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January 24, 2018

VIA E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0049 – Hydro One Networks Inc. 2018-2022 Distribution Customer IR Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

Please find enclosed the Notice of Intervention of VECC in the above-noted proceeding. We have also directed a copy of the same to the Applicant.

Yours truly,

Mark Garner

Consultant for VECC

Hydro one:
Ms. Eryn MacKinnon – Regulatory@HydroOne.com
McCarthy Tetrault LLP:
Mr. Gordon Nettleton – gnettleton@mccarthy.ca
Mr. George Vegh – gvegh@mccarthy.ca

REQUESTOR NAME	**VECC**
TO:	**Hydro One Networks**
DATE:	**January 22, 2018**
CASE NO:	**EB-2017-0049**
APPLICATION NAME	**2018-2022 Distribution Custom Rate Application**

A. GENERAL

1. Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

N/A

2. Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

2.0-VECC-1

a) Please provide a table showing a summary by topic of customer concerns provided to Hydro One related to this application.
b) Please show how/where in the evidence the concern expressed is addressed

2.0-VECC-2

Reference: Exhibit A, Tab 4, Schedule 1, page 7

a) Does Hydro One's Ombudsman Office provide reports to the management of the Company?
b) If yes please provide the most recent report.

3. Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

N/A

4. Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

N/A

5. Are Hydro One's proposed rate impact mitigation measures appropriate and do any of the proposed rate increases require rate smoothing or mitigation beyond what Hydro One has proposed?

N/A

6. Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

N/A

B. CUSTOM APPLICATION

7. Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

7-VECC-3

Reference: Exhibit A, Tab 3, Schedule 2

a) Starting at page 2 of the reference are five factors Hydro One claims make a Revenue Cap approach superior to Price Cap rate setting. For each of these factors please explain why Hydro One's proposal is a superior approach. For example, Hydro One claims Revenue Cap provides greater flexibility under which to eliminate rate classes (Seasonal). However, it is not clear why this should be the case. Please explain.

7-VECC-4

Reference: Exhibit A, Tab 3, Schedule 2

Pre-amble: Hydro One proposes to use the hybrid inflator using 70% of the GDP-IPI and 30% of the change in average weekly earnings.

a) What impact does Hydro One expect on the average weekly earnings statistics arising from the recent government policy which has and will continue to significantly increase the minimum wage.

7-VECC-5

Reference: Exhibit A, Tab 3,Schedule 2, page 7-8

a) Please clarify what factors other than inflation are variable during the rate plan from those as shown in Table 2 (section 1.4- page 7).

7-VECC-6

Reference: Exhibit A, Tab 3, Schedule 2

a) What is the rationale for adjusting the revenue cap for cost of capital in year 4 of the program?
b) If the rationale is related to the acquired utilities please explain why a rebasing with an integrated cost allocation rate design application is not preferable in 2021.

7-VECC-7

Reference: Exhibit A, Tab 3, Schedule 2

a) Given the number of adjustments to rate design, OM&A and capital planning

8. Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

7-VECC-8

Reference: Exhibit A, Tab 3, Schedule 1 7 Exhibit A-3-2, Attachment 1 (PSE TFP Study)

a) In its TFP Report dated November 4, 2016 "*PSE recommends setting the stretch factor no higher than 0.6%*" (page 5). Is the only difference between this recommendation and that made in the May 18, 2017 Report the addition analysis drawn from adding data from U.S. utilities? If not please list all other factors which caused PSE to change its November 16, 2016 recommendation.
b) Please list the methodological differences as between the PSE Benchmarking Study and the PEG July 2017 Benchmark Study provided to the Ontario Energy Board.
c) Does Hydro dispute any of the conclusions in the 2017 PEG Study?
d) Please comment on the sensitivity of the model to adding or subtracting years of data. Specifically, what sensitivity analysis was undertaken to PSE to understand the stability of the model?

7-VECC-9

Reference: Exhibit A, Tab 3, Schedule 1, page 22

a) Please provide a list of productivity initiatives for each of the years 2018 through to 2022 which underpin the savings forecast.

9. Are the values for the proposed custom capital factor appropriate?

9.0-VECC-10

Reference: Exhibit A, Tab 3, Schedule 2

a) Please confirm that the proposed Custom Capital Factor (CCF) is based on the forecast present in Table 1 (page 6). That is, does the capital factor vary over time from the value shown in Table 2?
b) Given that capital expenditures are completely within the control of management (except for emergency repairs) why is it reasonable to calculate the proposed capital factor on a forecast rather than actual basis (i.e. as a trailing adjustment)?
c) If Hydro One used actual capital spending, capped at the forecast expenditures would the CISVA Account be necessary (i.e. would the outcome for rates be similar or the same)?

9.0-VECC-11

Reference: Exhibit A, Tab 3, Schedule 2

a) What is the theoretical linkage supporting the productivity factor as part of the CCF?
b) What is the relationship between the CCF and customer growth?
c) What is the relationship between the CCF and capital investment related reliability outcomes?

9.0-VECC-12

Reference: Exhibit A, Tab 3, Schedule 2

a) Please provide a table for the period 2010 through 2022 which shows the following for distribution plant:
   I. The total depreciation expense in the year;
   II. The actual capital spending in the year;
   III. Mid-year net plant additions;
   IV. Year-end plant additions;
   V. The ratio of year-end depreciation to year-end plant in-service; and
   VI. CRA CCA allocated to distribution in the year.

9.0-VECC-13

Reference: Exhibit A, Tab 3, Schedule 2

a) The CCF averages to 2% per year over the life of the rate program. Given an objective of rate stability (and if the adjustment is, apparently, to be made on a forecast not actual basis) why would it not be preferable to simply adjust the revenue requirement by the average of 2% per annum for capital additions over the rate program period?

9.0-VECC-14

Reference: Exhibit A, Tab 3, Schedule 2, page 8

a) Please explain how the CCF is adjusted for the inclusion of the acquired utilities in 2021.

10. Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

N/A

11. Are the results of the studies sufficient to guide Hydro One's plans to achieve the desired outcomes to the benefit of ratepayers?

N/A

12. Do these studies align with each other and with Hydro One's overall custom IR Plan?

N/A

13. Are the annual updates proposed by Hydro One appropriate?

N/A

14. Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?

14-VECC-15

Reference: Exhibit A, Tab 7, Schedule 1, page 3, Table 1.

a) Please explain the significant underspending of capital in 2015 and 2016 in the NPDI service area.
b) Please explain how Hydro One has assured that this underspending will not impact reliability to customers in that service area?

15. Is the proposed Earnings/Sharing mechanism appropriate?
N/A

16. Are the proposed Z-factors and Off-Ramps appropriate?

16-VECC-16

Reference: Exhibit A, Tab 3, Schedule 2, page 11

a) Hydro One lists Smart meters or similar type programs as a potential z-factors. Please clarify is this is meant to cover the normal replacement of meters for the residential and GS<>50 classes? If it is please explain how normal meter replacement would qualify as a z-factor.

C. OUTCOMES, SCORECARD AND INCENTIVES

17. Does the application adequately incorporate and reflect the four outcomes identified in the Rate Handbook: customer focus, operational effectiveness, public policy responsiveness, and financial performance?
N/A

18. Are the metrics in the proposed additional scorecard measures appropriate and do they adequately reflect appropriate outcomes?

18-VECC-17

Reference: Exhibit A, Tab 5, Schedule 1, page 7

a) Please provide the most recent scorecards showing 2016 and 2017 results.

18.-VECC-18

Reference: Exhibit B1-1-1, DSP Section 1.4

a) Defective equipment is the 2nd largest contributor to outage duration. How does Hydro One's scorecard metrics demonstrate to customers the value added of its capital program in reducing outages due to defective equipment?
b) Scheduled outages are the 3rd largest contributor to reliability. What scorecard metric demonstrates Hydro One's ability to minimize schedule

outages and their duration?

18-VECC-19

Reference:

a) Why is there no relationship between the scorecard measures (or any other metric or outcome) and the rate adjustment methodology? That is, if Hydro One performs poorly as measured by SAIDI/SAIFI why should customers in the following rate year be required to increase or even maintain the same level of funding to the Utility.

19. Are the proposals for performance monitoring and reporting adequate and do the outcomes adequately reflect customer expectations?

N/A

20. Does the application promote and incent appropriate outcomes for existing and future customers including factors such as cost control, system reliability, service quality, and bill impacts?

