PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

October 26, 2021 **VIA E-MAIL**

Christine E. Long
Board Secretary and Registrar (registrar@oeb.ca)
Ontario Energy Board
Toronto, ON

Dear Ms. Long:

Re: EB-2021-00110 – Hydro One Networks Inc. 2023 Joint Rate Application (JRAP)
Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

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

Yours truly,

Mark Garner
Consultants for VECC/PIAC

Email copy:
Ms. Eryn Mackinnon, Senior Regulatory Coordinator, HONI
Regulatory@HydroOne.com

Mark C Garner Digitally signed by Mark C Garner
Date: 2021.10.26 23:52:38 -04'00'

REQUESTOR NAME	**VECC**
TO:	**Hydro One Networks Inc (HONI)**
DATE:	**October 26, 2021**
CASE NO:	**EB-2021-00110**
APPLICATION NAME	**2023 JRAP Rates -TX-DX Revenue Requirement**

EXHIBIT A - ADMINISTRATION

A-VECC-1

Reference: Exhibit A-2-3, Attachment 3, page 1, page 26

a) Please explain the provision for Vital Services section 2.3.2.I.1.

A-VECC-2

Reference: Exhibit A-3-1, Attachment 1 Business Plan, page 8 of 64

Recordable Rate and Serious Injury and Fatality Rate

(Incidents per 200,000 hours worked)

Year	2019 *Actuals*	2020 *Actuals*	2021 *Target*	2022 *Target*	2023 *Target*	2024 *Target*	2025 *Target*	2026 *Target*	2027 *Target*
Recordable Injury Rate	0.78	0.87	0.92	0.90	0.90	0.90	0.90	0.90	0.90
Serious Injury and Fatality Rate	0.18	0.21	0.11	0.08	0.04	0	0	0	0

a) Why is HONI's 'Recordable Injury Rate' target set above the two-year actual incidents (i.e., 2019 and 2020)?

A-VECC-3

Reference: Exhibit A-3-1, Attachment 1 Business Plan, page 8 of 64/ Table 12 and 13

a) In the Business Plan the Transmission revenue requirement for 2023 ($1,764M) is lower than that applied for in this application ($1,823.2). Similarly, the 2023 Business Plan Distribution Revenue requirement ($1,538M) is lower than that applied for ($1,632.4). Please explain the reasons for the material differences as between the Business Plan and what has been applied for in this Application.

A-VECC-4

Reference: Exhibit A-3-1, Attachment 1 Business Plan, page 54/ E-6-1, Section 3.4.1

a) Please provide the sum of the costs removed from revenue requirement subject to Bill 2 and voluntary ELT reductions in each of the years 2019 through 2027.

A-VECC-5

Reference: Exhibit A-4-1, page 1 of 8 /A-4-2 / A-4-3

a) In the Custom IR formula, RCI=I-X+C, the inflation factor 'I" is based on a custom weighted two-factor input price index. The weightings of the two factors are different for Transmission as compared to Distribution. What is the basis for a difference between the two operating units? Specifically, the labour component of 30% for distribution and 14% for transmission implies there is more than a 100% difference in the labour allocated to the distribution function. Please show how the allocation of labour as between transmission and distribution is demonstrative of their weighting used in the inflation calculation.
b) The OEB is reviewing its default inflation two factor inflation estimator due to anomalous results of the Average Weekly Earnings component. Is it the intention of HONI to apply the methodology approved by the Board in that proceeding?

A-VECC-6

Reference: Exhibit A-4-1/A-4-2 / A-4-3

a) The Distribution and Transmission RCI formulas also differ in the calculation of the productivity factor (X-factor). For distribution an x-factor of 0.3% is proposed. For transmission no X-factor is proposed (i.e., 0%). However, a number of costs, including Common and Other OM&A and Common Corporate Functions apply to both transmission and distribution functions. What is the underlying rationale for applying different x-factors to common cost allocated to each of utility function? Specifically, please explain the rationale for having the portion of common costs allocated to distribution subject to an incentive factor but the portion allocated to transmission not.

b) If an x-factor of 0.3% were applied to all common costs which are allocated to the transmission function what change would this have on that annual revenue requirement of TX? Please use Exhibit A-3-1 Table 17 and A-4-2-Table 1 Summary of Revenue Requirement Components for Hydro One Transmission to show any differences.

A-VECC-7

Reference: Exhibit A-4-1, page 6 of 8 / Exhibit G-01-02.

a) HONI proposes different treatments of the proposed CISVA accounts for Distribution and Transmission. CISVA Distribution is subject to an annual true-up whereas CISVA Transmission has a true-up at the end of the rate plan term. Please explain the reasoning for the different treatments.
b) Does the 2% dead band apply equally to both DX and TX CISVA accounts?

A-VECC-8

Reference: Exhibit A-4-2, Table 1 TX, page 5 -6 / A-4-3, Table 1 DX, page 5

a) Please show how the removal of working capital from the capital factor (Table 1/Line 1) is calculated.
b) Please show how line 12 is calculated (for example why is line 12 the same as line 8 in 2024?).
c) Please respond to a) and b) for the equivalent DX table.

EXHIBIT B2 – TX DSP

B2-VECC -9

Reference: Exhibit B-2-1, Section 2.9 Attachment 1 Appendix 2-AA T-Sx-x

a) We are having difficulty mapping the detailed projects (T-S- x) to the categories set out in Appendix 2-AA. If such a mapping is in evidence please provide that reference. If not please provide a mapping of the detailed project descriptions to Appendix 2-AA (TX).

EXHIBIT B3 – DX DSP

B3-VECC -10

Reference: Exhibit B3, D-SR-04

a) Please explain why if Distribution Stations require $179M in investments over the term of the new rate plan why Hydro One has only spent $17M on these assets in the 3 years prior to 2023. Specifically, if the assets are in such dire need of refurbishment why does the program not start in 2022 with lesser amounts spend in years 2023 onward?

B3-VECC -11

Reference: Exhibit B3 D-SA-04

a) Please explain why the acceleration in the meter Sustainment program does not begin in 2022.

B3-VECC -12

Reference: Exhibit B3, SR-12

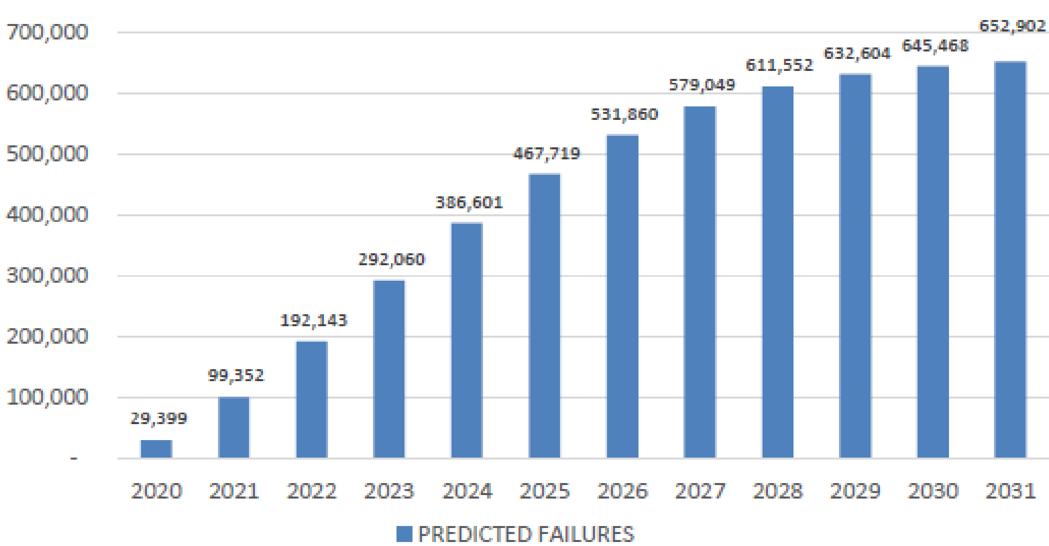

Figure 2: Projected Accumulated GEN 1 Meter Failures Based On ALT Results at the 50% Confidence Level

a) Given the magnitude of the project why did Hydro One not choose to use the regulatory constructs of the ACM or ICM for the AMI program?
b) Please provide the actual meter failures in 2020 and 2021 (to-date).
c) Please provide a list of the IT systems with operational interdependency to the AMI system. For each of these IT systems please note if and when an upgrade to that system will be required in conjunction with AMI 2.0; the timing of that update and its estimated cost.

EXHIBIT B4

B4-VECC -13

Reference: Exhibit Appendix 2-AA

a) Hydro One's proposed General Plant capital expenditures in 2023 are significantly higher than the rate period 5 years average. On an allocated basis for TX the 2023 spending is $146.8M whereas the 5-year average is $122M. For DX the 2023 proposed spending is $195.9M and the 5-year average is $182.4M. What are the impediments to Hydro One in reducing General Plant spending in 2023 so as to be more closely aligned with the average amount over the subsequent years of the rate plan? For example, why is it not possible to reduce DX fleet spending in line with past years (around $26 million) in 2023 and accelerate in later years of the rate plan?

B4-VECC -14

Reference: Exhibit B4, G-GP-01

Table 1 - Forecast of Acquisitions for 2023 to 2027 ($M)

Equipment Type	2023	2024	2025	2026	2027
Light & Heavy Non-PTO[1]	21.8	21.8	21.3	21.7	21.7
Heavy PTO[2]	25.7	28.3	25.5	25.8	28.8
Off-Road[3]	6.0	6.7	7.0	7.3	5.5
Miscellaneous[4]	5.2	3.3	6.8	6.7	7.8
Small Off-Road[5]	2.0	2.1	2.1	2.2	2.2
Service Equipment[6]	6.4	6.5	6.6	6.8	6.9
Total[7]	**67.2**	**68.7**	**69.3**	**70.4**	**72.8**

a) Please provide the equivalent table for the period 2017-2022.
b) Given the worldwide shortage in vehicle production what adjustment has Hydro One made to its vehicle acquisition plans for 2022 and 2023?

B4-VECC -15

Reference: Exhibit B4, G-GP-01

Proposed Funding	2021	2022	2023	2024	2025	2026	2027
Annual Capital	S26 ,238,742	S26,580, 590	S58,7 51,660	S60 ,020,550	S60,663 , 270	S61, 543,910	S63, 694, 290
Units Replaced	253	258	554	556	549	551	556
Annual Maintenance	S60 ,575,690	S62, 733, 890	S62, 506,600	S62 ,643,440	S62, 844, 990	S63,017,9 50	S63,166, 600
Annual ownership	$3 4,798,810	$3 3, 225, 780	S37,439,4 50	$4 1,045,210	$44 , 099, 020	S46,744,460	$49, 271,810
Total	S95 ,374,500	S9 5, 959, 670	S99,946,0 50	S103,688,700	S106,944, 000	S109,762 ,400	S11 2, 438,400
Out of Life	1,582	1, 923	1,936	1,981	1, 978	1,814	1, 827
AvgAge	9.77	1 0.02	9.70	9.52	9.38	9.26	9.14

Table 3 -Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	67.2	68.7	69.3	70.4	72.8	348.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**67.2**	**68.7**	**69.3**	**70.4**	**72.8**	**348.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**67.2**	**68.7**	**69.3**	**70.4**	**72.8**	**348.5**

a) Please clarify how the investment costs in Table 3 relate to the Annual Capital costs shown in the various Utilmarc tables – that is, is the Annual Capital Line in the Utilmarc study the equivalent comparator to the Gross Investment Line in Table 3?

B4-VECC -16

Reference: Exhibit B4, G-GP-17

G-GP-17	OUTAGE RESPONSE MANAGEMENT SYSTEM (ORMS) UPGRADE
Primary Trigger:	Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	5.5	5.5	0.0	0.0	0.0	11.0

Summary:

This investment involves the upgrade of Hydro One's Outage Response Management System (ORMS) that went into service in 2016 and has been in operation on a 24/7 basis. This upgrade is necessary for ORMS to remain compatible with newer technologies and systems that support Hydro One's distribution modernization and AMI 2.0 investments. The primary trigger for this investment is reliability. Other factors that influence this investment are safety, and regulatory compliance. The upgrade will improve ORMS' functionality, outage analytics and reporting, together with trouble call management for enhanced customer experience. This investment aligns with other distribution modernization investments at Hydro One.

a) Please clarify the interdependency of the Outage project with the AMI 2.0 program. Specifically, at what stage does the AMI program need to be in order to proceed the ORMS?

B4-VECC -17

Reference: Exhibit B4, G-GP-10

G-GP-10	PHYSICAL SECURITY UPGRADES
Primary Trigger:	Business Support Sustainment
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	14.0	8.0	8.0	8.0	4.0	42.0

Summary:

The investments under this ISD consist of two distinct physical security upgrade programs that are required in order to ensure the ongoing security of crucial transmission facilities and, in the case of certain facilities, to comply with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards. Through these investments, Hydro One will replace existing physical security technology systems (including access control, surveillance systems, security lighting, gates, intercoms, power supplies, alarms and other systems and technologies) that have reached or are expect to reach their useable end of life and/or are anticipated to fail and require replacement between 2023 and 2027. In addition, these investments will install perimeter security monitoring systems at seven critical transmission stations in order to mitigate physical security incidents and risks to transmission system reliability and resiliency, customer impact and risks to public safety.

a) Please explain why this spending is front loaded to the first years of the rate plan (2023). Why it is not possible to shift the spending on this category more evenly? For example, why is not possible to spend \$11M in 2023 \$11M in 2024 and achieve effectively the same results?

EXHIBIT C – RATE BASE

C-VECC-18

Reference: Exhibit C-1-1, page 2

Table 2 - 2022 OEB-approved versus 2022 Forecast Year Rate Base ($M)

Rate Base Component	2022 Forecast	2022 OEB-approved	Variance
Mid-Year Gross Plant	21,597.7	21,545.1	52.6
Less: Mid-Year Accumulated Depreciation	(7,941.4)	(7,943.9)	2.5
Mid-Year Net Utility Plant	**13,656.3**	**13,601.2**	**55.1**
Cash Working Capital	24.1	27.3	(3.2)
Materials & Supply Inventory	13.9	12.4	1.5
Total Rate Base	**13,694.2**	**13,640.9**	**53.3**

a) Why is Hydro One forecasting more TX in-service additions ($52.6M) in 2022 than the Board approved amount? Specifically, why is HONI not modifying its 2002 capital program to meet the Board approved amounts for 2022?

