UNDERTAKING JT-VECC-TCQ-01

Reference:

Exhibit G, Tab 1, Schedule 1, Attachment 3, page 2
Exhibit D, Tab 4, Schedule 1, Page 5 (Table 2)
Exhibit I, Tab 24, Schedule G-VECC 90, Attachment 1

Preamble:

The following is an extract from VECC 90 – Attachment 1, 2019 EE Variance Tab:

STEP 2: Total "verfiied" Savings (EE+C&S)

		2016	2017	2018	2019	Data Source
(3)	EE and C&S	2,512	2,598	2,562	2,532	2006-2017 Tally Persistence tabl
(1)	2018 EE program			173	173	2018 IESO program evaluation report
(2)	2019 EE program				60	2019 IESO program evaluation report

The table of "IESO 2006-2017 Savings & Pesistence Table" has been p
response to VECC-24 part (d) in EB-2019-0082,

Undertaking:

a) According to VECC 90, Attachment 1 the source of the data used for the verified 2016 and 2017 EE and C&S savings is the response to VECC 24 part (d) from EB-2019-0082. However, after downloading the file from the OEB's web site, VECC discovered that both the net energy and the net demand savings reported for 2015 and after are not accessible due to an apparent error in the references used in the spread sheet. Please provide a "readable" version of the file and confirm that the values used in VECC 90 are the total net demand saving as set out in columns FH through FK of the VECC 24 d) attachment.

b) In Exhibit D, Tab 4, Schedule 1, page 5 (Table 2) Hydro One Networks sets out the CDM impact on system peak demand for 2006-2027.

i. Please confirm that the values for the years 2016 through 2018 are the same as those used in the EB-2016-0160 application {Exhibit E1/Tab 3/Schedule 1, page 8}.

ii. Please explain why, in the current application, Hydro One Networks did not use the verified values for 2016, 2017 and 2018 as established for purposes of the LDC CDM and Demand Response Variance Account?

c) In Table 2 from Exhibit D, Tab 5, Schedule 1 the 2019 CDM savings are 2,511 MW at the point of Generation. This value is materially less than the verified 2019 savings used in the Variance Account calculation (2,766 MW at the point of end-use). Why weren't the verified savings for 2019 used in the current Application?

Response:

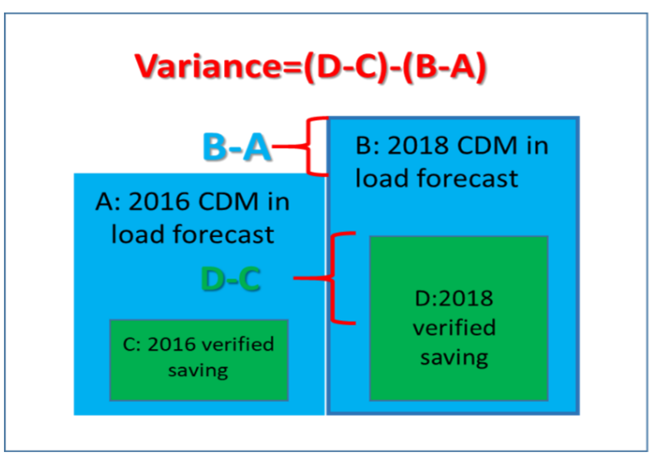
a) The table is provided in the attachment. Hydro One confirms that the values used in VECC 90 are the total net demand savings excluding DR programs as set out in columns FH through FK.

b)
   i. Yes, the values for the years 2016-2018 are the same as those used in the EB-2016-0160 application.

   ii. As approved in EB-2019-0082, Hydro One used the methodology of taking the difference of differences between (i) the estimated verified savings for 2017 vs 2016 and (ii) the forecasted savings 2017 vs 2016, to estimate the variance of EE and C&S savings for 2017 vs 2016. The same methodology is applied to calculate the EE and C&S savings variance for 2018.

c) As mentioned in the response to b ii), the CDM savings in table 2 from Exhibit D-5-1 and the value used in the variance account calculation are not comparable due to differences in purpose and methodology. Table 2 (Exhibit D, Tab 5, Schedule 1) provides the historical and forecasted CDM impact which is used for load forecasting. As indicated in Figure 5 of Exhibit D-5-1, historical CDM is added back to the historical load to arrive at gross load and then forecasted CDM is deducted from the gross load to derive the net load forecast. For the purposes of forecasting load, the consistency of the CDM definition and trending is extremely important to produce an unbiased forecast. For the years 2016-2018, there are no official verified total CDM savings with the same definition used in the load forecast.

Considering the methodology of incorporating CDM into the load forecast and the purpose of the variance calculation, Hydro One used the most recent available CDM saving as the proxy of the actual verified result. The following graph demonstrates how the savings variance is estimated.



UNDERTAKING JT-VECC-TCQ-02

Reference:

Exhibit I, Tab 24, Schedule D-VECC 40 f) & h)
Exhibit I, Tab 24, Schedule D-VECC 41 d) & h)

Undertaking:

a) With respect to VECC 40 f), please explain why Hydro One cannot provide a "predicted" value for last calendar year for which 12 months of actual historical data is available based on the Monthly Econometric Model. If Hydro One can provide predicted values for subsequent years based on forecast values for the Monthly Econometric Model's explanatory variables, why can't the actual values for the explanatory variables be used to produce a predicted value for a past year?

b) VECC 40 h) confirms that the Monthly Econometric Model is based on energy at point of generation while VECC 41 h) confirms that the Annual Econometric Model is based on point of use by the customer. What is the loss factor used to convert energy at point of use to energy at point of generation?

c) VECC 41 d) explicitly asked about how the Annual Econometric Model accounted for embedded behind the meter generation. Was the response provided meant to be applicable to embedded generation behind the customer's meter?

Response:

a) In linear regression software, the model is provided by the user. Thus, once the model coefficients are estimated by the software, the user can use the model and its estimated coefficients to predict actual over the estimation and forecast periods. In contrast, the equation is not selected by the user in the Forecast Master Plus software used for monthly econometric models. The software uses a combination of models that it selects based on their performance during sample period and a weighted sum of the models' forecasts is presented over the forecast period. The user is not informed by the software of such models, nor the weights used by the software. It follows that the user cannot use such unknown models to predict actual load during the estimation and forecast period. For the transmission monthly model, actual monthly data up to January 2021 are used so that the forecast is available for February 2021 onward. Similarly, for the distribution monthly model, actual monthly data up to December 2020 are used so that the forecast is available for January 2021 onward. In both cases, for the reasons noted above, there is no predicted value for 2020.

b) Energy figures at generation level are metered data obtained from IESO public files so that no loss assumption was made.

c) Yes, behind the meter generation (BTM) reduces the actual load and, thereby, projected load over the forecast period. In this case the gross forecast is already net of BTM so that future BTM is not deducted from the forecast in arriving at the net load forecast.

