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August 11, 2019 **VIA E-MAIL**

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

Dear Ms. Walli:

Re: EB-2019-0082 – Hydro One Network 2020 Transmission Revenue Requirement
Technical Conference clarification questions of the Vulnerable Energy Consumers Coalition (VECC)

Due to the unavailability of one of VECC's consultants, Mr. Bill Harper, we have attached written clarification questions in anticipation of the upcoming technical conference. We will also have further questions at the time of the conference as noted in our correspondence of August 7, 2019.

Yours truly,

Mark Garner
Consultants for VECC/PIAC

Ms. Linda Gibbons, Senior Regulatory Coordinator – Regulatory Affairs Hydro One Networks Inc.
regulatory@HydroOne.com

REQUESTOR NAME	**VECC – TECHNICAL CONFERENCE CLARIFICATIONS**
TO:	**Hydro One Networks Inc. – Transmission (H1TX)**
DATE:	**August 11, 2019**
CASE NO:	**EB-2019-0082**
APPLICATION NAME	**2020-2022 Transmission Rates/UTR Application**

LOAD FORECAST

VECC TCQ-1

REFERENCE: Exhibit E/Tab 3/Schedule 1, Tables 2 and 3

a) Are the CDM savings reported in the two tables different (e.g. for 2020 the values are 3,197 MW and 2,552 MW respectively) because the first is based on generation savings while the second is based on end-use savings?

VECC TCQ-2

REFERENCE: Exhibit I/Tab 10/Schedule 24 d), Attachment 1 (VECC-24 d)-Attachment 1)
Exhibit E/Tab 3/Schedule 1, Tables 2 and 3

a) Columns BQ, BR and BS of the Excel file report Net Energy Savings for 2015-2017. Similarly, Columns FG, FH and FI of the Excel file report the Net Demand savings for 2015-2017. However, in both instances, all of the values are not numerical (e.g. cell FI749) and totals by category (e.g., ICI) or for the columns overall cannot be calculated. Please provide a revised file containing the numerical values for the net energy and net demand savings for each program and the totals for these years.

b) Based on the Excel file showing IESO reported savings for 2006 to 2014 (i.e., VECC 24 d) - Attachment 1), please provide a schedule that sets out the actual net demand savings in 2014 through 2017 broken down into the following categories: DR, ICI, Dispatched Load and EE.

c) Do the 2017 CDM savings in Exhibit E/Tab 3/Schedule 1, Table 3 match the Net Demand savings attributable to EE programs for the 2017 as reported in Attachment 1 of VECC 24 d)? If not, please explain why.

VECC TCQ-3

REFERENCE: Exhibit I/Tab 10/Schedule 24 b); d) and h) i)
(VECC-24 b); d) & h) i))
Exhibit E/Tab 3/Schedule 1, Table 3

PREAMBLE: The response to VECC 24 b) contains the following data with respect to energy savings from CDM:

Table 3: Comparison of the LTEP and OPO Energy Savings

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
LTEP 2013 total energy savings (2006-2012 actual)	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0
OPO 2016 Total energy savings TWh (2006-2015 actual)	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	12.8	14.3	15.9	17.6	19.5	20.7	20.9	21.1

Reference 6 from VECC 24 d) contains the following data with respect to historic energy savings from CDM which differs from that in VECC 24 b) in 2015 and after:

Conservation Achievements												
TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
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
Conservation Program	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	9.7	9.4	10.0

Finally Reference 7 from VECC 24 d) contains historic data with respect to net energy savings from EE programs.

a) Please confirm that the 2006-2017 energy savings reported in References 6 and 7 of VECC 24 d) are not the same and that both differ from the savings reported in the 2013 LTEP for the same period.

b) Which of the references in VECC 24 d) (#6 or #7) contain the most recently issued values from the IESO regarding historic 2006-2017 CDM energy savings?

c) Which historical series of energy savings did HON use for purposes of developing its forecasting models?

d) If the most recent data from the IESO (per part (b)) was not used please explain why.

e) If the most recent data from the IESO regarding the historic and forecast energy savings differs from that in the 2013 LTEP, please explain how the demand savings history/forecast from the 2013 LTEP can still be valid – as claimed in the response to VECC 24 h) i).

f) The materials provided by the IESO for the Technical Planning Conference in September 2018 included the following forecast for new Conservation Program Savings in 2018 and after (VECC 24 d), Reference 6, Slide 20):

Long Term Conservation Forecast					
	2018	2019	2020	2021	2022
New Conservation Program Savings (TWh)	1.99	3.37	4.50	4.90	5.30
New Conservation Program Savings (MW)	317	537	710	773	831

Is the CDM forecast in Exhibit E/Tab 3/Schedule 1, Table 3 consistent with this forecast?

