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BY EMAIL AND RESS

December 4, 2020

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

Dear Ms. Long:

EB-2020-0194: 2017- 2022 Transmission Revenue Requirement and Charge Determinants and 2018-2022 Distribution Revenue Requirement and Rates, Remittal of Future Tax Savings Issue – Interrogatory Responses

Hydro One Networks Inc. is submitting written responses to interrogatories from Ontario Energy Board staff and intervenors in respect of the above noted proceeding.

An electronic copy of the responses has been submitted via the Regulatory Electronic Submission System.

Sincerely,

Frank D'Andrea

Frank D'Andrea

OEB STAFF INTERROGATORY #1

Reference:
p. 7 – Table 1

Interrogatory:
Table 1 shows the tax savings deducted from regulatory income taxes. The 2019 Transmission tax savings were calculated by escalating the 2018 tax savings by the Revenue Cap Index (RCI).[1] OEB staff notes that this is consistent with the determination of Hydro One Transmission's 2019 revenue requirement, which applies a revenue cap incentive rate-setting approach.

Similarly, the OEB accepted Hydro One's incentive rate-setting approach using an RCI for adjusting Hydro One's 2021 and 2022 Transmission revenue requirements,[2] as well as Hydro One's 2020 to 2022 Distribution revenue requirements.[3] However, unlike the 2019 Transmission tax savings, the escalation approach was not used to calculate Hydro One Transmission's 2021 tax savings, or to calculate Hydro One Distribution's 2020 and 2021 tax savings.

a) Please explain Hydro One's rationale for its approach in determining the 2021 Transmission and 2020-2021 Distribution tax savings.

b) Please provide a revised Table 1, using the escalation approach for Hydro One Transmission's 2021, and Distribution's 2020 and 2021 tax savings. Please provide an updated Table 3 using the revised amounts in Table 1.

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[1] OEB staff notes that Hydro One escalated 2018 tax savings by 1.34% instead of 1.4% as approved in the Decision and Order for the Application of 2019 Electricity Transmission Revenue Requirement, April 25, 2019, EB-2018-0130
[2] Decision and Order for Electricity Transmission Revenue Requirement beginning January 1, 2020 until December 31, 2022, p. 23, EB-2019-0082, April 23, 2020
[3] Decision and Order for Electricity Distribution Rates beginning January 1, 2018 until December 31, 2022, p.23, EB-2017-0049, March 7, 2019,

Response:

a) The 2021 Transmission Misallocated Tax Savings and 2019-2021 Distribution Misallocated Tax Savings reflect the actual Misallocated Tax Savings amounts allocated to ratepayers, as calculated annually and presented in each of the relevant Draft Rate Orders. These are attached in the response to SEC-02.

The 2019 Transmission Misallocated Tax Savings amount was determined by escalating the 2018 Misallocated Tax Savings amount by the approved RCI for 2019 as there was no buildup of the 2019 Transmission revenue requirement.

On the contrary, with respect to the Transmission 2021 revenue requirement and Distribution 2019-2021 revenue requirement, a built-up by component was provided to support the Transmission System Plan and Distribution System Plan requirements. As part of the Custom IR Framework approved for Transmission (2020-2022) and Distribution (2018-2022), the following tables summarize the approved/proposed Revenue Cap Index (RCI) for each respective year.

As further presented in part b) below, escalating the Misallocated Tax amounts by the approved RCI for a given year results in higher recovery from rate payers as the annual RCIs during a Custom IR period are developed on an aggregate basis to be applied to the overall revenue requirement and not to one specific component within the revenue requirement. Hydro One is not proposing to escalate these amounts by the RCI unless otherwise ordered to do so by the OEB.

Dx Annual RCI

Custom Revenue Cap Index by Component (%)	**2019**[4]	**2020**[5]	**2021**[6]
Inflation Factor (I)	1.50	2.00	2.20
Productivity Factor (X)	-0.45	-0.45	-0.45
Capital Factor (C)	1.65	1.21	1.95
Custom Revenue Cap Index Total	**2.70**	**2.76**	**3.70**

Tx Annual RCI

Custom Revenue Cap Index by Component (%)	**2020**[7]
Inflation Factor (I)	2.00
Productivity Factor (X)	-0.30
Capital Factor (C)	2.88
Custom Revenue Cap Index Total	**4.58**

[4] 2019 Dx approved RCI from EB-2017-0049
[5] 2020 Dx approved RCI from EB-2019-0043
[6] 2021 Dx proposed RCI from EB-2020-0030
[7] 2021 Tx proposed RCI from EB-2020-0202

b) The reproduced Table 1 from Exhibit A, Tab 1, Schedule 1 is provided below.

Table 1: Misallocated Tax Savings Amounts Deducted from Regulatory Income Tax

Year	**Transmission**	**Proceeding**	**Distribution**	**Proceeding**
2017	$31.2M[8]	EB-2016-0160	-[9]	N/A
2018	$35.1M[10]	EB-2016-0160	$19.3M[11]	EB-2017-0049
2019	$35.4M[12]	EB-2018-0130	$29.7M =28.9*(1+2.70%)	Recalculated by escalating 2018 amount by 2019 approved Dx RCI from part a) above
2020	$32.8M[13]	EB-2019-0082	$30.5M =29.7*(1+2.76%)	Recalculated by escalating 2019 calculated amount by 2020 approved Dx RCI from part a) above
2021	$34.3M =32.8*(1+4.58%)	Recalculated by escalating 2020 amount by 2021 proposed Tx RCI from part a) above	$31.6 =$30.5*(1+3.70%)	Recalculated by escalating 2020 calculated amount by 2021 proposed Dx RCI from part a) above
Total for 2017-2021	**$168.8M**		**$111.1M**	

[8] EB-2016-0160/EB-2017-0280, Draft Rate Order dated 2017-11-16
[9] No tax savings in the 2017 Distribution rates
[10] EB-2016-0160/EB-2017-0359, Draft Rate Order dated 2017-12-04
[11] Tax savings on the DRO ($28.9M) was pro-rated by 8/12 as rate increases were effective May 1st ($28.9M * 8/12)
[12] Amount is based on 2018 tax savings for 4 months and 2018 tax savings adjusted by inflation (35.1M * 1.0134) for 8 months as 2019 rates were escalated by inflation and given the effective date of May 1, 2019
[13] EB-2019-0082, Draft Rate Order dated 2020-05-28

Given that the approach of escalating 2018 Distribution amount by the approved RCI components to derive 2019-2021 Dx and escalating 2020 Transmission amount by the approved RCI to derive 2021 Tx results in higher Misallocated Tax Savings ($18.7M for Dx and $3.8M for Tx in addition to higher interest) and Hydro One is not proposing to collect the higher Misallocated Tax amounts, reproducing Table 3 would not be provide any further helpful context in determining the appropriate interest to be collected.