UNDERTAKING JT-VECC-TCQ-03

Reference:

Exhibit I, Tab 24, Schedule D-VECC 42 b) & e)

Undertaking:

a) With respect to VECC 42 b), please explain why it was not necessary to add CDM back into the actual values for the End Use model and why the forecast is gross of incremental CDM over the forecast period

b) With respect to VECC 42 e), please explain why predicted values using the End Use model are not available "for the base year (2020) due to the nature of the End-use model".

Response:

a) In econometric models, historical CDM is added back to the load to have a consistent series for developing a relationship between load and economic / demographic factors. The model is then used to forecast gross load.

   In contrast, End-Use models use latest actual data, net of CDM, to develop the gross forecast based on economic / demographic factors alone. Consequently, the End-Use gross forecast only includes incremental CDM (rather than total CDM), which needs to be deducted to arrive at the net forecast.

b) The End-Use forecast is based on latest (2020) actual data. Consequently, the model does not have a "predicted" value for 2020 as it is the same as the actual value for that year.

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UNDERTAKING JT-VECC-TCQ-04

Reference:

Exhibit I, Tab 24, Schedule D-VECC 43 c)

Preamble:

VECC 43 c) sets out the annual energy growth rates produced by each models and the annual energy growth rates used by Hydro One in in developing the Transmission load forecast.

Undertaking:

a) Are the 2021 growth rates for each of the three models based on comparing the model's forecast for 2021 with the actual (weather normal) use in 2020?

b) The response to VECC 43 c) indicates that the growth rates are "gross of the load impact of CDM and Embedded Generation when applicable". Does this mean that:

   i. For the Monthly Model the growth rates are gross of CDM and Embedded Generation, but
   ii. For the Annual Model and the End Use Model the growth rates are gross of CDM but not Embedded Generation?

   If not, what does it mean?

c) The response to VECC 43 c) states:
   "The growth rates used in the proposed forecast are higher compared to the average forecast growth rate implied by the forecasting model in view of other considerations including developments in Leamington and surrounding areas and to account for potential additional load growth due to other factors (e.g., EVs) that could materialize."

   i. What impact from the Leamington developments was factored into the 12 month average system peak forecast for 2021 to 2027?
   ii. What incremental impact was attributed to electric vehicles for the years after 2020?
   iii. What other considerations led to adopting a higher load forecast?

Response:

a) They reflect the year-over-year growth rate of gross load for each forecasting model tuned to 2020 weather-normalised gross load.

b)
   i. Yes.
   ii. No; annual Econometric and End-Use model are based on usage at customer level (no matter who is the generator) and, as such, are already gross of embedded generation. Thus, embedded generation is not added to actual since it would lead to double-counting embedded generation. Consequently, these forecasts are gross of both embedded generation and CDM as in monthly model.

c) i-iii. The requested information is provided in the following table. The figures are provided as average monthly peak values in MW.

Year	EV	Other *	Leamington
2021	39	132	33
2022	61	53	222
2023	83	32	435
2024	109	72	501
2025	139	126	515
2026	172	211	525
2027	213	292	525

* Includes impact of electrification and short-term considerations (basically in 2021 and 2022).

The last column of above table reflects the load impact of new customer connections, largely greenhouses, in Leamington and surrounding areas. The adjustments for EVs and Other factors (e.g., electrification and short-term considerations) were added based on the confidence intervals for the potential impact of those factors on peak load. As noted on page 45, lines 21-26 of the December 14th, 2021, transcript for the technical conference in this proceeding, the adjustments were made to mitigate the high-side risk related to EV and electrification. These adjustments are to the benefit of customers as they result in a load forecast that is higher than what would be implied by the forecasting models alone. The adjustments for short-term considerations reflect load that was added in view of increasing optimism regarding the future state of economy (i.e., economic recovery) at the time of forecast.

UNDERTAKING JT-VECC-TCQ-05

Reference:

Exhibit I, Tab 24, Schedule D-VECC 40 b) & c)
Exhibit I, Tab 24, Schedule D-VECC 57 c), Attachment 1

Preamble:

VECC 40 b) sets out the annual historic CDM energy savings added back for purposes of the Monthly Energy model.

VECC 40 c) refers to VECC 57 c) for the source of values and VECC 57 c) indicates that, for the period 2006-2018, the source of these values is the 2018 OPO. VECC 57 c), Attachment 1 (Figure 19) provides the actual values as copied below:

Long Term Conservation Forecast													
TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2	5.2	6.3	7.0
Existing program savings and persistence (2006-2018)	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	9.7	9.4	10.0	11.3
Savings from future energy efficiency initiatives (2019 onward)													
	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	13.9	14.6	16.3	18.4

Undertaking:

a) Please confirm that the 2018 OPO was produced by the IESO and whether the values are based on point of generation or point of use.

b) Please explain why the values provided in VECC 57 c), Attachment 1 (Figure 19) differ from those in VECC 40 b).

Response:

a) Yes, the 2018 OPO was produced by the IESO and the values are based on point of generation.

b) In response to VECC 57-part c), Hydro One provided a table which indicated the various sources that were used to arrive at the CDM values. The table should have indicated that CDM savings for use in forecasting load for the years 2015-2018 (and beyond) were also informed by consultation with the IESO. This consultation with the IESO was noted in Hydro One's response to VECC-40-part c).

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UNDERTAKING JT-VECC-TCQ-06

Reference:

Exhibit I, Tab 24, Schedule D-VECC 57 c)

Preamble:

VECC 40 b) sets out the annual historic CDM energy savings added back for purposes of the Monthly Energy model.

VECC 40 c) refers to VECC 57 c) for the source of values and VECC 57 c) indicates that, for the period 2006-2018, the source of these values is the 2018 OPO. VECC 57 c), Attachment 1 (Figure 19) provides the actual values as copied below:

Long Term Conservation Forecast													
TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2	5.2	6.3	7.0
Existing program savings and persistence (2006-2018)	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	9.7	9.4	10.0	11.3
Savings from future energy efficiency initiatives (2019 onward)													
	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	13.9	14.6	16.3	18.4

Undertaking:

a) VECC 57 c) indicates that the source of the Ontario CDM energy savings for 2019-2021 is from the IESO and refers to VECC 92 Attachment 1 as the source. However, the Attachment to VECC 92 deals solely with the MW savings attributable to ICI for 2016 to 2019 and has no energy savings data.

   i. Please provide the source of the CDM energy savings values used for 2019-2021.
   ii. As part of the response, please demonstrate that the energy savings for 2019-2020 are consistent with the 1.4 TWh of savings the IESO's Interim CDM Framework targeted for that period.

Response:

i. The sources of the CDM energy savings values used for 2019-2021 are provided in the table below. Hydro One uses these two different sources to estimate the CDM energy savings because the EE and C&S savings for 2020-2021 are not available in the 2020 APO.