20-VECC-20

Reference: Exhibit A, Tab 5, Schedule 3

a) Does Hydro One operate its company (transmission and/or distribution) on a regional basis? If yes, please provide an Ontario Map showing the regional operating zones of the Company.
b) Please explain how each region is managed including a description of the level and number of senior managers/executives responsible for each region.
c) Does Hydro One combine reports from these regions to develop its various reports? Specifically:

   I. does each region provide a SAIDI/SAIFI report? If yes please provide the regional annual reports for the 2012 to 2017 period.
   II. does each region provide its own emergency response report. If yes please provide these reports for the 2012 – 2017 period.
   III. does Hydro One benchmark or compare outcomes (including cost efficiencies) of the different regions? If yes please provide these reports.

21. Does the application adequately account for productivity gains in its forecasts and adequately include expectations for gains relative to external benchmarks?

N/A

22. Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

N/A

D. DISTRIBUTION SYSTEM PLAN

23. Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

N/A

24. Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

24-VECC-21

Reference: Exhibit A-3-1, Attachment 3 (Auditor General Report 2016 Follow-up)

In her 2015 Report the Auditor General made the following comment with respect to Hydro One's implementation of its capital plan:

> ***Hydro One not replacing very high-risk assets, contrary to its rate applications****: We found Hydro One was not replacing assets it determined were in very poor condition and at very high risk of failing, and it used these assets in successive rate applications to the Ontario Energy Board to justify and receive rate increases. Power transformers that are identified as being in very poor condition should be replaced at the earliest time possible; however, Hydro One replaced only four of the 18 power transformers it deemed to be in very poor condition in its 2013-2014* (2015 Report page 248)

a) Please explain what steps Hydro one has taken to address this criticism.
b) Specifically please explain what reporting Hydro One proposes to make to the Ontario Energy Board so as to provide assurance that the DSP presented to the Board is this proceeding is in fact substantively implemented as planned?

24-VECC-22

Reference: Exhibit A-3-1, Attachment 3

a) What are the costs (by recommendation) in years 2017 through 2023 of addressing the Auditor General's concerns as set out the Hydro One's Internal Audit Report by AG Recommendations 1 through 17?

25. Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

N/A

26. Does the Distribution System Plan address the trade-offs between capital and OM&A spending over the course of the plan period?

26-VECC-23

Reference: Exhibit A-3-1 Attachment 1 & 2 and Exhibit Q-1-1, Attachment 1

a) Aside from matters arising from the inclusion 2023 (and completion of 2017) what are the material differences between the 2017-2012 and the 2018-2023 Distribution Business Plans?
b) Has Hydro One updated the Consolidated Business Plan? If yes please file this plan.

27. Has the distribution System Plan adequately addressed government mandated obligations over the planning period?

N/A

28. Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

N/A

29. Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

N/A

29-VECC-24

Reference: Exhibit B1-1-1, DSP section 3.2, page 9

a) Please explain the “lumpiness” in the General Plant spending in 2019.
b) The Board has articulated a policy of capital expenditure pacing. Please explain what programs could be delayed (or eliminated) in order for capital expenditures in 2019 through 2022 to continue on the same trend as general plant investment was between 2016 and 2018 (forecast).

29-VECC-25

Reference: Exhibit B1-1-1, DSP Section 3.2

a) Hydro One proposes a significant increase in its system renewal capital expenditures in 2018 as compared to 2013 through 2018 (forecast). As compared to the last cost of service filing (EB-2013-0416) what new asset condition data has been gathered to support this large increase?

29-VECC-26

Reference: Exhibit B1-1-1, DSP Section 1.4

a) Do any of Hydro One’s DSP performance measures/metrics utilize reliability /outages by cause code?
b) Specifically does Hydro One have a metric which compares outages due to defective assets against the level of investment in those assets. If not why not?
c) What efforts has Hydro One made to develop a metric which ties capital investment to an understanding of how any particular investment improves reliability?
d) How are outcomes of capital investments linked to the rate making proposal for capital adjustments?

29-VECC-27

Reference: Exhibit B1-1-1 DSP, Section 1.4

a) The leading causes of outages are (in order of magnitude) Tree Contacts, Defective Equipment, and Schedule Outages. Taken together in 2016 these factors were approximately 80% of the duration of all outages. What quantitative evidence has Hydro One provided in this Application that its capital program will address these 3 factors sufficiently to either maintain or reduce outage duration?
b) Does Hydro One consider outage data (by cause code) to be a lagging, current or leading indicator of capital investments?
c) Whichever indicator type it is does Hydro One believe it possible to model capital investment with outage data so as to better understand the

effectiveness of capital program? Specifically has Hydro One attempted to regress capital investment spending against lagged outage (by cause code) data to see if there are significant correlations? If not please explain why not?

d) Has Hydro One done an environmental scan to see if other utilities (including those not electric) or their regulators do this type of modelling? If yes what was the result of those enquiries?

30. Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

N/A

31. Are the methodologies used to allocate Common Corporate capital expenditures to the distribution business appropriate?

N/A

32. Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

<u>E. RATE BASE & COST OF CAPITAL</u>

33. Are the amounts proposed for the rate base from 2018 to 2022 appropriate?

33-VECC-28

Reference: Exhibit D1, Tab 1, Schedule 2

a) Please breakout the $104.6 million in higher than approved capital spending in 2015 as between the three listed categories – storm damage, in-service additions, and relocation projects.
b) Please provide the actual and forecast (Board approved) amounts for each category in 2015.

33-VECC-29

Reference: Exhibit D1, Tab 1, Schedule 2

a) For the period 2012-2018 please provide the forecast and actual budgets for storm damage capital works.

33-VECC-30

Reference: Exhibit D1, Tab 1, Schedule 4

a) In her 2015 Report the Auditor General criticized Hydro One for keeping higher than necessary spare transformers (2015 Annual report Section 4.3, page 274).
b) Please explain how Hydro One has addressed this criticism.
c) Please provide a table showing he number of (distribution related) transformers in inventory for each of the years 2013 through 2022.
d) In the same table please include separately the maintenance expense in each related to spare transformers.

33-VECC-31

Reference: Exhibit D1, Tab 1, Schedule 5, Table 1

a) Please explain how the rate for interest capitalized shown in Table 1 is calculated.

34. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

34-VECC-32

Reference: Exhibit D1, Tab 1, Schedule 3

a) Have the billing period for any customer classes changed since the last lead-lag study undertaken by Hydro One.
b) If yes, please explain how this change was incorporated into the new study.

34-VECC-33

Reference: Exhibit D1, Tab 1, Schedule 3

a) What is the revenue requirement impact of the working capital difference 7.7% and the Board default rate of 7.5%

34-VECC-34

Reference: Exhibit D1-1-3 Attachment 1, page 3, Table 1

a) Table 1 shows varying working capital requirements for the years 2018 through 2022. Please confirm that Hydro One does not intend to adjust the revenue requirement for changes in working capital for the duration of the rate plan.

35. Is the proposed capital structure appropriate?
N/A

36. Are the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rate implementation appropriate?
N/A

37. Is the forecast of long term debt for 2018 and further years appropriate?

37-VECC-35

Reference: Exhibit D1, Tab 2, Schedule 2, page 4

a) Please update Tables 2 and 3 showing the forecast debt issues for 2017 and 2018.

37-VECC-36

Reference: Exhibit D1, Tab 2, Schedule 2, page 5

a) Please update Tables 4 to show the actual (2017) and updated forecast (2018) yield and spreads.

F. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

38. Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

38-VECC- 37

Reference: Exhibit Q-1-1, Tab1, Schedule 1, page 3 & Attachment 1

a) Please explain the difference in Table 1of the OM&A costs for 2018 (579.6M) and those in the updated business plan for the same year (583M)

38-VECC- 38

Reference: Exhibit Q-1-1, Tab1, Schedule 1, page 8

a) Please explain the scope refinements to the Integrated Operating Center investment that caused the $4.2 million increase in costs.
b) When was this scope change made?

38-VECC-39

Reference: Exhibit Q-1-1, Tab 1, Schedule 1, page 14, Attachment 1, DBP page 13 ; Exhibit C1, Tab1, Schedule 2, page 3

a) Please provide the reporting metrics for the Quality Assurance and Quality Control Program for vegetation management.
b) How will these metrics be used to measure success of the program and improve its effectiveness over time?
c) How is this program expected to impact to the costs of vegetation management in 2018 to 2022?. Have these changes been imputed into the most recent forecast costs of OM&A?

38-VECC-40

Reference Exhibit Q-1-1, Tab1, Schedule 1, Attachment 1 (DBP) pages 17-18

a) At the above reference Hydro One lists a number of drivers for savings as part of the new business plan. For each of the drivers (listed under the headings "Operations/Operations-Procurement/Customer/Information Technology/People and Culture) please provide the projected savings in 2018 through 2023.
b) Please confirm (or not) that the savings identified in response to a) have been included in the updated 2018 OM&A or capital costs of this Application.