VECC TCQ-4

REFERENCE: Exhibit I/Tab 10/Schedule 26 a) & b) (VECC-26 a) & b)) & Exhibit I/Tab 10/Schedule 27 a) (VECC-27 a))

a) VECC 27 a) indicates that none of the forecast models used provide a forecast of the 12 monthly peaks. Rather, the monthly peaks are forecast by applying the growth rates from the models to a base year's peak values. However, VECC 26 indicates that the actual 2018 monthly peak values were not known when the forecast was determined (part a)) but also indicates that the growth rates were applied to forecast values for the 2018 billing determinants. How were these forecast 2018 billing determinants established (given the models do not forecast monthly peaks)?

VECC TCQ-5

REFERENCE: Exhibit I/Tab 10/Schedule 27 b) & c) & (VECC-27 b) & c))

a) In VECC 27 c) the response explains that the actual growth rates applied were higher than those from the models as they included the load impact of developments in the Leamington and surrounding areas. Please explain what these developments are and how the adjustment to the growth rates produced by the models was established.

VECC TCQ-6

REFERENCE: Exhibit I/Tab 10/Schedule 31 b) (VECC-31 b))

a) The last sentence in the response to part (b) states: "In practice, extreme weather may occur on any day of the month, and Hydro One must take this fact into account in calculating monthly peak in order to accurately forecast the monthly peaks that drive the collection of transmission revenue". This suggests that Hydro One's load forecast takes into account extreme weather. As requested in the original question - please reconcile this statement with the fact that the load forecast is meant to be weather normalized based on 31 years.

EXTERNAL REVENUES

VECC TCQ-7

REFERENCE: Exhibit I/Tab 10/Schedule 17 (VECC-17)
Exhibit I/Tab 10/Schedule 19 (VECC-19)

a) Please provide the actual External Revenues for each of the four categories for the first six months of 2019. For Secondary Land Use Revenue, please break-out the revenues attributable to Easements and Operational Land Sales.

b) In the same schedule please provide the actual External Revenues for the first six months of 2018 at the same level of detail.

VECC TCQ-8

REFERENCE: Exhibit I/Tab 10/Schedule 21 (VECC-21)

a) Please provide the average monthly cash balances for Hydro One Networks Transmission business for 2017 and 2018.

VECC TCQ-9

REFERENCE: Exhibit I/Tab 01/Schedule 149 b) (OEB Staff-149 b))
Exhibit I/Tab 10/Schedule 16 (VECC-16)

a) Please provide the actual MSP Revenues for each of the years 2016, 2017 and 2018.

b) Please provide the actual Low Voltage Switch Gear provided for each of the years 2016, 2017 and 2018.

DEFERRAL/VARIANCE ACCOUNTS

VECC TCQ-10

REFERENCE: Exhibit I/Tab 10/Schedule 45 a) i) (VECC-45 a) i))
Exhibit I/Tab 10/Schedule 24 d), Attachment 1
(VECC-24 d) – Attached Excel File: IESO 2006-2017 Saving & Persistence Table)
Updated Exhibit H/Tab 1/Schedule 2, Attachment 11, Table 2

a) With reference to the functional/working Excel file requested in VECC TCQ-3 for the IESO 2006-2017 Savings and Persistence Table, for each of 2016 and 2017 please indicate which rows in the Excel file contribute to each of the following categories of CDM: ICI, Dispatched Load, DR and EE. and demonstrate that the totals for the respective rows reconcile with the values reported in Updated Exhibit H/Tab 1/Schedule 2, Attachment 11, Table 2 for each category.