OEB STAFF INTERROGATORY #2

Reference:
p. 8 – Table 2, pp. 9-11, 16

Interrogatory:
At the above references, carrying charges and related matters are discussed:

a) Carrying charge rates are provided on page 8, Table 2. The weighted average cost of debt (WACD) appears to be equal to Hydro One's approved WACD. The weighted average cost of capital (WACC) does not appear to be equal to Hydro One's approved WACC.

i. Please state whether the WACD and WACC in Table 2 are based on actual or approved rates.

ii. Table 2 shows the 2019 and 2020 Transmission WACD are 4.52% and 4.31%, respectively; and the Distribution WACD for both 2019 and 2020 is 4.33%. The 2019 and 2020 Transmission WACC are 5.59% and 5.31%, respectively; and the Distribution WACC for both 2019 and 2020 is 5.51%. If the WACD and WACC are based on actuals, please discuss whether the minor decline from 2019 to 2020 rates fully reflect the current economic environment.

iii. If the WACC in Table 2 are based on approved rates, please provide the references to the approved WACC in the applicable Hydro One proceedings.

iv. Based on the response provided for part a, please provide Hydro One's rationale for using actual or approved rates.

v. Please provide both the actual and approved WACD and WACC rates and associated carrying charge amounts, if not already provided in Table 2 and 3.

b) Carrying charge amounts are provided in Table 3. Please confirm that carrying charges are calculated using the simple interest method. If not confirmed, please explain how interest is calculated and why this method was used instead of the simple interest method.

c) On page 10, Hydro One indicated that as a result of the Original Decision[1], it had incurred a higher level of debt than it would have otherwise incurred. Please quantify the incremental debt incurred.

d) Hydro One has been directed to establish a new sub-account under Account 1592 specifically for the purposes of recording the revenue requirement impact of changes in CCA rules[2]. Similar to the misallocated tax savings issue, the 1592 sub-account is also used to record a revenue requirement difference related to income taxes. However, the 1592 sub-account allows for carrying charges at the prescribed rate. Please explain why Hydro One proposes to apply carrying charges at the WACD rate for a revenue requirement difference stemming from misallocated tax savings when the 1592 sub-account requires the prescribed rate to be used.

e) Hydro One proposed that carrying charges be applied during the recovery period. On page 16, Hydro One provides an example of the recovery mechanism using Option 3, where $183.3M (including carrying charges up to 2021) would be divided by seven and included in Hydro One's revenue requirement used to set UTRs for 2021 to 2027.
   i. Please explain how the carrying charges incurred during the recovery period will be recovered.

   ii. Please state whether a forecasted or actual carrying charge rate is proposed to be used during the recovery period and explain the reasons for the proposed approach. Please use an example to illustrate the timing of the recovery in relation to the carrying charge rate used.

<u>Response:</u>

a)
   i. The WACD and WACC in Table 2 in Exhibit A, Tab 1, Schedule 1 are based on the OEB approved capital structure and long-term debt, short-term debt and common equity allowed return rates, as shown below. The WACC is calculated using a 26.5% tax rate on the long and short-term debt rates.

[1] Decision and Order for 2017 and 2018 Transmission Revenue Requirements and Charge Determinants, November 1, 2017, EB-2016-0160
[2] Interim Rate Order for Electricity Distribution Rates beginning January 1, 2018 until December 31, 2022, June 6, 2019, EB-2017-0049

WACD and WACC		OEB Approved			
		Distribution	Transmission		
	Capital Structure Ratios	2018-22	2017	2018/2019	2020-22
a	Long-term Debt	56%	56%	56%	56%
b	Short-term Debt	4%	4%	4%	4%
c	Total Debt	60%	60%	60%	60%
d	Common Equity	40%	40%	40%	40%
	Allowed Return Rates				
e	Long-term Debt	4.47%	4.67%	4.68%	4.42%
f	Short-term Debt	2.29%	1.76%	2.29%	2.75%
g	WACD ((a*e)/c)+((b*f)/c)	4.33%	4.47%	4.52%	4.31%
h	Tax Rate	26.5%	26.5%	26.5%	26.5%
i	Common Equity	9.00%	8.78%	9.00%	8.52%
j	WACC (g*(1-h)*c)+(d*i)	5.51%	5.48%	5.59%	5.31%

ii. Not applicable as the WACD and WACC in Table 2 in Exhibit A, Tab 1, Schedule 1 are based on approved rates.

iii. The references to the components of the WACC's approved allowed return shown in Table 2 in Exhibit A, Tab 1, Schedule 1 (long-term debt, short-term debt and common equity) are in the applicable Hydro One Draft Rate Order proceedings, and are also included as attachments to this interrogatory, as referenced below:

Distribution	Transmission		
2018-22	**2017**	**2018**	**2020-22**
EB-2017-0049	EB-2016-0160 EB-2017-0280	EB-2016-0160 EB-2017-0359	EB-2019-0082
Attachment 1	Attachment 2	Attachment 3	Attachment 4

iv. Hydro One has always used approved interest rates for calculations relating to interest and sees no reason to deviate from this practice. All historic rates relevant to the approved rates are included in the schedules used to develop the approved rates. The interest rates on actual debt issued from the prior approval would be reflected in the rebasing of the approved WACD in 2023 and will impact any future interest calculations starting in 2023, in the event that the Misallocated Tax Savings are not fully recovered by 2023.

v. Approved WACD and WACC rates and associated carrying charge amounts are provided in Tables 2 and 3 in Exhibit A, Tab 1, Schedule 1. The actual rates are not applicable as discussed in response to part iv above.

b) Confirmed, carrying charges are calculated using the simple interest method.

c) The higher levels of debt that Hydro One would have otherwise incurred are consistent with the amounts provided in Table 1 in Exhibit A, Tab 1, Schedule 1.

d) The Divisional Court has determined that no part of the Future Tax Savings is allocable to ratepayers and should instead be paid to the shareholders in its entirety[3] because the amounts do not pertain to the provision of rate regulated service and thus fall outside of the calculation of rates. Given this, the amounts of the Misallocated Tax Savings Amounts cannot properly be characterized as a "Regulatory Asset" and subject to deferral and variance account treatment.[4]

The injured parties are Hydro One's shareholders; parties who are not directly involved in the rate setting process. During the Recovery Period, Hydro One shareholders would continue to suffer the effects of the time value of money in the same manner as they had sustained when the misallocations occurred. The longer the recovery period, the greater the potential exists for Hydro One and its shareholders to receive less than the amount they would have received had the Original Decision correctly determined the matter in accordance with the Divisional Court's reasoning.