	2019	2020	2021	Data source
EE saving	11.81	11.87	12.86	Information from the IESO 202102 (VECC38 Attachement 1)
C&S	7.6	7.8	8	OPO2018
Total Savings (TWh)	19.41	19.67	20.86	

ii. The EE savings from the IESO included 2006-2018 historical programs, as well as 2019-2020 Framework programs. In the 2020 APO and most recently released 2021 APO, the IESO does not separately present the energy savings for 2019-2020 Framework programs. The table below shows the EE and C&S energy savings in the 2020 and 2021 APO.

APO	Savings TWh	2016	2017	2018	2019	2020	2021
APO2020	Energy Efficiency - Programs	9.86	10.96	12.27	12.11	Not provided	
	Codes and Standards	5.17	6.28	7.07	7.37		
	Total	15.03	17.24	19.34	19.48		
APO2021	Programs (Energy Efficiency Programs)	9.86	10.96	12.27	13.03	13.53	Not provided
	Regulations (Codes & Standards)	5.17	6.28	7.07	7.37	7.37	
	Total	15.03	17.24	19.34	20.4	20.9	

UNDERTAKING JT-VECC-TCQ-07

Reference:

Exhibit I, Tab 24, Schedule D-VECC 38 b)

Undertaking:

a) Under Step 1 there are two tables. The first is described as: "The EE peak savings for 2019-2027 is provided by the IESO in Feb 2021". The second is described as "The EE summer peak savings for 2019-2027 is provided by the IESO in Feb 2021". As the transmission system peaks occur in the summer, why do the MWs of EE savings differ between the two tables – for example for 2019 the first table shows 2022 MW while the second shows 2511 MW?

b) Why are the values from the second table used in the Application?

Response:

a) The first table in step 1 was inadvertently mislabeled in the original response and actually reflects savings from the 2013 LTEP. The information from the IESO in February 2021 is shown in the second table. Hydro One leverages the information in these two tables to estimate the savings for 2025-2027.

b) As explained in steps 2 and 3, the savings for 2019-2024 are based on the information from the IESO in February 2021, which was the most recent information available. For the 2025-2027 savings, Hydro One added C&S savings from table 1 to the EE savings in table 2 to derive the total peak savings as the IESO's February 2021 data did not provide C&S savings. This ensures a consistent data set for load forecasting purposes.

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UNDERTAKING JT-VECC-TCQ-08

Reference:

Exhibit I, Tab 24, Schedule D-VECC 46 c)

Undertaking:

a) VECC 46 c) asked for the June and July 2021 customer counts by class and an indication of the Seasonal class' breakdown between UR, R1 and R2. The response stated: "The requested information is not readily available." Does this response apply to both requests (i.e., the counts for the existing classes and the Seasonal breakdown)?

b) If yes, please explain why the actual customer counts by class are not available, as other LDCs frequently provide year to date customer counts in response to similar queries made during the review of their COS rate applications.

Response:

a) Yes.

b) The database query that Hydro One's load forecasting team uses for customer counts does not currently distinguish customers from Orillia and Peterborough from the customer counts for Hydro One's other rate classes. As a result, the requested information is not readily available. Hydro One notes that this issue does not impact the customer counts proposed in this application.

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UNDERTAKING JT-VECC-TCQ-09

Reference:

Exhibit I, Tab 24, Schedule D-VECC 47, Attachment 1
Exhibit I, Tab 24, Schedule L-VECC 109

Undertaking:

a) In VECC 47, Attachment 1the forecast for the total number of Residential/Seasonal customers is based on the annual change in the number of Ontario households and then this total is broken down into the separate classes. The Attachment provides the percentage breakdown for each year by class but does not indicate how the percentages were derived. Please explain their derivation?

b) Also, VECC 47, Attachment 1 adjusts the individual Residential and Seasonal class customer counts for "reclassification" (see rows 24-31). Are the reclassification adjustments shown for 2021 and 2022 the result of the density review done in the later part of 2020?

c) VECC 109 b) sets out the reclassification that occurred as a result of the density review done in Q4 of 2020. However, the adjustments shown in Attachment 1 of VECC 47 don't match the customer movement set out in VECC 109 b). For example, for R1 VECC 47 shows a net decrease of 1,108. However, the adjustments described in VECC 109 result in a net decrease of 2,124. Please reconcile and indicate if the customer class count forecasts used in the Application need to be revised.

d) According to Exhibit L, Tab 1, Schedule 2, page 2 density boundary reviews are undertaken annually and according to VECC 109 a) the boundary review used for the 2018 rate application (EB-2017-0049) was completed in November 2016. The response to VECC 109 b) suggests that the only time customers have been reclassified as a result of subsequent density-based rate class boundary reviews was for the 2020 review.

   i. Please confirm that annual reviews were undertaken in 2017, 2018 and 2019.
   ii. Please confirm that there were no boundary adjustments/customer reclassifications as a result of these reviews?

e) VECC 109 d) states that the most recent boundary review was completed in 2020. Was there no boundary review done in 2021? If not, why not?

<u>Response:</u>

a) As noted in response to VECC-47, the percent breakdown of sales amongst different rate classes is based on historical trends in this regard.

b) Please see response to part c) below.

c) Hydro One has reviewed the referenced worksheet as well as the response to VECC 109 b). Hydro One notes that the worksheet only accounted for customers moving from lower density classes to higher density classes (e.g. R2 to R1) but did not capture customers moving from higher density classes to lower density classes (e.g. R1 to R2). A revised worksheet consistent with VECC 109 b) is provided as Attachment 1 to this response. Hydro One will update for the impacts of this correction at the time of the draft rate order.

d)

i. The "annual" review process described in L-1-2 page 2 is a new process to be implemented in 2022. As approved by the OEB and documented on page 2 of Exhibit G1-2-1 in Hydro One's last distribution rate application EB-2017-0049, Hydro One previously proposed to update the rate class review on a province-wide basis to coincide with the resetting of rates as part of a rates application.[1] As such, no annual review was undertaken in 2017, 2018 and 2019.

ii. See response in i. above.

e) No boundary review was done in 2021. See response in d) above for more information.

[1] In its March 12, 2015 Decision on Hydro One's 2015-2017 Distribution Rate Application (EB-2013-0416), the OEB agreed that a five-year cycle of review and reclassification may be appropriate for Hydro One in the future (page 44).

