the amount of Shared Costs to be included in rates, including those for former OPDC customers.

a) Does Hydro One Networks consider the impact on rates for former OPDC customers and HONI's legacy customers as being relevant factors for purposes of establishing the methodology for allocating Shared Costs to customer classes or is the consideration of impacts limited to the adjustments that may be made to rates based on the revenue to customer class revenue to cost ratios that are calculated based on the established cost allocation methodology for Shared Costs?

VECC-20

Reference: Exhibit A/Tab 4/Schedule 1, pages 2-5

a) The difference in the Year 11 Rate Base as between the Status Quo Scenario (Table 1) and the Residual Cost to Serve Scenario (Table 3) is primarily due to the difference in Working Capital. Please provide the calculations supporting the working capital values used in both tables.

VECC-21

Reference: Updated Exhibit A/Tab 4/Schedule 1, page 8 (lines 5-10)

Preamble: At page 8 the Application states: "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 LV charges (totaling $7.9 M); and (b) the Year 11 revenue requirement under the OPDC Status Quo scenario plus Year 11 LV charges (totaling $14.4 M)." (Emphasis Added)

a) The choice of the word "collected" as opposed to say "allocated" suggests that HON is proposing that regardless of the results of the cost allocation methodology that will be used at the time of the harmonization and rebasing application, HON will (at that time) propose a revenue to cost ratio for the customer class representing the former

OPDC customers such that the resulting rates will result in revenues between the two values referenced in the quote. Please confirm whether or not this is the intent of HONI's proposal as set out in the Preamble. If it is not, please clarify what HONI is proposing.

b) If response to part (a) is yes, would a similar approach be used in subsequent rebasing applications? If so, how would the values for the Residual Cost to Serve and OPDC Status Quo cost to serve be established? If a similar approach is not to be used, how will HON ensure that in subsequent rebasing Applications former OPDC customers will continue to pay less than they would have if the transaction had not occurred?

c) If the response to part (a) is yes and the resulting revenues produce a revenue to cost ratio that is below the policy range established by the Board, would it be HONI's intent that any shortfall in revenue be recovered from the other customer classes?

VECC-22

Reference: Exhibit A/Tab 4/Schedule 1, page 9 (lines 13-22)

Preamble: The Application states that to calculate the Status Quo forecast in Year 11 Hydro One will use the forecast as provided in the current Application but that it would need to be adjusted for: i) unforeseen costs and ii) the weighted average cost of capital applicable at the time.

a) Are there any other factors that would need to be accounted for such as: i) changes in working capital due to changes in the expected load, the expected cost of power or the working capital allowance percentage or ii) changes in tax rates?

VECC-23

Reference: Exhibit A/Tab 5/Schedule 1, page 3 (lines 4-19) and
page 8 (lines 1-2)
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 OPDC's incremental OM&A costs until the time that OPDC 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 OPDC 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 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 OPDC 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 OPDC 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 OPDC'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 OPDC include Property Taxes and Rights Payments attributable to OPDC's service area?

VECC-24

Reference: Exhibit A/Tab 5/Schedule 1, 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 OPDC 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 OPDC's existing customer classes, including its current USL, Street Lights, Sentinel Lights and Large Use classes?

VECC-25

Reference: Exhibit A/Tab 5/Schedule 1, page 5 (lines 13-16)
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 OPDC rate classes that will be less than what the cost-to-serve the OPDC customers would be if OPDC 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 OPDC customers would be if OPDC 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-26

Reference: Exhibit A/Tab 5/Schedule 1, page 6 (lines 16-19)
EB-2017-0049

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

a) Does Hydro One accept that the OM&A costs attributed to the local assets used to serve OPDC 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) Please provide a schedule that sets out: i) the 2021 Residual Costs to Serve associated with the acquired utilities in EB-2017-0049 and ii) based on the cost allocation proposed for the acquired utilities in EB-2017-0049, 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-27

Reference: Exhibit A/Tab 5/Schedule 1, pages 7-8

a) Based on EB-2017-0049, what were: i) the total costs 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 OPDC customers in year 11 based on OPDC's forecast Residual Cost to Serve.

VECC-28

Reference: Exhibit A/Tab 5/Schedule 1, page 8 (line 21) to page 9 (line 3)
Exhibit A/Tab 5/Schedule 1/Appendix A, page 8

Preamble: The Supplemental Evidence states: Hydro One fully anticipates that it will be possible to set rates for the OPDC 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 OPDC customers. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One is committing to charge OPDC customers no more than the higher goal post amount of $14.4 M and no less than their residual cost to serve of $7.9 M." (emphasis added)

a) In Hydro One's view, is there any possibility that it will not be able to set rates for the OPDC 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 OPDC customers? If not, please explain why.

b) Please confirm that if achieving both objectives is not possible then Hydro One would set the rates for OPDC customers such that the costs to be borne would not exceed $14.4 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 OPDC 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-29

Reference: Exhibit A/Tab 5/Schedule 1, pages 8-9

a) Please confirm that the rate design proposals set out on pages 8-9 (in particular the commitment to charge OPDC 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.

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

VECC-30

Reference: Exhibit A/Tab 5/Schedule 1, pages 10-11

Preamble: The Supplemental Evidence states: "In the Table 2 illustration, the cost allocation model has allocated $45 M to the acquired utility ($30 M in residual costs to serve plus $15 M 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-31

Reference: Exhibit A/Tab 5/Schedule 1, pages 10-12

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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