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[3] Divisional Court Decision at para 60.

[4] The Board's prescribed interest rates as determined in EB-2006-0117, were expressly described to apply to costs that are properly the subject-matter of rate regulation and which are accounted for in approved regulatory accounts under the Uniform System of Accounts for natural gas utilities and electricity distributors. The prescribed interest rates also apply to the regulatory accounts of other rate or payment regulated entities when authorized by the OEB to use these rates and involve deferral and variance accounts or construction work in progress. The EB-2006-0117 Decision establishing these prescribed rates did not contemplate circumstances rates of interest or methods of calculating carrying charges (i.e. simple or compound interest) on categories of costs erroneously determined to be part of a rates revenue requirement.

The Original Decision ordered the unlawful allocation of tax savings. The Divisional Court has now determined, effectively, that this part of the decision is a nullity. The task now at hand is how the Board should exercise its discretion to fairly place parties in the position that they would have been, but for the error committed in first instance. Hydro One's proposal of using its weighted average cost of debt (as opposed to a higher rate based on the Board approved return on equity) and use of simple and not compounded interest is intended to provide a fair and balanced result and to avoid windfalls or be punitive in nature. This approach is consistent with the principles applied in awards of pre-judgment and post-judgment interest in accordance with ss. 128-130 of the *Courts of Justices Act*. See also *Hislop*, 2004 CanLII 43774 (ONCA) para 145; *Pilon* 2006 CanLII 6190 (ONCA) para 27*; Cobb*, 2017 ONCA 717 para 86.

Having the Board exercise discretion by approving a carrying cost charge based on Hydro One's approved weighted average cost of debt is analogous to the discretion courts have used to award simple interest at higher rates than statutorily prescribed rates, or for longer periods than the statutorily described period, if it considers it just to do so under s. 130(1). Section 130(2) prescribes seven factors courts should take into account in making this determination:

a. changes in market interest rates;
b. the circumstances of the case;
c. the fact that an advance payment was made;
d. the circumstances of medical disclosure by the plaintiff;
e. the amount claimed and the amount recovered in the proceeding;
f. the conduct of any party that tended to shorten or to lengthen unnecessarily the duration of the proceeding; and
g. any other relevant consideration.

By allowing courts discretion to depart from a default rate, s. 130 ensures courts can provide fair compensation to a plaintiff for injury (without over-compensation or under-compensation) in light of economic realities: *Cobb*, 2017 ONCA 717, para 86-88. Similar circumstances apply in these unique circumstances.

The OEB has applied this principle in the past when it was reasonable to do so, and awarded interest at rates higher than the prescribed rate, including in the following circumstances:

- Great Lakes Power Transmission LP - EB-2012-0300
    - Account 1575 (IFRS-CGAAP Transitional PP&E Amounts) is interest improved using the approved cost of capital rate
- OEB Accounting Procedures Handbook Guidance - March 2015 Update
    - Accounts 1575 and 1576 (CGAAP Accounting Changes) reference a "rate of return" component, with no reference to the OEB prescribed interest rates
- Report of the OEB - Regulatory Treatment of Pension and Other Post-employment Benefits Costs (EB-2015-0040)
    - Several different interest rate options were considered in this consultation ranging from the OEB's prescribed rate for deferral and variance accounts to a utility's weighted average cost of capital (WACC)

Other regulators have also applied this principle. For example, in the context of a prudency determinations, the Alberta Utilities Commission has exercised discretion and used the weighted average cost of capital of the utility to calculate recovery of carrying costs attributable to imprudently incurred costs.[5] Imprudently incurred costs are, by definition, costs determined to fall outside of the regulated rate setting paradigm. Akin to the present circumstances, the issue concerned fairness in calculating the refund amount improperly collected through rates.

In the circumstances at hand, the Divisional Court has clearly determined that the cost category does not pertain to rate setting and that all of the benefit from the misallocation should be provided to shareholders (at paragraph 60):

> Therefore under the long established benefits follows costs principle, no part of the benefit of the Future Tax Savings is allocable to ratepayers and should instead be paid to the shareholders in its entirety. The application of this principle is not affected by the Board’s mandate to approve “just and reasonable rates” or to achieve a reasonable balance between the interests of utility ratepayers and the interests of shareholders.

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[5] Alberta Utilities Decisions 24805-D01-2020; Decision 3378-D010-2016, at I-10-02-01 (Attachment to VECC-02).

Applying a rate less than Hydro One's WACD to the carrying cost amount would provide ratepayers with benefit arising from the Misallocation of Tax Savings and due to the time value of money arising from over the Recovery Period.

e)

(i) Hydro One will require two distinct accounts over the recovery period for the following amounts:

a. First, an account for Distribution to track the difference between approved and recovered Misallocated Tax Savings Amounts on an annual basis, with differences to be disposed of at the end of the recovery period; and
b. Second, a Carrying Cost Differential Account for Transmission and Distribution to capture the monthly carrying charge on the outstanding balance of the Misallocated Tax Savings Amounts over the recovery period. Hydro One proposes that the balances be brought for disposition at its 2028 rebasing, or such other time as the OEB determines.

(ii) The actual carrying charge rate is proposed to be used during the recovery period. Please see response to this IR under a) iv and e) i.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2017-0049