38-VECC-41

Reference: Exhibit Q-1-1, Tab1, Schedule 1, Attachment 1, DBP, page 20

a) Please update the Scorecard to show 2017 actual results.

38-VECC-42

Reference: Exhibit C1, Tab 2, Schedule 1, Attachment 7, page 5 & Exhibit C1-02-01, Attachment 6 (filed 2017-10-11)

a) Please confirm that the Table 1 of Attachment 6 market "Unrepresented" is the same group as that marked as "MCP" in Attachment 7

b) Please confirm that Attachment 6 (all tables) where only on Headcount figure is shown this represents “FTEs”.

38-VECC-43

Reference: Exhibit C1, Tab 1, Schedule 1, Table 1

a) Please update Table 1 for 2017 actual (unaudited) results.

38-VECC-44

Reference: Exhibit C1, Tab 1, Schedule 1, page 8/ Schedule 5, page 8-9

a) What were the actual customer care costs in 2017?
b) Please explain how the bad debt provision forecast for 2018 was calculated.
c) Hydro One states that it expects to “return closer to historical norms”. What is the historical norm or target bad debt provision expected by the end of the rate period (2022).
d) Please explain what DSC changes related to interval meters and monthly billing are driving increases to customer care. What are the incremental costs in 2018 related to these factors?

38-VECC-45

Reference: Exhibit C1, Tab 1, Schedule 2, page 27

a) With respect to Telecom, Monitoring and Control costs drivers please explain what is meant by cost increases due to “*the allocation of smart meter telecom supports costs and the modernization of the distribution network*”. Specifically what costs are being allocated and from what to where?

38-VECC-46

Reference: Exhibit C1, Tab 1, Schedule 7, page 2-6

a) Please update Table 1, 2 & 3 (Common Corporate Functions) for the December 21, 2017 update to executive compensation.
b) Please do the same for Table 4 and 6.

38-VECC-47

Reference: Exhibit C1, Tab 1, Schedule 7, page 21

a) Please provide both the total and allocated to distribution, OEB assessment costs for each year 2012 through 2018 (forecast).

38-VECC-48

Reference: Exhibit C1, Tab 2, Schedule 1, Table 1

a) What is the reason for significant increase in Casual PWU Hiring Hall (HH) employees in 2018 and the subsequent decline in 2019 onward?
b) For budgeting purpose what cost does Hydro One estimate for each Casual PWU HH (hiring hall) FTE?
c) Please also provide the similar average FTE cost for Casual Construction.

38-VECC-49

Reference: Exhibit C1, Tab 2, Schedule 1, page 26

a) What is the current value (liability) of the share grant (ESOP) in 2018 for each of the employee categories (MCP/Society/PWU).

38-VECC-50

Reference: Exhibit C1, Tab 1

a) If Hydro One is a member of the Electricity Distributors Association please provide the annual fees for each year 2014 through 2018 (forecast).
b) Please provide a list of corporate memberships with material annual fees (above 25k) in the 2018 forecast.
c) Please provide the actual cost and forecast budget for the period 2014 through 2018 for professional and other membership fees paid by Hydro One on behalf of its employees.

38-VECC -51

Reference: Exhibit A, Tab 6, Schedule 3
Exhibit C1, Tab 1, Schedule 1, Table 1
Exhibit A, Tab 7, Schedule 1, Table 4

a) Please explain the treatment of the OM&A costs related to the acquired utilities Norfolk, Haldimand and Woodstock in both Exhibit A, Tab 6, Schedule 3 and Exhibit C1, Tab 1, Schedule 1, Table 1.
b) Please reconcile the difference between the OM&A values for 2017 and 2018 as reported in the two references in part (a) (e.g. for 2018 - $594 M vs. $591.1 M).
c) Please provide a breakdown of the forecast 2017 and 2018 OM&A costs associated with Norfolk, Haldimand and Woodstock using the same categories as set out in Exhibit C1, Tab 1, Schedule 1, Table 1.
d) If the differences noted in part (b) are (in part or whole) related to the OM&A costs associated with Norfolk, Haldimand and Woodstock, please

reconcile the variances noted in part (b) for 2017 and 2018 with the forecast 2017 and 2018 OM&A costs for these acquired utilities as set out in Exhibit A, Tab 7, Schedule 1, Table 4.

38-VECC -52

Reference: Exhibit A, Tab 6, Schedule 2

a) Please provide a copy of Hydro One Distribution’s 2016 Financial Statements.

39. Do the proposed OM&A expenditures include the consideration of factors such as system reliability, service quality, asset condition, cost benchmarking, bill impact and customer preferences?

39-VECC-53

Reference: Exhibit B-1-1-1, DSP Section 1.4, pages 14-28

a) Does Hydro One breakdown outages due to defective equipment by equipment type (e.g. transformer, insulator etc.).
b) If not why not.
c) If yes, please provide the reports for the period 2014 through 2017 of outages for defective equipment by cause code.

40. Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

40-VECC -54

Reference: Exhibit C1, Tab 1, Schedule 6, pages 1-2

a) Please provide schedules that for 2016, 2017 and 2018 set out the allocation of the total Common Corporate OM&A costs (per Table 1) between Hydro One’s distribution and transmission businesses and each of its unregulated accounting segments.
b) Are any of the Common Corporate OM&A costs allocated to Hydro One’s distribution business subsequently assigned to the acquired utilities Norfolk, Haldimand and Woodstock?
    i. If no, why not – particularly for purposes of the 2018 proposed revenue requirement?
    ii. If yes, please indicate what the amounts were for 2016, 2017 and 2018 and provide a schedule that reconciles these amounts with the amounts allocated to Hydro One’s distribution business (per part (a))

and the amounts included in the proposed revenue requirement (per page 2, Table 2).

40-VECC- 55

Reference: Exhibit C1, Tab 1, Schedule 6, pages 1-2
Exhibit C1, Tab 4, Schedule1, Attachment 1, Table 4

a) Please reconcile the total Common Corporate OM&A costs for 2018 as reported in: i) Exhibit C1, Tab 1, Schedule 6, Table 1 and ii) Exhibit C1, Tab 4, Schedule1, Attachment 1, Table 4.
b) Please reconcile the Common Corporate OM&A costs allocated to the distribution business for 2018 as reported in: i) Exhibit C1, Tab 1, Schedule 6, Table 2 and ii) Exhibit C1, Tab 4, Schedule1, Attachment 1, Table 4.

G. REVENUE REQUIREMENT

41. Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

41-VECC -56

Reference: Exhibit A, Tab 6, Schedule 3
Exhibit C1, Tab 6, Schedule 1, Tables 1, 2 and 3

a) Please explain the treatment of the depreciation & amortization costs related to the acquired utilities Norfolk, Haldimand and Woodstock in both Exhibit A, Tab 6, Schedule 3 and Exhibit C1, Tab 6, Schedule 1, Table 1.
b) Please reconcile the differences between the depreciation values for 2017 and 2018 as reported in the two references in part (a).
c) Please provide the forecast 2017 and 2018 depreciation costs associated with Norfolk, Haldimand and Woodstock using the same categories as set out in Exhibit C1, Tab 6, Schedule 1, Tables 1, 2 and 3.
d) If the differences noted in part (b) are (in part or whole) related to the depreciation costs associated with Norfolk, Haldimand and Woodstock, please reconcile the variances noted in part (b) for 2017 and 2018 with the forecast 2017 and 2018 depreciation costs for these acquired utilities as set out in part (c).

42. Are the proposed other revenues for 2018 – 2022 appropriate?

42-VECC-57

Reference: Exhibit E1, Tab 1, Schedule 2, pages 2-3

a) In terms of revenues from unregulated work, please identify the three types of external work performed that contribute the most towards External Revenues.
b) For each type of three, please indicate the “margin” added above costs per page 3, lines 21-22.

42-VECC-58

Reference: Exhibit E1, Tab 1, Schedule 2, pages 5-8, Table 4

a) What were the actual 2017 volumes and revenues for each Rate Code? If year-end values are not available, provide the most current year-to-date values and indicate the period covered?
b) Please indicate the specific adjustments that were made to the revenues forecast for 2021-2022 to account for the integration of Norfolk Power, Haldimand Hydro and & Woodstock Hydro in 2021.