VECC TCQ-11

REFERENCE: Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1 (VECC-45 a) ii), Attachment 1)
Exhibit H/Tab1/Schedule 2, Attachment 11, page 2

PREAMBLE: The Attachment contains the following data:

Peak Demand Saving (MW)

	2016	2017
EE	1662	1575
Codes and Standards	505	525
Total	2167	2099

Generator level	2016	2017
ind-TX	115	147
ALL LDCs	2,052	1,952
Total	2,167	2,099

OPA Loss Factor Assumption

	2016	2017
distribution	0.065	0.065
transmission	0.025	0.025
Total	0.09	0.09

Generator level MW	2016	2017
ind-TX	112	144
ALL LDCs	1,927	1,833
Total	2,039	1,976

a) Is the fourth set of data meant to represent Peak Demand Savings at the Generator level (as indicated) or at the End Use level (as suggested subsequently in the Attachment where the values 2,039 and 1,976 match those attributed to the savings assumptions used for 2016 and 2017at the end-use level)?

b) If at the Generator level, please explain why these values differ from those in the second set of data – which is also at the Generator level.

c) If at the End Use level, please indicate how the values were calculated using the Loss Factor Assumptions.

VECC TCQ-12

REFERENCE: Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1
(VECC-45 a) ii), Attachment 1)
Exhibit H/Tab1/Schedule 2, Attachment 11, pages 2-4

PREAMBLE: The Attachment contains the following data:

I-10-VECC-45 a(ii)
variance in KW

Month	LF assumption at the end use level (KW)			EE monthly profile used in LF		IESO EE saving EMV resutls (KW)			variance in KW (Dif of dif)
	2016	2017	dif (2017 vs 2016)	2016	2017	2016	2017	dif (2017 vs 2016)	2017
	A	B	C= B-A			D	E	F= E-D	F-C
1	1,433,588	1,447,218	13,630	0.703098233	0.732290385	1,766,438	1,902,247	135,809	122,179
2	1,419,005	1,431,228	12,223	0.6959462	0.724199799	1,748,469	1,881,230	132,761	120,537
3	1,312,901	1,325,258	12,357	0.643908009	0.670578944	1,617,730	1,741,941	124,211	111,854
4	1,342,374	1,343,303	929	0.658362855	0.679709696	1,654,046	1,765,660	111,613	110,684
5	1,417,979	1,418,906	927	0.695442939	0.717964835	1,747,205	1,865,034	117,829	116,901
6	1,874,071	1,876,242	2,171	0.919131829	0.949376204	2,309,192	2,466,163	156,971	154,800
7	2,038,958	1,976,289	(62,669)	1	1	2,512,363	2,597,667	85,305	147,973
8	1,855,321	1,860,329	5,009	0.909935719	0.941324401	2,286,088	2,445,247	159,159	154,150
9	1,681,441	1,684,207	2,766	0.824657241	0.852206779	2,071,838	2,213,750	141,912	139,146
10	1,326,777	1,331,972	5,196	0.650713035	0.67397638	1,634,827	1,750,766	115,939	110,743
11	1,353,137	1,361,789	8,652	0.663641321	0.689063398	1,667,308	1,789,957	122,650	113,998
12	1,439,403	1,451,722	12,319	0.705950388	0.734569584	1,773,603	1,908,167	134,564	122,245

a) Please confirm that, in the above data, the values 2,039 MW and 1,976 MW are meant to represent the EE savings assumptions included in the load forecast for those years. If not confirmed what do the values represent and why at they use in the calculation?

b) If confirmed, please provide a reference to the EB-2016-0160 Application that demonstrates these were the assumed values used in the load forecast for the impact of CDM at the end use level.

c) Exhibit H/Tab1/Schedule 2, Attachment 11, page 2 states that "Hydro One's 2017 load forecast approved by the OEB included the same total CDM peak savings amount assumed for 2016 (i.e., 1,638 MW)". Please explain why, in VECC-45 a) ii), Attachment 1, the savings assumptions for 2016 and 2017 are different (2,039 MW and 1,976 MW respectively) and reconcile the differences.

d) What is the difference between the actual peak EE savings achieved for 2016 and 2017 as set out in: i) Exhibit H/Tab1/Schedule 2, Attachment 11, Table 2 and ii) that provided in Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1 per the above Preamble.

e) The calculations set out in: i) Exhibit H/Tab1/Schedule 2, Attachment 11, Table 2 and ii) in Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1 per the above Preamble are fundamentally different but yield the same monthly variance for peak EE savings. Please explain why.