C-VECC-19

Reference: Exhibit C-1-1, page 7

Table 7 - 2022 OEB-approved versus 2022 Forecast Year Rate Base ($M)

Rate Base Component	2022 Forecast	2022 OEB-approved	Variance
Mid-Year Gross Plant	13,941.7	14,152.7	(211.0)
Less: Mid-Year Accumulated Depreciation	(5,411.5)	(5,692.6)	281.1
Mid-Year Net Utility Plant	**8,530.2**	**8,460.0**	**70.2**
Cash Working Capital	308.4	338.2	(29.8)
Materials & Supply Inventory	5.9	5.5	0.4
Total Rate Base	**8,844.5**	**8,803.7**	**40.8**

a) Why is Hydro One forecasting more DX in-service additions ($211.0M) in 2022 than the Board approved amount? Specifically, why is HONI not modifying its 2002 capital program to meet the Board approved amounts for 2022?

C-VECC-20

Reference: Exhibit C-3-1/8 & E-4-8

a) HONI has used the same consulting firm to review the Corporate Cost Allocation and the Overhead Capitalization Methodology (i.e., Black& Veatch or 'B&V'). Please explain why the runner up to the RFP was rejected. What weight was given to obtaining an opinion unrelated to the original authorship?
b) Do the original and the new B&V studies have any common authorship?
c) At Exhibit E-4-8, page 3 it refers to the "***2023 Black and Veatch report (2023 B&V Study) provided as Attachment 1***…" Please confirm this refers to the attached study dated June 9, 2021 and referred to therein as <u>the Corporate Cost Allocation Review – 2020</u>, i.e., there is no other study being referred to?

C-VECC-21

Reference: Exhibit C-6-1

Table 1 - Inventory Levels 2018 – 2027 ($M)

Year	Historical				Bridge	Forecast				
Year End Balances	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**
Materials and Supplies	16.4	17.5	18.5	19.5	19.9	20.3	20.7	21.2	21.6	22.0
Allocated to Transmission	11.8	12.0	13.1	13.7	14.0	14.3	14.6	14.8	15.1	15.4
Allocated to Distribution	4.6	5.5	5.4	5.8	5.9	6.1	6.2	6.3	6.4	6.6

a) HONI explains the increase in inventory as attributable to inflation. Using CPI (Bank of Canada) the 2018 actual materials and supply amount would be today $17.53M as compared to the forecast of $19.5M. This is significantly above what would be expected from inflationary pressures. What are the other reasons explaining the increase in the material supplies from 2018 as compared to today?
b) Please explain what steps are taken by HONI to minimize the need to carry inventory.

c) Has HONI experienced any shortages of materials and supplies due to the ongoing pandemic? If so please comment on how the pandemic has affected Hydro One's inventory strategy.

C-VECC-22

Reference: Exhibit C-8-2

Table 1 - Overhead Capitalization Rates and Amounts for Transmission and Distribution

Overhead Cost Category	Test Years (%)					Test Years ($M)				
	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027
Transmission	8.0%	8.0%	9.0%	9.0%	9.0%	118.1	119.7	121.0	122.3	123.9
Distribution	9.0%	9.0%	9.0%	9.0%	9.0%	89.9	91.0	94.9	94.2	95.7

a) Please provide the historical amounts for Table 1 (i.e., 2017 through 2022 (forecast).

C-VECC-23

Reference: Exhibit C-8-2, Appendix 2-D

a) Hydro One Transmission's percentage of capitalized OM&A is on average double that for Distribution (about 12% vs 24%). In general terms, what accounts for the very different levels of OM&A capitalization as between these two operations?

C-VECC-24

Reference: Exhibit C-8-2, Attachment 1, page 4

"*Of particular significance is that Hydro One self-constructs most of their capital work. In our experience, this is in contrast to many of its peers which generally perform more construction activity*"

a) What is the evidentiary basis for the claim that Hydro One self-constructs more than its peers?

C-VECC-25
Reference: Exhibit C-9-3 Fleet

Table 1 - Transport and Work Equipment ($M)

Description	Historic				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Operations & Repairs	67.7	71.1	77.4	76.4	79.5	82.3
Fuel Costs	27.2	24.4	22.2	26.0	26.0	26.0
Depreciation	40.3	41.8	42.6	45.3	45.3	45.8
Subtotal	**135.2**	**137.2**	**142.2**	**147.7**	**150.8**	**154.1**
Rentals	0.5	0.9	1.9	2.0	2.0	2.0
Totals	**135.7**	**138.2**	**144.1**	**149.7**	**152.8**	**156.1**

a) Hydro One states that "*There was an overall 4% increase in fleet asset-related expenditures in 2020 from 2019 due to an increase in Operations and Repairs that was due to an increase in external labour rates".* Please provide more information on the nature of the increase in external labour rates.

EXHIBIT D – OPERATING REVENUES

TX External Revenues

D -VECC -26
Reference: Exhibit D, Tab 2, Schedule 1, page 2

Preamble: The Application states: "*The costing of external work is determined on the basis of cost causality, consistent with the costing of internal work, using the standard labour rates, equipment rates, material surcharge, and overhead rates. An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit to transmission ratepayers*".

a) Please provide a schedule that for each of the years 2018-2023 sets out the "margin" (i.e., the revenues in excess costs) included in each category of External Revenues in Table 1.

D -VECC -27

Reference: Exhibit D, Tab 2, Schedule 1, pages 3-4

a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Secondary Land Use External Revenue (per Table 2) for each year with the amounts approved for inclusion in rates over the same period.

b) At page 4 the Application states: "Hydro One has received or expects to receive $4M in 2020, $23M in 2021, and $9M in 2022 and 2023." Please confirm the amount actually received in 2020 and update the annual amounts expected for 2021-2022 as required.

c) The payments from Imperial Oil are characterized as the result of a "one time easement arrangement". For each of the years 2018-2022 what are the total revenues included in Table 2 for such arrangements and what are the forecast amounts included for each of the years 2023-2027?

D -VECC -28

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

a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Station Maintenance External Revenues (per Table 3) for each year with the amounts approved for inclusion in rates over the same period.

b) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Engineering and Construction External Revenues (per Table 4) for each year with the amounts approved for inclusion in rates over the same period.

D -VECC -29

Reference: Exhibit D, Tab 2, Schedule 1, page-6
EB-2019-0082, Exhibit 10, Schedule 20, part b)

a) Please provide a schedule that compares, for the 2018-2022 period, the actual/forecast Other External Revenues (per Table 5) for each year with the amounts approved for inclusion in rates over the same period.

b) Please explain why Other External Revenues decrease annually from 2023-2026 and then increase in 2027.

c) Do the forecast Other External Revenues include revenues as a result of the vegetation management cycle planned to be completed for Bruce to Milton Limited Partnership every 6 years? If yes, how much and in what years? If not, why not?

d) Do the actual/forecast Other External Revenues include revenues from the leasing of idle transmission lines? If not, why not? If yes, please provide a schedule of the annual actual/forecast revenues for 2018-2027.

e) Do the actual/forecast Other External Revenues include revenues from the by-pass charges? If not, why not? If yes, please provide a schedule of the annual actual/forecast revenues for 2018-2027.

DX External Revenues (D/2/2)

D -VECC -30

Reference: Exhibit D, Tab 2, Schedule 2, pages 4-8 and Attachment 1
OEB Chapter 2 Appendices Excel Model /(Updated July 12, 2021)

a) Please provide a breakdown of Distribution Other Operating Revenue using the individual USOA accounts as set out in Appendix 2-H of the July 12, 2021 model.

b) With respect to the Appendix 2-H Table provided in Attachment 1, should the USOA reference for the first row be “4225/4235” as opposed to “4225/4325”?

c) With respect to the Appendix 2-H Table provided in Attachment 1, please explain why USOA 4325 (Revenues from Merchandise Jobbing, Etc.) is used to record Regulated Revenues from Joint Use, Sentinel Lights, Other External Work and Distributor Generator Studies.

d) The Hydro One Networks does not appear to have included any revenue from Retail Service Charges – USOA #4082 & 4084 (per Exhibit L, Tab 7, Schedule 1, Attachment 1, page 17 of 18). Please confirm whether or not this is the case.

   i. If included, please indicate where and what the annual amounts are for 2018-2027

   ii. If not included, please explain why.

   iii. If not included and Hydro One receives such revenues, please provide the actual/forecast annual amounts for 2018-2022.

   iv. If not included, does Hydro One have a forecast of what the expected annual amounts are for 2023-2027?

D -VECC -31

Reference: Exhibit D, Tab 2, Schedule 2, pages 3 and 8
Exhibit D, Tab 2, Schedule 1, page 2

Preamble: With respect to Distribution, the Application states: "For unregulated work, Hydro One adds an appropriate margin above its cost to cover, at a minimum, the risk of non-payment by third parties."

With respect to Transmission, the Application states: "An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit to transmission ratepayers"

a) There appears to be a different basis for determining the margin for unregulated work under taken by the Transmission business as opposed to the Distribution business. Please clarify whether or not this is the case.

   i. If yes, please explain why.

   ii. If not, please clarify the common basis used to determine the margins for unregulated work.

D -VECC -32

Reference: Exhibit D, Tab 2, Schedule 2, page 4
Exhibit L, Tab 4, Schedule 1, Attachment 3

a) Please provide a schedule that maps the Rate Codes listed in Exhibit L, Tab 4, Schedule 1, Attachment 3 to the five rows set out in Table 3 of Exhibit D, Tab 2, Schedule 2.

b) Do the total revenues from all of the Rate Codes listed in Exhibit L, Tab 4, Schedule 1, Attachment 3 reconcile with the total revenues in Table 3? If not, please explain what accounts for any differences.

c) Please provide a schedule that for each of the years 2018-2027 sets out the anticipated annual volume of activity and revenues from each Rate Code in Exhibit L, Tab 4, Schedule 1, Attachment 3.

D -VECC -33

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

a) Is all of the year over year decline in Retail Services Revenue (2023-2027) shown in Table 4 due to the expected decline in new account set up requests completed via the call center? If not, what else accounts for the decline?

D -VECC -34

Reference: Exhibit D, Tab 2, Schedule 2, page 10

a) Are the historical Storm Revenues shown in Table 12 net of any costs incurred by Hydro One Networks to help other utilities affected by major power outages? If the amounts are gross revenues, what were the net revenues after accounting for the associated costs?

b) The Application states that "these instances are unpredictable and dependent on Hydro One's ability to deploy storm relief outside jurisdictions and, accordingly, are not forecast". Would Hydro One Networks be open to establishing a variance account to record net Storm Revenues over the 2023-2027 period and to subsequently refunding the amounts to customers? If not, why not?

Load Forecast – General (D/3/1)

D -VECC -35

Reference: Exhibit D, Tab 3, Schedule 1 (D/3/1)
Exhibit D, Tab 3, Schedule 1, Attachment 1

Preamble: D/3/1, page 1 states: "*The load forecasts in support of this Application were prepared in February 2021, using the economic and forecast information then available*".

a) With respect to the Tabs in Attachment 1, is data shown for years up to and including 2020 all based on actual values while the data for 2021 and subsequent years is all based on forecast? If not, for each Tab, please indicate where the basis of the data is different from that posited in the previous sentence.

b) For each of the Tabs in Attachment 1, please indicate the sources for the historical data. Similarly, please provide the source for the annual Housing Start values set out in Exhibit D, Tab 5, Schedule 1.

c) With respect to the following forecast values in Attachment 1:

- Broad Annual Series Tab: Please explain the basis for the forecasts for Ontario Population, Ontario Disposable Income, Ontario Commercial GDP and Ontario Industrial GDP. As part of the response please explain how the forecasts for Commercial GDP and Industrial GDP are made consistent with consensus forecast of Ontario GDP (per D/4/1, pages 30 & 32).

- Monthly Building Permits Tab values. Please explain how the forecast was derived from the forecast of housing starts (per D/4/1, Appendix A)
- Monthly GDP Tab values. Please explain how the forecast was derived from the annual GDP forecast in the Broad Annual Series Tab (per D/4/1, Appendix A).
- Physical Production Unit Tab values for each sector. Again, as part of this response please indicate how the forecast for physical production units by sector is related to the forecast of Ontario Industrial GDP (as set out in the Broad Annual Series Tab).
- Floor Space Tab values. Please explain how the forecast values for the individual sectors were derived.
- GDP Components Tab values. Please explain how the forecasts for the individual sectors were derived. As part of this response please indicate how the GDP Components forecast is consistent with the forecast of Annual GDP (as set out in the Broad Annual Series Tab).

d) Exhibit D, Tab 4, Schedule1, page 28 states that the forecast number of households is based on the consensus forecast of housing starts. However, for the forecast period, the year over year change in housings stock (per Attachment 1, Broad Annual Series Tab) does not equal (i.e., is less than) the annual Housing Starts forecast (per D/3/1, Appendix A). Please explain why and, as part of the response, provide a schedule that reconciles/explain the differences between the two.

e) With respect to D/3/1, Appendix A - please explain why, when the load forecast was prepared in February 2021 some of the forecasts for the inputs used date as early as January 2020. How dated would an input forecast source need to be before Hydro One would consider it too “old´ to use in determining the consensus forecast.

f) Please provide an update to D/3/1, Appendix A incorporating any more recent forecasts prepared by the sources cited.