Capital Structure and Return on Capital

		Hydro One Proposed					OEB Decision Impact					OEB Approved				
($ millions)	**Supporting Reference**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Return on Rate Base																
Rate Base		$ 7,648.1	$ 8,004.2	$ 8,403.4	$ 8,928.8	$ 9,291.1	$ (11.2)	$ (110.1)	$ (228.3)	$ (411.7)	$ (478.3)	$ 7,636.9	$ 7,894.1	$ 8,175.1	$ 8,517.1	$ 8,812.8
Capital Structure:																
Third-Party long-term debt		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Deemed long-term debt		56.0%	56.0%	56.0%	56.0%	56.0%	0.0%	0.0%	0.0%	0.0%	0.0%	56.0%	56.0%	56.0%	56.0%	56.0%
Short-term debt		4.0%	4.0%	4.0%	4.0%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Common equity		40.0%	40.0%	40.0%	40.0%	40.0%	0.0%	0.0%	0.0%	0.0%	0.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Capital Structure:																
Third-Party long-term debt																
Deemed long-term debt		$ 4,283.0	$ 4,482.3	$ 4,705.9	$ 5,000.1	$ 5,203.0	(6.3)	(61.7)	(127.9)	(230.5)	(267.8)	$ 4,276.7	$ 4,420.7	$ 4,578.1	$ 4,769.6	$ 4,935.2
Short-term debt		305.9	320.2	336.1	357.2	371.6	(0.4)	(4.4)	(9.1)	(16.5)	(19.1)	305.5	315.8	327.0	340.7	352.5
Common equity		3,059.3	3,201.7	3,361.4	3,571.5	3,716.4	(4.5)	(44.0)	(91.3)	(164.7)	(191.3)	3,054.8	3,157.6	3,270.0	3,406.8	3,525.1
		$ 7,648.1	**$ 8,004.2**	**$ 8,403.4**	**$ 8,928.8**	**$ 9,291.1**	**(11.2)**	**(110.1)**	**(228.3)**	**(411.7)**	**(478.3)**	**$ 7,636.9**	**$ 7,894.1**	**$ 8,175.1**	**$ 8,517.1**	**$ 8,812.8**
Allowed Return:																
Third-Party long-term debt		4.47%	4.47%	4.47%	4.47%	4.47%	0.00%	0.00%	0.00%	0.00%	0.00%	4.47%	4.47%	4.47%	4.47%	4.47%
Deemed long-term debt		4.47%	4.47%	4.47%	4.47%	4.47%	0.00%	0.00%	0.00%	0.00%	0.00%	4.47%	4.47%	4.47%	4.47%	4.47%
Short-term debt		2.29%	2.29%	2.29%	2.29%	2.29%	0.00%	0.00%	0.00%	0.00%	0.00%	2.29%	2.29%	2.29%	2.29%	2.29%
Common equity		9.00%	9.00%	9.00%	9.00%	9.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Return on Capital:																
Third-Party long-term debt		$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -
Deemed long-term debt		$ 191.6	$ 200.5	$ 210.5	$ 223.5	$ 232.6	(0.3)	(2.8)	(5.7)	(10.2)	(11.8)	$ 191.3	$ 197.7	$ 204.8	$ 213.3	$ 220.7
Short-term debt		$ 7.0	$ 7.3	$ 7.7	$ 8.2	$ 8.5	(0.0)	(0.1)	(0.2)	(0.4)	(0.4)	$ 7.0	$ 7.2	$ 7.5	$ 7.8	$ 8.1
Total return on debt		**$ 198.6**	**$ 207.8**	**$ 218.2**	**$ 231.7**	**$ 241.1**	**$ (0.3)**	**$ (2.9)**	**$ (6.0)**	**$ (10.5)**	**$ (12.3)**	**$ 198.3**	**$ 205.0**	**$ 212.3**	**$ 221.1**	**$ 228.8**
Common equity		**$ 275.3**	**$ 288.2**	**$ 302.5**	**$ 321.3**	**$ 334.3**	**$ (0.4)**	**$ (4.0)**	**$ (8.2)**	**$ (14.7)**	**$ (17.1)**	**$ 274.9**	**$ 284.2**	**$ 294.3**	**$ 306.6**	**$ 317.3**

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
Return on Rate Base							Note 2
Rate Base	Exhibit 1.2	$ 10,554.4	$ 11,225.5	$ (31.7)	$ (77.5)	$ 10,522.7	$ 11,148.0
Capital Structure:							
Third-Party long-term debt		56.00%	56.00%	-1.36%	-1.05%	54.64%	54.95%
Deemed long-term debt		0.00%	0.00%	1.36%	1.05%	1.36%	1.05%
Short-term debt		4.00%	4.00%	0.00%	0.00%	4.00%	4.00%
Common equity		40.00%	40.00%	0.00%	0.00%	40.00%	40.00%
Capital Structure:							
Third-Party long-term debt	Exhibit 1.4.1 and 1.4.2	5,910.4	6,286.3	(160.9)	(160.9)	5,749.5	6,125.4
Deemed long-term debt		0.0	0.0	143.1	117.5	143.2	117.5
Short-term debt		422.2	449.0	(1.3)	(3.1)	420.9	445.9
Common equity		4,221.7	4,490.2	(12.7)	(31.0)	4,209.1	4,459.2
		10,554.4	**11,225.5**	**(31.7)**	**(77.5)**	**10,522.7**	**11,148.0**
Allowed Return:							
Third-Party long-term debt	Exhibit 1.4.1 & 1.4.2	4.67%	4.52%	0.00%	0.00%	4.67%	4.52%
Deemed long-term debt	Exhibit 1.4.1 & 1.4.2	4.67%	4.52%	0.00%	0.00%	4.67%	4.52%
Short-term debt		1.76%	1.76%	0.00%	0.00%	1.76%	1.76%
Common equity		8.78%	8.78%	0.00%	0.00%	8.78%	8.78%
Return on Capital:							
Third-Party long-term debt		275.8	284.1	(7.5)	(7.3)	268.3	276.8
Deemed long-term debt		0.0	0.0	6.7	5.3	6.7	5.3
Short-term debt		7.4	7.9	(0.0)	(0.1)	7.4	7.8
AFUDC return on Niagara Reinforcement Proje	see below	4.6	4.5	-	(4.5)	4.6	-
Total return on debt		**$ 287.8**	**$ 296.4**	**$ (0.9)**	**$ (6.5)**	**$ 287.0**	**$ 289.9**
Common equity		**$ 370.7**	**$ 394.2**	**$ (1.1)**	**$ (2.7)**	**$ 369.6**	**$ 391.5**
AFUDC return on Niagara Reinforcement Project							
CWIP	Note 1	99.1	99.1			99.1	
Deemed long-term debt		4.67%	4.52%			4.67%	
		4.6	4.5			4.6	

Note 1: As per EB-2016-0160 Decision and Order on September 28, 2017.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Capital Structure and Return on Capital

($ millions)	Supporting Reference	OEB Approved 2018	CoC Update 2018	OEB Revised 2018
Return on Rate Base				
Rate Base	Exhibit 1.2	$ 11,148.0	$ -	$ 11,148.0
Capital Structure:				
Third-Party long-term debt		54.95%	(5.90%)	49.05%
Deemed long-term debt		1.05%	5.90%	6.95%
Short-term debt		4.00%	0.00%	4.00%
Common equity		40.00%	0.00%	40.00%
Capital Structure:				
Third-Party long-term debt	Exhibit 1.4.1	6,125.4	(657.3)	5,468.1
Deemed long-term debt		117.5	657.3	774.8
Short-term debt		445.9	-	445.9
Common equity		4,459.2	-	4,459.2
		11,148.0	**(0.0)**	**11,148.0**
Allowed Return:				
Third-Party long-term debt	Exhibit 1.4.1	4.52%	0.16%	4.68%
Deemed long-term debt	Exhibit 1.4.1	4.52%	0.16%	4.68%
Short-term debt		1.76%	0.53%	2.29%
Common equity		8.78%	0.22%	9.00%
Return on Capital:				
Third-Party long-term debt		276.8	(21.0)	255.8
Deemed long-term debt		5.3	30.9	36.2
Short-term debt		7.8	2.4	10.2
AFUDC return on Niagara Reinforcement Project		-	-	-
Total return on debt		**289.9**	**$ 12.3**	**$ 302.3**
Common equity		**$ 391.5**	**$ 9.8**	**$ 401.3**