UNDERTAKING JT-VECC-TCQ-10

Reference:

Exhibit I, Tab 24, Schedule D-VECC 52 a)

Undertaking:

a) VECC 52 a), parts ii), iii) and iv) requested the predicted 2020 Retail energy (before deducting CDM) based on the Monthly Econometric Model, the Annual Econometric Model and the End Use Model respectively. In response to part (ii) the same 2020 value was provided (21,323 GWh) for each of the models. Please confirm that this is the actual Retail Energy for 2020 (before deducting CDM).

b) The response to VECC 52 a) part (iii) provides the predicted 2020 Retail energy (before deducting CDM) based on the Annual Econometric Model. Please provide the predicted 2020 Retail Energy based on the Monthly Econometric Model – per the original interrogatory request.

c) Does the same explanation (as provided in response to VECC TCQ 3) as to why predicted 2020 value for transmission load is not available based on the Transmission End Use Model apply for the Distribution End Use Model?

Response:

a) Confirmed.

b) Please see response to VECC TCQ-2, part a).

c) Yes.

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UNDERTAKING JT-VECC-TCQ-11

Reference:

Exhibit I, Tab 24, Schedule D-VECC 52 c)

Undertaking:

a) Are the 2021 growth rates set out in VECC 52 c) based on the difference between each Model's predicted value for 2021 and the actual value for 2020?

b) The response to VECC 52 c) indicates that in developing the proposed Distribution load forecast Hydro One Networks looked at the GWH forecast from each of the models and, in considering other factors such as EV development, electrification and what you've characterized as "the future state of the economy in an evolving situation", proposed a higher forecast than suggested by the various models. Please provide more details on how the proposed forecast was determined in terms of the incremental impacts attributed to various factors considered.

Response:

a) They reflect the year-over-year growth rate of retail gross load for each forecasting model tuned to 2020 weather-normalised retail gross load. For monthly and annual Econometric models, general service load that was moved to ST rate-class was added back to historical period to have a consistent series. Consequently, the forecast of such general service load was deducted from the forecast of monthly and annual Econometric models before calculating the growth rate for retail gross load. Similarly, the End-Use forecast included total ST non-LDC load. Thus, before calculating the growth rates for retail gross load, the forecast of ST non-LDC load was deducted from the End-Use forecast.

b) Please see the requested information below which is provided as annual percentage growth rates.

Year	EV	Other *	Leamington
2021	0.19	2.03	0.15
2022	0.10	0.15	0.83
2023	0.10	-0.95	0.92
2024	0.11	-0.31	0.27
2025	0.13	0.08	0.06
2026	0.14	-0.52	0.04
2027	0.18	0.14	0.00

* Includes 0.6% growth due to electrification plus zero-sum adjustment making the load more front-loaded.

For EVs and the load impact of Leamington and surrounding areas, provincial impacts are prorated in accordance with the share of retail load in total Ontario load (15%). As noted in response VECC-TCQ-4, the provincial level of added load reflects the load impact of new customer connections, largely greenhouses, in Leamington and surrounding areas as well as adjustments for EVs based on the confidence interval to mitigate high-side risk related to EVs. Electrification adjustments largely relate to Go Transit, which applies to major metropolitan areas and, as such, does not relate to Hydro One's distribution retail load. However, a total of 0.6% is added to retail load to account for potential impact of other types of electrification (e.g., as it may occur to industries). Another consideration was to make growth rates of load more front loaded in view of increasing optimism that economy is on the way to recovery at the time of forecast.

On an overall basis, the outcome of the adjustments indicated in VECC-52 is to the benefit of customers as it results in a load forecast that is higher than what would be implied by the forecasting models alone.

UNDERTAKING JT-VECC-TCQ-12

Reference:

Exhibit I, Tab 24, Schedule D-VECC 53, Attachment 1

Undertaking:

a) VECC 53, Attachment 1 sets out the factors used to allocate the total delivered sales to the individual customer classes and how they change over time. Please explain how the factors for each year were established?

b) In determining the sales by customer classes, Attachment 1 makes adjustment for the elimination of the Seasonal class and the change in eligibility for the ST class. However, there are no adjustments made for the impact of the density-based boundary review done late in 2020. Please explain why.

Response:

a) Factors affecting allocation of total residential load and general service load before reclassification were determined in accordance with their corresponding historical trends (i.e., trend of each residential rate class sales relative to overall residential sales). Factors reflecting impacts due to customer reclassification are provided in the same attachment noted above for each year.

b) The sales figures for the year 2020 already includes the impact of such reclassifications so that no further adjustment is required over the forecast period (2021-2027).

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UNDERTAKING JT-VECC-TCQ-13

Reference:

Exhibit I, Tab 24, Schedule D-VECC 57 c)

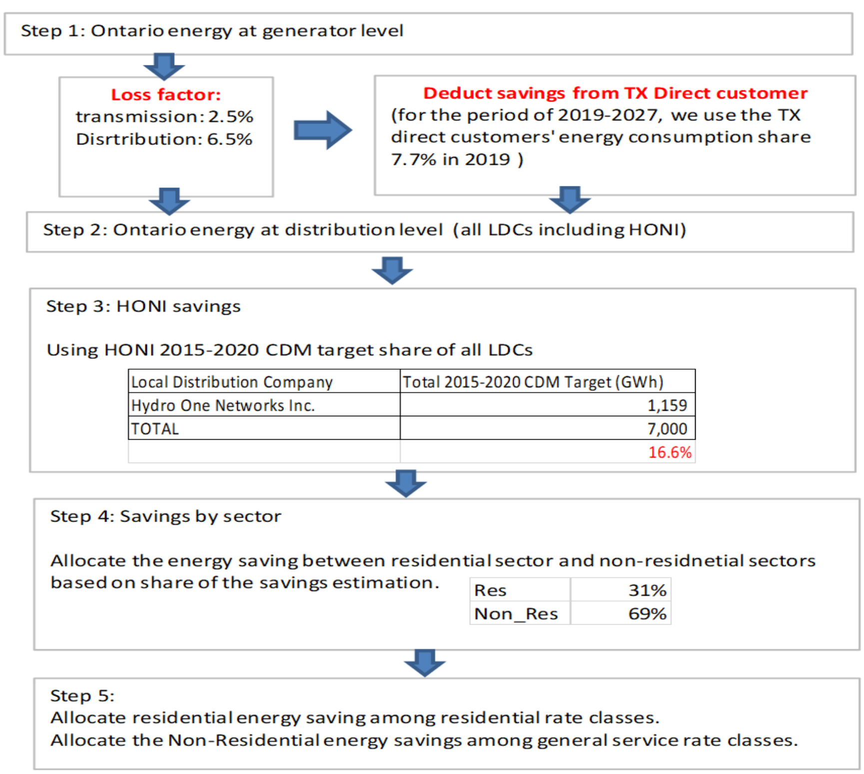
Undertaking:

a) VECC 57 c) states that the HON- Distribution's CDM savings are "based on the total savings for Ontario". Please explain how HON-Distribution's CDM savings were derived from the total savings for Ontario and provide any supporting references.

b) For the years 2006-2018 the source used for the total Ontario energy savings is the 2018 OPO. However, the reference used to source actual savings for purposes of the Transmission CDM variance account (EB-2019-0082 – response to VECC 24 d)) also includes verified Ontario energy savings for the period 2006-2017 and the numbers differ from those in the 2018 OPO. Why weren't the verified actual results used?