TX Load Forecast (D/4/1)

D -VECC -36

Reference: Exhibit D, Tab 4, Schedule 1, pages 4-5
EB-2019-0082, Exhibit I, Tab 10, Schedule 24 and
Exhibit JT2.34, Q 11 c)

Preamble: The Application states (page 5): "*Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2027*."

a) With respect to Table 2, for what years are the Cumulative CDM Impact on Peak Demand values actual vs. forecast?

b) Please provide breakdown of the Cumulative CDM Impact on Peak Demand as between Energy Efficiency Programs and Codes & Standards for each of the years 2006-2027.

c) Please confirm that the values for the years 2006-2018 are taken from the 2013 LTEP (as the values in Table 2 match those in the 2013 LTEP per EB-2019-0082, Exhibit I, Tab 10, Schedule 24)?

d) Are the values in Table 2 measured at point of delivery (end-use) or point of generation? The footnote suggests that it is point of delivery. However, in the response to Exhibit JT2.34, Q 11 c) the generation level values match those in Table 2.

e) It is noted that the Application refers to the values for the historical years as being "assumed" values (page 5, line 1)? What is the basis for assuming that the actual values for the years 2013-2018 are the same as the forecast values in the 2013 LTEP (e.g., is Hydro One Networks aware of any "after the fact" analysis that would verify this assumption)?

f) Between 2013 and 2018 did the IESO (or the former OPA) provide any updates/revisions to the actual or forecast MW CDM savings for the years prior to 2019 (e.g., in its Annual Planning Outlooks) that differed from the CDM savings for 2013-2018 in the 2013 LTEP? If yes, why weren't these values used instead?

g) Between 2013 and 2018 did the IESO (or the former OPA) provide any updates/revisions to either the actual or forecast MWH CDM savings for the year prior to 2019 (e.g., in its Annual Planning Outlooks) that differed from the CDM MWh savings in the 2013 LTEP? If yes, why weren't the CDM MW savings for 2013-2018 adjusted to reflect this change, assuming a change in MWh savings would result in a change in MW savings?

D -VECC -37

Reference: Exhibit D, Tab 4, Schedule 1, pages 4-5
EB-2019-0082, Exhibit I, Tab 10, Schedule 25

Preamble: The Schedule states: "*Hydro One derived monthly CDM savings using IESO's (formerly the OPA's) hourly load shape. The annual peak savings (July) is applied to the monthly saving profile to derive the monthly peak savings, and 12-month average peak savings, for the actual and forecast periods*."

a) Please clarify whether the hourly load shape used was an hourly load shape for CDM savings or for the overall system load.

b) If it was an hourly load shape for CDM savings, was the load shape used for the historical years revised every year to reflect the new CDM savings achieved each year?

c) If it was an hourly load shape for CDM savings, what was the basis for the load shape used for the forecast years?

d) If it was a system load shape, was the load shape used for each historical year revised based on that year's actual load profile?

e) If it was a system load shape, what was the basis for the load shape used for the forecast years?

D -VECC -38

Reference: Exhibit D, Tab 4, Schedule 1, pages 4-5
EB-2019-0082, Exhibit I, Tab 10, Schedule 24

Preamble: The Application states (page 4): "*Hydro One has used the 2013 LTEP assumptions and taken into account the IESO's latest province-wide conservation forecast to establish the CDM impacts in the load forecast. Hydro One adopted two CDM categories that are consistent with the IESO's (then the OPA) 2013 LTEP information: energy efficiency programs and codes and standards. Details of the latest information that was provided in February 2021 by the IESO, which are consistent with the IESO's latest Annual Planning Outlook APO), and the methodology used by Hydro One to derive the CDM impacts for the three charge determinants, have been documented in sections 3.1 and 4.0 of this exhibit*."

a) Did the 2013 LTEP forecast CDM MW savings for any of the years after 2022. If yes, please provide the forecast savings from energy efficiency programs and code & standards (separately). Please also provide a copy of the source reference.

b) It is noted that the CDM savings set out in Table 2 for the years after 2018 differ from those in the 2013 LTEP. Please describe how the savings from i) energy efficiency programs and ii) codes and standards were determined for each of the years 2019-2027 and provide copies of any relevant sources/references used.

c) If not included in the response to part (b), please demonstrate that the forecast values in Table 2 are consistent with the IESO's CDM demand savings targets for the Interim (CDM) Framework and the 2021-2024 CDM Framework.

d) What was the nature of the "latest information that was provided in February 2021 by the IESO"? Please provide copies of any correspondence or reports received.

e) What information from the latest IESO APO is the forecast consistent with and which IESO APO is the Application referring to?

D -VECC -39

Reference: Exhibit D, Tab 4, Schedule 1, page 6

a) What does Hydro One Networks include in "Embedded Generation"? For example, does it only include generators over a certain size and does it include both embedded generation sold to local distributors (e.g., MicroFIT and FIT) and behind the meter generation?

b) Does the forecast for either CDM or Embedded Generation include any impacts due to Energy Storage? If so, what are the annual values?

c) Does the forecast for either CDM or Embedded Generation include any impacts due to System By-Pass? If so, what are the annual values?

D -VECC -40

Reference: Exhibit D, Tab 4, Schedule 1, pages 6 & 11 and Appendix A

Preamble: The Application states: "*The load impacts of CDM and embedded generation are added back to the historical data set during the modelling process.*"

a) What historical months/years were used to estimate the Monthly Econometric Model?

b) What are the annual values for the load impact of CDM added back to the historical data set?

c) What was the basis for the annual CDM (energy) impacts added back to the historical data set? In responding, please indicate whether the historical amounts added back are consistent with the verified CDM results reported by the IESO.

d) What types of embedded generation were added back to the historical data and does the definition match that used for Embedded Generation in the Application (page 6)?

e) What were the annual load impacts for embedded generation that were added back in each of the historical years?

f) What is the Monthly Econometric Model's predicted annual energy use (before any deductions for CDM or Embedded Generation) for the last year for which 12 months of historical data was available? (Note: Predicted values would the model's prediction for those years where the actual results were known)? How does this value compare with the actual annual energy use in the same year?

g) What is the Monthly Econometric Model's predicted annual energy use for each of the subsequent years (before any deductions for CDM or Embedded Generation)?

h) Are the forecast values from the Monthly Econometric Model based on energy use measured at point of generation or at the point delivery to the customer?

D -VECC -41

Reference: Exhibit D, Tab 4, Schedule 1, pages 11-13 and Appendix B

Preamble: For each of the sectors, Appendix B (pages 27, 30, 32, 36 and 37) states that the impact of CDM has been included.

a) What historical years were used to estimate the Annual Econometric Model?

b) What are the annual values for the load impact of CDM added back to the historical data set? For each year, please provide a breakdown as between Residential, Commercial, Industrial, Agricultural and Transportation.

c) What was the basis for the annual CDM (energy) impacts added back to the historical data set? In responding, please indicate whether the historical amounts added back are consistent with the verified CDM results reported by the IESO.

d) There is no reference to the impact of embedded generation being added back to the energy use for the Commercial and Industrial sectors. How was the impact of embedded (behind the meter) generation accounted for in the modelling of Commercial and Industrial Use?

e) Given the Annual Econometric Model is sectoral (i.e., Residential, Commercial, etc.), how does the modelling account for the impact of embedded generation that is sold directly to local distributors?

f) What is the Annual Econometric Model's predicted annual energy use (before any deductions for CDM or Embedded Generation) for the last year for historical data was available? How does this compare with the actual annual energy use in the same year?

g) What is the Annual Econometric Model's predicted annual energy use for each of the subsequent years (before any deductions for CDM or Embedded Generation)?

h) Please confirm that the historical and forecast energy use values per the Annual Econometric Model are measured at the point of use by customers.

D -VECC -42

Reference: Exhibit D, Tab 4, Schedule 1, page 13 and Appendix C

Preamble: The Application states (page 13): "the resulting forecast is gross of the load impact of CDM and embedded generation".

a) What is the base year used for the End Use Model?

b) What is the CDM impact for each sector that was included in (added back to) the base year energy use?

c) What is the embedded generation impact for each sector that was included in (added back to) the base year energy use for each sector?

d) Given the End Use Model is sectoral (i.e., Residential, Commercial, etc.), how does the modelling account for the impact of embedded generation that is sold directly to local distributors?

e) What is the End Use Energy Model's predicted annual energy use (before any deductions for CDM or Embedded Generation) for the base year? How does this compare with the actual energy use for the year?

f) What is the End Use Energy Model's predicted annual energy use for each of the subsequent years (before any deductions for CDM or Embedded Generation)?

g) Please confirm that the historical and forecast energy use values per the End Use Model are measured at the point of use by customers.

D -VECC -43

Reference: Exhibit D, Tab 4, Schedule 1, page 6 & pages 16-18 and Appendix G/EB-2016-0160, Exhibit I, Tab 12, Schedule 25

Preamble: The Application states (page 6): "*The forecast base year is corrected for abnormal weather conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized base year value*".

The Application states (page 16): "*Table 3 presents the forecast prepared for this application before and after deducting the load impacts attributed to embedded generation and CDM for the period 2019 to 2027*".

The Application states (page 16): "*Appendix D to this Exhibit provides the historical actual and weather-corrected charge determinant data for years 2008 to 2020*"

a) The graph on page 6 and the second quote referenced above from page 16 suggest that the base year for the forecast was 2020. However, the first quote referenced above from page 16 suggests that it was 2018 (i.e., 2019 is part of the forecast period). Please clarify what the base year was to which the forecast growth rates were applied. As part of the response please confirm that the values for the base year to which the growth rates were applied are actual weather normalized values.

b) With respect to both Table 3 and Appendix G, please indicate for which years are the values provided actual results vs. forecast.

c) Please provide a schedule that sets out the forecast growth rates from each of the three models and the forecast growth rates that were used for to determine the forecast values for each year after the base year.

d) Please confirm that the methodology for forecast the Charge Determinants is the same as that described in EB-2016-0160: "the Ontario peak growth rates, prior to Embedded Generation and CDM deductions, were applied to the 2015 charge determinants. Then the corresponding Embedded Generation and CDM impacts were deducted to arrive at charge determinants net of those impacts." If not confirmed what is the approach used in the current Application?

e) Please provide a schedule that sets out the base year values for the Ontario Demand and each of the three Charge Determinant and their forecast (to

2027) annual values based on each of the three forecasting models and Hydro One's proposed forecast.

D -VECC -44

Reference: Exhibit D, Tab 4, Schedule 1, pages 5-7 and 16-18

a) With respect to Table 3 (page 17) please explain how the impacts of Embedded Generation on the 12 Month Average Peak values for each of Ontario Demand, Network Connection, Line Connection and Transformation Connection were derived from the system embedded generation impacts noted on page 6.

b) With respect to Table 3 (page 17) please explain how the impacts of CDM on the 12 Month Average Peak values for each of Network Connection, Line Connection and Transformation Connection were derived from the CDM impacts set out on page 5.

<u>DX Load Forecast (D/5/1)</u>

D -VECC -45

Reference: Exhibit D, Tab 5, Schedule 1, pages 1 and page 7

Preamble: The Application states (page 1): "*All forecasts presented in this section are weather-normal, and the numbers are at the wholesale level unless otherwise specified"*. The Application states (page 7): "*The load forecast also takes into account 2020 actual load*".

a) Please explain what is meant by the "wholesale level".

b) Please indicate for which tables in the Exhibit D, Tab 5 (including the Appendices and associated Excel Spreadsheets) the data presented is not at the "wholesale level" and, in each case, explain at what point the data is being measured.

c) For each customer class please indicate the loss factor the wholesale values reported would need to be divided by in order to obtain the kWh delivered to the customer.

d) Are all of the 2020 kWh and kW values used in Exhibit D, Tab 5 (including the Appendices and associated Excel Spreadsheets) actual values or weather normalized actual values (as opposed to a forecast value)? If not, please indicate for which tables and spreadsheets the 2020 values are not actuals and explain what the basis for the 2020 values in such cases is.

e) Are all of the 2020 customer count values used in Exhibit D, Tab 5 (including the Appendices and associated Excel Spreadsheets) actual values (as opposed to a forecast value)? If not, please indicate for which tables and spreadsheets the 2020 values are not actuals and explain what the basis for the 2020 values in such cases is.

D -VECC -46

Reference: Exhibit D, Tab 5, Schedule 1, pages 8 and 37

a) What is the basis for the customer counts referenced on page 8 and set out in Table E.3 (i.e., are they year-end values, average of 12 months values, or determined on some other basis)?

b) For the Street Light, Sentinel and USL classes do the values in Table E.3 represent the number of customers, number of connections or number of devices?

c) Please provide the customer count for each class as of June 30, 2021 and July 31, 2021. For the Seasonal class, please indicate the breakdown between those in the UR, R1 and R2 geographic areas.

D -VECC -47

Reference: Exhibit D, Tab 5, Schedule 1, page 8

Preamble: The Application states: "*The customer forecast takes into consideration new customers requiring distribution services, existing customers moving out, provincial housing demand, population and household forecasts, vacancy rates and specific growth patterns of various customer groups*".

a) Please provide a schedule that sets out the derivation of the forecast customer count for each Residential class (including Seasonal and Acquired Utilities) for each of the years 2021-2027. In doing so please provide all equations, inputs used and associated calculations.

b) If not dealt with in the previous question, please explain how Seasonal customer are dealt with for purposes of the customer count forecast (e.g., was the Seasonal count forecast for each year through to 2027 and then assigned to the other Residential classes or was the Seasonal customer forecast for 2022 assigned to the other Residential classes and then forecasts for those classes developed for 2023 and afterwards using adjusted 2022 values?).

c) Please provide a schedule that sets out the derivation of the forecast customer count for each General Service class (including each Acquired GS class) for each of the years 2021-2027. In doing so please provide all equations, inputs used and associated calculations.

d) Please provide a schedule that sets out the derivation of the forecast customer count for the ST customers for each of the years 2021-2027. In doing so, please explain how the forecast methodology accounts for the fact the customer numbers for Norfolk, Haldimand and Woodstock are integrated into Hydro One Distribution for 2023 onwards.

e) Please provide a schedule that sets out the derivation of the forecast customer count for the Street Light, Sentinel Light and USL classes for each of the years 2021-2027.

f) Have the forecast customer counts for the ST class and the General Service (demand) classes been adjusted to account for GS customers that will now qualify as ST customer based on Hydro One Distribution's proposal to change the ST class eligibility requirements (per L/1/2, page 3)?

   i. If yes, specifically what adjustments were made?

g) Please provide a working excel version of Table E.3.

