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BY EMAIL AND RESS

October 30, 2020

Ms. Christine E. Long
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long:

EB-2017-0049 – Hydro One Networks' 2018-2022 Distribution Rate Application – 2021 Annual Rate Update (EB-2020-0030) – Interrogatory Responses

Hydro One Networks Inc. is submitting written responses to the Ontario Energy Board ("OEB") staff and intervenors interrogatories on Hydro One Networks' 2021 Annual Update received on October 15th and October 19th.

An electronic copy of the responses has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

Frank D'Andrea

Frank D'Andrea

OEB STAFF INTERROGATORY #1

Reference:
p.10 and p. 14 of Chapter 3 Filing Requirements for Electricity Distribution Rate Applications, 2020 Edition for 2021 Rate Applications, May 14, 2020

Interrogatory:
Hydro One is requesting disposition of its December 31, 2019 Group 1 DVA balances.

a) Please clarify if Hydro One is requesting interim or final disposition of Group 1 balances.

b) If Hydro One is requesting final disposition, please explain the rationale for this given that Hydro One has not fully implemented the Feb. 21, 2019 accounting guidance[1] for Account 1588 and Account 1589.

Response:
a) Hydro One is requesting final disposition of Group 1 balances.

b) Since the Accounting Guidance was issued in February of 2019, Hydro One has had ongoing communication with OEB Staff on the costs and technology issues associated with implementing OEB Staff's recommended Accounting Guidance, and has discussed options and solutions to these issues. Hydro One is committed to continuing to work with the OEB Staff in order to identify a solution that is both compliant and cost-effective. Once the appropriate solution is determined, Hydro One intends to adopt the Feb. 21, 2019 accounting guidance for Account 1588 and Account 1589 on a prospective basis.

[1] https://www.oeb.ca/sites/default/files/Accounting-Guidance-Commodity-Accounts-20190221.pdf

OEB STAFF INTERROGATORY #2

Reference:
Exhibit 1.0 – DX DVA Continuity Schedule

Interrogatory:
In Hydro One Distribution's DVA Continuity Schedule, the amounts in the "Opening Principal Amounts" column for 2015 (i.e. closing 2014 principal balance) equal the amounts in the "OEB Approved Disposition During 2019" column for the approved disposition of 2014 principal balances.[1] Hydro One Distribution was also approved to dispose of 2012 balances in its 2015 rate application.[2] The corresponding amounts are shown in the "OEB Approved Disposition During 2015" column of Hydro One Distribution's DVA Continuity Schedule.

OEB staff does not expect the "Opening Principal Amounts" for 2015 to equal to "OEB Approved Disposition During 2019" because typically, the ending 2014 principal balance would have included the 2012 balance (as disposition is not recorded until 2015) while the ending 2014 principal balance that was approved for disposition would have excluded the 2012 balance that had already approved for disposition in the 2015 rate application.

a) Please confirm that the 2012 balance approved for disposition was removed from the 2014 balance approved for disposition. If not confirmed, please explain why this was the case and how Hydro One has treated the 2012 balance approved for disposition in subsequent years.

b) Please explain the treatment of the 2012 balance approved for disposition, in the context of OEB staff's expectation of the 2015 opening balance stated above.

c) Please confirm that the 2012 balance approved for disposition has not been double-counted for disposition purposes.

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[1] EB-2017-0049, Draft Rate Order, Page 18, Table 7, Filed April 5, 2019
[2] EB-2013-0416

<u>Response:</u>

a) Hydro One Distribution was approved to dispose of 2013 audited balances in its 2015-2017 Distribution rate application (EB-2013-0416).

b) In the 2018-2022 Hydro One Distribution application (EB-2017-0049), the OEB approved the disposition of Group 1 deferral and variance accounts as at December 31, 2014 including interest to June 30, 2019. Furthermore, the OEB approved the disposition of fifty percent of the $121.8 million IESO credit in the RSVA-GA account which was recognized in 2017.

c) The 2013 audited balance approved for disposition was not removed from the 2014 audited balance approved for disposition as the dispositions for the 2013 balance commenced in 2015.

d) Please refer to response (a).

e) In EB-2017-0049, the OEB approved the disposition of Group 1 deferral and variance accounts as at December 31, 2014 including interest forecast to June 30, 2019 and fifty percent of the $121.8 million IESO credit which was recognized in 2017. As part of the DRO process, Hydro One submitted the audited balance as at December 31, 2014 for disposition consistent with the Decision and Order, which was approved by the OEB.

f) The 2013 audited balance was included in the 2014 audited balance approved for disposition. If Hydro One was directed to exclude the 2013 audited balance (which occurred in 2015 actuals) from the final disposition amount, the balance approved for disposition would have been approximately $46 million in EB-2017-0049 (not including the fifty percent of the $121.8 million IESO credit) representing actual 2014 activity; however, the OEB approved approximately $8 million (not including the fifty percent of the $121.8 million IESO credit). As a result, Hydro One Distribution collected approximately $38 million less than it should have.

g) Hydro One submits that the balances requested for disposition in this proceeding are based on 2019 audited balances and consider the above, as the balances approved for disposition in EB-2017-0049 were recognized and accounted during 2019. As such, the Group 1 deferral and variance accounts balances are appropriately calculated for disposition in this proceeding.

OEB STAFF INTERROGATORY #3

Reference:

Ref: p.10
Ref: Exhibit 1.2 Allocation of Consolidated Balance
Ref: Exhibit 1.4 GA Analysis Workform

Interrogatory:

On page 10, Hydro One indicated that in its 2019 rate application,[1] Group 1 balances as at December 31, 2014 and 50% of a $121.8M IESO credit recorded in Account 1589 were approved for disposition.

a) Please discuss Hydro One's final treatment of the $121.8M IESO credit, including whether there were any revisions to the credit amount, the accounts in which it was recorded and when it was recorded in the general ledger. If there were revisions, please provide further details.

b) It appears that Hydro One has excluded the remaining ($60.9M) in Account 1589 that has not been disposed in the allocation of the consolidated balance to Hydro One Distribution and Acquired Utilities, but has included this credit for disposition in 2017 in Hydro One Distribution's DVA Continuity Schedule. Please confirm.

   i. If not confirmed, please explain what is Hydro One's proposed treatment for the remaining IESO credit.

c) In Exhibit 1.2, 2015 to 2018 includes footnotes to indicate that the consolidated balance to be allocated, excludes adjustments to Account 1589 of $12.6M for 2015, $35.7M for 2016 and ($60.9M) for 2017, which was specific to Hydro One Distribution. These amounts are allocated specifically to Hydro One Distribution.

   i. Please confirm the three amounts are all related to the $121.8M IESO credit.

   ii. If so, please explain why the absolute sum of the three amounts does not total $121.8M

[1] EB-2017-0049

iii. Please explain why the adjustment is a debit for 2015 and 2016, and a credit for 2017 and 2018. Please explain how it reconciles to the total credit of $121.8M.

iv. Please indicate in which years, and for what corresponding amounts, the credit was recorded in the general ledger.

v. If part i is not confirmed, please explain what each of the adjustments are for, the reason for the adjustments, the accounts impacted and the corresponding amounts recorded in each account in each year, as well as why those accounts are impacted.

d) In the GA Analysis Workform, there are reconciling items to adjust the general ledger balance for ($37.1M), ($38.7M) and $121.8M in 2015, 2016 and 2017, respectively. This suggests that the balance in the year included $37.1M in 2015, $38.7 in 2016 and ($121.1.8) in 2018 that should be removed for reconciliation purposes as they do not relate to 2015, 2016 or 2017, respectively.

i. Please confirm this understanding. If not confirmed, please explain why and how these amounts are reconciling items.

ii. Please explain how these reconciling items correspond to the adjustments noted in Exhibit 1.2, which implies that $12.6M, 35.7M and ($60.9M) were included in Account 1589 for 2015, 2016 and 2017, respectively.

<u>Response:</u>

a) As indicated during the EB-2017-0049 proceeding[2], a full credit in the amount of $121.8 million was recognized in 2017. No further adjustments were made to the IESO credit amount.

b) Confirmed.

c)

i. Confirmed

[2] EB-2017-0049 Hydro One Networks Inc.'s Reply Argument August 31, 2018 p.170

ii. to iv.: The $121.8 million overcharge (Debit) was accumulated from 2005 to 2016. Table 1 below provides the annual amounts as agreed by the IESO related to the overcharge.

Table 1

GA overcharged by IESO by Year	
2005	$ (261,689.74)
2006	$ 202,932.78
2007	$ 137,382.43
2008	$ 385,830.00
2009	$ 2,336,610.23
2010	$ 1,618,553.19
2011	$ 4,412,458.07
2012	$ 7,334,208.72
2013	$ 11,383,093.10
2014	$ 20,173,610.76
2015	$ 38,387,970.51
2016	$ 35,678,525.98
Total GA overcharged by IESO	$ 121,789,486.02

Since the $121.8 million overcharge as occurred between 2005 to 2016 and subsequent refund as recognized in 2017 is only applicable to Hydro One Distribution, it needs be excluded from the RSVA GA balances which are allocated between Hydro One Distribution, Norfolk, Haldimand and Woodstock.

The RSVA GA balances prior to September 2015 did not require consumption based allocation, since these amounts were separately recorded. Norfolk was integrated in September 2015, therefore only the last four months (September to December) of the overcharge which was $12.6M (debit in 2015) needs to be excluded from the RSVA GA balance to be allocated between Hydro One Distribution and Norfolk. Table 2 below provides a breakdown of the monthly IESO GA overcharge amounts in 2015.