VECC TCQ-13

REFERENCE: Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1
(VECC-45 a) ii), Attachment 1)
Exhibit H/Tab1/Schedule 2, Attachment 11, pages 2-4
Exhibit I/Tab 10/Schedule 29 d) (VECC-29 d))

a) Please confirm that in Exhibit H/Tab1/Schedule 2, Attachment 11, Table 2 the peak savings reported for DR, Dispatched Load and ICI are savings at the time of the system peak. If not confirmed, what do they represent?

b) VECC 29 d) indicates that DR is a peak shifting program. Are Dispatched Load and ICI also peak shifting programs (i.e., meant to shift load away from the system peak)?

c) Since the billings demands for Network Service, Line Connection Service and Transformation Connection Service are not based on a transmission customer's peak at the time of the system peak, why is it appropriate to use the impact of these programs on system peak demand for purpose of calculating the variance account amounts?

d) To the extent these are peak shifting programs could they not actually shift load from the system peak in a manner that increased the customer's non-coincident peak demand?

VECC TCQ-14

REFERENCE: Exhibit I/Tab 10/Schedule 45 b) & d)
(VECC-45 b) & d))
Exhibit I/Tab 10/Schedule 31 c) (VECC-31 c))

PREAMBLE: VECC 45 b) confirms that 2014 was the last year for which actual data regarding CDM was used in preparing the load forecast for EB-2016-0160.

VECC 31 c) indicates that the weather corrected actual load data includes the impact of DR.

VECC 45 d) requested that the analysis in Table 2 (Attachment 11) be redone using the incremental savings per IESO from the last year for which actual data was used in EB-2016-0160 (which was 2014) up to 2017 for each category of CDM set out in Table 2. The response refers back to the original Table 2 which calculates savings in reference to 2016 – not 2014.

a) Please provide a schedule that, for each of the CDM categories used in Table 2, sets out:
   i. the actual CDM savings incorporated in the 2014 data used for EB-2016-0160,
   ii. the assumed savings incorporated in the 2017 load forecast per EB-2016-0160;
   iii. the actual savings for 2017.

b) If the incremental DR savings after 2014 assumed in the load forecast are not zero, as indicated in the response to VECC 31 c), please explain why.

c) If the cumulative EE assumed for 2017 load forecast do not equal 1,638 MW, as indicated in Exhibit H/Tab1/Schedule 2, Attachment 11, page 2, please explain why.

d) If the actual 2014 and 2017 EE and DR savings by category do not match those set out in the Excel file provided in VECC 24 d) please explain why.

COST ALLOCATION

VECC TCQ-15

REFERENCE: Exhibit I/Tab 10/Schedule 48 b) (VECC-48 b))
Exhibit I/Tab 10/Schedule 49 b) (VECC-49 b))

PREAMBLE: With respect to the response to VECC 48 b), it is noted that for a number of the Transmission Lines the explanation for the change in functional category (from that in EB-2016-0160) is due to "Application of OEB Decision in Proceeding EB-2011-0043".

Similarly, in VECC 49 b), it is noted that for a number of the Transmission Stations the explanation for the change in functional category (from that in EB-2016-0160) is due to "Application of OEB Decision in Proceeding EB-2011-0043".

a) Please explain how the Board's Decision in EB-2011-0043 specifically affected the functionalization of lines and stations related to Project D5 (Guelph Area Transmission Reinforcement), Project D09 (Brant TS); Project D19 (Runnymede TS) and Project SS02 (Wataynikaneyap Line to Pickle Lake Connection)

b) Since the Decision is from EB-2011-0043, please explain why it was not implemented for the EB-2016-0160 proceeding.

c) What was the impact on the rates approved in EB-2016-0160 of not correctly reflecting the Board's Decision from EB-2011-0043 in the functionalization of costs and the determination of the rates?