42-VECC-59

Reference: Exhibit E1, Tab 1, Schedule 2, pages 5-6 and page 9 (lines 1-4)

a) Are there currently on-line self-service tools in place that allow customers to request/access each of the services identified as “Call Centre Requests” (per page 9, lines 1-4)? If not, when is the on-line service expected to be in place?
b) Why is there little to no volume/revenue history for the “Call Centre Request” activities?
c) How was the forecast decline in volumes determined for each activity?

42-VECC-60

Reference: Exhibit E1, Tab 1, Schedule 2, page 6 and page 9 (lines 6-8)

a) When was the on-line service for this activity (Rate Code 14) put in place?
b) How was the forecast decline in volumes determined for this activity?

42-VECC-61

Reference: Exhibit E1, Tab 1, Schedule 2, page 8 and page 9 (lines 14-20)

a) The Application states that Late Payment revenue is expected to increase as the customer base increases. Did the forecast revenue also account for the fact that customers' monthly bills are also increasing over the period? If yes, please explain how this was taken into account.
b) Please explain the significant increase in Late Payment revenues between 2014 and 2015.
c) Please explain the drop in revenues as between those historically seen in 2015 and 2016 versus those forecast for the 2018-2022 period.

42-VECC-62

Reference: Exhibit E1, Tab 1, Schedule 2, page 7 and page 10 (lines 1-6)
Exhibit H1, Tab 2, Schedule 3, page 6

a) Exhibit H1 indicates that Rate Code 31 is new. However, Exhibit E1 indicates there were volumes/revenues for 2014-2016. Please reconcile.
b) Why are there no forecast volumes/revenues associated with Rate Code 31b?

42-VECC-63

Reference: Exhibit E1, Tab 1, Schedule 2, page 14

a) Why is there no increase in the volumes associated with Rate Code 49 for the period 2021-2022 to account for the integration of Norfolk Power, Haldimand Hydro & Woodstock Hydro in 2021?

42-VECC-64

Reference: Exhibit E1, Tab 1, Schedule 2, page 19
EB-2015-0141, OEB Decision, page 8

a) In its EB-2015-0141 Decision the Board determined that vegetation management costs would not be recovered in the pole attachment rate. How does Hydro One Networks propose to recover the vegetation management costs incurred on behalf of 3rd party pole attachers?
b) What were the actual costs for such vegetation management in 2016 and what are the forecast costs for 2018-2022?

H. LOAD AND REVENUE FORECAST

43. Is the load forecast methodology including the forecast of CDM savings appropriate?

43-VECC-65

Reference: Exhibit E1, Tab 2, Schedule 1, page 1 (lines 14-15)

a) Please clarify what point on Hydro One’s system is considered to be the “wholesale level”.
b) Please provide a listing of the tables in Schedule 1 where the values are not reported at the “wholesale level” and in each case indicate at what level the values are reported.

43-VECC-66

Reference: Exhibit E1, Tab 2, Schedule 1, page 2 (lines 8-9)

a) The evidence states that one standard deviation is an “accepted standard in the industry”. Please indicate the basis for this statement.

43-VECC-67

Reference: Exhibit E1, Tab 2, Schedule 1, page 2 (lines 16-19)

a) Are the comparisons set out in Appendix E, Table E.1 based on Hydro One Distribution’s total load forecast or its forecast for retail sales?
b) If based on retail sales, please provide a table similar to E.1 based on Hydro One Distribution’s forecast and actual ST sales.

43-VECC-68

Reference: Exhibit E1, Tab 2, Schedule 1, page 4 (lines 7-15)
Exhibit E1, Tab 2, Schedule 1, pages 6-8
Exhibit E1, Tab 2, Schedule 1, pages 37-38
Exhibit E1, Tab 2, Schedule 1, Attachment 1

a) With respect to the Broad Annual Series set out at pages 1-2 of Attachment 1, please provide a schedule that sets out for each variable (excluding CDD, HDD, Ontario GDP and Ontario Housing Starts) the following:
   i. The source of the actual and forecast data
   ii. The date the forecast data was published
   iii. An indication as to which years are actual vs. forecast values.
   iv. The actual 2016 values for those variables where Attachment 1 was based on forecast values.

    v. An update to the forecast if a more recent forecast is now available.

b) With respect to Tables E.2 and E.3 please provide a schedule that sets out:
    i. The actual 2016 Ontario GDP growth rate and Housing Starts.
    ii. The most recent forecasts from each source and resulting average through to 2022.

c) With respect to the monthly values set out at pages 3-4 of Attachment 1, please provide schedules that set out for each variable:
    i. The source of the actual and forecast data
    ii. The data the forecast data was published
    iii. An indication as to which years are actual vs. forecast values.
    iv. An update to the forecast if a more recent forecast is now available.

43-VECC-69

Reference: Exhibit E1, Tab 2, Schedule 1, page 4, Table 2
Exhibit E1, Tab 2, Schedule 1, page 5, Table 3
Exhibit E1, Tab 2, Schedule 1, page 20, Table 7
Exhibit E1, Tab 2, Schedule 1, page 39, Table E.5
Exhibit E1, Tab 2, Schedule 1, Attachment 1, page 6

a) Please reconcile the 2015 and 2016 Retail load values reported in Attachment 1 versus those in Tables 2 & 7.

b) The Gross Electricity values reported in Attachment 1 are broken down as between Retail and LDC Load.
    i. Are the values reported actuals or weather normalized?
    ii. Please clarify what is included in LDC Load (i.e., does it just include embedded LDCs or does it also include Direct ST customers.
    iii. If Direct ST customer load is not included in LDC Load, are they included in the Retail Load reported in Attachment 1 or excluded entirely?
    iv. If Direct ST customer load is excluded from Attachment 1, please provide a revised table with a separate column that reports Direct ST customer load by year.

c) With respect to Table 7, please confirm that "Embedded Customers" includes both Direct ST customers and Embedded LDC ST customers.

d) Please explain the difference between the actual 2016 load reported in Table E.5 and the total Gross Electricity Usage for 2016 (i.e., 23,507.7 GWh + 12,287.2 GWh) reported in Attachment 1.

43-VECC-70

Reference: Exhibit E1, Tab 2, Schedule 1, pages 9-10
Exhibit E1, Tab 2, Schedule 1, page 39, Table E.4

a) Are the customer count values in Table E.4 year-end or average annual values?

b) Please provide the customer count by customer class as of: i) June 30, 2017 and ii) December 31, 2017.

43-VECC-71

Reference: Exhibit E1, Tab 2, Schedule 1, pages 9-10
Exhibit E1, Tab 2, Schedule 1, page 39, Table E.4
EB-2013-0416, Exhibit I, Tab 6.06, Schedule 6-VECC 79

Preamble: The response to VECC 79 stated: “For residential customers, the consensus forecast of housing starts is used to forecast the change in the number of households in Ontario and hence the change in the number of retail residential customers. Historical share of retail in the number of households in Ontario and its dynamics over time is taken into account. Over the forecast period, residential load growth also contributes to the forecast of the number of residential customers.”

a) Please provide a schedule that sets out the actual derivation of the forecast residential customer count for each of the years 2017-2020. In doing so please provide all equations, inputs used and associated calculations.
b) Please explain how the forecast was broken down as between the various “residential classes” (including the residential classes for acquired utilities).

43-VECC-72

Reference: Exhibit E1, Tab 2, Schedule 1, pages 9-10
Exhibit E1, Tab 2, Schedule 1, page 39, Table E.4
EB-2013-0416, Exhibit I, Tab 6.06, Schedule 6-VECC 79

Preamble: The response to VECC 79 states: “For other rate classes, two basic factors affecting the number of customer forecast are considered. First, load growth for these classes as determined by the overall economic factors. Second, residential customers’ changes within the retail territory are considered as most general service customers serve the retail community.”

a) For each of the other (non-residential) rate classes, please provide a schedule that sets out the actual derivation of the forecast customer count for each of the years 2017-2020. In doing so please provide all equations, inputs and associated calculations.
b) Please explain how the customer count forecasts for ST, Street Light, Sentinel Light and USL are developed such that the values for 2017-2020 exclude the acquired utilities but the values for 2021-2022 include the

acquired utilities.

43-VECC-73

Reference: Exhibit E1, Tab 2, Schedule 1, pages 9, 20 and 39-42

a) Please provide versions of Tables 4, 7, E.5, E.6, E.7 and E.9 that also include the years back to 2005.
b) Please provide a schedule that for the years 2015 and 2022 reconciles the CDM savings as reported in Table 4 with those reported in Table E.9.