Table 2

2015-Jan	$	982,903
2015-Feb	$	423,202
2015-Mar	$	1,999,088
2015-Apr	$	5,093,825
2015-May	$	6,604,899
2015-Jun	$	5,369,825
2015-Jul	$	3,123,987
2015-Aug	$	2,216,262
2015-Sep	$	2,199,268
2015-Oct	$	2,707,020
2015-Nov	$	4,616,856
2015-Dec	$	3,050,835
2015	**$**	**38,387,971**
Sep to Dec 2015	$	12,573,979

Similarly, the entire $35.7 million which relates to the 2016 overcharge (debit in 2016) by IESO was excluded from the RSVA GA balance to be allocated between Hydro One Distribution, Norfolk, Haldimand and Woodstock.

Please refer to OEB Staff IR #10 part (a) for further discussion in regards to the adjustment of $60.9 million in 2017.

Hydro One submits that there were no further adjustments in 2018 related to the $121.8 million IESO credit. The $2.2 million adjustment was for an IESO error related to Waubaushene transformer station. Please refer to OEB Staff IR #13 part (a) for further explanation.

v. N/A

d)

i. These amounts are removed from the reconciliation since these were overcharged amount by IESO that were not included in the kWh or the GA rate used for the GA workform calculation. The same applies to the $121.8M refund received in 2017.

ii. Please refer to response in part c) above.

In reviewing the GA Analysis Work Form, Hydro One notes that the original 2015 and 2016 submitted GA form presented a different number than the final amount in the general ledger. As a result, the form has been revised and updated accordingly.

Please refer to attachment 1 to this exhibit for the revised 2015 and 2016 amounts.

OEB STAFF INTERROGATORY #4

Reference:
Ref: p.10

Interrogatory:
With regards to the $121.8M IESO credit, per the information in Hydro One's 2019 rate application, the refund from the IESO was received due to a clarification of embedded generation submissions used in the calculation of the Global Adjustment applicable to Hydro One Distribution from January 2005 through to August 2016.[1]

Please state whether Hydro One follows the guidance for embedded generation as outlined in the OEB's February 21, 2019 accounting guidance related to Accounts 1588 and Account 1589 and if not, please explain.

Response:
Confirmed, Hydro One is following the new guidance for embedded generation.

[1] EB-2017-0049, OEB Staff Submission, page 159, August 3, 2018

OEB STAFF INTERROGATORY #5

Reference:

Ref: Exhibit. 1.1 Consolidated DVA Continuity Schedule

Interrogatory:

Typically, large balances are not expected for Account 1588 as it should only hold the variance between commodity costs based on actual line losses and commodity revenues based on values for line losses approved by the OEB in the utility's last rebasing application.

Based on RRR data filed for Hydro One Distribution and Acquireds (where available) for Account 4705 Cost of Power, OEB staff calculates the annual net activity (i.e. transactions plus principal adjustments) from the DVA Continuity Schedule as a percentage of annual Account 4705 to be as follows:

	Net Activity in Account 1588 ($)	Account 4705 ($)	% of net activity compared to Account 4705
2019	(4,999,818)	512,373,616.78	(1.0%)
2018	(27,734,062)	664,302,318.10	(4.2%)
2017	23,676,456	388,880,263.70	6.1%
2016	(2,941,619)	438,107,535.95	(0.7%)
2015	24,604,718	644,455,590.39	3.8%
Cumulative	12,605,675	2,648,119,325	0.5%

a) Please confirm this calculation or provide a revised calculation.

b) For year(s) where the percentage is greater than +/-1%, please provide an explanation as to why the Account 1588 activity would be high in consideration of line losses.

Response:

a) Hydro One currently reports RPP vs. Spot Claim variances under USofA 4710 which should also be considered in the overall calculation. RSVA 1588 is a function of tracking the difference for all customers of the commodity revenues and costs. For RPP customers, it is settled on the RPP rate. USofA 4705 includes the SPOT equivalent costs only.

Hydro One's revised calculation is provided below which also includes USofA 4710:

	Net Activtity in Account 1588 ($)	Account 4705 ($) Commodity purchased at SPOT Price	4710= RPP Claim amount for RPP vs. SPOT	4705+4710= Commodity Cost for RPP kWh @ RPP and SPOR kWh @ HOPE	% of net activtity Compared to Account 4705 + 4710
	a	b	c	d=b+c	a/d
2019	(4,999,818)	512,373,617	1,221,641,916	1,734,015,532	-0.3%
2018	(27,734,062)	664,302,318	971,515,842	1,635,818,160	-1.7%
2017	23,676,456	388,880,264	1,248,091,472	1,636,971,736	1.4%
2016	(2,941,619)	438,107,536	1,462,980,361	1,901,087,897	-0.2%
2015	24,604,718	644,455,590	1,225,703,343	1,870,158,934	1.3%
Cumulative	12,605,675	2,648,119,325	6,129,932,934	8,778,052,259	0.1%

b) There are other factors besides the difference between actual and OEB approved line losses that would impact the balance in Account 1588, including: the fact that revenue includes an unbilled estimate, billing adjustments related to prior periods, etc. As such, it is not possible to determine the extent to which differences in Account 1588 are associated with line losses.

Hydro One notes that due to its very large service territory, and in many cases the long distribution lines required to service its territory, actual line losses can be impacted by many uncontrollable factors, including weather conditions. While yearly fluctuations are expected, Hydro One notes that the cumulative difference, which would tend to cancel out the non-loss related factors noted above, is only 0.1%.

OEB STAFF INTERROGATORY #6

Reference:

Exhibit 1.2 Allocation of Consolidated Balances

Interrogatory:

The second table of the 2015 tab calculates the Post-Integration Consolidated Transactions as i) Consolidated Transactions minus ii) Norfolk Power service area's 2014 Closing Balance, minus iii) Pre-integration utility specific transactions.

The same approach is used in 2016, where the Post-Integration Consolidated Transactions are calculated as i) Consolidated Transactions minus ii) Haldimand County Hydro service area and Woodstock Hydro service area's 2015 closing balances, minus iii) Pre-integration utility specific transactions for Haldimand County Hydro service area and Woodstock Hydro service area, as well as the January to August 2016 transactions for Hydro One Distribution and Norfolk Power service area.

a) Please explain why closing balances (i.e. 2014 for Norfolk Power service area, 2015 for Haldimand County Hydro service area and Woodstock Hydro service area) need to be deducted from the 2015 and 2016 allocation calculations when the starting point of the calculation is consolidated transactions.

b) Please state whether pre-integration utility-specific transactions include the closing balances for each utility.
    i. If so, please explain whether there is any double counting of Norfolk Power/Haldimand County Hydro/Woodstock Hydro service areas' transactions in the allocation of consolidated balances in Exhibit 1.2.

Response:

a) The Columns labeled "Consolidated Transactions during 2015" in 2015 and "Consolidated (HONI DX+NPDI+HCHI+WSHI) Transactions during entire 2016" in 2016 tabs of Exhibit 1.2 include Life-To-Date balances of the acquired service areas before integration (i.e. up to August 2015 for Norfolk and August 2016 for Haldimand and Woodstock). This is because, for the consolidated entity, these balances are considered transactions in the integration year. As per the approved methodology, all balances that are specific to the acquired service areas have been excluded from the consolidated balances.

b) No, the Columns labeled “pre-integration utility-specific transactions during Jan-Aug” in tabs 2015 and 2016 of Exhibit 1.2 do not include closing balances for each of the acquired service areas. The amounts in these columns only reflect the transactions between January and August of the respective years.

OEB STAFF INTERROGATORY #7

Reference:
Exhibit 1.3 Account 1595 Workform

Interrogatory:
Per the rate rider analysis in the Account 1595 Workform, the majority of the variance (credit $4.2M out of credit $6.5M) in Account 1595 is due to the Sub-Transmission Service Classification rate class for both the "Group 1 and 2 excluding Global Adjustment" rate rider and the Global Adjustment rate rider. The main variance for this rate class is due to the differences in forecasted and billed volumes from the volumetric "Group 1 and 2 excluding Global Adjustment" rate rider.

Please explain the variance in Account 1595 attributable to this rate class in greater detail.

Response:
The total Sub-Transmission (ST) rate class variance of -$4.2M can be split into three components:

1. Total Group 1 and Group 2 excluding Account 1589 (GA) – (Volumetric Rider)
Allocated Balance = $13,891,202[1]
Rider Amount billed = $17,178,843[2]
The variance of -$3,287,641 represents a 24% over-collection from customers (-$3,287,641/$13,891,202).

Hydro One believes that this over-collection from customers was mainly due to the actual weather during the 2015-2017 period resulting in higher ST customer demand and consumption relative to the normal weather assumed in establishing the ST class charge determinants. Since the ST rate class consists of many embedded LDCs, the impact of weather variations during the summer was larger than other rate classes.

[1] Exhibit 1.3, Worksheet 1595 (2015-2017), Column F, Row 44
[2] Exhibit 1.3, Worksheet 1595 (2015-2017), Column I, Row 44

2. Account 1589 (GA) – (Volumetric Rider)
Allocated Balance = -$7,133,111[3]
Rider Amount billed = -$6,264,460[4]
The variance of -$868,652 represents a 12% under-payment to customers (-$868,652/-$7,133,111).

Hydro One believes that the main factor contributing to this variance is the significant expansion of the Ontario government's Industrial Conservation Initiative (ICI) over the 2015-2017 period. Over this period many high usage Class B customers transitioned to Class A in an attempt to reduce GA payments, and once these transition customers became Class A customers, they no longer received the GA rider credit amounts as they were no longer eligible. These transition activities were not accounted for in the OEB approved forecast used to set the ST charge determinants, given that the changes to the ICI program were not known at the time the forecast was approved. As such, the ST charge determinants used to derive the rider were larger than actually materialized, resulting in an under-payment. The impact of increased ICI transition customers is partially offset by actual versus normal weather during the 2015-2017.