Response:

a) The following graph demonstrates the steps for deriving Hydro One distribution's CDM savings based on the total saving for Ontario.



b) As mentioned in the response to VECC 24 d) in EB-2019-0082, Hydro One has taken into account all the available information to be assured that the assumptions used for the load forecast are reasonable. Only verified energy savings are available for each LDC and Ontario. There are no peak verified savings. For the transmission CDM variance calculation, only peak savings are used for the estimation.

UNDERTAKING JT-VECC-TCQ-14

Reference:

Exhibit I, Tab 24, Schedule H-VECC 96 b) and VECC 100

Undertaking:

a) VECC 96 b) briefly describes the change in methodology for determining the Line Connection portion of Dual Function lines. In order to better understand the change, please provide a simple (illustrative) example.

b) The response to VECC 96 b) i) states that the change results in costs being shifted from the Network Pool to the Line Connection Pool. However, in VECC 100 b) for those lines where the change in allocation is attributed to this correction in methodology, in 7 out of the 8 instances, the percentage of costs allocated to the Network Pool are now higher. Please reconcile these results with the response to VECC 96?

Response:

a) The overall DFL allocation methodology has not changed. As in previous applications, the customer load connected to the DFL (DFL Customer Demand) and the minimum of the average of summer and winter transmission capacity of the DFL (Minimum DFL Capacity) are used to allocate the DFL asset value between Network and Line Connection Functions. The DFL Customer Demand is the total of the allocated portion of each customer's average forecast monthly coincident peak demand.

In this application, Hydro One has refined how the allocated demand is calculated:

- In previous applications, and most recently EB-2019-0082, the allocated demand for each customer delivery point was calculated using the total number of upstream circuits.
- In this application, it was determined that using the total number of upstream circuits inappropriately divided customer load between circuits that are not directly supplying the delivery point, which resulted in less load being associated with the DFL. This application uses the total number of DFL circuits that directly supply the delivery point, which reflects the power flow more appropriately.

An illustrative example is below:

Table 1 - Allocation of Load as in Previous Applications

Circuit	Delivery Point (DP)	Total DP Load (MW)	Total Count of Circuits Connected to DP	Allocated Load (MW)
		(A)	(B)	(C = A/B)
A3RM	Merivale MTS	127	4	32
A3RM	Riverdale TS	767	4	192
A3RM	Slater TS	852	5	170
A3RM	Cyrville MTS	244	5	49
A3RM	King Edward TS	711	4	178
A3RM	Moulton MTS	196	4	49
A3RM	OHSC CGS	5	4	1
A3RM	Overbrook TS	630	4	157
A3RM	Russell TS	508	4	127
TOTAL CUSTOMER LOAD ALLOCATED TO A3RM				**955**
Divided by Minimum DFL Capacity				**3504**
Proportion Allocated to Line Connection of DFL				**27%**

Table 2 - Allocation of Load as in Current Application

Circuit	Delivery Point (DP)	Total DP Load (MW)	Count of Circuits Directly Connected to DP	Count of Upstream Circuits	Is A3RM the last line to the DP?	Step 1: Allocate total load equally by number of direct supplying circuits	Step 2: If D="No", further split load equally by number of upstream circuits that map to a network station	Allocated Load (MW)
		(A)	(B)	(C)	(D)	(E = A/B)	(F = E/C)	(G)*
A3RM	Merivale MTS	127	1	3	Yes	127	N/A	127
A3RM	Riverdale TS	767	3	1	Yes	256	N/A	256
A3RM	Slater TS	852	3	2	Yes	284	N/A	284
A3RM	Cyrville MTS	244	2	3	No	122	41	41
A3RM	King Edward TS	711	2	2	No	355	178	178
A3RM	Moulton MTS	196	1	3	No	196	65	65
A3RM	OHSC CGS	5	1	3	No	5	2	2
A3RM	Overbrook TS	630	3	1	No	210	210	210
A3RM	Russell TS	508	2	2	No	254	127	127
TOTAL CUSTOMER LOAD ALLOCATED TO A3RM								**1,289**
Divided by Minimum DFL Capacity								**3504**
Proportion Allocated to Line Connection of DFL								**37%**

*Final allocated load G is equal to column E if column D="Yes" or column F if column D="No".

b) The lines with allocation changes due to a data correction in VECC 100 b) are unrelated to the change described above in part a). During the review of the DFL methodology, an error was found in previous applications and was corrected in this application. The circuits with a material change in allocation (+/- 10%) due to the data correction can be found in VECC 100 b). None of the circuits impacted by the changes in part a) had an allocation change greater than +/- 10%.

As discussed in I-24-H-VECC-096 part b (Hydro One's response to VECC IR#96), the overall impact of these changes represents an immaterial change to the assets in the Network and Connection pools.

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UNDERTAKING JT-VECC-TCQ-15

Reference:

Exhibit I, Tab 24, Schedule L-VECC 107 a)

Undertaking:

a) The preamble to VECC 107 includes an extract from the current 2021 tariff sheet which states that one of the requirements for ST eligibility is that the customer's load is connected at between 13.8 and 44 kV. Does this mean that eligible customers must be taking power at voltages between 13.8 and 44 kV? If not, what it the requirement?

b) Please confirm that the proposed eligibility criteria for ST contain the same provision.

   i. If confirmed, please reconcile with the fact that the proposed change in eligibility means that ST customers using an HON transformer can be taking power at 347/600 volts (per VECC 107 a), Table 1).

c) Will these newly eligible ST customers being served by a HON transformer be required to own the lines on the secondary side of the transformer or, in some instances, could HON own these lines?

Response:

a) Yes, eligible ST Load Customers (non-LDCs) must be taking power at voltages between 13.8 and 44 kV inclusive.

b) Confirmed. The proposed eligibility criteria for ST contains the same provision. The only difference is:
   - Currently, the local transformer must be customer-owned.
   - In this Application, Hydro One proposes that the local transformer could be either customer-owned or Hydro One-owned.

   To further clarify the proposed eligibility criteria, Hydro One proposes to revise the ST tariff sheet (2023 rates) as follows (bolded and underlined text below is text proposed to be added):

SUB TRANSMISSION - ST

This classification applies to either

- Embedded supply to Local Distribution Companies (LDCs). "Embedded" meaning receiving supply via Hydro One Distribution assets, and where Hydro One is the host distributor to the embedded LDC. Situations where the LDC is supplied via Specific Facilities are included. OR

- Load which:
    - is three-phase; and
    - is connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive**, where 44 kV and 13.8 kV are the voltage of the primary side of the local transformer; local transformer can be Hydro One-owned or customer-owned**; and
    - is greater than 500 kW (monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is greater than 500kW).

c) The secondary cables will be customer-owned.