43-VECC-74

Reference: Exhibit E1, Tab 2, Schedule 1, page 42, Table E.9
EB-2013-0416, Exhibit A, Tab 16, Schedule 3, page 4, Table 1
EB-2013-0416, Exhibit I, Tab 6.06, Schedule 6-VECC 80 b) & c)

a) Please reconcile the 2012 Retail CDM savings reported in the following three references: i) EB-2013-0416, VECC 80 b) (i.e., 1,142 GWh); ii) Table 1 per EB-2013-0416, Exhibit A, Tab 16, Schedule 3, page 4 and iii) the 2012 CDM savings for the Retail classes as reported in Table E.9.
b) Please reconcile the 2012 ST CDM savings reported in EB-2013-0416, VECC 80 b) with the 2012 CDM savings for the ST class as reported in Table E.9.

43-VECC-75

Reference: Exhibit E1, Tab 2, Schedule 1, pages 9 (Table 4), 11 and 20 (Table 7)
IESO Ontario Planning Outlook (OPO)
EB-2013-0416, Exhibit A, Tab 16, Schedule 3, page 4, Table 1

Preamble: The Application states that the load forecast takes into account CDM detailed information consistent with the IESO Ontario Planning Outlook.

a) Please complete the following schedule showing the impact of each year's CDM activity on Retail load consistent with Exhibit E1, Tab 2, Schedule 1, Table 4 and EB-2013-0416, Exhibit A, Tab 16, Schedule 3, Table 1

	Results by Year (Actual & Forecast)								
Initial Activity Year	2005	2006	2007	Annually to ---→					2022
2005									
2006									
2007									
Annually To ->									
2022									
Total									

b) Please complete the following schedule showing the impact of each year's CDM activity on ST-Direct customer load consistent with Table 4.

	Results by Year (Actual & Forecast)								
Initial Activity Year	2005	2006	2007	Annually to ---→					2022
2005									
2006									
2007									
Annually To ->									
2022									
Total									

c) Please complete the following schedule showing the impact of each year's CDM activity on ST-LDC customer load consistent with Table 4.

	Results by Year (Actual & Forecast)								
Initial Activity Year	2005	2006	2007	Annually to ---→					2022
2005									
2006									
2007									
Annually To ->									
2022									
Total									

d) Please explain how the actual savings reported in the parts (a)-(c) for programs implemented in each of the years 2006-2016 were determined and provide the sources used.
e) Please provide a schedule that compares the CDM savings assumed in EB-2013-0416 from CDM initiatives implemented in each of the years 2013-2016 with the actual values used in the current Application.
f) Please provide a breakdown of the 2006-2016 savings from CDM initiatives (per parts (a) to (c)) into the various CDM categories utilized by the IESO (per OPO, page 21). If not possible, please explain how the historical results are consistent with the OPO.
g) Please provide a copy of IESO 2011-2014 verified CDM results (including persistence for the post 2014 period) report for Hydro One Networks. Please reconcile the values reported by the IESO with those attributed to 2011-2014 program savings per part (f).
h) Please provide a copy of the IESO's 2016 verified CDM results report for Hydro One Networks. Please reconcile the values reported by the IESO with those attributed to 2015 and 2016 program savings per part (f).
i) Please provide a copy of Hydro One Networks current 2015-2020 CDM Plan as approved by the IESO. Please reconcile the CDM Plan values for 2017-2020 with those attributed to 2017-2020 program savings per part (f).
j) Please explain how the total CDM savings assumed savings from initiatives undertaken in 2017-2022 were determined and reconcile with IESO's OPO (page 21). Provide copies of any reports/analyses relied upon.

43-VECC-76

Reference: Exhibit E1, Tab 2, Schedule 1, pages 20 and 22-31

a) Please provide a schedule that sets out:
    i. The actual weather normalized Retail Load for 2016 (before deducting impact of CDM)
    ii. The predicted Retail load for 2016 and the forecast Retail load for 2017-2022 based on the Monthly Econometric Model.
    iii. The predicted Retail load for 2016 and the forecast Retail load for 2017-2022 based on the Annual Econometric Model.
    iv. The predicted Retail load for 2016 and the forecast Retail load for 2017-2022 based on the End Use Model.
    v. The forecast Retail load for 2017-2022 per the Application (before deducting impact of CDM).
b) Please explain how each of the models and resulting forecasts accounted for the fact that the forecast for 2017-2020 excluded the load for the acquired utilities but the forecast for 2021-2022 included this load.
c) Please provide the detail calculations setting out how the proposed Retail load forecast (before deducting CDM) for each of the years 2017 to 2022

was determined using the results of these three models.

43-VECC-77

Reference: Exhibit E1, Tab 2, Schedule 1, pages 17 and 27

a) Please provide a schedule that sets out:
   i. The actual weather normalized load for each of Embedded LDC and Embedded Industrial Customers for 2016 (before deducting impact of CDM)
   ii. The predicted Embedded LDC load for 2016 and the forecast Embedded LDC load for 2017-2022 based on the Annual Econometric Model.
   iii. The forecast Embedded LDC load for 2017-2022 per the Application (before deducting impact of CDM), if different from the values provided per part (ii). If such is the case please, separately, provide an explanation as to why.
   iv. The Embedded Industrial Customers load forecast Embedded LDC load for 2017-2022 based on the Industrial Analysis (before deducting CDM).
   v. A breakdown of the 2015-2022 CDM savings attributable to Embedded Customers as between Embedded LDC and Embedded Industrial Customers (per page 20).
b) Does the Embedded LDC load forecast for 2017-2020 include the load for the acquired utilities?
   i. If not, why not?
   ii. If yes, please explain how the Annual Econometric Model used to forecast the Embedded LDC Load accounted for the fact that the forecast for 2017-2020 included the load for the acquired utilities but the forecast for 2021-2022 excluded this load.

44. Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

44-VECC-78

Reference: Exhibit E1, Tab 2, Schedule 1, page 5
Exhibit E1, Tab 2, Schedule 1, page 39

a) With respect to Tables E.4 and E.5, please indicate which years are based on actual values. For those years in Table E.5 that are based on actual values please provide the actual delivered GWhs, the weather-normalized GWhs and the Board approved values.
b) What is the impact on the values in Tables E.4 & E.5 and Table 3 of the elimination of load transfer arrangements?

44-VECC-79

Reference: Exhibit E1, Tab 2, Schedule 1, page 4, Table 2
Exhibit E1, Tab 2, Schedule 1, page 39, Table E.4

a) For each of the Residential and GS customer classes, please provide a schedule similar to Table 2 that compares the actual customer counts for 2014-2016 with those forecast in EB-2013-0416.

45. Has the load forecast appropriately accounted for the addition of the Acquired Utilities' customers in 2021?

45-VECC-80

Reference: Exhibit E1, Tab 2, Schedule 1, page 5

a) What is the impact on the values in Table 3 of integrating the load and customer numbers for Norfolk, Haldimand and Woodstock?

I. COST ALLOCATION AND RATE DESIGN

46. Are the inputs to the cost allocation model appropriate and are costs appropriately allocated?

46-VECC-81

Reference: Exhibit G1, Tab 2, Schedule 1, pages 1-2

a) Please provide a table similar to Table 1 that sets out number of customers that have been "reclassified" during the period between the EB-2013-0416 Decision and the referenced rate class review.

46-VECC-82

Reference: Exhibit G1, Tab 2, Schedule 1, page 3

a) Since December 1, 2016 has Hydro One Networks received any communications from the Board regarding the status or next steps with respect to the elimination of the seasonal rate class?
b) If yes, please provide copies of any written communications and/or summarize any oral communications received.

46-VECC -83

Reference: Exhibit G1, Tab 2, Schedule 1, page 8

a) What were the average customer densities for the former Norfolk Power and Haldimand Hydro?

46-VECC-84

Reference: Exhibit G1, Tab 2, Schedule 1, page 8

a) At lines 4-13 the Application states: i) that the Hydro One bills its Sentinel Light and Street Lighting customers on kWh and ii) it proposes that the Sentinel and Street Lighting customers of the acquired utilities will adopt the Hydro One charge determinants in 2021. The Application then states the existing kWh consumption from these acquired Street Lighting and Sentinel customers will be used as the billing determinant. Please clarify what is meant by "existing kWh consumption" (e.g. is it the current 2016 consumption, their consumption as it will exist in 2021 and 2022 or some other value?).

46-VECC-85

Reference: Exhibit G1, Tab 3, Schedule 1, page 3, lines 1-8

a) For purposes of the 2021 CAM, did Hydro One review what the impact would be of adding the acquired utilities assets on the previously established minimum system splits?
   i. If yes, please provide the results of the assessment.
   ii. If not, why not?