3. Total Group 1 and Group 2 excluding Account 1589 (Global Adjustment or GA) – (Fixed Rider)
Allocated Balance = $338,261[5]
Rider Amount billed = $337,930[6]
The variance of $331 under-collection from customers or 0.1% ($331/$338,261) is an insignificant contributor to the total ST variance.

[3] Exhibit 1.3, Worksheet 1595 (2015-2017), Column F, Row 72
[4] Exhibit 1.3, Worksheet 1595 (2015-2017), Column I, Row 72
[5] Exhibit 1.3, Worksheet 1595 (2015-2017), Column E, Row 44
[6] Exhibit 1.3, Worksheet 1595 (2015-2017), Column H, Row 44

OEB STAFF INTERROGATORY #8

Reference:
p.15

Interrogatory:
On February 21, 2019, the OEB issued accounting guidance related to Account 1588 and Account 1589. This accounting guidance was effective January 1, 2019 and was to be implemented by August 31, 2019. Distributors are expected to consider this accounting guidance in the context of pre-2019 historical balances that have yet to be disposed of on a final basis

a) In section 3.6 of the pre-filed evidence, Hydro One discusses the RPP settlement process in regards to the Feb. 21, 2019 accounting guidance. In Hydro One's review of pre-2019 historical balances in the context of the Feb. 21, 2019 accounting guidance, has Hydro One identified any other systemic issues?

b) If so, please discuss each systemic issue. Please also discuss the action Hydro One has taken to address each systemic issue.

c) Has Hydro One made any material adjustments to account balances as a result of the Feb. 21, 2019 accounting guidance?

d) If so, for each adjustment, please discuss the nature the adjustment, the amount of the adjustment and the reason for the adjustment.

Response:
Hydro One has not implemented the Feb. 21, 2019 accounting guidance. As stated in response to OEB Staff #1, Hydro One is committed to continuing to work with OEB Staff to identify a solution that is both compliant and cost-effective. As such, the above questions are not applicable to Hydro One.

Hydro One notes that the OEB previously issued an audit report on Hydro One's RPP settlement process (for the period of January 1 to December 2017) which concluded that Hydro One's RPP settlement process complies with current regulatory requirements.

OEB STAFF INTERROGATORY #9

Reference:
Exhibit 1.4 – GA Analysis Workform

Interrogatory:
In the GA Analysis Workform, there is a reconciling item of $2.3M for "Norfolk integrated balance" for 2015. There is also a reconciling item of ($0.6M) for the "Woodstock and Haldimand integrated balance for 2016".

a) Please confirm that the consumption data used to calculate the expected GA balances for 2015 and 2016 exclude the consumption data prior to integration for Norfolk Power service area in 2015, and Woodstock Hydro service area and Haldimand County Hydro service area in 2016.

b) If confirmed, please explain how the reconciling item is calculated. In particular, please explain why it does not equal the sum of the ending balance in the year of integration plus the pre-integration utility-specific transactions in the integration year as shown in Exhibit 1.2 (for example, $3.7M for Norfolk Power service area = $2.5M +$1.2M as per Exhibit 1.2).

c) If part a) is not confirmed, please explain what the reconciling items for the Acquired's integrated balances are for and why they are needed as reconciling items.

Response:
a) Confirmed, the acquired LDCs pre-integration consumption data was excluded when determining the expected GA balances for the respective years.

b) The reconciliation between Exhibit 1.2 and GA workform related to the acquire LDC's pre-integration amount is shown below.

Norfolk:

- 2015 GA workform: $2,294,957.85 represents the integrated RSVA GA balance from Norfolk on Sept 1, 2015
- 2015 Exhibit 1.2: Pre-integration Utility Specific Transactions during Jan-Aug 2015 + NPDI's YE 2014 Closing Balances = First table in the 2015 year (-

$1,052,499.44) + Second Table in the 2015 year (-$1,242,458.41) = $2,294,957.85

Haldimand:

- 2016 GA workform: $621,750.80* represents the integrated RSVA GA balance from Haldimand on Sept 1, 2016
- 2016 Exhibit 1.2: Table 3 2016 Pre-integration Utility Specific Transactions during Jan-Aug 2016 + Table 4 2016 HCHI's YE 2015 Closing Balances = $211,100.00+ $410,650.80 = $621,750.80

Woodstock:

- 2016 GA workform: -$37,861.06* represents the integrated RSVA GA balance from Woodstock on Sept 1, 2016
- 2016 Exhibit 1.2: Table 3 2016 Pre-integration Utility Specific Transactions during Jan-Aug 2016 + Table 4 2016 WHSI's YE 2015 Closing Balances = (-$825,834.11) + $787,973.05 = (-$37,861.06)

**on the 2016 GA workform reconciling item shows the sum of Haldimand ($621,750.80) and Woodstock (-$37,861.06) pre-integration balance together totaling $583,889.74*

c) Not applicable

OEB STAFF INTERROGATORY #10

Reference:
Exhibit 1.4 – GA Analysis Workform
Exhibit 1.1 – Consolidated DVA Continuity Schedule

Interrogatory:
In the GA Analysis Workform for 2017, the "Net Change in Principal Balance in the GL" under Note 5 is ($149,940,135). In the consolidated DVA Continuity Schedule, the transactions for Account 1589 for 2017 is ($88,634,742). The difference is $61,305,394.

a) Please explain the reason for the difference.

b) If the difference pertains to the adjustment made relating to the $121.8M credit, please explain how it relates and how the reconciling item of $121.8M in the GA Analysis Workform is appropriate.

Response:
a) The differences are due to the following:

Disposition related to Haldimand is removed from the Dx DVA Continuity Schedule.

The $121.8M GA credit was received from IESO in 2017 and recorded in the general ledger and USoA in 2017. However, half of the total refund ($60.9M credit) was reflected in the Dx DVA Continuity Schedule as an adjustment in 2014, as the OEB approved this amount for disposition in EB-2017-0049. This created a difference between the 2017 USoA balance which shows the total refund was recorded in 2017 whereas the DVA Continuity Schedule reflects half of the total refund adjusted for as part of the 2014 year-end balance and the other half remains in the 2017 transactions column.

The GA Analysis Workform anchors to the USoA balances* filed with the OEB; which does not include the disposition of half of the $121.8M refund mentioned above.

**note the USoA balance in account 1589 includes carrying charges whereas the GA Analysis Workform excludes carrying charges as it is not relevant to the analysis*

b) It is appropriate to include the $121.8M refund as a reconciliation item since the refund was received from IESO in the year of 2017; however, it is not included in the kWh used in the GA workform calculation and therefore should be considered when reconciling to the expected GA balances.

OEB STAFF INTERROGATORY #11

Reference:
Exhibit 1.4 – GA Analysis Workform
Exhibit 1.1 – Consolidated DVA Continuity Schedule
p. 15

Interrogatory:
In the GA Analysis Workform for 2015 to 2019, reconciling items 1a and 1b for CT 148 true-ups, and 2a and 2b for unbilled to actual revenue true-ups are identified.

a) As Hydro One states that it is still exploring technology solutions that may allow it to obtain the necessary data from its billing system and the Meter Data Management Repository system, please explain how Hydro One has quantified the reconciling items for 1a, 1b, 2a and 2b.

b) Reconciling items 1a, 1b, 2a and 2b are identified as principal adjustments for Account 1589 in each of the 2015 to 2019 GA Analysis Workform tabs. However, these principal adjustments do not appear as principal adjustments in the "Principal Adjustment" column of the consolidated, Distribution or Acquired DVA Continuity Schedules.
   i. Please explain why these principal adjustments are not included for disposition in the DVA Continuity Schedules. Please revise the evidence as needed.

   ii. If Hydro One is not proposing to include the principal adjustments for disposition as per the Feb. 21, 2019 accounting guidance, please explain why Hydro One is proposing to deviate from the accounting guidance.

Response:
a) Reconciliation items 1a and 1b are accounting for the GA rate change from the 2nd estimate to the actual rate used in the RPP Settlement amount. Reconciliation items 2a and 2b were based on a high level approach to estimate the unbilled to actual invoiced volume true-up.

   This approach is not based on actual calendarized meter read data; and was established for the completion of the GA Analysis Workform only. There is no systematic solution for Hydro One to conduct a meter reading calendarization calculation to comply with the OEB accounting guidance and settle with the IESO on a monthly basis.

Hydro One has continued to work with the OEB to identify a solution that is both compliant and cost-effective.

Please refer to Hydro One response to OEB Staff IR #1 for further background.

b) The disposition balances in the DVA Continuity Schedules are anchored to audited balances. The GA Analysis Workform true-up calculations are based on a high level estimate only; its purpose is to help validate the reasonableness of the RSVA GA balance recorded in account 1589. Since it is a high level estimation only, Hydro One does not believe it is appropriate to include it as part of the 2019 year-end disposition balance.

Please refer to Hydro One response to OEB Staff IR #1 for further background.

OEB STAFF INTERROGATORY #12

Reference:

Exhibit 1.4 – GA Analysis Workform
Exhibit 1.1 – Consolidated DVA Continuity Schedule

Interrogatory:

In the GA Analysis Workform, the Principal Adjustment tab does not appear to be completed for Account 1589 and Account 1588.

a) Please complete the Principal Adjustment tab in the GA Analysis Workform.

b) Please confirm that the CT 148 true-ups identified as reconciling items and principal adjustments for Account 1589 in the GA Analysis Workform tabs for 2015 to 2019 are also applicable to Account 1588 and are equal and offsetting to the amounts identified for Account 1589.
   i. If not confirmed, please explain why not.

c) There are no principal adjustments that are shown in the "Principal Adjustment" column of the consolidated, Distribution or Acquired DVA Continuity Schedules for Account 1588.
   i. If principal adjustments are identified for Account 1588 as per part a above, please explain why they are not included for disposition in the DVA Continuity Schedules. Please revise the evidence as needed.
   ii. If Hydro One is not proposing to include the principal adjustments for disposition as per the Feb. 21, 2019 accounting guidance, please explain why Hydro One is proposing to deviate from the accounting guidance.