D -VECC -48

Reference: Exhibit D, Tab 5, Schedule 1, pages 5, 7 and 18

a) With respect to Table 3, does the customer count for 2021 and 2022 treat the Acquired Utilities as ST customers but, for the years 2023 onwards, include each retail customer of the Acquired Utilities as a separate customer? If not, how are the Acquired Utilities treated for purposes the customer counts in Table 3?

b) With respect to Table 3, does the GWh Delivered Forecast for 2021 and 2022 include the Acquired Utilities as ST customers but for 2023 onwards assume their retail customers are retail customers of Hydro One Distribution? If not, how are the Acquired Utilities treated for purposes the GWH Delivered Forecast in Table 3?

c) In Table 3, does the integration of the load for the Acquired Utilities into Hydro One Distribution in 2023 impact the value for the Delivered GWh for that year? If yes, please explain why and indicate what the GWh impact is.

d) With respect to Table 4, is the CDM attributable to the Acquired Utilities reported as LDC CDM for 2019-2022 and then as Retail Customer CDM for

2023 onwards? If not, how is it reported?

e) In Table 4, does the change in the reporting of the CDM attributable to Acquired Utilities change the total CDM for 2023? If yes, please explain why and what the GWH impact is.

f) In Table 4, is the increase is LDC CDM in 2023 over 2022 (70 GWh) net of any the reduction that would occur due to the integration of the Acquired Utilities into Hydro One Distribution? If so, what was the reduction associated with the integration?

D -VECC -49

Reference: Exhibit D, Tab 5, Schedule 1, pages 11, 18 and 20-21 (Appendix A)

Preamble: The Application (page 11) states: "Both monthly and annual econometric models are used to forecast Hydro One Distribution's total distribution system load."

a) With respect to the Monthly Econometric Model, what historical years were used to estimate the regression model?

b) At page 20, the Application states that the dependent variable is the logarithm of retail load. Have the historic retail load values used to estimate the regression equation been weather-normalized? If not, how are weather impacts accounted for?

c) At page 20, the Application states that the dependent variable is the logarithm of retail load. However, page 11 states that the monthly econometric model was used to forecast total distribution system load. Please confirm that Hydro One's reference to total distribution load forecast excludes the ST customers but includes all of the other customer classes. If not confirmed, what customer classes are included in the load used as the dependent variable for the Monthly Econometric Model?

d) For the historical period used for the Monthly Econometric Model have the same LDCs and Direct customers been treated as ST customers and their load excluded throughout.

e) Please explain how the Monthly Econometric Model accounted for the fact that Norfolk, Haldimand and Woodstock are ST customers for 2021 and 2022 by then into Hydro One Distribution for 2023 onwards. If the load forecast for the retail customers in these utilities was for 2023 onwards was done separately, please explain the basis for the forecast.

f) Does the forecast result for the Monthly Econometric Model reflect the same definition of Retail as used in Table 5 (D/5/1, page 18)?

D -VECC -50

Reference: Exhibit D, Tab 5, Schedule 1, pages 11 and 22-27 (Appendix B)

Preamble: The Application (page 11) states: "Both monthly and annual econometric models are used to forecast Hydro One Distribution's total distribution system load."

Appendix B states: "*In this Appendix, regression results for annual econometric models are presented. As explained in the main text, in each case, two sets of results are provided; one base on Toronto weather data and the other on average weather data for 5 weather stations across Ontario (Thunder Bay, Windsor, Toronto, Ottawa, and North Bay). The results are discussed in Section 2.2.*"

a) With respect to the Annual Econometric Model, what historical years were used to estimate the regression model?

b) Please confirm that the reference in Appendix B should be to section 3.2 (D/5/1) and not section 2.2.

c) Does the retail load used as the dependent variable in the Annual Econometric Model include the same customer classes as that used in the Monthly Econometric Model? If not, what are the differences?

d) It is noted that the Annual Econometric Model does not include cooling degree days as a dependent variable. Please explain why.

e) For the historical period used for the Annual Econometric Model have the same LDCs and Direct customers been treated as ST customers and their load excluded throughout?

f) Please explain how the Annual Econometric Model accounted for the fact that Norfolk, Haldimand and Woodstock are ST customers for 2021 and 2022 by then into Hydro One Distribution for 2023 onwards. If the load forecast for the retail customers in these utilities was for 2023 onwards was done separately, please explain the basis for the forecast.

g) Do the forecast results for the Annual Econometric Model reflect the same definition of Retail as used in Table 5 (D/5/1, page 18)? It not, what is the difference?

D -VECC -51

Reference: Exhibit D, Tab 5, Schedule 1, pages 11 and 28-30 (Appendix B)

Preamble: The Application (page 18) state: "*End-use models are used to analyze the distribution system load by customer rate class*".

a) What is the base year used in the End-Use Model and is it the same for all sectors?

b) Do the combined Residential, Commercial, Industrial and Agricultural sectors (per the End-Use Model) represent the same customer classes as the Retail Load used as the dependent variable in the Monthly Econometric Model? If not, please explain the difference.

c) Please explain how the End-Use Model accounted for the fact that Norfolk, Haldimand and Woodstock are ST customers for 2021 and 2022 by then into Hydro One Distribution for 2023 onwards. If the load forecast for the retail customers in these utilities was for 2023 onwards was done separately, please explain the basis for the forecast.

d) Do the forecast results for the End-Use Model reflect the same definition of Retail as used in Table 5 (D/5/1, page 18)? It not, what is the difference?

e) Please provide a schedule that, of each of the three models (Monthly Econometric, Annual Econometric and End-Use, sets out the actual 2020 weather normalized energy (before deducting CDM) and reconcile the differences with the2020 value set out in Table 5 (page 18) for Retail Customers.

D -VECC -52

Reference: Exhibit D, Tab 5, Schedule 1, pages 16-18

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 2020 and the forecast Retail load for 2021-2027 based on the Monthly Econometric Model (before deducting CDM).
   iii. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on the Annual Econometric Model (before deducting CDM).
   iv. The predicted Retail load for 2020 and the forecast Retail load for 2021-2027 based on the End Use Model (before deducting CDM).
   v. The actual Retail load for 2020 and the forecast Retail load for 2021-27 per the Application (before deducting impact of CDM).

b) With respect to the response to part (a), was the same forecast used for the 2023-2027 retail load associated with the Acquired Utilities for all three models. If not please provide the 2023-2027 forecast for the retail load associated with the Acquired Utilities included in each Model's results and in the 2023-2027 forecast Retail load per the Application (Table 5).

c) Please provide the detail calculations setting out how the proposed Retail load forecast (before deducting CDM) for each of the years 2021 to 2027 was determined using the results of these three models.

d) Have the forecast customer volumes for the ST class and the General Service (demand) classes been adjusted to account for GS customers that will now qualify as ST customer based on Hydro One Distribution's proposal to change the ST class eligibility requirements (per L/1/2, page 3)?

   a. If yes, specifically what adjustments were made?

D -VECC -53

Reference: Exhibit D, Tab 5, Schedule 1, pages 13, 18 and 38 (Table E.5)

a) Please explain how the forecast of 2021-2027 forecast for total Retail load (per page 18) is disaggregated into the individual rate classes (per Table E.5) and provide schedules with the supporting calculations.

D -VECC -54

Reference: Exhibit D, Tab 5, Schedule 1, page 17

Preamble: The Application states: "*The peak forecast for each rate class is derived from corresponding sales forecast using load factor*."

a) Please explain how the "load factor" used for each rate class was determined.

D -VECC -55

Reference: Exhibit D, Tab 5, Schedule 1, pages 6 and 13-14

Preamble: The Application (page 13) states: "*ST customers include embedded distribution utilities, or large industrial and commercial customers. Both econometric and customer analysis based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.*"

The Application also states (page 14): "*The econometric approach was used to forecast the load for embedded utilities and industrial analysis was used to forecast the load for the embedded industrial customers. In both cases, results from the customer survey were taken into account in developing the forecast.*"

a) Please outline the econometric analysis used to forecast the embedded distribution utility load. As part of the response please indicate how the analysis addressed the fact that the Acquired Utilities are only ST customers for 2021 and 2022.

b) Please provide a schedule that sets out:

   i. The actual (weather corrected) embedded distribution utility load for 2020 and the forecast values for 2021-2027 per the Application (before deducting CDM).

   ii. The predicted embedded distribution utility load (before deducting CDM) for 2020-2027 based on the econometric analysis.

   iii. How the customer survey results were taken into account in developing the forecast.

D -VECC -56

Reference: Exhibit D, Tab 5, Schedule 1, pages 6 and 13-14

Preamble: The Application (page 13) states: "*ST customers include embedded distribution utilities, or large industrial and commercial customers. Both econometric and customer analysis based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast*."

The Application also states (page 14): "*The econometric approach was used to forecast the load for embedded utilities and industrial analysis was used to forecast the load for the embedded industrial customers. In both cases, results from the customer survey were taken into account in developing the forecast.*"

a) Please outline the industrial analysis used to forecast the Direct (i.e., large industrial and commercial) load.

b) Please provide a schedule that sets out:

   i. The actual (weather corrected) Direct customer load for 2020 and the forecast for 2021-2027 per the Application (before deducting CDM).

ii. The predicted Direct customer load (before deducting CDM) for 2020-2027 based on the industrial analysis.

iii. How the customer survey results were taken into account in developing the forecast.

D -VECC -57

Reference: Exhibit D, Tab 5, Schedule 1, pages 7 and 18

a) Please explain how CDM is defined for purposes of Tables 4 and 5 (e.g., does it just include the impact or OPA/IESO and distributor-funded efficiency programs?).

b) Tables 4 and 5 only show the impact of CDM on Retail and ST Customers for 2019 and after. Please provide a schedule as to the annual impact of CDM on each of Retail Load and ST Load (broken down between Direct and LDC) for each historical years used to estimate the Monthly Econometric Model and/or the Annual Econometric Model. If CDM includes more than just the impact of energy efficiency programs, please provide a further breakdown by CDM component.

c) Please provide the source documents (or their web-links) from which the historic values provided in part (b) were derived and any supporting calculations regarding their derivation.

d) Are the historical CDM values used by Hydro One consistent with those published by the IESO in its most recent Annual Planning Outlook (APO) and previous publications?

i. If not, why not?

ii. If yes, please provide schedule that sets out the actual CDM savings reported by the IESO in its most recent APO and previous publications for the historic period used by Hydro One in its econometric models and demonstrate how the values used by Hydro One are consistent.

D -VECC -58

Reference: Exhibit D, Tab 5, Schedule 1, pages 7 and 18

Preamble: The Application states (page 7): "*The CDM figures for all years are consistent with IESO Annual Planning Outlook (APO), including the load impact of LDC energy efficiency programs for the years 2019-2020. The methodology for incorporating CDM into the load forecast is described in Section 3 of this Exhibit*".

a) Please provide the CDM figures per the IESO's APO (along with a copy or link to the actual document) and demonstrate that the CDM values used by Hydro One for Retail customers, Direct Customers and Embedded LDCs for the period 2019-2027 were derived from and/or are consistent with the IESO's values.

b) Are the Hydro One's incremental CDM savings in 2019 and 2020 consistent with the targets set out by the IESO in its Interim Framework for the period April 1, 2019 to December 31, 2020?

   i. If not, why not?

   ii. If yes, please provide a schedule that reconciles the incremental CDM savings Hydro One has assumed for 2019 and 2020 with the Interim Framework's targets.

c) Are the Hydro One's incremental CDM savings in 2021-2024 consistent with the targets set out by the IESO in its 2021-2024 Conservation and Demand Management Framework Program Plan?

   i. If not, why not?

   ii. If yes, please provide a schedule that reconciles the incremental CDM savings Hydro One has assumed for 2021-2024 Conservation and with the targets in the IESO's 2021-2024 CDM Framework.

EXHIBIT E – OM&A

E-VECC-59

Reference: Exhibit D-1-1, page 13- /E-2-1, page 8

Preamble: Hydro One suggests that reduction in OM&A following the completion of the PCB program is unwarranted. The Utility further states that upon completion of the PCB Program it "*plans to resume preventive maintenance on transmission stations and lines assets that were deferred in 2019-2022*." The Utility also suggests that the resources currently used on the PCB program will be redirected to correct 'defects' which have grown by "*an average of approximately 11,500 defects per year*."

a) At E-2-1, page 3 Hydro One states that it needs to increase OM&A spending starting in 2023 to "*address deferred stations maintenance that allowed Hydro One to continue funding PCB remediation work as planned in 2019-2022*." If Hydro One is already increasing spending in 2023 for station remediation than how can it also be true that it would be "unwarranted" to reduce OM&A spending upon completion of the PCB program?

b) Is the PCB program currently being executed by Hydro One staff or third-party contractors or a combination of the two? Please provide details.
c) Provide number of defects identified and addressed in each of the years 2017-2021

E-VECC -60

Reference: Exhibit E /Exhibit A-3-1, Attachment 1 Business Plan, page 28 / E-2-2, page 22

"*The air-blast circuit breakers are approximately ten times more costly to maintain and four times less reliable than the SF6 circuit breakers*."

Table 13 - Breaker Refurbishment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Breaker Refurbishment	3.9	2.2	0.4	1.9	2.0	2.1

a) Please explain how the capital plan to replace SF6 breakers impacts the future OM&A costs for this asset.
b) For each year shown in Table 13 please show the number of circuit breakers refurbished/maintained.

E-VECC-61

Reference: Exhibit E-1-1, page 13- /E-2-1, page 8 / E-5-1

a) Please provide a list of all major activities (with annual costs above the materiality threshold) previously outsourced (e.g., Inergi, Capgemini,) that will be insourced beginning 2022 or are planned to be insourced during the new rate plan.
b) Please provide the same for all major activities previously insourced that are expected to be outsourced beginning 2021 and during the rate plan.
c) For each transition (in-to-out and out-to-in) please provide the expected date of that transition and the actual or forecast one-time costs of the transition.
d) For each transition, please provide the expected/forecast net savings (or cost) of the change in program delivery structure and the actual savings (cost) realized.
e) Please identify any major activity that was transitioned out of then back into the Utility within the last 7 years.

TX

E-VECC-62

Reference: Exhibit E-2-1, page 3

> *Starting in 2023 Hydro One needs to increase its OM&A spending in some respects, mainly to: (i) 5 address deferred stations maintenance that allowed Hydro One to continue funding PCB remediation work as planned in 2019-2022; (ii) address security needs related to evolving security threats and NERC CIP standard; and (iii) fund planned corrective maintenance work on overhead lines.*

a) Hydro One proposes to almost double its capital spending on Overhead Lines Refurbishment Projects (Appendix 2-AA). Will this capital spending result in lowering of maintenance of these types of assets in 2023 and future years? If not please explain why not.

E-VECC-63

Reference: Exhibit E-2-2, page 3, 40-

a) What is the incremental cost of the Joint Security Centre? Please explain what year the full annual incremental cost is expected to occur. Please divide these costs into labour and other OM&A costs.
b) Are these costs captured in the Telecommunications (including cybersecurity line of Appendix 2-JC?