VECC TCQ-16

REFERENCE: Exhibit I/Tab 10/Schedule 48 b) (VECC-50 b))
Exhibit I/Tab 10/Schedule 49 b) (VECC-51 b))

PREAMBLE: The response to VECC 50 b) indicates that for Dual Function Lines the allocation factors used to split the asset value between Network and Line Connection functions are derived using the average forecast monthly coincident peak demand of customer load connected to the DFL and the minimum of the average of summer and winter transmission capacity of the DFL and that the allocation might differ from one year to another due to any change in customer load forecast or due to addition of new DFL lines.

Similarly, VECC 51 b) indicates that the allocation of asset value for Generator Line Connections between "Generators" and "Load" depends on the sum of the maximum annual non-coincident peak demand of all delivery points connected to the connection facility and the maximum installed capacity of generation connected to that facility and can differ from one year to another if there was a change in the annual non-coincident peak demand or due to connection/disconnection of a generator.

a) With respect to VECC 50 b), how much can the allocation vary from year to year strictly due to changes in customer load forecast (i.e., no addition of new DFL lines)?

b) In such instances, would it be more appropriate to use an average annual value (e.g., a three or four year average)? If not, why not?

c) With respect to VECC 51 b), how much can the allocation vary from year to year based strictly on changes in the annual non-coincident peak demand (i.e., no connection of new or disconnection of existing generators)?

d) In such instances, would it be more appropriate to use an average annual value (e.g., a three or four year average)? If not, why not?

RATES

VECC TCQ-17

REFERENCE: Exhibit I/Tab 10/Schedule 55 b) (VECC-55 b))

a) Please provide the actual export volumes for the first six months of 2019. In the same schedule please include the actual export volumes for the first six months of 2017 and 2018.

b) VECC 55 b) indicates that the annual export volumes have been decreasing over last four years (2015-2018). Can Hydro One offer any insight as to why this is the case?

VECC TCQ-18

REFERENCE: Exhibit I/Tab 01/Schedule 225 b) (OEB Staff-225 b))
Exhibit I2/Tab 6/Schedule 1, Attachment 1, page 3

PREAMBLE: The response to OEB Staff 225 b) states: "It is Hydro One's interpretation and practice to include customers with energy storage facilities and/or solar generators (the individual inverter with capacity is 1 MW or higher) in the data provided to the IESO for billing Line Connection and Transformation Connection customers on a gross load basis as per the approved UTR tariff".

It is noted that in the currently approved 2019 Uniform Transmission rates, renewable embedded generation only attracts Line and Transformation Connection charges if the generator unit rating is 2 MW or greater and the 1 MW cut-off applies to non-renewable generators.

a) Please explain why the cut-off for energy storage and solar generators is 1 MW and not 2 MW, particularly in the case of solar generators.

VECC TCQ-19

REFERENCE: Exhibit I/Tab 3/Schedule 1 c) (APPRO-1 c))

PREAMBLE: The response notes that the updated Elenchus Study used "Fixed Assets dedicated to Exports (interconnections) as of 2017 year-end".

a) Please confirm that the updated Elenchus Study used the proposed 2020 Transmission Revenue Requirement.

b) Were there any additional assets placed in service or forecast to be placed in-service in the period 2018-2020 that could be designated as "Fixed Assets Dedicated to Exports". If yes, what are they and what is their gross book value as of year-end 2020?

VECC TCQ-20

REFERENCE: Exhibit I/Tab 3/Schedule 1 a) (APPRO-1 a))
EB-2014-0140, HON 2015-2016 Revenue Requirement Application, Exhibit TCJ2.01

PREAMBLE: The response to APPRO 1 a) provides a copy of the 2015 Elenchus cost allocation model updated using the latest available information.

In several of the responses to questions posed inEB-2014-0140 (e.g., TCJ2.01) it was stated that "The Elenchus model is a simple cost based model" and it was acknowledged that refinements could be made.

a) Were any refinements or changes made to the original Elenchus cost allocation methodology for purposes of preparing the model filed in response to APPRO 1 a)?

b) If yes, please outline in detail what the refinements/changes were and the impacts each have on the results.