Response:

Please refer to Hydro One response to OEB Staff IR #11

OEB STAFF INTERROGATORY #13

Reference:
Exhibit 1.4 – GA Analysis Workform

Interrogatory:
In the GA Analysis Workform for 2018, there is a reconciling item of $2.2M for a payment received from the IESO related to Waubaushene TS.

a) Please further explain the reason for the payment.

b) Please explain how the payment was recorded in the general ledger (i.e. did it impact Account 1588 or other commodity accounts).

Response:
a) The payment was as a result of IESO's 2016 metering installation Audit Report. The IESO discovered settlement errors due to wrong meter readings of HONI's Waubaushene transformer station (delivery point 100051) for the past 7 years preceding March 2016. The settlement recalculations were conducted by the IESO and settled on the August 2019 invoice.

b) The full $2.2M refund was recorded in USofA 4707 (GA cost) resulting in a liability recorded in account 1589 (RSVA GA).

OEB STAFF INTERROGATORY #14

Reference:
p.16-17

Interrogatory:
At the above reference, Hydro One states the following:

The IESO settlement amounts discussed above are also estimated based on unbilled consumption for accounting accrual purposes. These accrual amounts are not included in the monthly IESO declaration. Only the settlement amounts based on the actual invoices are declared to the IESO.

a) Please confirm that the above statement is applicable for 2019 and prior years. If not confirmed, please explain.

b) As noted above, settlements amounts are based on actual invoices. The settlement amount will appear as charge type 142 on the IESO invoice. Please confirm that the actual charge type 142 amount that appears on the IESO invoice is not recorded in the general ledger, as charge type 142 is recorded on an accrual basis (based on invoiced and unbilled consumption) in the general ledger for accounting purposes.
    i. Please confirm that charge type 142 on the IESO invoice for RPP settlements is recorded fully in Account 1588. If not confirmed, please explain how charge type 142 is recorded in the general ledger.

c) If part b above is not confirmed, please provide further explanation on how the RPP settlement amount is calculated and how the resulting charge type 142 amount invoiced is recorded in the general ledger.
    ii. Please discuss whether Hydro One has materially changed its processes for RPP settlement submissions at any point between 2014 and today's date. If so, when?

d) Please confirm that, as settlements are done based on actual invoices only, Hydro One only performs a price variance true-up between the GA estimated price and GA actual price and no volume true-up is performed. If not confirmed, please explain.

e) Please confirm that RPP settlement is trued-up to actuals based on wholesale volumes. If not, please confirm that the difference between retail to wholesale volumes for RPP settlement is recorded in Account 1588.

Response:

a) Confirmed.

b)

i. actual settlement amounts (charge type 142 on IESO invoice) and un-invoiced settlement amounts are recorded in the general ledger.

The portion related to the difference between RPP consumption at RPP rate and RPP consumption at HOEP rate is recorded in Account 1588. The portion related to RPP consumption at GA Rate is recorded in Account 1589.

c) Not applicable

d) Confirmed.

e) Hydro One currently settles the RPP claim with the IESO on retail sales volume adjusted for line losses. The difference between line loss adjusted retail volumes to wholesale volumes for RPP settlement is recorded in 1588 and 1589.

Please refer to the response to b) i above for further details.

OEB STAFF INTERROGATORY #15

Reference:

p. 17

Interrogatory:

At the above reference, Hydro One stated the following:

The ESM credit balance requested for disposition to be shared with distribution customers in the current application reflects both a credit of $1.2M in 2018 and a credit $20.2M in 2019. Both the 2018 and 2019 amounts were recorded in 2019 due to the timing of the EB-2017-0049 Decision. In 2019, the achieved ROE was 1.9% higher than the deemed ROE of 9.0% owing to weather and achieved productivity reductions, offset in part by increased operations, maintenance, and administration expenses.

a) Please provide the calculations supporting the 2019 ROE referenced above.

b) Please provide a breakdown of the 2018 credit of $1.2 million and the 2019 credit of $20.2 million between the factors cited above and include an explanation of the reasons for each of the variances.

Response:

a) Please refer to Attachment 1 in the response to OEB Staff Interrogatory #17.

b) Breakdown for the 2018 credit – please refer to response to OEB Staff Interrogatory #17 part (b).

Analysis breakdown for the 2019 credit reflecting the material variances impacting the over-earning are provided in the table below in $ millions:

	Approved in EB-2017-0049	2019 Actuals	2019 Hydro One Distribution Over-Earnings	Explanations
Volume	0	60	60	More favourable weather
OM&A	550[1]	559	-9	Higher OM&A incurred in various work programs partially offset by higher productivity gains
Removal costs	70	55	15	Variations in in-year capital investments
Depreciation	345	347	-2	Variations in in-year capital asset mix
Taxes	50	53[2]	-3	Tax impacts relating to the above variances and CCA
			61	

The $61 million represents 1.94% over-earning as calculated in the OEB Staff IR #17 Attachment 1.

[1] Given the Custom IR framework where 2019 revenue requirement is derived by escalating 2018 revenue requirement by (inflation – productivity + capital factor), OM&A beyond 2018 which was embedded in the 2019 approved revenue requirement is derived by escalating 2018 approved OM&A by (inflation – productivity). The 2019 figure is simply used for the purpose of explaining ESM related variances as there is no approved OM&A beyond 2018 or an associated build-up.

[2] The 2019 Actuals of $53M excludes the accelerated CCA impact as it is net income neutral and there is no impact to ROE.

OEB STAFF INTERROGATORY #16

Reference:
p. 17

Interrogatory:
At the above reference, Hydro One stated the following:

As summarized in the Hydro One Networks' 2018-2022 Distribution Rate Application – Distribution Productivity Report ("Productivity Report") for 2018 and 2019 years, Hydro One was able to achieve additional $4.5 million in productivity savings in 2018 and an additional $25 million in productivity savings in 2019 relative to the forecast filed in the application.

Please state how the additional 2018/2019 productivity savings referenced above impacted the 2018 and 2019 ESM credit amounts and provide a quantification of these impacts for each year.

Response:
Hydro One's productivity program validates initiatives that result in cost savings without sacrificing work volumes. The incremental productivity achieved in 2018 and 2019 resulted in cost reductions to operations, maintenance, and administration (OM&A). These reductions were offset by other increases in OM&A expenses.

OM&A is a direct input into the net income calculation, which in turn is an input into the ESM calculation. Please refer to response to AMPCO IR #2 for further details in regards to achieved productivity savings.

OEB STAFF INTERROGATORY #17

Reference:

p. 17

Interrogatory:

Hydro One is proposing to dispose of the balance in the ESM account for 2018 and 2019, totaling ($21.7M).

a) Please provide the ESM calculations for 2018 and 2019.

b) Please explain how the ESM amount was calculated for 2018 given that it was a rebasing year and rates were effective May 1, 2018. Please explain the assumptions used for the calculation.

c) At the reference above, Hydro One states that "The ESM calculation methodology utilized by Hydro One is similar to what is outlined in the annual RRR 2.1.5.6 filing".
   i. Please explain each difference in i) the methodology and ii) adjustments made to regulatory net income in deriving the adjusted regulatory net income for ESM purposes between Hydro One's ESM calculation and the one outlined in the RRR 2.1.5.6.
   ii. Please explain why each of the differences in methodology and adjustments to regulatory net income were made in Hydro One's ESM calculation.

d) Please confirm the ESM is calculated using actual earnings and not weather normalized earnings.

e) In the decision and order[1] for Hydro One's 2020 Custom IR Update rate application, the OEB found that "The ESM deferral account is to be reviewed as part of the 2021 rate application and will also be reviewed for disposition in Hydro One's next rebasing application".
   i. Please explain whether Hydro One is seeking interim disposition or final disposition of the 2018 and 2019 ESM amounts.

[1] Page 6, Decision and Order, December 17, 2019, EB-2019-0043

ii. Please explain whether Hydro One is agreeable to interim disposition of the 2018 and 2019 ESM amounts in the current application, and subsequently requesting final disposition in its next rebasing application, allowing for further review of the 2018 and 2019 amounts, should it be required.

Response:

a) Please refer to Attachment 1.
Note that $21.7M includes forecasted 2020 interest.

b) Please refer to Attachment 1. The 2018 foregone revenues (from May 1, 2018 to December 31, 2018) arising from the receipt of the Hydro One Distribution 2018-2022 rate application were recorded in March 2019 but the 2018 ESM calculation was adjusted to include this foregone revenue.

c) Due to the timing of the Hydro One Distribution 2018-2022 Decision and DRO process (which was approved in June 2019), the RRR 2.1.5.6 calculation did not consider the outcomes arising from the Decision and DRO process. Therefore, a comparison between the two calculations for 2018 is not appropriate. The comparison for 2019 is provided below.

2019

	RRR 2.1.5.6 Filing	ESM Calculation	Difference	Explanation
Regulated Net Income	344.1	345.5	1.40	**Note 1**
Rate Base	7,896.5	7,894.1	(2.40)	**Note 2**
Common Equity %	40%	40%		
Achieved ROE	10.9%	10.9%		

Note 1 The majority of the variance is due to the 2018 ESM sharing amount recorded in 2019 for accounting income purposes but added back to normalize for the in-year ESM calculation.