E-VECC-64

Reference: Exhibit E-2-2

a) In 2018 Hydro One spent $229.4M on Sustainment maintenance activities. Between 2019 and 2021 (forecast) the spending was reduced to an average of $205.5 per year. In the test year (2023) the proposal is to increase spending to $219.6. What are the reasons that Hydro One underspent on this activity over the past four years as compared to what was spent in 2018 and what is now being sought to be recovered in rates in 2023?

E-VECC-65

Reference: Exhibit E-2-3, pg. 7- /E-3-s, page 8-

TX - Table 3 - RD&D Program OM&A ($ Million)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
RD&D Program	2.2	1.8	2.3	3.4	3.9	3.3

Table 6 - Summary of RD&D OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Research Development & Demonstration	3.2	2.6	2.3	5.0	5.0	5.9

a) Total R&D is proposed to increase by over 60% as compared to 2018 (i.e., $5.4M to $9.2M). What research programs would Hydro One eliminate should the Board decided that rates should fund only the average of the prior 3 actual years (i.e., 2018-2020).
b) What was the total subscription costs for involvement in the EPRI and CEATI in each of 2018 through 2021?
c) Is the R&D budget specific to DX and TX activities or is the amount simply allocated? If the latter please explain how this is done.
d) What portion of the proposed R&D (combined) is for subscription costs?

E-VECC-66

Reference: Exhibit E-2-2, page 3, 40-

a) What is the incremental cost of the Joint Security Centre? Please explain what year the full annual incremental cost is expected to occur. Please divide these costs up into labour and other costs.
b) Is this cost captured in the Telecommunications (including cybersecurity line of Appendix 2-JC?

<u>DX</u>

E-VECC-67

Reference: Exhibit E-3-2, pages 38-

Table 16 - Retail Revenue Meters OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Retail Revenue Meters	10.4	10.3	8.9	11.2	11.1	12.2

Table 17 - Wholesale Revenue Meters OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Wholesale Revenue Meters	2.3	1.9	2.1	2.2	2.3	2.4

a) Please explain why retail revenue meter costs increase in 2023 by over 20% since 2018 whereas wholesale meter costs stay relatively the same over the same period. What is different about these two types of metering that result in such different outcomes?

E-VECC-68

Reference: Exhibit E-3-3, page 7

Table 5 - Summary of Distribution Standards OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Distribution Standards Program	0.6	0.2	0.5	1.2	1.4	1.5

a) Please provide a list of the inventory of documents ("*standards and guidelines*"). Please also provide the expected date of revisions for each of the items in the inventory.

b) Is all the work on updating these standards and guidelines done internally?

<u>Common</u>

E-VECC-69

Reference: Exhibit E-4-1

Table 1 - Summary of Total Common and Other OM&A Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Common Corporate Functions & Services (CCF&S)	203.4	192.6	183.9	206.5	207.8	214.6
Planning	46.8	40.2	39.5	39.0	41.1	42.5
Information Solutions	125.5	136.2	131.2	137.4	134.9	141.8
Cost of Sales - External Work	18.8	9.0	11.8	10.4	9.3	10.1
Other OM&A	-222.5	-256.1	-195.6	-239.4	-247.4	-203.0
Total[2]	**172.1**	**121.9**	**170.7**	**153.9**	**145.8**	**206.1**
Year over Year Change		**-29.2%**	**40.0%**	**-9.8%**	**-5.3%**	**41.4%**

a) Please map the categories in Table 1 above to the associated categories for TX and DX Appendix 2-JC - OM&A Programs tables.

E-VECC-70
Reference: Exhibit E-3-4, page 6

Table 4 - Third Party Support OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Third Party Support P(2)	15.5	15.9	17.6	24.7	23.8	25.0

a) Please provide the cost of the "new density review program" as well as the business case or budget for this program.
b) What is the incremental cost of the myAcount portal changes in each year beginning 2019 (using 2018 as the starting point)?
c) What is the most common complaint about myAccount? How are these concerns being addressed over the term of the rate plan?

E-VECC-71

Reference: Exhibit E-3-4,

a) What is the default billing option offered to a new residential account?
b) Please show how many customers in 2021 are on e-billing and paper billing.

E-VECC-72
Reference: Exhibit E-2-2, page 3, 40-

Table 6 - Regulatory Compliance (LEAP) OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Regulatory Compliance (LEAP)	4.4	2.2	0.5	2.5	2.5	2.7

a) Is the United Way of Greater Simcoe the only recipient agency of Hydro One LEAP funding? If yes, does this agency distribute funds for all regions served by Hydro One?
b) Please provide the correspondence from the Ontario Energy directing the suspension of LEAP payments in 2020.
c) The LEAP funding in 2018 is particularly high as compared to the required $1.9 million (0.12% of approved revenue requirement). Please explain why.

E-VECC-73
Reference: Exhibit E-2-2, page 3, 40-

Table 7 - Net Bad Debt OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Net Bad Debt	13.6	16.9	31.8	15.4	15.1	18.0

a) Leaving aside the anomalous peak pandemic year of 2020 - the three-year average bad debt amount would be approximately $15.3M. The evidence on this issue suggests the incorporation of ongoing pandemic circumstances into the calculation of bad debt in 2023 and beyond. Given the current year's forecast of bad debt is close to the three-year average (absent 2020) why is 2021 not the better estimate of the bad debt over the period of the rate plan?

E-VECC-74
Reference: Exhibit E-4-2, page 15

Table 7 - Summary of Allocated Human Resources Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission	**10.4**	**10.9**	**12.4**	**10.2**	**11.0**	**12.4**
Change Year over Year		5.1%	14.0%	-17.8%	8.0%	12.3%
Allocated to Distribution	**9.7**	**9.0**	**9.7**	**10.0**	**10.8**	**12.1**
Change Year over Year		-7.1%	7.7%	2.5%	8.0%	12.6%
Allocated to Other	**1.4**	**2.3**	**1.8**	**1.6**	**1.7**	**1.8**
Total	**21.5**	**22.2**	**23.9**	**21.7**	**23.5**	**26.3**

a) What steps is Hydro One taking to reducing HR costs over the term of the rate plan?
b) By how much in each year after 2023 are HR costs estimated to be reduced from productivity savings?
c) What is the allocator of HR costs to the DX and TX operations?

E-VECC-75

Reference: Exhibit E-2-2, page 3, 40-

Table 8 - Summary of Allocated Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission						
Indigenous Relations	1.0	0.9	0.7	1.8	1.6	1.7
Communications and Stakeholder Relations	3.1	3.1	3.3	4.8	5.0	5.2
Outsourcing Services	0.4	0.4	0.4	0.7	0.7	0.7
Total	**4.6**	**4.5**	**4.4**	**7.2**	**7.3**	**7.6**
Change Year over Year		**-2.7%**	**-0.3%**	**61.2%**	**2.4%**	**3.3%**
Allocated to Distribution						
Indigenous Relations	1.7	1.5	1.1	1.3	1.2	1.3
Communications and Stakeholder Relations	5.1	5.3	5.1	5.0	5.3	5.5
Outsourcing Services	0.7	0.7	1.0	0.5	0.6	0.6
Total	**7.5**	**7.5**	**7.2**	**6.9**	**7.1**	**7.3**
Change Year over Year		**-0.3%**	**-3.7%**	**-4.8%**	**2.9%**	**3.1%**
Allocated to Other	**0.1**	**0.2**	**0.2**	**0.6**	**0.7**	**0.7**
Total	**12.2**	**12.2**	**11.9**	**14.7**	**15.1**	**15.6**

a) What accounts for the much larger increase since 2018 in “Communications and Stakeholder Relations” allocated to Transmission as compared to that for Distribution?

E-VECC-76
Reference: Exhibit E-2-2

Table 13 - Summary of Allocated Facilities and Real Estate Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission						
Real Estate	7.4	8.6	9.1	7.9	8.4	8.7
Facilities	25.3	26.0	25.3	28.3	28.9	30.0
Total	**32.7**	**34.7**	**34.3**	**36.2**	**37.3**	**38.7**
Change Year over Year		6.1%	-1.0%	5.4%	2.9%	3.8%
Allocated to Distribution						
Real Estate	1.2	1.4	1.0	1.2	1.3	1.3
Facilities	24.0	24.7	24.2	27.8	28.4	29.5
Total	**25.2**	**26.1**	**25.2**	**29.0**	**29.7**	**30.8**
Change Year over Year		3.6%	-3.4%	15.1%	2.3%	3.8%
Allocated to Other	**0.0**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**
Total	**57.9**	**60.9**	**59.6**	**65.3**	**67.0**	**69.5**

a) What are the cost drivers explaining the material increase in facilities costs in 2023 as compared to 2018?
b) What is the cost allocator for this group of costs and why are no Facilities and Real Estate costs allocated to 'Other'?

E-VECC-77
Reference: Exhibit E-4-2 Attachment 1

Table 5: Summary of Benchmark Results (2019 Costs)

Function	**Normaliser**	**Hydro One**	**1st Quartile**	**Median**	**3rd Quartile**
Corporate Management	$M of Revenue	$2,701	$1,232	$2,490	$4,692
Finance	$M of Revenue	$5,777	$4,472	$5,777	$8,371
Real Estate	# of Employees	$1,150	$1,205	$1,983	$3,630
Human Resources	# of Employees	$2,612	$2,601	$3,226	$4,538
Legal	$M of Revenue	$2,048	$2,170	$2,848	$3,649
Regulatory Affairs	$M of Revenue	$1,695	$1,107	$1,695	$2,088
AM Planning	$M of Net Assets	$1,598	$1,529	$2,749	$5,774
Corporate Affairs	# of Customers	$6.2	$6.0	$9.4	$15.2
System Operations	Circuit kM	$323	$304	$321	$429

a) Please recast the Table 5 removing the utilities who declined to participate – i.e., Hydro Ottawa and Toronto Hydro.
b) Please explain what exchange rate was used to convert U.S. values into Canadian dollars. How does a change in the Cdn-US exchange rate impact the results shown in Table 5?

E-VECC-78

Reference: Exhibit E-2-2, page 3, 40-

Table 3 - Operations Costs Allocated to Distribution ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Operations	20.7	18.4	18.4	23.8	25.9	27.0
Operations Support	14.8	16.4	13.6	14.5	14.2	12.4
HSE	1.8	1.9	1.0	1.3	1.3	1.3
Total Allocated to Distribution	**37.3**	**36.6**	**33.0**	**39.7**	**41.3**	**40.8**

a) Please confirm that the 'Operations Support' line in Table 3 includes the line 'Smart Grid ' in Appendix 2-JC DX (i.e., E-03-01-01A_20210805.XLSX).

b) Appendix 2-JC shows that 'Smart Grid' spending has declined precipitously since 2018. What are the reasons for this?

E-VECC-79

Reference: Exhibit E-5-1

a) If Hydro One is a member of the Electricity Distributors Association please provide the annual fees for 2018 through 2023.

E-VECC-80

Reference: Exhibit E-5-1, page 10-

"*Hydro One opted for a benchmarking review of Inergi fees for the supply chain services SOW. The report was completed October 2020 by Information Services Group Inc. (ISG), an outsourcing advisory firm, retained as an independent third party to undertake the review*."

a) If not already in evidence, please provide the referenced benchmarking report.
b) Was there any termination or penalty costs associated with the ending of the Inergi Agreement? If so please explain in what year those costs were expensed.

E-VECC-81
Reference: Exhibit E-6-1, page 18

Table 1 - Actual and Planned FTEs for 2019 to 2027

Type	Representation	2019 Actual	2020 Actual	2021 Plan	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan	2027 Plan
Regular	MGT/Non-Represented	613	647	724	760	765	760	760	763	763
	Society	1425	1449	1674	1771	1781	1783	1791	1817	1841
	PWU	3534	3603	3704	3748	3737	3720	3718	3703	3674
	Total Regular	**5572**	**5699**	**6103**	**6280**	**6283**	**6264**	**6269**	**6283**	**6278**
Casual	PWU Hiring Hall	1373	1197	1329	1300	1388	1397	1480	1602	1524
	CUSW	936	948	938	911	912	912	912	912	912
	EPSCA	217	223	198	192	192	192	192	192	192
	LIUNA	272	291	247	237	237	237	237	237	237
	Total Casual	**2798**	**2659**	**2712**	**2639**	**2729**	**2738**	**2820**	**2943**	**2864**
	Temporary	194	152	175	158	159	158	157	157	157
Total		**8564**	**8509**	**8990**	**9077**	**9171**	**9160**	**9247**	**9383**	**9299**

a) Using Table 1 please show the number of repatriated FTEs in each year (e.g., from Inergi etc.).

E-VECC-82
Reference: Exhibit E-6—s Table 1, page 18 & E-5-6-1 Attachment 2B Table 1

a) The two tables referenced appear to have slightly different sum totals of FTEs (e.g., 2023 Table 1 FTE's = 9171; whereas 2023 Table 1 Attachment 2B 2023 FTE's are 4,285+4,830 =9,115). Please explain the reasons for the difference in these two presentations.

E-VECC-83
Reference: Exhibit E-3-1

a) What was the incremental operating cost for the Acquired Utilities in each year 2018 through 2023?

b) Are these amounts included in each presented in Appendix 2-JC (DX)?

EXHIBIT F – COST OF CAPITAL

F-VECC-84

Reference: Exhibit F-1-1

a) What is Hydro One's current projection of its 2021 regulated ROE for the DX and TX operations?

F-VECC-85

Reference: Exhibit F-1-1

"Hydro One is considering a proposal for a midterm update to the 2026 and 2027 cost of capital parameters. Hydro One will indicate prior to the hearing of the Application whether or not it intends to proceed with that proposal. If so, Hydro One would provide information on its updated actual and forecasted debt issuances, the latest economic forecasts then available, as well as its full rationale for requesting the midterm update."

a) Hydro One is required to put a rate plan before the Ontario Energy Board sufficient to provide notice of that proposal to ratepayers. What is current proposal with respect to a mid-term update?
b) Please explain when (date by month) the Applicant would be seeking to amend its application to change its current proposal and what notification to the public of that change it intends to make of that change.