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Capital Structure and Return on Capital

($ millions)	Supporting Reference	Hydro One Proposed 2020	Hydro One Proposed 2021	Hydro One Proposed 2022	OEB Decision Impact 2020	OEB Decision Impact 2021	OEB Decision Impact 2022	OEB Approved 2020	OEB Approved 2021	OEB Approved 2022
Return on Rate Base										
Rate Base		$ 12,407.0	$ 13,130.2	$ 13,951.7	$ (47.4)	$ (202.9)	$ (310.8)	$ 12,359.6	$ 12,927.3	$ 13,640.9
Capital Structure:										
Third-Party long-term debt		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Deemed long-term debt		56.0%	56.0%	56.0%	0.0%	0.0%	0.0%	56.0%	56.0%	56.0%
Short-term debt		4.0%	4.0%	4.0%	0.0%	0.0%	0.0%	4.0%	4.0%	4.0%
Common equity		40.0%	40.0%	40.0%	0.0%	0.0%	0.0%	40.0%	40.0%	40.0%
Capital Structure:										
Third-Party long-term debt										
Deemed long-term debt		$ 6,947.9	$ 7,352.9	$ 7,813.0	(26.5)	(113.6)	(174.0)	$ 6,921.4	$ 7,239.3	$ 7,638.9
Short-term debt		496.3	525.2	558.1	(1.9)	(8.1)	(12.4)	494.4	517.1	545.6
Common equity		4,962.8	5,252.1	5,580.7	(18.9)	(81.2)	(124.3)	4,943.8	5,170.9	5,456.4
		$ 12,407.0	**$ 13,130.2**	**$ 13,951.7**	**(47.4)**	**(202.9)**	**(310.8)**	**$ 12,359.6**	**$ 12,927.3**	**$ 13,640.9**
Allowed Return:										
Third-Party long-term debt [1]		4.33%	4.33%	4.33%	0.09%	0.09%	0.09%	4.42%	4.42%	4.42%
Deemed long-term debt		4.33%	4.33%	4.33%	0.09%	0.09%	0.09%	4.42%	4.42%	4.42%
Short-term debt		2.75%	2.75%	2.75%	0.00%	0.00%	0.00%	2.75%	2.75%	2.75%
Common equity		8.52%	8.52%	8.52%	0.00%	0.00%	0.00%	8.52%	8.52%	8.52%
Return on Capital:										
Third-Party long-term debt		$ -	$ -	$ -	-	-	-	$ -	$ -	$ -
Deemed long-term debt [2]		$ 300.1	$ 318.5	$ 338.4	6.1	1.8	(0.4)	$ 306.2	$ 320.3	$ 338.0
Short-term debt		$ 13.6	$ 14.4	$ 15.3	(0.1)	(0.2)	(0.3)	$ 13.6	$ 14.2	$ 15.0
Total return on debt		**$ 313.8**	**$ 332.9**	**$ 353.7**	**$ 6.0**	**$ 1.6**	**$ (0.7)**	**$ 319.8**	**$ 334.5**	**$ 353.0**
Common equity [3]		**$ 421.9**	**$ 447.5**	**$ 475.5**	**$ (0.7)**	**$ (7.0)**	**$ (10.7)**	**$ 421.2**	**$ 440.6**	**$ 464.9**

Note 1: Proposed in Argument in Chief November 2019, which reduced the ROE from 8.98% to 8.52% and deemed short term debt rate from 2.82% to 2.75% based on the cost of capital parameters issued by the OEB on October 31, 2019. In addition, the long term debt rate was reduced from 4.57% to 4.33% reflecting both the impact of 2019 actual debt issuances as of April 2019 and the lower forecast interest rates on the remaining 2019 forecast debt issuances and 2020 forecast debt issuances.

Note 2: Hydro One Proposed Long-term debt of $300.1 million for 2020 equals rate base of 12,407 x 56% x 4.33% less $0.4 million reduction to incorporate revenue requirement impact associated with OEB IR -206.

Note 3: Hydro One Proposed Common Equity of $421.9 million for 2020 equals rate base of 12,407 x 40% x 8.52% less $0.7 million reduction to incorporate revenue requirement impact associated with OEB IR -206.

OEB STAFF INTERROGATORY #3

<u>Reference:</u>
p. 9

<u>Interrogatory:</u>
At the above reference, the statement is made that:

> *"Matters involving the payment of monies made under errors of law and impacted by lengthy appeal periods are distinguishable from normal utility operation circumstances."*

Please state whether the above statement is Hydro One's opinion only, or whether it is supported by legal or other precedents. Please provide references to any relevant cases.

<u>Response:</u>
The above mentioned statement is Hydro One's opinion and is intended to reflect the unique circumstances involved with the repayment of large sums of monies and in contrast to its normal utility operations.

Hydro One's normal utility operations concern the provision of rate regulated services. The Misallocated Tax Savings Amounts do not form part of costs for the provision of rate regulated services. Hydro One's normal utility operations do not include the recovery of monies paid under errors of law. The current circumstances have resulted in a lengthy process where an amount that would have otherwise been payable to shareholders was erroneously determined to be included in the regulatory rate setting paradigm.

The unique features in these circumstances are: (1) that the underlying amount was not a cost or cost category that Hydro One had ever applied-for rate treatment, but instead the regulator imposed this result; (2) the impugned costs arose from Hydro One's sole shareholder selling a portion of its ownership interests in Hydro One's parent entity; and (3) the parties aggrieved are not the ratepayers, but rather Hydro One's shareholders. These facts are not part of Hydro One's normal day to day utility operations.

As discussed in its response to AMPCO-01 and BOMA-03, Hydro One views the present circumstance to be analogous to commercial disputes that result in judicial pronouncements and judicial determinations. While these types of circumstances are a normal part of its business, the resolution of such disputes before a court would look to the application of pre and post-judgement interest as outlined in the *Court of Justice Act* ("**CJA**"),[1] and the equitable principles of keeping whole aggrieved parties and the factors outlined pursuant to section 128 and 129 may be helpful to the Board in the case at hand. Please see AMPCO-01 for a full discussion of the CJA.