46-VECC-86

Reference: Exhibit G1, Tab 3, Schedule 1, page 3, lines 16-20
2021 CAM, Tab I3 (TB Data)

a) With respect to rows 20-442 of Tab I3, please provide a excel spreadsheet the breaks out the values for each account associated with the acquired utilities for both the direct allocation column (Column G) and the reclassified balance column (Column H)..
b) With respect to rows 490-533, please provide an excel spreadsheet that breaks out the values for each account associated with the acquired utilities for the reclassified balance column (Column E).

46-VECC-87

Reference: Exhibit G1, Tab 3, Schedule 1, page 3 (lines 20-23) and page 4, Table 1
EB-2009-0265 (Haldimand), Cost Allocation Model
EB-2010-0145 (Woodstock), Cost Allocation Model
EB-2011-0272 (Norfolk), Cost Allocation Model

a) Please provide a copy of the reviews (referenced at page 3, lines 21-22) that confirm the continued appropriateness for the 2018 CAM of the Billing & Collecting and Services weighting factors previously used.

b) A review of the CAM filed by each of the three acquired utilities in their last cost of service application indicates that all three utilities assigned Services weights greater than zero to their GS<50 and GS>50 customer classes. Some of these utilities also attributed Services' assets to their Street Lighting and USL classes. Given these facts, why has Hydro One Networks assumed (per Table 1) that there are no Services assets associated with the acquired customers in these customer classes?

46-VECC-88

Reference: Exhibit G1, Tab 3, Schedule 1, page 3 (lines 20-23), page 4, Table 2 and page 5, Table 3

a) Table 2 does not provide the weighted average cost (i.e., $/meter) for each class as suggested by the table's title. Please provide a revised table setting out weighted average cost by customer class as used in the 2018 and 2021 CAMs.

b) Please include in the preceding table the weighted average cost per meter as used in the EB-2013-0416 CAM.

c) Table 3 does not provide the weighted average cost for each class as suggested by the table's title. Please provide a revised table setting out average meter reading cost (relative to UR) as used in the 2018 and 2021 CAMs.

d) Please include in the preceding table the weights for meter reading for each customer class as used in the EB-2013-0416 CAM.

46-VECC-89

Reference: Exhibit G1, Tab 3, Schedule 1, page 5 (lines 6-9)

a) If a density value of other than 1 was used in the 2021 CAM for the six acquired rate classes, would the resulting revenue to cost ratios in Tab O1 change?

b) What is the basis of Hydro One Networks' assumption that the density factors for the existing rate classes do not need to be updated/revised? Please provide any analysis undertaken to support this assumption.

46-VECC-90

Reference: Exhibit G1, Tab 3, Schedule 1, page 6 (lines 3-14) and page 7, Table 5

EB-2009-0265 (Haldimand), Cost Allocation Model

EB-2011-0272 (Norfolk), Cost Allocation Model

EB-2010-0145 (Woodstock) Cost Allocation Model

a) Please confirm that, prior to acquisition by Hydro One, Norfolk and Haldimand were ST customers of Hydro One.
   i. If not confirmed, please explain the basis for the LV charges currently included in the approved 2017 tariff sheets for the former customers of these utilities.
b) Are the bulk distribution assets discussed at lines 9-14 of page 6 the assets used to serve these two utilities as ST customers? If not, please explain what assets are being referred to at these lines.
c) Please provide the detailed derivation of the GFA Adjustment Factors set out in Table 5. As part of the response, please indicate for each of the three acquired utilities:
   i. The value of the assets in each of the 1830-1860 accounts based on the assets of the utility at time of acquisition plus the in-service additions up to 2021.
   ii. The assets in each of the 1830-1860 accounts that have been allocated to each of the new acquired rate classes (per lines 6-8) and how the allocation was done.
   iii. The values for bulk distribution assets (and their associated USoA numbers) that have been allocated to the acquired rate classes (per lines 9-12) and how they were determined.
   iv. How these bulk distribution assets were attributed to the acquired utilities (per lines 12-14).
   v. What adjustments were made, if any, to account for the fact that Street Lighting, Sentinel Light, USL and MicroFIT customers from the acquired utilities have been incorporated into Hydro One Networks' existing customer classes?
d) Please provide schedules that for each of Haldimand, Woodstock and Norfolk sets out:
   i. The percentage of USoA 1830-1860 GFA attributed to their Residential, GS<50 and GS>50 customer classes for purposes of the 2021 CAM (i.e., response to c(i) versus c(ii)).
   ii. The percentage of USoA 1830-1860 GFA attributed their Residential GS<50 and GS>50 customer classes in the last Cost Allocation used for rate setting prior to acquisition.
e) Please explain why a separate GFA Adjustment Factor was not determined for each of the 1830-1860 USoA accounts or, for that matter, for each of the sub-accounts used in the CAM.
f) What would the GFA Adjustment Factors for Accounts #1830 and #1860 be, if calculated separately?
g) Were the bulk distribution assets attributable to the acquired utilities and removed from the assets allocated to customer classes in the 2018 CAM?
   i. If not, why not since the customers in the former utilities of Haldimand and Norfolk continue to pay LV charges?
   ii. If not, please re-state the revenue requirement for 2018 with the

costs attributable to these assets removed, using the same approach to identify in the assets as was used for the 2021 CAM.

iii. If not, please re-do the 2018 CAM with these assets removed.

iv. If yes, please indicate how this was done with reference to the 2018 CAM.

46-VECC-91

Reference: Exhibit G1, Tab 3, Schedule 1, page 6 (lines 16-19)

a) What USoA accounts are the assets discussed at line 16-19 recorded in?
b) Please provide a schedule setting out the value of these assets (by USoA) allocated to each of the acquired rate classes in the 2021 CAM.
c) What portion of the total assets allocated to each of the acquired rate classes do the assets discussed at lines 16-19 represent?
d) Were the any of these assets attributable to the acquired rate classes and removed from the assets included in the 2018 revenue requirement and allocated to customer classes in the 2018 CAM?
    i. If not, why not?
    ii. If yes, please indicate how this was done with reference to the 2018 revenue requirement and 2018 CAM.

46-VECC-92

Reference: Exhibit G1, Tab 3, Schedule 1, pages 6-7
Exhibit A, Tab 7, Schedule 1, page 11 (lines 5-14)
2021 CAM
Exhibit B1, Tab 1, Schedule 1, Appendix A, pages 6-11

a) Please provide a schedule that sets out the gross fixed assets, accumulated depreciation and net fixed assets for each acquired utility as of January 1, 2021 that was added to the opening balances per page 11?
b) Please reconcile the values reported in part (a) with the Net Plant for each acquired utility reported in Appendix A.
c) Please provide a schedule that sets out the Net Plant allocated to each of the six acquired utility rate classes per the 2021 CAM.
d) Please provide schedules that contrast:
    i. The Net Plant allocated to the Acq. UR, Acq. UGS_e, and Acq. UGS_d classes per the 2021 CAM with the total Net Plant attributable to Woodstock in 2021 (per Appendix A)
    ii. The Net Plant allocated to the Acq. Res, Acq. GS_e, and Acq. GS_d classes per the 2021 CAM with the total Net Plant attributable to Haldimand and Norfolk in 2021 (per Appendix A)

46-VECC -93

Reference: Exhibit G1, Tab 3, Schedule 1, pages 7-8
2018 and 2021 CAM Models (Tab O6 – lines 111-107)

a) Please provide a schedule showing the derivation of the NFA and NFA ECC adjustment factor for each acquired customer class.
b) Was the GFA to NFA relationship used based on all distribution assets for just those for accounts 1830-1860?
c) If based on all distribution assets, please explain why and recalculate Table 6 using just the relationship for assets in accounts 1830-1860.
d) With respect to Tab O6, please explain why the values for NFA Excluding Credit for Capital Contribution (NFA ECC – row 117) and NFA (row 116) both use the value for GFA - Distribution plant (exclude credit for contributed capital) in row 112 as the starting point before subtracting the relevant accumulated depreciation value. In particular, why isn't GFA - Distribution plant (credit to contributed capital) from row 111 used in one of the calculations?
e) Was the NFA for the bulk distribution assets attributable to the acquired utilities removed from the assets allocated to customer classes in the 2018 CAM?
    i. If not, why not since the customers in the former utilities of Haldimand and Norfolk continue to pay LV charges?
    ii. If not, please re-do the 2018 CAM with these assets removed. Using the same approach to identify in the assets as was used for the 2021 CAM.
    iii. If yes, please indicate how this was done with reference to the 2018 CAM.