EXHIBIT G - DEFERRAL AND VARIANCE ACCOUNTS

G-VECC-86

Reference: G-1-2 & C-7-1, pages 7-

a) Hydro One is seeking a new Distribution Connection Cost Agreement (CCA) akin to Transmission CCRA Variance Account. Is Hydro One aware of any other Ontario distribution utility which has a similar account?
b) What is the rationale for Hydro One Distribution to have such an account if other regulated distributors do not have a similar account? Why is Hydro One different from other LDCs in Ontario?

c) For each of the last 5 years 2016-20 please list the number of Connection Cost Agreements that required trueing up and the associated amount of the true-up (i.e., show the materiality of the account had it been in place since 2016). In showing the cost impacts, please show the load true-up impact separate from any tax impacts.

G-VECC-87

Reference: G-1-2 & C-7-1, pages 7-

Preamble: "*The variance account will not include the impact of the Notional Account, section 6.5.7 of the TSC, prior to the final true up. Notional Accounts do not trigger a payment by Hydro One and therefore do not adjust rate base nor result in a tax implication. This account will also not include the impact of the Initial Economic Evaluation (IEE) based upon actual costs as the capital contributions can be forecasted based on initial customer commitments in their individual contract and will not trigger an immediate tax obligation as these are collected within the time frame allowed under the Income Tax Act. For capital contributions collected in accordance with TSC Section 6.5.2 for the IEE as well as when the transmitter subsequently recalculates the customer capital contribution based on actual cost, these are individually disclosed for each project in the relevant Investment Summary Documents. Each of these capital contributions is an offset to rate base when the asset is placed into service*."

a) We are unclear how the two adjustments described in above paragraph work. If possible, please provide an example from a past circumstance showing how entries into the account would be made. If an actual circumstance is not available please show a theoretical circumstance showing how the account books entries.

G-VECC-88

Reference: G-1-2, page 42 – Depreciation Expense (Asset Removal Cost) Variance Account

Hydro One is seeking to establish a new depreciation expense (asset removal) variance account.

a) Is Hydro One aware of any other Ontario distribution utility with a similar similar account approved by the OEB?
b) Please show the annual variance that would have been booked into this account had it been approved at the last distribution cost of service application.

G-VECC-89

Reference: Exhibit G, Tab 1, Schedule 1, Attachment 3, pages 2-4
EB-2016-0160, Exhibit I, Tab 12, Schedule 29 a)
EB-2016-0160, Exhibit I, Tab 12, Schedule 28 f)

a) Please confirm that the cumulative CDM values in Table 1 only reflect savings due to EE programs and codes & standards (C&S). If not confirmed, what sources of savings do the values represent and reconcile with the response to VECC 29 from EB-2016-0160?

b) In terms of the EE program contribution to the annual values set out in Table 1, are they meant to reflect: i) both the incremental impact of the CDM programs in the year along with any (negative) impact due to the loss of persistence of savings achieved in prior years or ii) do they simply reflect the sum of the annual CDM savings in each year with no allowance for loss of persistence in savings from previous years' programs.

c) The Application states that "the difference between the incremental change in actual EE monthly peak savings and <u>the incremental change in monthly peak amounts assumed in the approved forecast</u> was used to calculate the revenue impact tracked in the CDM and DR Variance Account" (emphasis added). According to the response to VECC 28 f) (per EB-2016-0110), the incremental EE peak savings over 2016 that were included in the forecast for 2018 were 92 MW. Please confirm that this was the case. If not confirmed what was the incremental amount included in the EB-2016-0110 load forecast for 2018?

G-VECC-90

Reference: Exhibit G, Tab 1, Schedule 1, Attachment 3, pages 2-4

Preamble: The Application states that "*the difference between <u>the incremental change in actual EE monthly peak savings</u> and the incremental change in monthly peak amounts assumed in the approved forecast was used to calculate the revenue impact tracked in the CDM and DR Variance Account*" (emphasis added).

a) According to the text on page 2 states that Footnote 4 contains a web-link for the sources of the actual EE savings for 2018 and 2019. However, the link itself is a link to multiple reports for both 2018 and 2019. Please indicate which specific reports are the sources of the EE savings for 2018 and 2019. If a single report is the source for each year, please provide the title and page reference. If multiple sources were used for each year please provide schedules setting to the derivation of each year's actual EE savings with reference to the reports (including page numbers) where each input used can be found.

b) Please provide the reports (and associated page numbers) supporting the EE actual 2016 peak savings used in Table 2. If multiple sources were used for 2016 please provide schedules setting to the derivation of the year's actual EE savings with reference to the reports (including page numbers) where each input used can be found.

c) Do the actual EE peak savings for 2016 in Table 2 reflect: i) the EE peak demand impact of programs implemented in 2016 or ii) the cumulative impact in 2016 of CDM programs implemented over the period 2006-2016? If the later, does the cumulative impact account for losses in persistence of savings from EE implemented prior to 2016.

d) Do the actual EE peak savings for 2018 in Table 2 reflect: i) the EE peak demand impact of programs implemented in 2018; ii) the cumulative impact in 2018 of CDM programs implemented over the period 2016-2018 or iii) the cumulative impact in 2016 of CDM programs implemented over the period 2006-2018? If either (ii) or (iii), does the cumulative impact account for losses in persistence of savings from EE implemented prior to 2018?

G-VECC-91

Reference: Exhibit G, Tab 1, Schedule 1, Attachment 3, pages 2-4

Preamble: The Application states that (page 2) "*the difference between the incremental change in actual EE monthly peak savings and the incremental change in monthly peak amounts assumed in the approved forecast was used to calculate the revenue impact tracked in the CDM and DR Variance Account*" (emphasis added).

The Application also states (page 4): "*Consistent with the methodology previously approved by the OEB in calculating the 2017 peak savings amounts, the difference between the forecasted and actual peak savings is the variance amount used for the calculation.*"

a) The calculation in Table 2 simply compares the 2016 actual EE peak savings in 2018 with the actual saving in 2016. This appears to be inconsistent with the calculation as described in the Application (per the Preamble) with compares actual vs. forecast savings differences. Please reconcile and explain how Table 2 capture the difference for 2018 as between the EE peak savings included in the load forecast and the actual EE peak savings.

G-VECC-92

Reference: Exhibit G, Tab 1, Schedule 1, Attachment 3, pages 3-4

a) Pages 3-4 describe the calculation of the actual ICI amounts. Please provide a schedule setting out the actual calculation for 2018.

G-VECC-93

Reference: Exhibit G, Tab 1, Schedule 1, Attachment 3, page 4

> Preamble: The Application states: "*The IESO provided Hydro One with the information related to the demand measures that were dispatched over the 2016-2019 timeframe. The demand measures include both the dispatchable loads and the resources secured through the demand response auction. The difference between 2018 and 2019 versus 2016 is used to calculate the revenue impact tracked in the CDM and DR Variance Account.*"

a) Are the amounts shown for 2016, 2018 and 2019 the amounts actually dispatched in each month or the amounts under contract that could be dispatched if required?

G-VECC-94

Reference: G-1-4

a) Hydro One proposes to dispose of its Distribution credit balance of $87.7M over 5 years. While this may mitigate rate impact from the proposed rate increase of the Utility it also increases intergenerational inequities. For the period 2017 to 2021 (to date). Please provide the annual number of (1) account closures; (2) Account openings; (3) Account name changes. For the combined residential classes.
b) Based on the current proposal please show the distribution residential rate impacts (750kWh) if the credit was disposed of over a three-year period.

EXHIBIT H - COST ALLOCATION AND RATE DESIGN TRANSMISSION

H-VECC-95

Reference: Exhibit H, Tab 1, Schedule 2, page 2

Preamble: The Application states: "*A key activity in determining the rates revenue requirement for each rate pool is the process of grouping similar physical assets owned by Hydro One into functional categories. The assignment of functional categories is based on the normal system operating condition of assets in-service as of the end of 2020, with due consideration given to the OEB Decision in Proceeding EB-2011-0043 in regards to the expanded definition of Network assets, the electrical system and customer connectivity, and the load forecast data for the 2023 test year*".

a) Please clarify what is meant by "normal system operating condition".

b) Were or are any new Transmission assets (lines and/or stations) placed/forecast to be placed in service between the end 2020 and the 2023 test year?

   i. If yes, please explain the basis on which they are functionalized.

H-VECC-96

Reference: Exhibit H, Tab 1, Schedule 2, pages 2-11

a) Please confirm that the definition of what are Network Assets, Dual Function Assets, Line Connection Assets, Transformation Connection Assets, Generation Line and Transformation Connection Assets and Common Assets has not changed from that used in EB-2019-0082.

   i. If not confirmed, please explain what the changes are and how they impact the cost functionalization as shown in Table 2.

b) Please confirm that the methodology used to allocate the cost of Dual Function Assets as between Network and Line Connection has not changed from that used in EB-2019-0082.

   i. If not confirmed, please explain what the changes are and how they impact the cost functionalization as shown in Table 2.

c) Please confirm that the methodology used to allocate the cost of (shared) Generation Line and Transformation Connection Assets Dual Function Assets as between Generators and Load Customers has not changed from that used in EB-2019-0082.

i. If not confirmed, please explain what the changes are and how they impact the cost functionalization as shown in Table 2.

H-VECC-97

Reference: Exhibit H, Tab 1, Schedule 3, page 5

Preamble: The Application states: "*This Section provides the annual mid-year net book value and transmission rates revenue requirement for each of the three rate pools: Network, Line Connection, and Transformation Connection. For 2023, this is derived using the methodology described above in Section 2. For the remaining years, 2024 to 2027, the net book value and the transmission rates revenue requirement have been allocated among the three rate pools using the same percentage split as 2023*".

a) Please provide a schedule that set out for the years 2024-2027 the net book value of assets forecast to come into service after 2023.

b) With respect to the schedule provided in response to part (a), please provide a breakdown of the total for each year (2024-2027) as between Network, Line Connection, Transformation Connection, Common and Other Assets.

c) Based on Hydro One's investment plans for 2024-2027, is the assumption that the split of the net book value and revenue requirement in each of these years will be the same at that in 2023 reasonable and why?

H-VECC-98

Reference: Exhibit H, Tab 2, Schedule 1

a) Please provide a schedule that lists the new Transmission Lines that were not included in EB-2019-0082. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Lines whose functional categorization has changed from that in EB-2019-0082 and provide an explanation as to the reason for the change

H-VECC-99

Reference: Exhibit H, Tab 2, Schedule 2

a) Please provide a schedule that lists the new Transmission Stations that were not included in EB-2019-0082. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Stations whose functional categorization has changed from that in EB-2019-0082 and provide an explanation as to the reason for the change

H-VECC-100

Reference: Exhibit H, Tab 3, Schedule 1

a) Please provide a schedule that lists the new Dual Function Lines that were not included in EB-2019-0082. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional categorization percentages it has been assigned and indicate why.

b) Please provide a schedule that lists those Dual Function Lines whose functional categorization percentages have changed from that in EB-2019-008 2 and provide an explanation as to the reason for the change.

H-VECC-101

Reference: Exhibit H, Tab 3, Schedule 2

a) Please provide a schedule that lists the new Generator Line Connections that were not included in EB-2019-0082. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional categorization percentages it has been assigned and indicate why.

b) Please provide a schedule that lists those Generator Line Connections whose functional categorization percentages have changed from that in EB-2019-0082 and provide an explanation as to the reason for the change.

H-VECC-102

Reference: Exhibit H, Tab 3, Schedule 3

a) Please provide a schedule that lists the new Generator Station Connections that were not included in EB-2019-0082. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional categorization percentages it has been assigned and indicate why.

b) Please provide a schedule that lists those Generator Station Connections whose functional categorization percentages have changed from that in EB-2019-0082 and provide an explanation as to the reason for the change.

H-VECC-103

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

a) Please explain why it is reasonable to allocate the External Revenues and Regulatory Assets Balance on the basis of the total revenue requirement split by rate pools.

H-VECC-104

Reference: Exhibit H, Tab 7, Schedule 1
Exhibit D, Tab 4, Schedule 1, page 17

a) Do the forecast values for the Charge Determinants set out in Table 3 (Exhibit D, Tab 4, Schedule 1) include the load requirements for generators?

   i. If yes, please confirm that the values in Table 3 are meant to be equal those set out in Table 1 from Exhibit H, Tab 7, Schedule 1.

   ii. If not, please confirm that the Charge Determinants set out in Table 1 from Exhibit H, Tab 7, Schedule 1 are equal to the Charge Determinants set out in Table 3 (Exhibit D, Tab 4, Schedule 1) plus an allowance for the load requirements of generators. Also, please indicate how these requirements were determined.

H-VECC-105

Reference: Exhibit H, Tab 9, Schedule 1, page 6

Preamble: The Application states: "Hydro One's ETS revenue, used for establishing the rates revenue requirement proposed in this

Application, is calculated using the currently approved tariff of $1.85/MWh and the three year historical rolling average volume of electricity exported from Ontario".

a) Please provide a schedule setting out the historical export volumes for the most recent five years.

b) Please provide the export volumes used to determine the forecast annual ETS revenues for 2023 to 2027 and the basis for the "three year rolling average used for each.

H-VECC-106

Reference: Exhibit H, Tab 10, Schedule 1, page 1

Preamble: Table 1 shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer.

a) The Commodity cost included in Table 1 is referred to as the "YTD Weighted Average Rate". Please explain what is meant by "YTD".

   i. If it is not the full year value for 2019, please provide the full year value if it is now available.

b) With respect to the Wholesale Transmission Charge in Table 1, is the 1.06 cents/kWh the average cost of transmission for 2019?

   i. Will the value be higher/lower for individual transmission customers based on the load factor for the customer and whether the customer is charged transformation connection and/or line connection charges? If yes, is there any estimate available as to the possible variation?

c) With respect to the Distribution Service Charges in Table 1, is the 3.02 cents/kWh an average across all customer classes and all utilities?

   i. Will the value be higher/lower for specific customer classes in specific distribution utilities? If yes, is there any estimate available as to the possible variation?

EXHIBIT L -DISTRIBUTION COST ALLOCATION AND RATE DESIGN

L –VECC -107

Reference: Exhibit L, Tab 1, Schedule 1, page 2
Exhibit L, Tab 1, Schedule 2, pages 3-4
Exhibit L, Tab 2, Schedule 1, page 18
Exhibit L, Tab 7, Schedule 1, Attachment 1, page 8 of 22
Exhibit L, Tab 7, Schedule 2, Attachment 1, page 8 of 22

Preamble: The Application states (L/1/1, page 2): "*In this Application, Hydro One proposes to remove the requirement for Sub-Transmission (ST) customers to own their local transformation from the ST rate class eligibility requirements. This proposed change responds to customer feedback and is consistent with other distributors' local transformation options for connecting larger customers*."