UNDERTAKING JT-VECC-TCQ-16

Reference:
Exhibit I, Tab 24, Schedule L-VECC 107 b)

Preamble:
VECC 107 b) discusses the practices of other large distributors with respect to providing utility owned transformers. The response indicates that Alectra and Ottawa Hydro will own 27.6kV-347/600V service transformers up to 3000 kVA and 2500 kVA, respectively. It also indicates that it is also Hydro One's understanding Toronto Hydro will own 27.6kV-347/600V service transformers up to 2500 kVA.

Undertaking:

a) In such circumstances are the Alectra, Ottawa Hydro and Toronto Hydro customers with loads peak demands between 500 kW to 3,000 kW treated as General Service customers?

b) Does HON currently have customers in its GS classes with loads in the 500 kW to 3,000 kW range that will continue to be classified as such even with this change in eligibility for ST?

c) If yes, why wouldn't offering to provide HON transformers of up to 3,000 kVA to customers in the GS class be a more appropriate way of addressing the issue?

Response:

a) Yes.

b) Yes.

c) In this Application, Hydro One is proposing to offer transformers up to 3,000 kVA for customers connected at 27.6 kV and 44 kV primary voltages and transformers up to 1,000 kVA for all customers connected at lower primary voltages (both GS classes and ST class) as required to meet forecast peak demand. Hydro One believes that local transformation ownership should be eliminated as a consideration in determining a customer's rate class. The costs associated with local transformation are minor compared to the costs associated with the amount of distribution assets required to serve the customer (i.e. being supplied from the sub-transmission level vs lower voltage distribution system). As such, Hydro One is proposing to remove the local transformation ownership as part of the rate class eligibility criteria.

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UNDERTAKING JT-VECC-TCQ-17

Reference:

Exhibit I, Tab 1, Schedule L-Staff 322, Part c)

Undertaking:

a) Staff 322 c) asked for "a cost allocation scenario where both the costs associated with the transformers used by the ST rate class, and the revenues associated with the ST transformers are allocated to the ST rate class". The response indicated that this was inappropriate because the CAM would use the total ST class demand data to allocate a portion of the line transformer cost to the ST rate class when most of the class uses their own transformers. Cannot this problem be readily resolved in the same way it is for the allocation of transformer (USOA 1850) costs to other classes such as the various GSd classes where the customer count allocators and demand allocators for transformers are based not on the total customer count and demand for the class but rather on the customer count and demand associated with the HON transformers?

   i. If yes, please provide the requested cost allocation scenario.
   ii. If not, why not?

Response:

No, this problem cannot be readily resolved by using the customer count and demand associated with the HONI transformers to allocate USoA 1850 costs.

As discussed in L-2-1, page 19, section 5.2.7.1, the ST local transformation monthly fixed charge recovers the installed capital cost of a 501 kVA overhead transformer (for larger size transformers, the incremental costs will be collected through a capital contribution) and therefore the cost is not primarily driven by the demand associated with the ST customers who are supplied by HONI transformers. Unlike other rate classes (i.e. non-ST), it is not appropriate to use the customer count and demand associated with the HONI transformers to allocate USoA 1850 costs to the ST rate class.

Please refer to EB-2021-0110 Technical Conference Transcript Volume 4 pages 52 to 55, for further information regarding Exhibit I, Tab 1, Schedule L-Staff 322 c).

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UNDERTAKING JT-VECC-TCQ-18

Reference:

Exhibit I, Tab 1, Schedule L-Staff 323
Exhibit I, Tab 24, Schedule L-VECC 120
Exhibit L, Tab 1, Schedule 3, Page 4
Exhibit L, Tab 1, Schedule 3, Attachment 2, Page 3.

Undertaking:

a) Staff 323 indicates that the load profiles for customer classes were based on one year of hourly data and that an additional year's data was available as backup.

   i. What year's data was used to develop the load profiles?
   ii. If it was 2020, are the calculated load profiles impacted by the pandemic?
   iii. What was the year for which the "additional year's data" is available.

b) Please re-calculate the 2023 demand allocators using the average of the two years' results?

c) VECC 120 c) sets out the 12 CP values assuming the seasonal class is not eliminated.

   i. Please confirm that the total for the various Residential classes and the Seasonal class is 26,548,689.
   ii. Are the 12 CP values in VECC 120 c) in meant to be the Transformation, Delivery or Bulk System 12 CP values?

d) Exhibit L, Tab 1, Schedule 3, Attachment 2, page 3 sets out the 12 CP allocators used in the 2023 Cost Allocation model – in which the Seasonal class is eliminated. It is noted that the sum of the 12 CP values for the Residential classes does not equal 26,548,689 regardless of which definition of 12 CP is used. Please explain why when the Application states (Exhibit L, Tab 1, Schedule 3, page 4) the overall 12 CP remains the same before and after seasonal elimination.

Response:

a)
   i. 2019
   ii. Not applicable in view of response to part a)
   iii. 2018; please see response to part b) below for further clarifications.

b) Hydro One does not have two forecasts for load shapes to use their average to calculate allocation factors and thus the information is not readily available. For delivery points, there is only one set of forecasts for load shapes, which is based on 2019 data. The 2018 back up data was available in case a delivery point would have missing data for an extended period such that available 2019 data could not be used to estimate missing 2019 data. However, this situation did not arise. Consequently, only 2019 data was required to develop the load shapes used in this application. Hydro One notes that the use of one year of hourly data to develop the load shapes has been the method reviewed and approved by the OEB in all the previous Hydro One rate filings.

c)
   i. Confirmed.
   ii. 12 CP values in VECC 120 c) are the Total System CP values.

d) The referenced statement in Exhibit L, Tab 1, Schedule 3 is in respect of meter level consumption data (i.e., excluding losses), while the 12 CP values used in the Cost Allocation Model are based on wholesale purchase level consumption data (i.e., including losses). Since the total loss factor (TLF) for the Seasonal class in Seasonal Status Quo scenario differs from those of the year-round residential classes, the 12 CP values in the Seasonal Eliminated scenario is slightly lower (by 0.07%) than in Seasonal Status Quo scenario.

UNDERTAKING JT-VECC-TCQ-20

Reference:

Exhibit L, Tab 3, Schedule 1, Pages 10-11
Exhibit I, Tab 24, Schedule L-VECC 138 b)

Preamble:

Exhibit L, Tab 3, Schedule 1, page 10 sets out the calculation of the upper and lower "goalposts" for the combined former Haldimand/Norfolk and the former Woodstock acquired customer classes. The evidence also states (page 11) that as long as the revenues collected from the former customers of the acquired utilities fall within these goal posts both the acquired customers and HON's legacy customers are better off as a result of the acquisition.