Note 2 The ESM calculation of the ROE is based on OEB approved mid-year rate base while the RRR 2.1.5.6 Filing uses actual rate base.

d) Confirmed.

e) Hydro One is seeking final disposition of the 2018 and 2019 ESM amounts. The 2018 foregone revenues arising from the receipt of the Hydro One Distribution 2018-2022 rate application were recorded in March 2019 but the 2018 ESM calculation was adjusted to include this foregone revenue. It is not expected that there would be any further adjustments made to the 2018 and 2019 ESM amounts. The disposition of amounts on a final basis is also aligned with the OEB’s intent for Hydro One Distribution to return amounts to ratepayers in a timely and efficient manner. Hydro One believes that the language from the EB-2017-0049 decision which indicates that the ESM account will also be reviewed in the next rebasing application refers to amounts for years 2020, 2021 and 2022.

Hydro One Distribution

		2018	2019
Mid-Year Rate base (OEB approved)	**A**	$ 7,636.9	$ 7,894.1
Capital Structure:			
Long-term debt	**B**	56%	56%
Short-term debt	**C**	4%	4%
Common equity	**D**	40%	40%
Allowed Return:			
Long-term debt	**E**	4.47%	4.47%
Short-term debt	**F**	2.29%	2.29%
Allowed ROE	**G**	9%	9%
Regulated Net Income (actual)	**H**	$ 307.3	$ 345.5
Achieved ROE	**I = H / (A x D)**	10.06%	10.94%
Allowed ROE	**J**	9%	9%
Over/(Under) earning (%)	**K = H - J**	1.06%	1.94%
OEB allowed earnings threshold	**L**	1%	1%
Over/(Under) earning to allowed threshold (%)	**M = K - L**	0.06%	0.94%
Excess earnings pool	**N = A x D x M**	**$ 1.8**	**$ 29.7**
Sharing with ratepayers	**O**	50%	50%
Sharing with ratepayers	**P = N x O**	$ 0.9	$ 14.9
Tax Grossed-up amount[1]	**Q = P / 0.735**	**$ 1.2**	**$ 20.2**

[1] Includes the tax gross-up, being the incremental tax benefit to shareholders as a result of returning excess earnings. The tax gross up (Q = P/.735) serves to return these incremental tax benefits to ratepayers.

OEB STAFF INTERROGATORY #18

Reference:
Exhibit 4.1 GA Transition Customers

Interrogatory:
The calculation of the percentage allocation of Account 1589 to current Non-RPP Class B customers is as follows:

Non-RPP Class B consumption excluding WMP, Class A and transition customers = (total Non-RPP Class B excluding WMP consumption) – (consumption of transition customer).

Please confirm that non-RPP Class A consumption is appropriately excluded in the calculated Non-RPP Class B consumption excluding WMP, Class A and transition customer’s amount. If not confirmed, please revise the calculation as needed.

Response:
Confirmed.

OEB STAFF INTERROGATORY #19

Reference:

Exhibit 4.0 – DVA Rate Riders

Interrogatory:

Per the Chapter 3 Filing Requirements for Electricity Distribution Rate Applications[1], page 15 states:

However, in the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580, Sub-account CBR Class B will be added to the Account 1580 WMS control account to be disposed through the general purpose Group 1 DVA rate riders.

In Exhibit 4.0, the volumetric rider for CBR Class B is zero in the fourth decimal places for some rate classes. Please confirm that Hydro One is proposing to dispose of Account 1580, Sub-account CBR Class B through a volumetric rate rider even though a rate rider is not generated for all rate classes. If not confirmed, please explain Hydro One's proposal.

Response:

The calculated 2021 CBR Class B volumetric riders for the rate classes UR, R1, R2, Seasonal, GSe, UGe, Streetlight, Sentinel light and USL fall below the OEB's materiality threshold as defined in the Filing Requirements (i.e. rounds to zero in the fourth decimal place). However, consistent with the OEB's approval to use five decimal places in establishing the volumetric acquisition riders for Haldimand County Hydro Inc. USL rate class in its Final Rate Order under EB-2014-0244 and for Woodstock Hydro Services Inc. residential rate class in its Final Rate Order under EB-2018-0042, Hydro One proposes to use five decimal places for these rate classes' 2021 CBR Class B volumetric riders. This will change the proposed 2021 volumetric rider shown in Exhibit 4.0 from \$0.0000/kWh to a \$0.00003/kWh credit for these rate classes.

[1] Filing Requirements For Electricity Distribution Rate Applications - 2020 Edition for 2021 Rate Applications, May 14, 2020

This change will be reflected in Exhibits 4.0, 5.0 and 6.0 as a part of Hydro One’s update once the OEB issues the 2021 inflation factor in the course of this proceeding.

OEB STAFF INTERROGATORY #20

Reference:
p. 24

Interrogatory:
At the above reference, Hydro One stated the following:

The 2021 tariff schedule includes the applicable Specific Service Charges for the 2021 rate year described in EB-2017-0049, Exhibit H1, Tab 2, Schedule 3.24 The retailer service charges and the specific charge for access to power poles - telecom will be adjusted for inflation, in accordance with the "Report of the Ontario Energy Board - Wireline Pole Attachment Charges" issued March 22, 2018 under EB-2015-0304, after the OEB issues the 2021 inflation factor in the course of this proceeding.

a) Please clarify whether or not the above statement means that Hydro One is updating the retailer service charges in accordance with the referenced OEB wireline pole attachment charges report, or, if not, please explain.

b) Please provide a table containing the following information:
   i. a listing of all specific service charges that are being adjusted in the current application and the current and proposed rate for any such charges,

   ii. the basis (e.g. OEB policy or other reasons) for making each proposed adjustment and how any such adjustments are being calculated.

Response:
a) In accordance with the referenced OEB wireline pole attachment charges report, Hydro One will update the retailer service charges for inflation after the OEB issues the 2021 inflation factor in the course of this proceeding.

b) The following table lists all of the 2021 proposed changes to specific service charges and the basis for each change.

2021 Proposed Changes to Specific Service Charges

Specific Service Charge Description	**Current 2020**	**Proposed 2021**	**Basis for Proposed 2021 Change**
Customer Administration			
Easement letter - letter request	$ 89.67	$ 91.12	OEB Decision, EB-2017-0049
Other			
Specific charge for access to power poles - telecom	$ 44.50	Subject to annual inflationary adjustment	OEB Policy, EB-2015-0304
Additional service layout fee - basic/complex (more than one hour)	$ 577.91	$ 586.72	OEB Decision, EB-2017-0049
Pipeline crossings	$ 2,430.28	$ 2,465.43	
Water crossings	$ 3,618.57	$ 3,668.82	
Railway crossings	4,830.33 plus Railway Feedthrough Costs	$4,899.24 plus Railway Feedthrough Costs	OEB Decision, EB-2017-0049
Overhead line staking per meter	$ 4.30	$ 4.36	
Underground line staking per meter	$ 3.09	$ 3.14	
Subcable line staking per meter	$ 2.70	$ 2.74	
Conversion to central metering <45 kw	$ 1,572.92	$ 1,593.19	
Conversion to central metering >=45 kw	$ 1,472.92	$ 1,493.19	
Connection impact assessments - net metering	$ 3,239.70	$ 3,285.66	
Connection impact assessments - embedded LDC generators	$ 2,921.93	$ 2,960.07	
Connection impact assessments - small projects <= 500 kw	$ 3,315.83	$ 3,361.46	
Connection impact assessments - small projects <= 500 kw, simplified	$ 2,001.42	$ 2,028.44	
Connection impact assessments - greater than capacity allocation exempt projects - capacity allocation required projects	$ 8,765.05	$ 8,890.57	
Connection impact assessments - greater than capacity allocation exempt projects - TS review for LDC capacity allocation required projects	$ 5,817.80	$ 5,895.15	
Specific Charge for LDCs Access to the Power Poles ($/pole/year)			
LDC rate for 10’ of power space	$ 87.90	$ 89.24	OEB Decision, EB-2017-0049
LDC rate for 15’ of power space	$ 105.48	$ 107.09	
LDC rate for 20’ of power space	$ 117.20	$ 118.99	
LDC rate for 25’ of power space	$ 125.57	$ 127.49	

Specific Service Charge Description	**Current 2020**	**Proposed 2021**	**Basis for Proposed 2021 Change**
LDC rate for 30’ of power space	$ 131.85	$ 133.86	
LDC rate for 35’ of power space	$ 136.73	$ 138.82	
LDC rate for 40’ of power space	$ 140.64	$ 142.79	
LDC rate for 45’ of power space	$ 143.83	$ 146.03	
LDC rate for 50’ of power space	$ 146.50	$ 148.74	
LDC rate for 55’ of power space	$ 148.75	$ 151.03	
LDC rate for 60’ of power space	$ 150.68	$ 152.99	
Specific Charge for Generator Access to the Power Poles ($/pole/year)			
Generator rate for 10’ of power space	$ 87.90	$ 89.24	OEB Decision, EB-2017-0049
Generator rate for 15’ of power space	$ 105.48	$ 107.09	
Generator rate for 20’ of power space	$ 117.20	$ 118.99	
Generator rate for 25’ of power space	$ 125.57	$ 127.49	
Generator rate for 30’ of power space	$ 131.85	$ 133.86	
Generator rate for 35’ of power space	$ 136.73	$ 138.82	
Generator rate for 40’ of power space	$ 140.64	$ 142.79	
Generator rate for 45’ of power space	$ 143.83	$ 146.03	
Generator rate for 50’ of power space	$ 146.50	$ 148.74	
Generator rate for 55’ of power space	$ 148.75	$ 151.03	
Generator rate for 60’ of power space	$ 150.68	$ 152.99	

CCC INTERROGATORY #1

Reference:
Rate Application, p. 13

Interrogatory:
Please provide a detailed explanation as to how the DVA allocations to each rate zone (NPDI, HCHI, WHSI and HONI-Dx) were derived.