The proposed 2023 ST Tariff Schedule (L/7/2/1/1) describes ST customers as:
"*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; 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 500 kW)."

The currently approved ST Tariff (L/7/1/1) describes ST customers as:
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 directly connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive; the meaning of "directly includes Hydro One not owning the local

transformation; 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 500 kW*)."

a) It is noted that under both definitions a non-embedded distributor ST customer is connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive. The only difference in the definitions appears to be the elimination of "directly" from the new description. Please describe more fully the types of local transformation (e.g., high/low voltages, proximity to customer, etc.) that Hydro One can own under the new definition (but not the old definition) where the customer will now be classified as an ST customer.

b) Hydro One claims that this revised definition is "and is consistent with other distributors' local transformation options for connecting larger customers". Has Hydro One Distribution surveyed the customer connection and classification practices of other Ontario electricity distributors with large customers served between 44 kV and 13.8 kV and, if yes, what were the results in terms of the requirement that the customer own their local transformation?

c) Please describe the quantity, types and value (NBV or GBV) of "local transformation" assets that are included in Hydro One Distribution's proposed revenue requirement for each of the years 2023-2027 that are assumed to be associated with service to ST customers based on this revised definition. Also, as applicable, please distinguish between assets in-service as of December 31, 2022, assets that will be constructed by Hydro One Distribution over the 2023-2027 period, and assets that are currently owned by customers but it is assumed Hydro One Distribution will purchase over the 2023-2027 period.

d) Are any of the customers in Hydro One Distribution's General Service classes required to own their own local transformation?
   i. If yes, for which customers does this requirement apply?
   ii. If yes, why isn't a similar option being extended to these customers as well?

L –VECC -108

Reference: Exhibit L, Tab 1, Schedule 2, page 2
Exhibit L, Tab 7, Schedule 1, Attachment 1, page 7

Preamble: The Application defines the Distributed Generation class as: "*Includes all customers with generation capacity above 10kW*".

The Tariff Sheet for the Distributed Generation class states: "*This classification applies to an embedded retail generation facility connected to the distribution system that is not classified as MicroFIT generation*."

a) Does the Distributed Generation class only include retail generation facilities (i.e., facilities/customers whose primary business is the generation and sale of power)?

b) Does Hydro One Distribution purchase power from customers/facilities that have behind the meter generation and whose primary business is not the generation and sale of power?

c) If yes, how does Hydro One Distribution determine that a customer is a "retail generator"?

L -VECC -109

Reference: Exhibit D, Tab 5, Schedule 1, page 37 (Table E.3)
Exhibit L, Tab 1, Schedule 2, pages 2 and 5

Preamble: The Application states (L/1/2, page 2): "*On an annual basis, Hydro One will create or modify rate class boundaries for known areas of customer growth and ensure that affected customers are reclassified accordingly. Outside of the annual review, there is also an opportunity to update the density boundaries in response to customer inquiries to Hydro One's call centre*".

a) When (i.e., in what month/year) was the rate class boundary review done and the boundaries revised that established the geographic class boundaries as used for purposes of setting the 2018 rates (per EB-2017-0049)?

b) Please provide a schedule that sets out from point in time identified in part (a) to the preparation of the current Application, each time the rate class geographic boundaries were revised. As part of the response, please indicate for each revision: i) whether it was the result of an annual review or a customer query to the call centre, ii) what was the net impact of the resulting reclassification of customers on the customer count for the UR, R1 and R2 classes and iii) how the new boundary "lines" were determined.

c) What was the net impact of these boundary revisions on the customer counts for UR, R1 and R2 in each of the years 2018 through 2020?

d) Do the 2020 customer counts for the UR, R1 and R2 customer classes as set out in Table E.3 fully reflect the results of the most recent boundary review?

e) Please provide a break out of the 2020, 2021 and 2022 Seasonal customer count (per Table E.3) into the three Residential geographic areas (UR, R1 and R2).

f) Please for each of the years 2023-2027 please provide a breakdown of the "seasonal customers" (i.e., those that do not meet the year-round definition) included in each of the UR, R1 and R2 classes.

g) Have there been any changes to the geographic Residential customer class boundaries as a result of either annual reviews or customer inquiries to the call centre since the preparation of the current Application.

   i. If yes, what is the net impact of the resulting reclassification of customers on the customer count for the UR, R1 and R2 classes?

   ii. If yes, has this changed the break-out of Seasonal customers to the UR, R1 and R2 classes as shown in Table 1 (L/1/2, page 5).

h) When is the next annual boundary review scheduled to take place?

L -VECC -110

Reference: Exhibit L, Tab 1, Schedule 2, pages 6-7

Preamble: The Application states: "*Customer density for former Norfolk Power was 25 customers/km of line (Source: 2014 Yearbook of Electricity Distributors), and it was 12 customers/km of line for former Haldimand County Hydro (Source: 2015 Yearbook of Electricity Distributors)*."

a) Based on its own GIS system, can Hydro One Distribution provide more update values as to the customer density for the former Norfolk Power and Haldimand County Hydro? If yes, please do so.

b) Please provide a schedule that, using the most recent year for which comparable data is available, set out for each of Norfolk, Haldimand and Woodstock: i) the OM&A per customer and iii) NBV of Distribution Assets per customer.

L -VECC -111

Reference: Exhibit D, Tab 5, Schedule 1, page 37 (Table E.3)
Exhibit L, Tab 1, Schedule 3, Attachment 1, Tab I6.2

a) The 2023 Street Light customer count differs as between Table E.3 (5,494) and Tab I6.2 (CAA-20,653). Please explain why.

b) The 2023 Sentinel Light customer count differs as between Table E.3 (19,409) and Tab I6.2 (CAA-9,705). Please explain why.

L -VECC -112

Reference: Exhibit D, Tab 5, Schedule 1, page 37 (Table E.3)
Exhibit L, Tab 1, Schedule 3, Attachment 1, Tab I7.1

a) The 2023 ST customer count differs in Table E.3 (910)) differs from the ST meter count in Tab I71 (608). Please explain why.

L -VECC -113

Reference: Exhibit L, Tab 1, Schedule 3, Attachment 1, pages 4-5
EB-2017-0049, JT 3.18-9 a)

Preamble: The Application states: "*The Services weighting factors, as well as the Billing and Collecting weighting factors (CAM sheet I5.2), for the six new acquired rate classes, have been established by adopting values from similar existing Hydro One rate classes. The Services weighting factors for all Hydro One existing rate classes remain unchanged from the factors used in the 2018 CAM. These factors reflect an estimate of the relative cost of services assets provided by Hydro One to its rate classes. The weighting factors for the residential classes are based on an estimated relative service connection length of 30, 15 and 10 metres for R2, R1 and UR customers, respectively*."

JT 3.18-9 a) states: "*The Services weighting factors are based on an estimated relative service connection length of 30, 20, 15,and 10 metres for the R2, Seasonal, R1 and UR customers, respectively, as described in Exhibit G1, Tab 3, Schedule 1 of Hydro One's last distribution application EB-2013-0416*."

a) Please confirm that assigning Seasonal customers to the UR, R1 and R2 classes does not change the Services assets used by these customers.

b) If confirmed, why is it appropriate to assume previous Seasonal customers now have a weighting factor for Services equivalent to the Residential class they are being assigned to?

L -VECC -114

Reference: Exhibit D, Tab 5, Schedule 1, page 37 (Table E.3)
Exhibit L, Tab 1, Schedule 3, page 7 & Attachment 1, Tab I7.2
EB-2016-0315, Report on Elimination of the Seasonal Class, page 39
EB-2017-0049, Exhibit G1, Tab 1, Schedule 3, Attachment 3

a) Please explain the basis for the number of manual meter reads in 2023 by rate class as used in Tab I7.2.

b) The Report on the Elimination of the Seasonal Class contained various options regarding the frequency of meter reading for Seasonal customers after the class was eliminated. What assumptions are used in the 2023 Cost Allocation model regarding the frequency of meter reading for Seasonal customers assigned to each of the UR, R1 and R2 classes?

c) In the 2018 CAM, what was the weighted average cost of meter reading for each of the UR, R1, R2 and Seasonal classes?

d) In the current 2023 CAM, please confirm that the 2018 CAM weights for the UR, and R2 classes were also applied to the Seasonal customers assigned to each class.

   i. If confirmed, please explain why this is appropriate – particularly if the 2018 CAM weight for Seasonal differed from those used for the other Residential classes.

e) Are there costs associated with obtain the readings for meters that are not read manually?

   i. If not, why not?

   ii. If yes, in what USOA account(s) are they recorded and what was the total cost for 2020 by USOA?

L -VECC -115

Reference: Exhibit L, Tab 1, Schedule 3, page 7 & Attachment 1, Tab I7.1

a) Please explain why the smart meter costs are different for the various Residential classes (including the acquired classes). As part of the response, please explain why for Hydro One Distribution's existing classes meter costs for R1 are greater than for UR but for the acquired classes the smart meter cost for AR are less than those for AUR.

L -VECC -116

Reference: Exhibit D, Tab 5, Schedule 1, page 37 (Table E.3)
Exhibit L, Tab 1, Schedule 3, pages 5-7 & Attachment 1, Tab I5.2
EB-2016-0315, Report on Elimination of the Seasonal Class, page 39

a) Please explain the basis for the 2023 number of bills by rate class as used in Table 2 (L/1/3, page 6).

b) The Report on the Elimination of the Seasonal Class contained various options regarding the frequency of billing for Seasonal customers after the class was eliminated. What assumptions are used in the 2023 Cost Allocation model regarding the frequency of billing for Seasonal customers assigned to each of the UR, R1 and R2 classes?

L -VECC -117

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

Preamble: The Application states: "*The density factors for all existing density-based rate classes remain unchanged from the factors used in the 2018 CAM given there have been no material changes to the relative asset use, maintenance and operation of the distribution system by rate class*."

a) Please explain what is meant by "relative asset use".

b) Please provide the data/analysis that Hydro One Distribution has relied on to make the claim referenced in the Preamble.

c) Please provide a schedule that sets out the following data for Hydro One Distribution system for when the original density study was prepared, for when the 2018 CAM was prepared and for now: i) the total number of customers in each of Hydro One Distribution's density zones, ii) the number of km of line in each of Hydro One Distribution's density zones, and iii) the number of customers per km of line in each of the density zones.

L -VECC -118

Reference: Exhibit L, Tab 1, Schedule 3, pages 8-9
Exhibit L, Tab 1, Schedule 3, Attachment 1, Tab E3

a) Please provide the equivalent to Tables 7 and 8 based on the 2018 CAM.

b) With respect to Tables 7, are the 2,543 distribution feeders used to serve all of Hydro One Distribution's customers, including all of its ST customers?

c) Please explain why the customer count used in Table 7 does not match the values in Tab E for either the total number of bulk customers or the total number of primary customers.

d) With respect to Table 8, how many customers are served from the 526,236 existing transformers?

e) Please explain why the customer count used in Table 8 does not match the CCLT total customer count in Tab E3.

f) Directionally, which rate classes will be allocated a greater proportion of the revenue requirement based on the changes in the PLCC values?

L -VECC -119

Reference: Exhibit L, Tab 1, Schedule 3, page 9
EB-2017-0049, Exhibit G1, Tab 1, Schedule 3, Attachment 3

a) Please provide a schedule that compares, for each USOA, the total costs that are directly allocated in the current cost allocation model vs. those directly allocated in the 2018 CAM.

b) Please provide a schedule that compares, for each rate class, the total costs directly allocated in the current cost allocation model vs. those directly allocated in the 2018 CAM.

c) In the 2018 CAM costs were directly allocated to the Sentinel rate class. However, there is no direct allocation of cost to the Sentinel class in the 2023 CAM. Please explain why.

d) If there has been a material change in the relative portion of costs directly allocated to any of the other rate classes – please explain why.

L -VECC -120

Reference: Exhibit L, Tab 1, Schedule 3, page 3
EB-2017-0049, Exhibit G1, Tab 1, Schedule 3, Attachment 3

Preamble: The Application states (page 3): "*All inputs to the 2023 CAM have been reviewed and updated to reflect Hydro One's 2023 proposed revenue requirement, charge determinants and <u>updated load profiles, which are based on the latest hourly metered data results from legacy Hydro One customers and acquired customers</u>*." (emphasis added)

The Application also states (page 4): "*The Coincident Peak (CP) and Non-coincident Peak (NCP) inputs to the CAM were updated based on the load forecast established for the "new" UR, R1 and R2 residential classes that include the seasonal customers. Hydro One's approach ensures that the CP values for total distribution system remain the same before and after seasonal elimination.*"

a) What was the basis for the updated load profiles (e.g., what years of hourly data were used and how were the data/results weather normalized)?

b) If hourly data was not available for all customers in all customer classes, how were the load profiles established?

c) Please provide the 12CP and 4NCP values for the UR, R1, R2 and Seasonal classes for 2023 assuming the Seasonal class was not eliminated.

L -VECC -121

Reference: Exhibit L, Tab 2, Schedule 1, page 4

Preamble: The Application states: "*Hydro One's development of distribution rates for this application follows generally accepted ratemaking principles*".

a) Please indicate how considerations regarding "efficiency" were taken into account in the development of the distribution rates.

L -VECC -122

Reference: Exhibit L, Tab 2, Schedule 1, pages 5-6 and Attachment 1
EB-2020-0246, Exhibit I, Tab 5, Schedule 7

a) Is the approach used to determine the rates revenue requirement by class for the years 2024-2027 the same as that used in the 2018-2022 CIR?

b) In EB-2020-0246, VECC #7 questioned the bill impacts calculated due to the elimination of the Seasonal class and, as part of the response, Hydro One Distribution stated:

"The inconsistency is due to the methodology approved in Hydro One's last distribution rates application (EB-2017-0049) for adjusting the annual revenue requirement by rate class over the 2019 to 2022 period, and revenue-to-cost ratio adjustments in 2019 and 2020."