Undertaking:

a) For Woodstock, the goal posts are roughly $7.0 M and $9.3 M and that the proposed revenue to be recovered from customers of the former Woodstock utility in 2023 is $8.5 M – which falls between these two values. However, the 2023 R/C ratios for the Acquired Urban Classes are 0.94, 0.80 and 0.80 for the Residential, General Service<50 and GS>50 classes respectively (per Exhibit L, Tab 2, Schedule 1, page 7)and the costs allocated to the customers of the former Woodstock utility total $9.5 M ((per VECC 138 b). Would it be correct to conclude that if the revenue to cost ratios for the Acquired Urban classes were to be increased to 100% then the resulting revenues would exceed the upper goal post of $9.3M? If not, why not?

b) Does this result have any implications for the appropriate policy range for the R/C ratios for the Acquired Urban Utility classes. In particular, should the upper end of the policy range for these classes be set at 98% (i.e., the value that results from dividing the upper goal post by the allocated costs)? If not, why not?

c) VECC 138 b) indicates that the costs allocated to the former Haldimand/Norfolk customer classes are approximately $28.6 M. Comparing this to the upper goal post for this group of $32.9 M, the resulting ratio is 115%. Similarly, comparing the lower goal post for this group ($23.9 M) to the allocated costs yields a ratio of roughly 84%. Do these results suggest that the R/C ratio range applicable to the GS customer classes in this group should be narrower than the standard 80% to 120%? If not, why not?

Response:

a) Yes, it is correct. Hydro One notes that increasing the revenue to cost ratios as suggested would result in a corresponding decrease in revenues recovered from Hydro One's other classes. This would effectively result in a shift of the benefits of consolidation to Hydro One's other classes. The overall sector benefit of consolidation in the form of reduced revenues that would otherwise be collected from customers would remain the same as outlined in Table 6 of Exhibit L, Tab 3, Schedule 1 (i.e. a reduction in overall revenue requirement of $11.3M).

b) No, Hydro One does not believe the result as described in part a) has any implications for the appropriate policy range for the R/C ratios for the Acquired Urban Utility classes. The upper goal post is a figure that is only relevant at the time of harmonization to determine the degree to which consolidation has resulted in a benefit for customers. Per established OEB policy, the Board's R/C ratio ranges are used to determine whether the rates of a particular class are reasonably reflective of the cost to serve. Provided that a class' revenue results in an R/C ratio within the OEB's approved ranges, revenues are considered to be reflective of the costs allocated to that class and no further adjustments are required. Hydro One submits that fundamental OEB policy such as appropriate R/C ratio ranges should be consistently applied to all rate classes.

c) No. See response to part b) above.

UNDERTAKING JT-VECC-TCQ-21

Reference:

Exhibit L, Tab 2, Schedule 1, pages 5-7 and Attachment 1
Exhibit I, Tab 24, Schedule L-VECC 123

Undertaking:

a) Please confirm that in calculating the status quo Revenue to Cost Ratios for the years after 2023 the Application, when determining the "revenues" to be used, takes into account year over year changes in the billing determinants for each customer class (per Step 4 as described on page 5) and thereby addresses that fact (per VECC 123) that the "the billing determinants for the various rate classes (i.e., customer/connection counts, kWh values and kW values) do not all change by the same percentage for each year during the 2024-2027 period".

b) Please confirm that in calculating the status quo Revenue to Cost Ratios for the years after 2023 the Application, when determining the "costs" to be used, simply increases each customer class' allocated costs from the previous year by the same percentage and, in doing so, does not account for the fact that the customer and demand allocators for the various rate classes may all not change by the same percentage for each year during the 2024-2027 period.

Response:

a) Confirmed.

b) Confirmed. As mentioned in the response to L-VECC-123, part (b), it is unclear how the allocated costs for each class could be adjusted to take into account the load forecast by rate class without running the Cost Allocation Model for each year.

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UNDERTAKING JT-VECC-TCQ-22

Reference:

Exhibit L, Tab 2, Schedule 1, page 11

Undertaking:

a) With respect to the design of Hydro One's distribution rates, please clarify whether your proposal to maintain the current fixed variable split for all of the non-residential classes (per L/1/2, page 11) means that for each of the test years:

i. The percentage split between fixed and variable revenues is the same as calculated for 2022 based on the rates and billing determinants for 2022, or
ii. The percentage is based on relative fixed and variable revenues as calculated using the previous year's rates and the forecast billing determinants for test year.

b) Is the approach used by Hydro One consistent with the OEB's June 2021 Chapter 2 Filing Guidelines which at page 54 state: "*Calculations of fixed/variable proportions should use the billing determinants from the proposed load forecast as the basis of the calculation*."

Response:

a) Hydro One's current proposal for the legacy non-residential rate classes is to maintain the percentage split between fixed and variable revenues at the same level as approved by the OEB in Hydro One's last distribution rate application (EB-2017-0049) for the 2023-2027 period.

For the new acquired non-residential rate classes, the fixed-variable split in 2023 is based on 2022 rates and 2023 forecast billing determinants. For 2024-2027, the proposal is to maintain the fixed-variable split at the 2023 level.

b) Hydro One believes that its proposal is consistent with the OEB's Filing Requirements. The fixed/variable proportions of revenue are determined each year and resulting rates are calculated using billing determinants from Hydro One's proposed load forecast as the basis of the calculation.

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UNDERTAKING JT-VECC-TCQ-23

Reference:

Exhibit I, Tab 24, Schedule L-VECC 124

Undertaking:

a) The response to VECC 124 references the $8.38 change in fixed charges based on a 7-year phase-in cited in the Board Staff's EB-2015-0079 submissions. However, in its Decision the Board rejected the 7 year phase-in in favour of 8 years. Please indicate what the increase in the fixed charge was for 2016 based on the eight year transition approved by the Board.

Response:

Based on the eight year transition period approved by the OEB, the increase in the fixed charge for 2016 was $7.34.

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UNDERTAKING JT-VECC-TCQ-24

Reference:

Exhibit I, Tab 24, Schedule L-VECC 107
Exhibit L, Tab 2, Schedule 1, page 20 (Table 11)

Undertaking:

a) The response to VECC 107 indicates that the number of transformers HON will own that serve ST customers will increase from by 5 per annum going from 24 to 49 by the end of 2027. Exhibit L, Tab 2, Schedule 1, Table 11assumed an average of 51 ST customers with HON transformers over the period up to 2032 in deriving the $200 charge. Can you confirm that this is based on the assumption that the number of customers will continue to increase by 5/year up to 2032?

b) Please confirm that, by using a simple average of 51 customers, the ST rate calculation does not account for the fact there are fewer customers in the earlier years when, on a net present value basis, the revenues are “worth” more.

c) Please provide:
   i. the annual 2023-2032 revenue requirement values associated with the $1.2 M total (per Table 11) and;
   ii. what the annual charge would be such that, using HON’s cost of capital, the total NPV of the revenue from the charge equals the total NPV of the annual revenue requirements.