In this context, and when exercising its discretion, Hydro One submits it is reasonable for the Board to take the following factors into consideration in a manner analogous to the approach Ontario courts would apply under the CJA:

- the lengthy appeal process;
- the negative effects on Hydro One and its shareholders;
- the fact that the shareholders reasonably anticipated all of the impugned tax savings would form part of Hydro One's valuation and offsetting the real and upfront cost of the Departure Tax; and
- the notional carrying costs that Hydro One has incurred given the lengthy period incurred to both resolve this dispute in addition to the length of time of the Recovery Period durations.

As referenced in the application, a similar but factually different circumstance has occurred in Alberta where disputes involving allocations of line losses to regulated customers was the subject matter of lengthy litigation.[2] In that case, unlike the present, the party responsible for determining and applying the impugned line loss methodology, the Alberta Electric System Operator, was not aggrieved by either application of the unlawful line loss method or the re-determined method. There was no dispute that the cost category involved, line losses, were a cost of providing rate regulated services. At issue was the proper calculation and allocation of this cost and whether an additional carrying costs was appropriate. In the Decision, the Alberta Utilities Commission ultimately approved the utility's weighted average cost of capital in calculating carrying costs included in the overall amount returned to ratepayers.

[1] Courts of Justice Act, R.S.O. 1990, c. C.43.
[2] Alberta Utilities Commission Decision 790-D04-2016.

OEB STAFF INTERROGATORY #4

Reference:

p. 11

Interrogatory:

At the above reference, it is stated that:

> *The proposed implementation of Misallocated Tax Savings Amounts recovery is January 1, 2021 or, if that is not possible from a timing perspective, approximately 30 days from the date that the Board issues its decision in this matter.*

Please provide Hydro One's views on the extent to which the COVID-19 pandemic should be a factor in determining the timing of the recovery of these amounts.

Response:

Delaying the recovery of the Misallocated Tax Savings until after the COVID-19 pandemic is acceptable provided Hydro One shareholders are held whole through the application of a carrying charge at the WACD rate. The two trade-offs the OEB must balance are: (i) whether the delay now is worth the higher cost to customers incurred through the application of a carrying charge; and (ii) intergenerational inequities that will arise with a longer or delayed recovery period.

The OEB may also wish to consider that delaying recovery may mean missing the opportunity to partially offset the rate increase with the rate decrease proposed as part of Hydro One's annual update for 2021 distribution rates (EB-2020-0030).

As well, Hydro One's recovery proposal is designed to stagger rate increases over a three year period (2021 – Misallocated Tax Savings; 2022 – remove allocation of Future Tax Savings; 2023 – Hydro One Tx and Dx rebasing). If the OEB decides to delay recovery of the Misallocated Tax Savings, it may wish to consider any other rate impacts in the year it proposes to commence recovery of these amounts so it mitigates rate impacts to customers by staggering rate increases over time.

OEB STAFF INTERROGATORY #5

Reference:
pp. 12-13

Interrogatory:
At the above reference, it is stated that:

> *Consistent with the OEB approved treatment of the recovery of foregone revenue amounts as an adjustment to base distribution rates in EB-2017-0049, Hydro One expects that R1 and R2 distribution customers will be protected from distribution rate increases associated with the recovery of Misallocated Tax Savings Amounts (i.e. the $1.87 impact shown in Table 5) as a result of the distribution rate protection (DRP) program.*

Please provide the expected impacts in the format of Table 5 for each of Hydro One's residential classes including the seasonal rates class for Options 1, 2 and 3.

Response:
The estimated impacts on Hydro One's R1 residential class from the recovery of Misallocated Tax Savings Amounts is provided in the submission based on the assumption that the average rate increases will apply equally across all rate classes. Using the same assumption, the estimated impacts on Hydro One's R2, UR and Seasonal residential classes are provided in Appendices 1 to 3, respectively.

Appendix 1
R2 Residential Class

Table 5: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2022

Year	Rates Increase		Bill Impact		$ Impact on Typical R2 Residential Customer *
	Dx	Tx	Dx R2 Residential Customer *	Tx Customer	
2021	3.3%	5.5%	1.0%	0.4%	$2.16 **
2022	0.0%	0.0%	0.3%	0.0%	$0.66

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR.
** Hydro One anticipates that R2 customers would not see this increase as a result of the DRP program.

Table 6: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2024

Year	Rates Increase		Bill Impact		$ Impact on Typical R2 Residential Customer *
	Dx	Tx	Dx R2 Residential Customer *	Tx Customer	
2021	1.6%	2.8%	0.5%	0.2%	$1.08 **
2022	0.0%	0.0%	0.2%	0.0%	$0.33

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR.
** Hydro One anticipates that customers would not see this increase as a result of the DRP program.

Table 7: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2027

Year	Rates Increase		Bill Impact		$ Impact on Typical R2 Residential Customer *
	Dx	Tx	Dx R2 Residential Customer *	Tx Customer	
2021	0.9%	1.6%	0.3%	0.1%	$0.62 **
2022	0.0%	0.0%	0.1%	0.0%	$0.19

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR.
** Hydro One anticipates that customers would not see this increase as a result of the DRP program.

Appendix 2
UR Residential Class

Table 5: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2022

Year	Rates Increase		Bill Impact		$ Impact on Typical UR Residential Customer *
	Dx	Tx	Dx UR Residential Customer *	Tx Customer	
2021	3.3%	5.5%	0.7%	0.4%	$1.12
2022	0.0%	0.0%	0.4%	0.0%	$0.73

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 6: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2024

Year	Rates Increase		Bill Impact		$ Impact on Typical UR Residential Customer *
	Dx	Tx	Dx UR Residential Customer *	Tx Customer	
2021	1.6%	2.8%	0.3%	0.2%	$0.56
2022	0.0%	0.0%	0.2%	0.0%	$0.36

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 7: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2027

Year	Rates Increase		Bill Impact		$ Impact on Typical UR Residential Customer *
	Dx	Tx	Dx UR Residential Customer *	Tx Customer	
2021	0.9%	1.6%	0.2%	0.1%	$0.32
2022	0.0%	0.0%	0.1%	0.0%	$0.21

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Appendix 3
Seasonal Residential Class

Table 5: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2022

Year	Rates Increase		Bill Impact		$ Impact on Typical Seasonal Residential Customer *
	Dx	Tx	Dx Seasonal Residential Customer *	Tx Customer	
2021	3.3%	5.5%	1.5%	0.4%	$2.08
2022	0.0%	0.0%	0.2%	0.0%	$0.27