Does the approach used in the current Application resolve this inconsistency?

i. If yes, please explain how.
ii. If no, please explain the potential impacts of this inconsistency on the derivation of distribution rates over the 2024-2027 period.

L -VECC -123

Reference: Exhibit L, Tab 2, Schedule 1, pages 5-9 and Attachment 1

Preamble: The description of the determination of the rates revenue requirement by class for the years 2024-2027 on pages 5-6 simply makes reference to the subsequent steps undertaken in Attachment 1 to: i) also allocate the total costs to customer classes, ii) to calculated revenue to cost ratios and iii) adjust the rate revenue requirement by class as required to maintain the OEB's revenue to cost policy ranges.

a) Please confirm that 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. If not confirmed, why not.

b) If confirmed, would it be reasonable to conclude that the cost allocation parameters (e.g., customer/connection count, 12 CP values and 4NCP values) for each customer class will not all change by the same percentage for each year during the 2024-2027 period?

i. If yes, why in Attachment 1 is it reasonable to assume that the costs allocated to each rate class (Column D) will increase by the same amount for each year in the 2024-2027 period?

c) Would it not be simpler and just as accurate to, for each of the years 2024-2027, increase the rates for all customer classes by the same percentage (i.e., the percentage calculated in Step 4 on page 5 of Exhibit L, Tab 2, Schedule 1?

L -VECC -124

Reference: Exhibit L, Tab 2, Schedule 1, pages 9-10
and Attachment 2 (pages 3-4)

a) It is noted that, for the R2 class, the increase in the monthly fixed charge due to the move to a fully fixed rate is $7.92 in 2023 and $8.24 in 2024. Are these increases comparable to the increases that were anticipated when the Board approved the phase-in period for the R2 class?

L -VECC -125

Reference: Exhibit L, Tab 2, Schedule 1, pages 10-11 and 22
Exhibit L, Tab 1, Schedule 3, Attachment 1, Tab O2
Exhibit L, Tab 7, Schedule 2, Attachment 1

a) Please provide a schedule that for each rate class sets out: i) the 2022 approved fixed monthly charge, ii) the proposed 2023 fixed monthly charge and iii) the value for the Customer Unit Cost per month - Minimum System with PLCC Adjustment per Tab O2 of the 2023 CAM.

b) The Application states (page 22): "For the Streetlight, Sentinel light and Unmetered Scattered Load classes, customers will continue to be charged a monthly per account service." If for either of the USL, Sentinel Light or Street Light classes, the fixed charge billing determinant is not the same as the determinant used to calculate the Customer Unit Cost per month - Minimum System with PLCC Adjustment value for the class, please re-calculate the Customer Unit Cost per month - Minimum System with PLCC Adjustment value per Tab O2 using the actual billing determinant for the class.

L -VECC -126

Reference: Exhibit L, Tab 2, Schedule 1, pages 14 and 18-21
Exhibit L, Tab 1, Schedule 3, Attachment 1

Preamble: The Application states (page 14):
"*Under this proposal, while ST customers will continue to be fully responsible for the costs of the local transformation, they will be offered an option to connect to Hydro One owned local transformation. Customers who choose this new option will be subject to a fixed monthly "local transformation charge" and a one-time transformation capital contribution. The derivation of*

this new charge does not affect the methodology used to establish the existing ST rates."

a) With respect to the 2023 CAM, in what USOA (asset) account are the costs of the Hydro One owned local transformation included?

b) How are the costs in the USOA account identified in part (a) allocated to the rate classes? As part of the response, please provide the percentage of the costs that will be allocated to each rate class.

c) Have any changes been made to the 2023 CAM methodology or inputs to reflect the option ST customers will have under the proposal outlined in the preamble.

   i. If yes, please outline what changes have been made and why.

L -VECC -127

Reference: Exhibit L, Tab 2, Schedule 1, pages 19-20
Exhibit L, Tab 1, Schedule 3, Attachment 1

Preamble: The Application states:
"*In addition to the installed capital costs described above, the calculation of the transformation charge also includes the costs associated with keeping spare transformers for ST customers, the costs associated with replacing failed transformers, and the cost associated with the on-going visual inspection of these ST transformers*."

a) Please provide the supporting details/calculations for the annual costs set out in Table 11.

b) What types of overheads were included in the annual costs and did they include an allowance for corporate overheads or general plant?

c) In calculating the transformation charge was any provision made for ongoing maintenance and repair costs over and above the costs of on-going visual inspection?

L -VECC -128

Reference: Exhibit L, Tab 2, Schedule 1, page 20
Exhibit L, Tab 1, Schedule 3, Attachment 1

Preamble: The Application states:
"*For the purposes of cost allocation, the revenue from this new charge will be recorded as a revenue off-set in USofA Account 4220 – "Other Electric Revenue". This revenue off-set has been allocated to all non-ST rates classes in the 2023 CAM to ensure that the incremental costs of supplying local transformation to ST customers are not borne by non-ST customers*."

a) With reference to the 2023 CAM, please indicate where in the model these revenues are included (e.g., what USOA account in Tab I3) and where in Tab E2 the allocation details are documented.

b) Is the allocation factor used for the revenues the same factor as it used to allocate the costs associated with Hydro One Distribution owned local transformation?

L -VECC -129

Reference: Exhibit L, Tab 2, Schedule 1, pages 16

Preamble: The Application states:
"The Common ST Line rate will be adjusted to reflect changes to the HVDS-high charge, as a part of Hydro One's expected annual applications from 2024 for 2027."

a) Please describe how Common ST Line rate will be adjusted to reflect changes in the HVDS-high charge and provide an illustrative example.

L -VECC -130

Reference: Exhibit L, Tab 2, Schedule 1, pages 17-18

Preamble: The Application states:

- "*Customers in the ST class can obtain transformation from above 50 kV to a voltage between 44 kV and 13.8 kV either through the use of a High Voltage Distribution Station, referred to as an "HVDS-high" station, or a TS owned by Hydro One Transmission." (page 17)*
- *"for consistency purposes, the HVDS-high rate is set equivalent to the RTSR – Transformation rate adjusted for*

losses. HVDS-high is a volumetric charge." (page 17)

- *"High Voltage Distribution Station that transforms power from above 50 kV to under 13.8 kV, is referred to as an "HVDS-low" station". (page 18)*
- *"the HVDS-low rate is set to be the sum of the HVDS-high rate and LVDS-low rate." (page 18)*
- *"Low Voltage Distribution Station, referred to as an "LVDS-low" station, transforms power from above (or at) 13.8 kV to under 13.8 kV." (page 18)*
- *"The ST LVDS low portion of the distribution stations costs is based on the gross book value of assets associated with providing ST service from LVDS-low stations as a share of the total LVDS station assets. LVDS-low is a volumetric charge*." (page 18)

a) Overall, do the rates charged for HVDS-high and HVDS-low over or under recover the cost of HVDS stations allocated to the ST class and by how much?

L -VECC -131

Reference: Exhibit L, Tab 2, Schedule 1, pages 23-25

Preamble: The Application states (pages 23-24):
"*The total IESO transmission charges are allocated to each of the distribution rate classes in proportion to their coincident demand to Hydro One's network and connection peaks at the transmission delivery points."*

It also states: "The use of Hydro One's RTSR methodology is important to ensure that ST customers, which include all embedded LDCs supplying their own customers' load, pay an appropriate share of transmission charges levied to Hydro One."

a) Please clarify specifically what demand from each delivery point is used to allocate: i) network costs and ii) line connection and transformation connection costs.

b) Why is the use of Hydro One's RTSR methodology (as opposed to the RTSR Workform) is important to ensure that ST customers, which include all embedded LDCs supplying their own customers' load, pay an appropriate share of transmission charges levied to Hydro One?

c) Is Hydro One Distribution charged RTSRs by other LDCs where Hydro One is an embedded utility (per A/2/3, page 6)?

i. If not, why not?

ii. If yes, how are these charges accounted for in the determination of the Retail Transmission Rates?

L -VECC -132

Reference: Exhibit A, Tab 2, Schedule 3, page 6

Preamble: The Application indicates that Hydro One Distribution is partially embedded in a number of other Ontario electricity distributors.

a) Given Hydro One Distribution is partially embedded in a number of other Ontario electricity distributors, why does Hydro One Distribution not have any LV rates to recover the distribution charges from these utilities? How are any such charges recovered?

L -VECC -133

Reference: Exhibit L, Tab 3, Schedule 1, pages 9-13 and Attachment 3
Exhibit L, Tab 1, Schedule 3, Attachment 1

a) With respect to Attachment 3, Tab 1, are the in-service additions for each year net of retirements? If not, how is retirement of assets over the 2016-2022 period accounted for?

b) With respect to Attachment 3, Tab 2, it is noted that for Woodstock's USOA 1815 the class allocation factors for Norfolk+Haldimand were used. What would be the class allocation if based on the appropriate allocators from Woodstock's last CAM model?

c) With respect to Attachment 3, Tab 5 (lines 20-52) please address the following:

   i. With reference to the various columns please explain how the "bulk assets" attributable to the acquired utilities are calculated. (i.e., how does multiplying the values of the assets specifically related to the acquired utilities (per Tab 3) by the factors derived in Column F and G yield the appropriate proportion of Hydro One Distribution's bulk assets that should be assigned to the acquired utilities?).

   ii. Please explain what the "Bulk Factor" (Column F) is meant to represent and why the formula used yields the desired result. As an illustration, please explain the derivation of the factor for USOA 1830.

   iii. Please explain what Column G is meant to represent and why the formula used yields the desired result.

L -VECC -134

Reference: Exhibit L, Tab 3, Schedule 1, pages 9-13 and Attachment 3
Exhibit L, Tab 1, Schedule 3, Attachment 1

a) Please explain where/how the GFA, NFA and Depreciation Direct Allocation Factors are incorporated into the 2023 CAM for purposes of allocating cost to the six acquired utility rate classes.

b) Are the costs in accounts 1815 to 1860 all allocated to customer classes on the same basis? If not, what are the differences in how the costs in the accounts are allocated?

c) Please provide a schedule that set outs out for each of the accounts 1815 to 1860 the GBV allocated to each of the six acquired utility customer classes per the 2023 CAM.

d) It is noted that the GFA Direct Allocation Factors are calculated based on the aggregate value of the USOA 1815-1860 assets for each customer class. Please provide a schedule that sets out the resulting GFA Direct Allocation Factors by rate class for each USOA – where the values are calculated separately for each USOA.

e) The Application states that "The amount of GFA not assigned to the new acquired rate classes as a result of applying the direct allocation factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes." Please explain where/how this is done in the 2023 CAM.

L -VECC -135

Reference: Exhibit L, Tab 3, Schedule 1, pages 9-13 and Attachment 3

a) Does Hydro One Distribution intend to continue to track the capital additions for the acquired utilities?

b) Please outline how Hydro One Distribution intends to calculate the GFA Direct Allocation Factors for purposes is next rebasing/CIR application.

L -VECC -136

Reference: Exhibit L, Tab 3, Schedule 1, pages 3-7
Exhibit L, Tab 3, Schedule 1, Attachments 1, 2 and 3

a) With respect to Attachment 2, for each of the three acquired utilities please explain how the following values were derived for the end of the deferral period:

i. Depreciation
ii. Cost of Debt
iii. Cost of Equity
iv. Tax
v. Revenue Offsets

b) With respect to Attachment 3, what would be the resulting CAGR based on: i) the average value of all the individual CAGR's used in the Attachment and ii) the median values of all the individual CAGR's used in the Attachment?

c) With respect to Table 3 (L/3/1), please provide a table with separate values for Norfolk and Haldimand.

L -VECC -137

Reference: Exhibit L, Tab 3, Schedule 1, pages 7-8

a) With respect to Table 4 (L/3/1), please provide a table with separate values for Norfolk and Haldimand.

L -VECC -138

Reference: Exhibit L, Tab 3, Schedule 1, pages 8-9

a) Please provide a revised version of Table 5 (L/3/1) that separates out Norfolk and Haldimand.

b) Please provide a revised version of Table 5 (L/3/1) where:

i. The Costs Allocated to the New Acquired Rate Classes is used instead of the Revenues Collected.
ii. If practical, for those acquired customers that will be moving to Hydro One's existing Street Light, Sentinel Light, Unmetered Scattered Load and Sub-Transmission rate classes, an appropriate portion of each class' allocated costs is used instead of an estimate of the revenue collected/costs charged.

L -VECC -139

Reference: Exhibit L, Tab 4, Schedule 1, page 2

a) Hydro One Distribution proposes to maintain SSCs at the 2022 OEB-approved amount for the 2023 to 2027. With the exception of the charges set by the OEB for access to power poles (telecom), and Non-Payment of Account Services, why didn't Hydro One propose to escalate the other SCCs annually based on the OEB's approved inflation rate?

L -VECC -140

Reference: Exhibit L, Tab 7, Schedule 2, Attachment 1, page 21

a) There is no mention in the Application has to how Hydro One Distribution proposes to set Retail Service Charges over the 2023-2027 period. Please address.

L -VECC -141

Reference: Exhibit L, Tab 5, Schedule 1, page 6

Preamble: The Application states: *"In its Decision in EB-2020-0194, the misallocated Future Tax Savings. Those riders will be in effect from July 1, 2021 to June 30, 2023. As a result of the assumption used in this application that the Seasonal class elimination will be implemented on January 1st, 2023, it is necessary to recalculate the amounts of the misallocated Future Tax Savings to be recovered from each rate class. This is accomplished by using the Net Fixed Assets allocator from the 2018 CAM under the 'No Seasonal' scenario as prepared in the Seasonal Class Elimination proceeding (EB-2020-0246). The Base Rate Adjustment Riders are then derived using the proposed 2023 charge determinants."*

a) Please provide the calculations leading to the proposed charges set out in Table 4.

b) Please explain why the Net Fixed Assets allocator from the 2018 CAM under the 'No Seasonal' scenario is used to reallocate the amounts.

L -VECC -142

Reference: Exhibit L, Tab 6, Schedule 1, pages 18-19

a) The Application states that the bill credit will be calculated prior to January 1st of each year. In determining the bill credit for Sentinel Light and USL customers from acquired utilities, how will the bill for the upcoming year (prior to mitigation) be calculated? For example, will only the distribution related charges be changed from those applicable in the prior year or will some of the other charges (e.g., RTSRs) be changed to reflect known changes for the upcoming year?

End of document