Response:
As mentioned on the referenced page, Hydro One used the post-integration sales volume (kWh) for each of the four rate zones to allocate the Group 1 DVA balances[1]. A set of allocators, based on the sales volume, were developed for each of the Group 1 DVAs, depending on the group of customers that contribute to a particular DVA. For example, the balances in USofA 1589 (Global Adjustment) were allocated using kWh for non-RPP, non-wholesale market participants (non-WMP), non-LDC, and class B customers while the balances in USofA 1580 (Wholesale Market Service Charge) were allocated using kWh for non-WMP customers.

Each worksheet in Exhibit 1.2 includes a table that shows the allocator for each of the Group 1 DVAs.

[1] Sales volume was used for all Group 1 DVAs, except USofA 1551 (Smart Meter Entity Charge Variance Account), where number of residential and general service < 50kW customers was used as the allocator.

CCC INTERROGATORY #2

Reference:

Rate Application, p. 17

Interrogatory:

The evidences indicates that in 2019 the achieved Return on Equity (ROE) was 1.9% higher than the deemed rate of 9% owing to weather and achieved productivity reductions, offset by increased operations, maintenance and administration expenses. Please provide a complete detailed list of all of the factors referred to and the associated amounts (savings and costs). Please explain the variances from forecast.

Response:

Please refer to the response to OEB Staff IR #15, part (b).

CCC INTERROGATORY #3

Reference:
Rate Application, p. 17

Interrogatory:
HON's evidence is that it was able to achieve $4.5 million in productivity savings in 2018 and $25 million in 2019. Please provide a detailed explanation as to how these amounts were calculated. What were the projected productivity savings for each of those years?

Response:
On March 4, 2020, Hydro One filed a Distribution Productivity Report, in response to the OEB's direction[1] to "file a report, within twelve months of this Decision and Order, showing the status of the productivity initiatives listed in I-25-Staff-123, including actual savings, with a discussion of any deviation from plan. The report, is to be filed on a standalone basis and will not be adjudicated. Hydro One is expected to update the report to file with its next rebasing application."

This report provides a detailed analysis of filed versus achieved productivity, as well as variance explanations. Please refer to attachment 1 within SEC IR #4 for a copy of this report.

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[1] Decision and Order EB-2017-0049, dated March 7, 2019

CCC INTERROGATORY #4

Reference:
Rate Application, p. 17

Interrogatory:
HON is proposing to allocate its ESM deferral account balance to rate classes in proportion to their share of the 2021 rates revenue requirement. Did HON consider other allocation methodologies? If not, why not? If so, why was the revenue requirement approach chosen?

Response:
Hydro One did not consider other allocation methodologies. In the absence of an OEB model to allocate ESM deferral account balance to rate classes, Hydro One submits that allocating this balance to rate classes in proportion to their share of the 2021 rates revenue requirement is the most appropriate method. The same approach was proposed by Alectra Utilities Corporation in its Draft Rate Order, filed on February 10, 2020 (EB-2019-0018, establishing 2017 ESM Rate Riders) and subsequently approved by the OEB (EB-2019-0018, 2020 Interim Rate Order pg. 3, dated February 28, 2020).

CME INTERROGATORY #1

Reference:
EB-2020-0030 HONI Distribution Rate Application, page 17 of 25 (PDF page 18).

Interrogatory:
At page 17 of 25 of the application, HONI stated that in 2019 ROE was 1.9% higher than the deemed ROE of 9.0% because of "weather and achieved productivity reductions, offset in part by increased operations, maintenance and administrative expenses".

a) Please outline the impact of each driver that lead to outperforming the ROE.

b) With respect to productivity reductions, please:
   i. Confirm that 'productivity reductions' are either increases in productivity, or reductions in cost, such that HONI was able to outperform its deemed ROE.
   ii. Separate the total productivity or savings achieved into each individual initiative, showing the impact of each one.
   iii. Provide a description of what was effective in the productivity initiatives, and any lessons learned that HONI will apply to other initiatives going forward.

c) Please describe, in detail, the increases to operations, maintenance and administrative expenses. Please include a description of what they were, why they occurred, and how HONI will try to address any of the drivers going forward.

Response:
a) Please refer to the response to OEB Staff IR #15, part b.

b) With respect to the incremental productivity achievement, please refer to Attachment 1 within SEC IR #4 for the Distribution Productivity report that was filed with the OEB on March 4 2020.

   i. Hydro One's productivity program is intended to track initiatives that can result in cost savings without sacrificing work volumes. Confirmed, incremental productivity has resulted in cost reductions.

ii. With respect to the incremental productivity achievement, please refer to Attachment 1 within SEC IR #4 for the Distribution Productivity report that was filed with the OEB on March 4 2020. The report highlights actual achievement relative to filed at the initiative level.

iii. Specific variance explanations are described within attachment 1 of SEC IR #4.

Furthermore, as identified in the Transmission 2020-2022 application, further incremental initiatives were identified in the common category since the Distribution 2018-2022 application was filed. The common savings result in a benefit to both Transmission and Distribution segments. For Distribution, as this initiative was developed in 2019, post approval of Distribution 2018-2022 application, the incremental savings impact the earnings sharing calculation, whereas in Transmission, the savings were presented as part of the Application, and were embedded directly in customer rates.

This effectively shows that Hydro One is crediting 'real' savings, and continues to add new, incremental initiatives to the productivity program, which help generate incremental benefit for customers.

c) Please refer to the response to OEB Staff Interrogatory #15, part b.

CME INTERROGATORY #2

Reference:

EB-2020-0030 HONI Distribution Rate Application, page 17 of 25 (PDF page 18).

Interrogatory:

At page 17 of 25, HONI stated that the 2018 ESM result was a $1.2 million credit to ratepayers.

a) Please provide an outline of the 2018 results in the same fashion as the 2019 results, including the components outlined in CME #1.

Response:

a) Please refer to OEB Staff IR #17 part (b).

CME INTERROGATORY #3

Reference:

EB-2020-0030 HONI Distribution Rate Application, page 17 of 25 (PDF page 18).

Interrogatory:

At page 17 of 25, HONI stated:

> *"Hydro One is committed to adhering to the robust governance process which has been established for defining and monitoring savings across the organization."*

a) Please provide a brief description of the governance process, and how that impacted HONI's savings for 2018 and 2019.

Response:

a) Hydro One's productivity framework is comprised of internal governance around the classification of productivity savings and the process for identifying and obtaining internal approval for productivity initiatives. The initiatives must meet certain criteria for acceptance, along with the corresponding accountabilities for approving initiatives, achieving savings, tracking and reporting on productivity performance, and integrating planned savings into the Business Plan.

   Hydro One introduced a tiered reporting structure so as to clearly differentiate between productivity improvements that will result in actual cost savings ("Tier 1 Productivity") and those that will enable Hydro One to complete more work for the same cost ("Tier 2 Productivity"). Only those savings that contribute to overall direct cost reductions in the Business Plan relative to their baseline, i.e. Tier 1 Productivity savings, are reported against productivity targets in Hydro One's corporate scorecards.

   The actual achieved productivity results in 2018 and 2019 would have been approved via the governance process noted above.

SEC INTERROGATORY #1

Reference:
Rate Application, p. 17

Interrogatory:
For each of 2018 and 2019, please provide a table that shows the inputs to the ROE calculation used for the purpose of the ESM calculation, as compared to the amounts approved in EB-2017-0049. Please provide an explanation for all variances.

Response:
Please refer to the response to OEB Staff IR #15 and OEB Staff IR #17.

SEC INTERROGATORY #2

Reference:
Rate Application, p. 17

Interrogatory:
Please provide a copy of the RRR 2.1.5.6 filings for each of 2018 and 2019 years. Please reconcile the filings with the detailed ESM calculations provided in response to SEC-1 and 4.0-Staff-17(a).

Response:
2018:
Due to the timing of the Hydro One Distribution 2018-2022 Decision and DRO process (which was approved in June 2019), the RRR 2.1.5.6 calculation did not consider the outcomes arising from the Decision and DRO process. Therefore, a comparison between the two calculations for 2018 is not appropriate.

2019:
Please refer to response provided to OEB Staff IR #17 part (c).

SEC INTERROGATORY #3

Reference:
Rate Application, p. 17

Interrogatory:
If the Board orders interim disposition of the ESM amounts for 2018 and 2019 as suggested by interrogatory 4.0-Staff-17, please explain what could cause the amount to change between the interim order and its next rebasing application when disposition on a final basis would be sought.

Response:
Please refer to OEB Staff IR #17 part (e).

SEC INTERROGATORY #4

Reference:
Rate Application, p. 17

Interrogatory:
Please provide a copy of the referenced Distribution Productivity Report.

Response:
A copy of the Distribution Productivity report is provided as Attachment 1 to this exhibit.

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application and Evidence.

DISTRIBUTION PRODUCTIVITY REPORT

1 INTRODUCTION

On March 31, 2017, Hydro One Networks Inc. ("**Hydro One**") filed a Custom Incentive Rate application (EB-2017-0049) (the "**Application**") seeking approval of its distribution rates from January 1, 2018 to December 31, 2022. The Ontario Energy Board (the "**OEB**") released its decision on March 7, 2019 (the "**Decision**") approving Hydro One's Application. Among other things, the OEB directed Hydro One to file a report showing the status of the productivity initiatives listed under OEB staff IR 123 within 12 months of the Decision.[1]

2 PRODUCTIVITY STATUS REPORT

Hydro One is providing the following Productivity Status Report which reflects the productivity initiatives as outlined in response to OEB staff IR 123 as well as the actual savings achieved in 2018 and 2019. The actual savings for 2018 and 2019 include additional initiatives that have materialized since Hydro One filed the Application. The additional initiatives are related to the Customer Contact Centre, Corporate Costs, and Pad Mount Transformers. Moreover, the reporting of the Move to Mobile initiative has been disaggregated between field efficiencies and back office FTE savings.