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 6: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2024

Year	Rates Increase		Bill Impact		$ Impact on Typical Seasonal Residential Customer *
	Dx	Tx*	Dx Seasonal Residential Customer *	Tx Customer	
2021	1.6%	2.8%	0.8%	0.2%	$1.04
2022	0.0%	0.0%	0.1%	0.0%	$0.13

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 7: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2027

Year	Rates Increase		Bill Impact		$ Impact on Typical Seasonal Residential Customer *
	Dx	Tx	Dx Seasonal Residential Customer*	Tx Customer	
2021	0.9%	1.6%	0.4%	0.1%	$0.59
2022	0.0%	0.0%	0.1%	0.0%	$0.08

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

OEB STAFF INTERROGATORY #6

Reference:
p.14 and p.15 Table 9

Interrogatory:
At the above reference, the following statement is made:

> *The adjustment to the calculation of regulatory income taxes will be reflected in Hydro One's annual distribution and transmission filings for 2022 revenue requirement and rates ("2022 Annual Updates").*

Please provide the expected bill impacts of making this adjustment for each of Hydro One's residential classes including the seasonal rates class in the format of Table 9.

Response:
The estimated impacts on Hydro One's R1 residential class from the adjustment to the calculation of regulatory income taxes in the calculation of the 2022 revenue requirement was provided in the submission based on the assumption that the average rate increases will apply equally across all rate classes. Using the same assumption, the estimated impacts on Hydro One's R2, UR and Seasonal residential classes are provided in Appendix 1.

Appendix 1

R2 Residential Class

Table 9: Bill Impacts of the 2022 Revenue Requirement Adjustment to Regulatory Income Tax

Year	Rates Increase		Bill Impact*		$ Impact on Typical R2 Residential Customer*
	Dx	Tx	Dx R2 Residential Customer	Tx Customer	
2022	1.4%	1.7%	0.5%	0.1%	$1.11 **

* The 2022 Transmission rate increase will not impact Distribution customer bills until 2023, and as such, the impact amount shown for a typical R2 residential customer includes a bill impact of 0.1% and a dollar impact of $0.21 that will not affect distribution customer bills until 2023.
** Hydro One anticipates that R2 customers would not see $0.90 of this increase as a result of the DRP program.

UR Residential Class

Table 9: Bill Impacts of the 2022 Revenue Requirement Adjustment to Regulatory Income Tax

Year	Rates Increase		Bill Impact*		$ Impact on Typical UR Residential Customer*
	Dx	Tx	Dx UR Residential Customer	Tx Customer	
2022	1.4%	1.7%	0.4%	0.1%	$0.70

* The 2022 Transmission rate increase will not impact Distribution customer bills until 2023, and as such, the impact amounts shown for a typical UR residential customer include a bill impact of 0.1% and a dollar impact of $0.23 that will not affect distribution customer bills until 2023.

Seasonal Residential Class

Table 9: Bill Impacts of the 2022 Revenue Requirement Adjustment to Regulatory Income Tax

Year	Rates Increase		Bill Impact*		$ Impact on Typical Seasonal Residential Customer*
	Dx	Tx	Dx Seasonal Residential Customer	Tx Customer	
2022	1.4%	1.7%	0.7%	0.1%	$0.95

* The 2022 Transmission rate increase will not impact Distribution customer bills until 2023, and as such, the impact amounts shown for a typical Seasonal residential customer include a bill impact of 0.1% and a dollar impact of $0.08 that will not affect distribution customer bills until 2023.

OEB STAFF INTERROGATORY #7

Reference:
p.15

Interrogatory:
Regarding regulatory income tax calculations after 2022, Hydro One states that:

> *"The amended calculation of annual regulatory income tax amounts would continue to be used in all future rates revenue requirements applications post 2022."*

a) Please confirm that the amended calculation is referring to the exclusion of any future tax savings (i.e. referred to as the "Deferred Tax Asset Sharing" line in Hydro One's draft rate orders for 2017 to 2022 rate applications) in regulatory income tax amounts included in future revenue requirements post 2022.

b) If not confirmed, please explain how the amended calculation is calculated and explain why the calculation is appropriate.

Response:
a) Confirmed. The "amended calculation" refers to the exclusion of the Deferred Tax Asset Sharing amounts in regulatory income tax amounts in future revenue requirement calculations after 2022 (at the next rebasing). The recovery of the Misallocated Tax Savings will also be included in rates over such period of time as directed by the OEB.

b) N/A.

OEB STAFF INTERROGATORY #8

Reference:
p.17

Interrogatory:
At the above reference, it is stated that part of the relief Hydro One is requesting is:

Amendments to rate orders for the 2017-2018 Transmission Revenue Requirement (EB-2016-0160), the 2019 Transmission Revenue Requirement (EB-2018-0130), the 2018-2022 Distribution Revenue Requirement (EB-2017-0049) and the 2020-2022 Transmission Revenue Requirement (EB-2019-0082) to give effect to the following:

a) Recovery of Misallocated Tax Savings Amounts commencing January 1 2021 or as determined by this Board and over a recovery period to be determined by the Board;

b) Revisions to the method of calculating regulatory income taxes beginning in 2022 to remove the allocation of tax savings from future calculations of regulatory income tax;

Direction to Hydro One to reflect such revisions in its 2022 annual update filings for distribution and transmission;

a) Please discuss what Hydro One would envisage the process as being for achieving the above requested relief with respect to rate order amendments.

b) Please state why Hydro One believes that it would be necessary for the OEB to provide the above-referenced direction regarding its 2022 annual update filings to Hydro One.

Response:

a) Misallocated Tax Savings – Distribution

In the case of the Distribution Misallocated Tax Savings Amounts, Hydro One anticipates the following process might be followed:

- the Board determines the implementation date and period of recovery as part of this proceeding.
- within seven (7) days of receiving the decision, Hydro One would file detailed calculations of the required fixed and variable base rate adjustments, by rate class, that would be required to implement the Board's decision.
- The Board would review those calculations and amend any previously issued rate order for 2021 distribution rates to include the fixed and variable base rate adjustments in the 2021 Distribution Tariff.
- The calculated distribution base rate adjustments could be included in the amended Tariff as a rider or as part of the base distribution fixed and variable rates that appear on the Tariff.[1] The Distribution Tariff would show the new riders or updated fixed and variable rates as being effective as of the date consistent with the Board's decision on implementation timing.