46-VECC-94

Reference: Exhibit G1, Tab 3, Schedule 1, page 8

a) Was the depreciation expense for the bulk distribution assets attributable to the acquired utilities removed from the costs included in the 2018 revenue requirement and allocated to customer classes in the 2018 CAM?
    i. If not, why not since the customers in the former utilities of Haldimand and Norfolk continue to pay LV charges?
    ii. If not, please restate the 2018 revenue requirement with this depreciation expense removed and re-do the 2018 CAM with these depreciation costs removed. Using the same approach to identify in the assets as was used for the 2021 CAM.
    iii. If yes, please indicate how this was done with reference to the 2018 revenue requirement and 2018 CAM.

46-VECC-95

Reference: 2021 CAM
EB-2009-0265 (Haldimand), Cost Allocation Model
EB-2011-0272 (Norfolk), Cost Allocation Model
EB-2010-0145 (Woodstock) Cost Allocation Model
EB-2016-0276, Hydro One Networks Final Argument, page 4

a) Please provide schedules that for each of Haldimand, Woodstock and Norfolk sets out the values and the percentage of total OM&A attributed their Residential GS<50 and GS>50 customer classes in the last Cost Allocation used for rate setting prior to acquisition.
b) Please provide a schedule setting out the total OM&A attributed to each of the acquired customer classes per the 2021 CAM.
c) Please provide a schedule that sets out, for each of the three acquired utilities, the total OM&A added to the Hydro One Networks' 2021 revenue requirement/2021 CAM.

47. Are the proposed billing determinants appropriate?

N/A

48. Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

48-VECC-96

Reference: Exhibit H1, Tab 1, Schedule 1, pages 3 and 7
Exhibit H1, Tab 1, Schedule 2

a) Does Hydro One plan on updating the 2021 CAM in order to reflect the 2021 revenue requirement? If not, why not?

48-VECC-97

Reference: Exhibit H1, Tab 1, Schedule 1, pages 9-10
Exhibit H1, Tab 1, Schedule 2

a) Please confirm that in Schedule 2 for the years 2019, 2020 and 2022, the Allocated Costs (i.e., Column B) for each customer class were determined by increasing the previous year's allocated costs by a common factor based on the overall percentage increase in the total revenue requirement from the previous year. If not, please explain how the values were determined.

b) Please explain why this approach is reasonable when the load forecasts for the various customer classes are not changing by a common factor?
c) With respect to tables in Schedule 2 for the years 2019, 2020 and 2022, please clarify whether Column Y (Revenues with Previous Year's Rates and Current Year's Charge Determinants) includes or excludes Miscellaneous Revenues.
    i. If included, please provide a breakout by class for each of the three years of the revenue attributable to Miscellaneous Revenues and indicate how the value for each class was determined.
d) Please provide a schedule that for each of years 2019-2022 compares the revenues at the proposed distribution rates versus the revenues using the previous year's rates and the current year's billing determinants and calculates the percentage change for each customer class for each year.
    i. If for any given year, the year over year increases (per part (e)) are not the same for all customer classes where the R/C ratio is not proposed to change from the previous year (per Exhibit H1, Tab 1, Schedule 1, pages 9-10), please explain why.
e) Please re-calculate the 2019 and 2020 revenues from distribution rates for each class using the following approach:
    i. Re-calculate the 2018 allocated revenue requirement for each customer class using the proposed R/C ratios for 2019/2020.
    ii. In each case, recalculate the 2018 Base Revenue Requirement for each customer class using the results from part (i) and the miscellaneous revenues allocated to the class by the 2018 CAM.
    iii. Determine the 2019/2020 Base Revenue Requirements for each customer class by based on the percentage increase from 2018 to 2019/2020 in the overall Base Revenue Requirement.
f) Please compare the results from part e) (iii) with Hydro One Networks' proposed base revenue requirements by customer class for the same years.

49. Are the proposed fixed and variable charges for all rate classes over the 2018 –2022 period, appropriate, including implementation of the OEB's residential rate design?

49-VECC -98

Reference: Exhibit H1, Tab 1, Schedule 1, pages 15-16
EB-2012-0410, Board Report, page 26

a) For each customer class that is transitioning to a 100% fixed charge, please provide a schedule that for each year of transition demonstrates whether the change in the fixed charge meets the Board's $4 criterion.

49-VECC-99

Reference: Exhibit H1, Tab 1, Schedule 1, pages 16-17

a) For Woodstock, please provide the current fixed variable split for each (non-residential) customer class and provide references from EB-2010-0145.
b) For Norfolk and Haldimand, please provide the fixed/variable splits for each (non-residential) customer class, the calculation of the revenue weighted fixed variable ratio for each of the resulting acquired customer classes and references from EB-2011-0272 and EB-2009-0265 for the values used.

49-VECC-100

Reference: Exhibit H1, Tab 1, Schedule 1, pages 23-24

a) Please provide a schedule that for each year (2018-2022) sets out the kWh billed customer classes where customers receive the transformer ownership allowance, include the kWh by class which receive the allowance and the resulting cost of providing the allowance.
b) Please provide a schedule that for each year (2018-2022) sets out the kW billed customer classes where customers receive the transformer ownership allowance, include the kW by class which receive the allowance and the resulting cost of providing the allowance to each class.
c) In Table 12, what accounts for the large increase in the recovery rate between 2020 and 2021?
d) Why is a common cost recovery factor (e.g., $0.0637/kW for 2018) applied to all kW bill classes with customers receiving the transformer ownership allowance?
e) Please calculate what the 2018 class specific recovery factors would be if each customer class was responsible for the recovering the cost of providing the transformer ownership allowance to the customers in that class.

50. Are the proposed Retail Transmission Service Rates appropriate?

N/A

51. Are the proposed specific service charges for miscellaneous services over the 2018 – 2022 period reasonable?

51-VECC-101

Reference: Exhibit H1, Tab 2, Schedule 3, page 4, Table 1

a) It is noted that in some cases the proposed rates are constant over the five-year test period (e.g., Rate Code 2) whereas, in other cases the rates increase annually (e.g., Rate Codes34 & 35).

i. Why wasn't the same approach used for all charges?
ii. What was basis for determining which approach would be applied to each Rate Code?

51-VECC-102

Reference: Exhibit H1, Tab 2, Schedule 3, page 10, lines 3-5

a) The Application states: "most of these charges are calculated based on the labour required to perform the work". Which charges are not calculated on this basis and why?

51-VECC-103

Reference: Exhibit H1, Tab 2, Schedule 3, pages 13-17, 21, 23, 25, 27, 31, 52

a) Why for Rate Codes 2, 4, 5, 7, 9, 10, 11, 15 and 31a is the proposed charge less than the calculated cost in any of the five years?

51-VECC-104

Reference: Exhibit H1, Tab 2, Schedule 3, pages 18-20

a) Why would an easement be unregistered and under what circumstances would a search be required/requested?

51-VECC-105

Reference: Exhibit H1, Tab 2, Schedule 3, page 22

a) Why is it appropriate to charge for Account History when the request is arises as a result of changes Hydro One made to its billing system?

51-VECC-106

Reference: Exhibit H1, Tab 2, Schedule 3, pages 26-27

a) What costs does Hydro One Networks incur in assessing and collecting the Returned Cheque charge (i.e., does it cost as much or more to collect the "charge" than the actual "charge" itself)?

51-VECC-107

Reference: Exhibit H1, Tab 2, Schedule 3, pages 30-31

a) If the customer has a smart meter, why would Field Staff be required in order to perform the off-cycle read?

51-VECC-108

Reference: Exhibit H1, Tab 2, Schedule 3, pages 32-33

a) What forms of payment are Hydro One Network employees permitted to receive (e.g., cash, cheque, credit card)?

51-VECC-109

Reference: Exhibit H1, Tab 2, Schedule 3, pages 34-35

a) On what basis is the decision made as to whether the service will be disconnected or a load limiter installed?
b) Why does it require less field staff time to disconnect service/install a load limiter (per page 35) than it does to perform an off-cycle meter read (per page 31)?
c) If a customer is disconnected and then subsequently pays and is reconnected during regular hours is this charge levied once or twice?
d) If a new customer takes over a premise where service has been disconnected and sets up an account with Hydro One, is the new customer levied a reconnection charge?
    i. If yes, why is this appropriate?

51-VECC-110

Reference: Exhibit H1, Tab 2, Schedule 3, pages 37-39

a) Why is the time required for an after regular hours reconnect (Table 13) significantly more than for a reconnect during regular hours (Table 12)?