Response:

a) Confirmed.

b) Given the relatively small amount of annual revenue associated with the ST local transformer charge and in the interest of providing customers a stable rate over the Custom IR period, Hydro One has not calculated the ST transformer rate on a Net Present Value basis.

   Hydro One proposes to derive the rate as follows:
   - Sum up the annual revenue requirement over the period from 2023 to 2032 ($1.2M)
   - Derive the average annual revenue requirement over the 10-year period ($120k)
   - Derive the monthly charge by dividing the average annual revenue requirement by the average number of customers, and then dividing by 12 months (i.e. $120k/51/12)

c)

i. The requested annual revenue requirements are provided in the Table below. Please note that the initial years' revenue requirement is suppressed by the age mix of existing assets serving current customers that are planned to be replaced over the study period.

	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Revenue Requirement in $k	$28.4	$59.2	$81.9	$95.1	$109.1	$126.5	$142.1	$157.8	$173.8	$191.1

ii. A flat monthly charge of $186.67 would be required to recover the net present value of the annual revenue requirements over a 10-year period. As noted above, the 2023 and 2024 revenue requirements are suppressed by the age mix of existing assets serving current customers. Performing the same net present value analysis but utilizing the revenue requirements of 2025 onwards would yield a flat rate of $200.10 which is consistent with Hydro One's proposed rate.

UNDERTAKING JT-VECC-TCQ-25

Reference:

Exhibit I, Tab 24, Schedule L-VECC 126 a) & 127 c)

Exhibit L, Tab 1, Schedule 3, Attachment 1 (2023 CAM), Tab I3 (TB Data-Account 5160)

Preamble:

VECC 126 a) indicates that the capital costs for transformers that will be used by the ST customers are recorded in USOA 1850. The maintenance costs for these transformers is recorded in USOA 5160 and that based on the cost breakout in the CAM model the amount for 2023 is just under $3 M. ($2,966,867).

Undertaking:

a) The response to VECC 127 c) states that "only visual inspection costs were included in the annual OM&A calculations. Service transformers are replaced on failure". Is the $3 M included in Account 5160 for 2023 all for visual inspections?

Response:

a) The statement provided in Hydro One's response to VECC IR #127 (I-24-L-VECC-127), "only visual inspection costs were included in the annual OM&A calculations" was incorrect. The $3M included in Account 5160 for 2023 includes costs related to trouble calls as well as visual inspection costs. The average USoA 5160 - Line Transformer OM&A 5160 cost per transformer was used as the OM&A assumption for determining the ST class transformer ownership charge.

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UNDERTAKING JT-VECC-TCQ-26

Reference:

EB-2020-0246 – OEB Decision re: Elimination of Seasonal Rates

Preamble:

On November 10, 2021 the OEB issued its Decision regarding the elimination of Seasonal Rates and with respect to mitigation for Seasonal moving to R2 determined that Phase-In option 2 A should be adopted whereby bill impacts are limited to 10% for low volume (50 kWh/month) Seasonal customers.

Undertaking:

a) In the Application Hydro One Networks set out the bill impacts by customer class for each of the years 2023-2027 (L/6/1). For those Seasonal customers moving to the R2 class the evidence did not include any proposals regarding bill impact mitigation – pending the Board's decision on the Elimination of the Seasonal class. The Board has now issued its decision (EB-2020-0246) regarding the elimination of the Seasonal class and the bill impact mitigation approach that's to be used for Seasonal customers moving to the R2 class. Based on this Decision, please provide the revised rates for each of the year 2023-2027 that will apply to Seasonal customer moving to the R2 class and for each year also provide bill the impact calculations based on the average monthly use for these customers and for 50 kWh/month usage.

b) In its EB-2020-0246 Decision the Board directed Hydro One to maintain existing billing and meter reading frequencies for seasonal customers. Given this Decision are there any incremental implementation costs for billing and metering due to the elimination of the Seasonal class and, if yes, what are they?

c) Will there be other implementation costs associated with the Decision and, if yes, please provide an estimate as to what these will be?

d) If there are incremental costs, is it still HON's intent to apply for a deferral account to capture these costs?

e) During the Seasonal Elimination proceeding HON indicated it would need an exemption from the DSC to continue its current meter reading and billing practices for former Seasonal customers and would apply for a deferral account at the same time as it applied for the DSC exemption. Is that still Hydro One Networks plan and, if yes, when does Hydro One Networks anticipate applying for the DSC exemption?

Response:

a) Tables below provide the requested information.

Table 1 - Proposed Distribution Rates for Seasonal Customers Moving to the R2 Class (with mitigation)

	Fixed Charge ($/month)	Volumetric Charge ($/kWh)
2023	$64.53	$0.0182
2024	$71.81	$0.0113
2025	$79.72	$0.0107
2026	$88.61	$0.0103
2027	$98.48	$0.0095

Table 2 - Bill Impacts for Seasonal Customers Moving to the R2 Class (with mitigation)

Bill Impacts for Seasonal-R2 customers	Monthly Consumption (kWh)	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
2023*	50	$7.93	13.0%	$7.55	11.7%
	369	$3.78	5.3%	$4.18	3.7%
2024*	50	$2.94	4.2%	$2.76	3.8%
	369	$0.73	1.0%	$0.69	0.6%
2025	50	$7.88	10.9%	$7.42	9.9%
	369	$7.69	10.2%	$7.23	6.1%
2026	50	$8.87	11.1%	$8.35	10.1%
	369	$8.74	10.5%	$8.23	6.5%
2027	50	$9.83	11.1%	$9.25	10.2%
	369	$9.57	10.4%	$9.01	6.7%

**Higher impact for low-volume customers in 2023 is the result of recalculated base rate adjustment rate rider for the seasonal customers moving to the R2 class. Although the impacts shown in this table assume that the base rate adjustment rider will come off in 2024 (resulting in lower than anticipated bill impact in 2024), in reality, the rate rider will come off on July 1, 2023.*

b) The OEB's direction (in EB-2020-0246) for Hydro One to maintain the existing billing and meter reading frequencies for seasonal customers is not expected to have any material impacts to the already provided cost estimates for system and process changes to support the elimination of the seasonal rate class.

c) The OEB Decision in EB-2020-0246 requires that Hydro One undertake significant changes to its billing and work management systems and related process. The overall efforts is currently expected to be in the range of $3 to $4 million, which is the same as the originally provided estimates[1].

d) Yes.

e) Yes, Hydro One plans to include a request for a deferral account at the time that it files for the DSC exemption. This application is expected to be filed in the second quarter of 2022.

[1] EB-2020-0246 Decision and Order, issued on November 10, 2021, page 10.

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