Hydro One measures Productivity savings on an aggregated level with certain initiatives impacting the Distribution Business, the Transmission Business or both the Transmission and Distribution businesses (i.e. common initiatives). Consistent with the productivity savings which were forecasted for 2018 to 2022 and provided in response to OEB Staff IR 123, the table below is specific to initiatives which were identified as those that benefit the Distribution business. The actuals for 2018 and 2019 are directly aligned to the aggregated corporate results that Hydro One reports on its Corporate Scorecards.

[1] Decision, p. 57, which states that "Hydro One to file, within twelve months of this Decision and Order, a report showing the status of the productivity initiatives listed in I-25-Staff-123, including actual savings, with a discussion of any deviation from plan."

2018 RESULTS

In 2018, Hydro One achieved $74.5 million in productivity savings as compared to $69.9 million of productivity savings which were previously forecasted in the Application. The variances between actual productivity savings achieved and forecasted productivity savings are discussed in the following three categories: capital, OM&A and common costs.

Capital: In 2018, Hydro One achieved $33.5 million in capital related productivity savings as compared to the $36.4 million previously forecasted in the Application. The main drivers for the lower productivity savings achieved are as follows:

- Hydro One achieved lower than planned savings in the Move to Mobile initiative due to higher than planned unit costs relative to the baseline; and
- Procurement savings in Distribution were below plan largely due to lower external spend on IT projects relative to forecast, affecting savings from negotiated rate reductions which are volume driven.

The reductions in productivity savings were partially offset by increases in productivity savings achieved in the following areas:

- Hydro One worked to find incremental opportunities and accelerated the Fleet Rationalization initiative (Telematics); and
- Hydro One introduced a new productivity initiative for utilization of lower cost Pad-Mounted transformers under the Operations Category.

OM&A: In 2018, Hydro One achieved $34.9 million in OM&A related productivity savings as compared to the $29.4 million previously forecasted in the Application. The OM&A productivity savings initiatives were materially in line with forecasted levels. Higher achieved productivity savings were mostly due to the following initiatives:

- Accelerated savings in the Cable Locate Outsourcing initiative;
- Accelerated saving in the In-Sourcing of the IT contract initiative; and

- Savings realized due to Customer Call Centre Insourcing which is a new initiative.

Common: In 2018, Hydro One achieved $6 million in common related productivity savings as compared to the $4 million previously forecasted in the Application. The increase in productivity savings was due to accelerated savings opportunities achieved via Early Pay discounts under the Procurement category.

2019 RESULTS

In 2019, Hydro One achieved $97.0 million in productivity savings as compared to $72.0 million of productivity savings which were previously forecasted in the Application. The variances between actual productivity savings achieved and forecasted productivity savings are discussed in the following three categories: capital, OM&A and common costs.

Capital: In 2019, Hydro One achieved $34.9 million in capital related productivity savings as compared to the $34.2 million previously forecasted in the Application. The main drivers for the higher productivity savings achieved are as follows:

- Continued acceleration of Fleet Rationalization savings initiative (Telematics);
- Incremental Procurement savings; and
- Incremental savings in the utilization of lower cost Pad-Mounted transformers which falls under the Operations Category.

These additional savings were partially offset by decreases in productivity savings mostly in the Move to Mobile initiative due to higher unit costs.

OM&A: In 2019, Hydro One achieved $39.1 million in OM&A related productivity savings as compared to the $33.7 million previously forecasted in the Application. Higher achieved productivity savings were mostly due to the following initiatives:

- Productivity savings realized due to Customer Call Centre Insourcing which is a new initiative; and
- Accelerated savings in the Cable Locate Outsourcing initiative.

These increases in productivity savings were partially offset by decreases in productivity savings realized in the following areas:

- Lower Move to Mobile initiative savings due to higher unit cost; and
- Lower ISD savings related to the Application maintenance contract reductions.

Common: In 2019, Hydro One achieved $23.0 million in common related productivity savings as compared to the $4.2 million previously forecasted in the Application. The increase in productivity savings was due to Hydro One's Corporate Costing initiative which significantly reduced vacancies and limited contract spending to critical functions. This was discussed in detail within the EB-2019-0082 Transmission 2020-2022 Custom IR application.

Below is an updated chart as it appeared in OEB staff IR 123, reflecting the forecasted and actual numbers for 2018 and 2019.

	Category in Rate Filing	Initiative Summary	Measurement and Expected Benefit	2018 As Filed	2018 Actuals	2019 As Filed	2019 Actuals	2020 As Filed	2021 As Filed	2022 As Filed
Capital	Move to Mobile	Field Force	Measures Labour Hours per Unit - Historical Baseline vs Actual *Plan allocation to expected unit cost savings in New Connections, Joint Use line Relocations, Pole Replacement, Field Meter Service, Component Replacement*	$ 10.3	$ 2.7	$ 10.5	$ (4.2)	$ 10.7	$ 10.7	$ 10.7
		FTE Reduction (Back Office)	Back Office FTE Reductions from field automation - Historical FTE vs Actual. Target dollars historically alloced under Field Force. Disaggregated for Actuals	$ -	$ 1.3	$ -	$ 0.7	$ -	$ -	$ -
	Procurement	Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Capital program spend)*	$ 12.7	$ 7.2	$ 13.2	$ 17.7	$ 17.0	$ 16.7	$ 18.6
	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected capital allocation of negotiated reductions*	$ -	$ -	$ 0.3	$ -	$ 0.3	$ 0.3	$ 0.3
	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.0	$ -	$ 0.0	$ -	$ 0.01	$ 0.01	$ 0.01
		Padmount Transformers	Cost Reduction - Actual Cost of Padmount transformer vs Average historical actual cost of alternative	$ -	$ 2.0	$ -	$ 1.5	$ -	$ -	$ -
	Telematics	Telematics	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ 13.4	$ 20.3	$ 10.1	$ 19.3	$ 9.8	$ 9.6	$ 9.3
OM&A	Customer	eBilling	Lower Cost per Customer *Expected customers enrolled in eBilling x Unit Savings*	$ 1.8	$ 1.8	$ 2.6	$ 3.5	$ 3.2	$ 4.1	$ 4.8
		Call center insourcing	Lower Cost for Call Centre - Prior Cost (as filed) when Outsourced vs Current Actual Cost	$ -	$ 2.2	$ -	$ 9.1	$ -	$ -	$ -
	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected savings from server/database decommissioning and negotiated infrastructure and application maintenance contract reductions*	$ 7.4	$ 9.1	$ 8.3	$ 5.4	$ 11.5	$ 11.5	$ 11.5
		Contract Rates - Minor Enhancement	(Old Rate - New Rate) * Expected ME Hours *Negotiated savings x Expected need for minor enhancement hours in business plan*	$ 0.9	$ 1.5	$ 1.0	$ 0.7	$ 0.9	$ 0.9	$ 0.9
		Telecom Services Contracts	Lower Cost per Contract *Reflects negotiated reduction in contract price*	$ 0.6	$ 0.6	$ 0.7	$ 0.6	$ 0.7	$ 0.7	$ 0.7
	Move to Mobile	FTE Reduction (Back Office)	FTE Reduction *Reflects expected reduction in 29 back office support staff by 2020*	$ 2.7	$ 0.5	$ 2.8	$ 0.3	$ 2.9	$ 2.9	$ 2.9
		Field Force	Measures Back Office FTE Reductions - Target dollars historically alloced under Field Force. Disaggregated for Actuals	$ -	$ 1.3	$ -	$ (1.9)	$ -	$ -	$ -
	Operations	Cable Locate Outsourcing	(Historical Cost - New Cost) * # of Units *Reflects negotiated savings for planned units being outsourced*	$ 7.6	$ 11.4	$ 7.8	$ 14.6	$ 7.9	$ 8.1	$ 8.2
		Fault Indicator Deployment	Lower Labour Hours per Unit *Estimate based on expected time savings for responding to a line fault. Tracked using historical data compared to actual response time*	$ 0.8	$ -	$ 0.8	$ -	$ 0.8	$ 0.8	$ 0.8
		Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to staff policy for inclement weather and expected overall unit volume reduction in trouble calls*	$ 2.8	$ 1.5	$ 4.1	$ 2.2	$ 5.9	$ 6.9	$ 7.9
		Stations Efficiencies	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.3	$ 0.4	$ 0.4	$ 0.1	$ 0.4	$ 0.4	$ 0.4
		Engineering Work Team Migration	FTE Reduction *A reduction in support staff that was utilizing the legacy software*	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
		Flexible Bill Window	Lower Cost per Unit for Meter Reads *Expected savings from a unit reduction in demand for manual meter reads and lower unit cost due to gained scheduling efficiencies*	$ 1.5	$ 1.5	$ 1.5	$ 1.6	$ 1.5	$ 1.5	$ 1.5
	Procurement	Procurement	IT Software Cost Reduction & RFP Rationalization *Reflects expected and negotiated savings*	$ 0.9	$ 1.7	$ 1.7	$ 1.5	$ 2.6	$ 2.6	$ 2.6
	Telematics	Telematics	Lower Liters of Fuel per KM *Reflects results of pilot program with expected reduction in Liters of fuel per KM driven*	$ 0.8	$ 0.1	$ 0.8	$ 0.1	$ 1.4	$ 1.3	$ 2.2
CCC	Administrative	Corporate Common Head Count Reductions	Spend Reduction *Identified headcount, consulting and Administrative reductions in Corporate Common. 2018 Plan vs Actual*	$ 1.7	$ 1.3	$ 1.9	$ 19.2	$ 1.9	$ 1.9	$ 1.9
	Procurement	Procurement	Lower Cost *Realized reduction in contracted spend in Corporate Common*	$ 2.3	$ 4.8	$ 2.3	$ 3.9	$ 2.3	$ 2.3	$ 2.3
Total	Capital			**$ 36.4**	**$ 33.5**	**$ 34.2**	**$ 34.9**	$ 37.8	$ 37.3	$ 39.0
	OM&A			**$ 29.4**	**$ 34.9**	**$ 33.7**	**$ 39.1**	$ 40.9	$ 42.9	$ 45.5
	Corporate Common			**$ 4.0**	**$ 6.0**	**$ 4.2**	**$ 23.0**	$ 4.2	$ 4.2	$ 4.2
	Total			**$ 69.9**	**$ 74.5**	**$ 72.0**	**$ 97.0**	$ 82.9	$ 84.4	$ 88.7