51-VECC-111

Reference: Exhibit H1, Tab 2, Schedule 3, pages 44-45

a) If the services of Measurement Canada are requested by the retailer, why is the customer charged and not the retailer?

51-VECC-112

Reference: Exhibit H1, Tab 2, Schedule 3, pages 46-48

a) Why is the time required for an after regular hours service call (Table 18) significantly more than for a service call during regular hours (Table 17)?
b) Is the customer charged the applicable during/after regular hour's rate even if there are "safety issues" involved?

51-VECC-113

Reference: Exhibit H1, Tab 2, Schedule 3, page 51

a) With respect to Rate Codes 31a & 31b, how does Hydro One know who the owner/landlord is at the time the power is disconnected (i.e., whether it is the previous customer, the new customer who subsequently seeks to have an account set up or some other party)?
b) If Hydro One does not “know” why is it appropriate to recover the reconnect fee from the new premise address owner?

51-VECC-114

Reference: Exhibit H1, Tab 2, Schedule 3, pages 58, 60, 62 and 64

a) Historically how much variation has there been in the time required to perform a various single-phase or three-phase service layouts (page 58)? If there is a material variation between jobs, why not charge actual cost?
b) Historically how much variation has there been in the time required to perform individual pipeline crossing designs (page 60)? If there is a material variation between jobs, why not charge actual cost?
c) Historically how much variation has there been in the time required to perform individual self-assessment for water crossings (page 62)? If there is a material variation between jobs, why not charge actual cost?
d) Historically how much variation has there been in the time required to obtain individual railway crossing agreements (page 62)? If there is a material variation between jobs, why not charge actual cost?

51-VECC-115

Reference: Exhibit H1, Tab 2, Schedule 3, page 67

a) Why isn’t the cost of the line staking simply included in the calculation of the capital contribution for system expansion?

51-VECC-116

Reference: Exhibit H1, Tab 2, Schedule 3, page 79

a) For net metering projects that have a capacity of less than 10 kW what work must Hydro One perform and are there any charges assessed against the customer?

51-VECC-117

Reference: Exhibit H1, Tab 2, Schedule 3, pages 102-103

a) Please provide the escalation factors used for 2016 through 2022 to derive the rates set out in Table 3 for 2017-2022.
b) Please re-calculate the rate of 2018 using the Board's inflation rate for 2018 (as opposed to CPI).
c) Please explain why the proposal is to use CPI for purposes of escalating the rate as opposed to the Board's inflation rate established for purposes of IRM Applications and published prior to the start of each year as the basis for the escalator.

51-VECC-118

Reference: Exhibit H1, Tab 2, Schedule 3, page 103

a) Please update Table 3 to reflect 2016 actual costs and data.

51-VECC-119

Reference: Exhibit H1, Tab 2, Schedule 3, page 103

a) What was the actual number of attachers per poles as of year-end 2015? .In responding, please provide the derivation of the value (i.e., total number of poles with attachers, total number of telecom attachers, and total number of a non-telecom attachers broken down by type).
b) What was the actual number of attachers per poles as of year-end 2016? .In responding, please provide the derivation of the value (i.e., total number of poles with attachers, total number of telecom attachers, and total number of a non-telecom attachers broken down by type).
c) Please provide the formula used to derive the percentage of total capital related costs per poles that are to be attributed to each attacher using the "communications space" and a schedule setting out the inputs used.

51-VECC-120

Reference: Exhibit H1, Tab 2, Schedule 3, page 104
EB-2015-0141, Exhibit I, Tab 1, Schedule 2.1, page 6
EB-2015-0141, Board Decision, Schedule A

Preamble: The calculation of the applicable Line Maintenance costs in the current Application differs from that used in Board's EB-2015-0141 Decision.

a) Please indicate where in the Application the historical 2015 Line

Maintenance costs (i.e., values for Accounts #5120, #5125 and #5020) can be found.

b) Please re-calculate the Line Maintenance costs using the same approach as in EB-2015-0141: Exhibit I, Tab 1, Schedule 2.1 and the Board's subsequent Decision.

51-VECC-121

Reference: Exhibit H1, Tab 2, Schedule 3, page 104, lines 4-9

a) Are there any other sub-accounts associated with Account #5120 apart from the #1464, #1467 and #1469? If yes, what are they, what are costs recorded in each, and why are none of these costs deemed to be pole-related?
b) How did Hydro One determine that only 5% of the costs in sub-accounts #1464, #1467 and #1469 are pole-related?
c) What are the other 95% of the costs attributable to?

51-VECC-122

Reference: Exhibit H1, Tab 2, Schedule 3, page 104, lines 10-15

a) Are there any other sub-accounts associated with Account #5125 apart from the #1464, #1467 and #1469? If yes, what are they, what are costs recorded in each, and why are none of these costs deemed to be pole or neutral related?
b) How did Hydro One determine that only 5% of the costs in sub-accounts #1464, #1467 and #1469 are related to the primary neutral conductor?

51-VECC-123

Reference: Exhibit H1, Tab 2, Schedule 3, page 104, lines 16-20

a) Is $7.7021 M the 2015 total for Account #5020? If not, what is the total and why was the balance of the costs excluded?
b) How did Hydro One determine that 77.5% of the time work is attributable to Overhead Distribution Lines and Feeders? What is the balance of time attributable to?
c) How did Hydro One determine that 50% of the time, work is related to the pole? What is the balance of time attributable to?

51-VECC -124

Reference: Exhibit H1, Tab 2, Schedule 3, pages 105-107

a) For purposes of the deriving the joint use rate for LDCs and Generators were the same values used regarding the number of attachers using the communications space and power space as were used in determining the joint use telecommunications rate? If not, please explain why.

b) Is the treatment and allocation of the “separation space” the same for the derivation of both the joint use telecommunications rate and the joint use LDC rate? If not, please explain why.
c) Is the buried space the same regardless of the overall height of the pole? If not, please indicate how this is treated in the derivation of the rate for power spaces in excess of 10’.

52. Are the proposed line losses over the 2018 – 2022 period appropriate?

52-VECC-125

Reference: Exhibit H1, Tab 5, Schedule 1, pages 1, 3, 4 and 8

a) Using the proposed loss factors (Distribution and Total) for the existing customer classes (per Table 1) and a weighted average approach please calculate an overall Distribution System Loss Factor and the Total Loss Factor for 2018 based on the forecast kWh per customer class.
b) Please explain why a Supply Facility Loss Factor of 0.6% is used in Table 1 whereas a Supply Facilities Loss Factor of 2.5% is used in Appendix 1.
c) Please comment on the difference between the values reported in response to part (a) and the 5-year average total loss factors reported on page 8.
d) With respect to Appendix 1 (page 8), please provide the derivation of the 1.025 Supply Facility Loss Factor.

52-VECC-126

Reference: Exhibit H1, Tab 5, Schedule 1, pages 5 and 8

a) Please provide the equivalent of Appendix 1 for each of Norfolk Power, Haldimand County Hydro and Woodstock Hydro for the most recent 5-years available.

53. Do the costs allocated to acquired utilities appropriately reflect the OEB’s decisions in related Hydro One acquisition proceedings?

N/A

J. DEFERRAL/VARIANCE ACCOUNTS

54. Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

54-VECC-127

Reference: Exhibit A, Tab 3. Schedule 1, Table 16 (F1-2-1)

a) Please update the deferral and variance account balances to show the year-end 2017 balances.

54-VECC-128

Reference: Exhibit F1, Tab1, Schedule 1, page 18

a) The evidence states in that in EB-2013-0416 the Board approved discontinuance of the Smart Grid Variance Account (1536). What was the projected balance provided in evidence to the Board for the year end 2014 in that proceeding?
b) If there was a material difference between the estimate EB-2013-0416 and the current balance please explain why.

55. Are the proposed new deferral and variance accounts appropriate?

55-VECC-129

Reference: Exhibit A, Tab 3, Schedule 2

a) What is the rationale for using a 98% cap on the CISVA account. That is why not 100% of in-service additions or for that matter 95%. What factors were considered in using 98%.
b) Does Hydro One measure budget to actual variances in its major projects? If so what variances have been found for small and large capital projects?
c) Is the variance tracking only on a dollar basis or does it also track variances in proposed (Distribution System Plan) against actual projects.
d) If the variance account only tracks dollars please explain who this methodology addresses the Auditor Generals observation that Hydro One does not complete projects which are presented as required in applications before the Board to increase rates.

56. Is the proposal to discontinue several deferral and variance accounts appropriate?

N/A

End of document