In summary, Hydro One achieved an additional $4.5 million in productivity savings in 2018 and an additional $25.0 million in productivity savings in 2019 relative to the forecast filed in the Application. Hydro One is committed to adhering to the robust governance process which has been established for defining and monitoring savings across the organization. Hydro One will continue to identify and develop new savings opportunities in both the Distribution and Transmission business for the benefit of ratepayers and stakeholders in 2020 and beyond. Ratepayers have directly benefited from the incremental OM&A savings as the associated cost reductions have contributed towards Hydro One's Earnings Sharing Mechanism, resulting in a refund to customers.

SEC INTERROGATORY #5

Reference:

Rate Application, p. 9

Interrogatory:

Please provide a table that shows the elements of the revenue requirement calculation approved in the EB-2017-0049 that is used to derive the fixed elements of the Capital Factor during the Custom IR term (i.e. a final version of Table 2 provided in EB-2017-0049, Draft Rate Order, p.11).

Response:

Table 2 as provided on page 11 of the Draft Rate Order submission from May 4, 2019 is provided below:

Table 2 – Summary of Revenue Requirement Components ($ millions)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,636.9	7,894.1	8,175.1	8,517.1	8,812.8
2	Return on Debt	E1-1-1	198.3	205.0	212.3	221.1	228.8
3	Return on Equity	E1-1-1	274.9	284.2	294.3	306.6	317.3
4	Depreciation	C1-6-2	397.8	415.0	425.5	442.4	455.6
5	Income Taxes	C1-7-2	43.1	50.0	51.1	54.5	64.5
6	Total Capital Related Revenue Requirement		914.1	954.2	983.2	1,024.7	1,066.1
7	Working Capital Related Revenue Requirement		21.2	22.4	23.4	24.5	25.7
8	Total Capital Related Revenue Requirement (excluding working capital component)		892.9	931.8	959.8	1,000.1	1,040.4
9	Less Productivity Factor (0.45%+0.15%)			(5.6)	(5.8)	(6.0)	(6.2)
10	Less Removing Working Capital from Capital Factor			(0.9)	(1.7)	(2.6)	(3.5)
11	**Total Capital Related Revenue Requirement**		**914.1**	**947.7**	**975.8**	**1,016.1**	**1,056.4**
12	OM&A	C1-1-1	544.4	550.1	555.9	561.7	567.6
13	Integration of Acquired Utilities	A-7-1					
14	**Total Revenue Requirement**		**1,458.5**	**1,497.9**	**1,531.7**	**1,577.9**	**1,624.0**
15	Increase in Capital Related Revenue Requirement			33.6	28.1	40.3	40.3
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.31%	1.87%	2.63%	2.55%
17	Less Capital Related Revenue Requirement in I-X			0.66%	0.66%	0.67%	0.68%
18	**Capital Factor**			**1.65%**	**1.21%**	**1.96%**	**1.88%**

Please note, that as stated in the Hydro One submission on page 9 footnote 2, the 2021 C factor is consistent with the 2020 Annual Update on August 30, 2019 (EB-2019-0043) and in the Decision and Rate Order on December 17, 2019 (EB-2019-0043). 2021 C factors reflects the correction made in the DRO Reply Submission on May 4, 2019 (EB-2017-0049) reflecting lower capital expenditures for 2021 and 2022.

Table 2 as provided in the EB-2019-0049 submission from August 30, 2019 is provided below.

Table 2 – Summary of Revenue Requirement Components ($ millions)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	Exhibit 1.2	7,636.9	7,894.1	8,175.1	8,514.1	8,803.5
2	Return on Debt	Exhibit 1.4	198.3	205.0	212.3	221.1	228.6
3	Return on Equity	Exhibit 1.4	274.9	284.2	294.3	306.5	316.9
4	Depreciation	Exhibit 1.2	397.8	415.0	425.5	442.3	455.4
5	Income Taxes	Exhibit 1.5	43.1	50.0	51.1	54.6	64.6
6	Total Capital Related Revenue Requirement		914.1	954.2	983.2	1,024.5	1,065.5
7	Working Capital Related Revenue Requirement		21.2	22.4	23.4	24.5	25.7
8	Total Capital Related Revenue Requirement (excluding working capital component)		892.9	931.8	959.8	999.9	1,039.8
9	Less Productivity Factor (0.45%+0.15%)			(5.6)	(5.8)	(6.0)	(6.2)
10	Less Removing Working Capital from Capital Factor	Exhibit 1.7		(0.9)	(1.7)	(2.6)	(3.5)
11	**Total Capital Related Revenue Requirement**		**914.1**	**947.7**	**975.8**	**1,015.9**	**1,055.8**
12	OM&A	Exhibit 1.1	544.4	550.1	555.9	561.7	567.6
13	Integration of Acquired Utilities						
14	**Total Revenue Requirement**		**1,458.5**	**1,497.9**	**1,531.7**	**1,577.7**	**1,623.4**
15	Increase in Capital Related Revenue Requirement			33.6	28.1	40.1	39.8
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.31%	1.87%	2.62%	2.52%
17	Less Capital Related Revenue Requirement in I-X			0.66%	0.66%	0.67%	0.68%
18	**Capital Factor**			**1.65%**	**1.21%**	**1.95%**	**1.85%**

SEC INTERROGATORY #6

Reference:
Rate Application, p. 9

Interrogatory:
Please provide the incremental reduction in the revenue requirement in 2021 (over the 2020 amount), as a result of the application of the stretch factor for: a) OM&A, and b) capital-related revenue requirement.

Response:
a)-b) As evident from Table 2 – Summary of Revenue Requirement Components ($ millions) as provided in SEC IR #5, 2021 OM&A is escalated by (inflation – productivity factor). 2021 OM&A of $561.7 relative to $555.9 million for 2020. The impact of the stretch factor on OM&A is approximately $3 million.

As for capital related revenue requirement reductions, Table 2 – Summary of Revenue Requirement Components ($ millions) as provided in SEC IR #5, lines 9 and 10 include the reductions on capital related revenue requirement due to productivity factor and the removal of working capital from capital factor calculation.

AMPCO INTERROGATORY #1

Reference:
Page 17

Interrogatory:
Hydro One states:

> *"As summarized in the Hydro One Networks' 2018-2022 Distribution Rate Application – Distribution Productivity Report ("Productivity Report") for 2018 and 2019 years, Hydro One was able to achieve additional $4.5 million in productivity savings in 2018 and an additional $25 million in productivity savings in 2019 relative to the forecast filed in the application. Hydro One is committed to adhering to the robust governance process which has been established for defining and monitoring savings across the organization."*

Please provide a description of the drivers of all productivity savings in 2018 and 2019 compared to forecast and explain how the additional productivity savings were achieved and measured.

Response:
On March 4, 2020, Hydro One filed the Distribution Productivity report. This was completed in response to the OEB's direction[1] to "file a report, within twelve months of this Decision and Order, showing the status of the productivity initiatives listed in I-25-Staff-123, including actual savings, with a discussion of any deviation from plan. The report, is to be filed on a standalone basis and will not be adjudicated. Hydro One is expected to update the report to file with its next rebasing application."

Please refer to attachment 1 within SEC IR #4 for a copy of this report.

The report filed provides analysis of the incremental achievement associated with both 2018 and 2019 actuals, relative to OEB filed levels.

[1] Decision and Order EB-2017-0049, dated March 7, 2019

AMPCO INTERROGATORY #2

Reference:
Page 17

Interrogatory:
Hydro One states:

> *"In 2019, the achieved ROE was 1.9% higher than the deemed ROE of 9.0% owing to weather and achieved productivity reductions, offset in part by increased operations, maintenance, and administration expenses."*

Please discuss if the increases in operations, maintenance, and administration expenses in 2019 are a one-time occurrence or expected to continue and why.

Response:
In 2019, Hydro One Distribution achieved incremental productivity, over and above the benefits provided directly to customers within the 2018-2022 OEB approved rate application. The incremental achievement was $5.4 million related to the customer call centre insourcing and accelerated savings with cable locates. For common initiatives, incremental savings of $18.8 million largely related to the corporate costing initiative. This is fully described in the Distribution Productivity report, filed with the OEB on March 4, 2020. Please refer to attachment 1 within SEC IR #4 for a copy of this report.

These incremental savings had the effect of partially offsetting other OM&A increases 2019, and as noted, contribute to the achievement of sharing of earnings.

An assessment of OM&A expenditures for 2020, 2021 and 2022 will be addressed in future applications and is not relevant to this proceeding.

AMPCO INTERROGATORY #3

Reference:

Interrogatory:

Please confirm the Group 1 account balances are consistent with the audited financial statements.

Response:

Confirmed