Misallocated Tax Savings – Transmission

In the case of the Transmission Misallocated Tax Savings Amounts, Hydro One anticipates the following process might be followed:

- the Board determines the implementation date and period of recovery as part of this proceeding
- The Board would update the 2021 Uniform Transmission Rate (UTRs) to include the recovery of the 2021 Transmission Misallocated Tax Savings amount in Hydro One's Rates Revenue Requirement included in the calculation of the 2021 UTRs. Hydro One anticipates that the 2021 UTRs could be updated to collect the full 2021 Misallocated Tax Savings amount over the remaining period in 2021, or the 2021 Misallocated Tax Savings amount could be prorated for the time remaining in 2021 (which would mitigate customer impacts), with any remaining 2021 balance included in the amounts to be recovered in subsequent years of the approved disposition period.

[1] This allows DRP rate protection for R1 and R2 customers. See pages 13 and 14 of Submission.

b) The 2022 Annual Update Transmission and Distribution Filings are contemplated to be the first filings following this proceeding where Hydro One will be providing detailed rates calculations for the final year of its approved Custom IR methodologies for Transmission and Distribution. Hydro One intends to remove the tax savings allocation deduction used to calculate regulatory income taxes and previously included in prior period Annual Update Filing commencing in the 2022 Annual Update Filings and also in all subsequent rate periods. Hydro One's request for this relief is viewed as providing clarity and is consistent with the Divisional Court's findings and remittal instructions found at paragraphs 60 and 61 of its Decision. Go-forward removal of the tax savings allocation from the calculation of regulatory income taxes is an integral part of how the errors in the Original Decision are proposed to be corrected.

LPMA INTERROGATORY #1

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

Interrogatory:
As part of the July 16, 2020 Ontario Divisional Court decision, did the decision make any determination on compensation/payment to Hydro One related to carrying costs?

Response:
No. The Divisional Court found that matters concerning the implementation of its decision, which Hydro One submits includes calculations and method of recovering of the Misallocated Tax Savings, were matters remitted to the Ontario Energy Board. See Hydro One Networks Inc. v. Ontario Energy Board, 2020 ONSC 4331 at paragraph 61 attached at the response to Energy Probe-01.

LPMA INTERROGATORY #2

Reference:
Exhibit A, Tab 1, Schedule 1, Tables 2 & 3 & page 10

Interrogatory:

a) Please add a section to Table 2 that shows the carrying cost rate equal to the Bank of Canada Rate plus 150 basis points.

b) Please add a section to Table 3 that shows the carrying cost using the Bank of Canada Rate plus 150 basis points.

c) Please provide a table that shows the calculation of the carrying cost rate and the carrying cost utilizing the Bank of Canada Rate plus 150 basis points, along with the dates for which each Bank of Canada rate was in place. Please provide a live Excel spreadsheet with these calculations.

d) Please add a section to Table 2 that shows the carrying cost rate equal to the Board approved short term debt rate for each year shown.

e) Please add a section to Table 3 that shows the carrying cost using the Board approved short term debt rate.

f) Are the rates shown for the weighted average cost of debt in Table 2 the weighted average of all debt or only the debt issued in the years shown? If the former, please add sections to Tables 2 and 3 that show the rates and costs associated only with the debt issued in the years shown. Please use the most recent forecast of the weighted average cost of debt to be issued for 2020 and 2021. If no debt was issued in any of the years shown, for either transmission or distribution, please explain the statement on page 10 that “Hydro One incurred a higher level of debt than it otherwise would have.”

Response:

a)

Bank of Canada Rate (Average) plus 150 basis points						
	2017	2018	2019	2020	2021[1]	2022[2]
Transmission	2.20%	2.90%	3.25%	2.10%	2.10%	2.10%
Distribution		2.90%	3.25%	2.10%	2.10%	2.10%

b)

Carrying costs based on Bank of Canada Rate (Average) plus 150 basis points					
($M)	2017	2018	2019	2020	2021
Transmission	0.3	1.4	2.7	2.5	3.1
Distribution		0.3	1.1	1.2	1.7

c) Please refer to Attachment 1 for a live Excel spreadsheet with these calculations, which includes the dates for which each Bank of Canada rate was in place

d)

Board Approved Short Term Debt Rate						
	2017	2018	2019	2020	2021	2022
Transmission	1.76%	2.29%	2.29%	2.75%	2.75%	2.75%
Distribution		2.29%	2.29%	2.29%	2.29%	2.29%

e)

Carrying costs based on Board Approved Short Term Debt Rate					
($M)	2017	2018	2019	2020	2021
Transmission	0.3	1.1	1.9	3.3	4.1
Distribution		0.2	0.7	1.3	1.9

f) The rates shown for the weighted average cost of debt in Table 2 are neither the weighted average of all debt or only the debt issued in the years shown. They are based on the approved short-term and long-term debt rates for each of those years (please refer to the response to Staff-02(a)(i) for WACD calculation). Hydro One's rationale for using approved rates is discussed in the response to Staff-02(a)(iv).

[1] 2021 rate assumes the 2020 Bank of Canada Rate (Average) plus 150 basis points
[2] 2022 rate assumes the 2020 Bank of Canada Rate (Average) plus 150 basis points

Actual 2020 and 2021 debt will be reflected in the approved WACD rates in 2023. If no long-term debt was issued in a particular year, borrowing would be temporarily funded with short-term debt, and long-term debt would be issued in the following year to replace this debt, which is what occurred in 2017 and 2018.

LPMA INTERROGATORY #3

Reference:

Exhibit A, Tab 1, Schedule 1, page 11

Interrogatory:

Please provide a table that shows the total carrying costs to be incurred during the three recovery periods noted in the evidence (i.e. 2021 – 2022, 2021 – 2024 and 2021 – 27) for each of the interest cost methodologies shown in Table 3, modified to include the Bank of Canada Rate plus 150 basis points, the Board approved short term debt rate and the rate for debt issued in the current year requested in Interrogatory #2 above. In all cases, please assume that the commencement date of the recovery for the Misallocated Tax Savings is April 1, 2021.

Response:

In respect of the carrying charges applicable to the Misallocated Tax Savings amounts over the 2017 - 2020 period, Hydro One will apply the rate approved in this proceeding, which it proposes to be WACD. Please see response to Staff-02(d) and (e).

To be responsive to this interrogatory, Hydro One has estimated future carrying costs over 2021 to the end of the recovery period based on the following assumptions:

1. Commencement date of the recovery for the Misallocated Tax Savings and effective date of 2021 rates is April 1, 2021;
2. Interest rates from 2023 – 2027 are assumed to be the same as 2022 rates;
3. The monthly recovery of Misallocated Tax Savings is assumed to be equal; however, the actual monthly amount may fluctuate slightly due to consumption.

			2023-2027 rates assumed to be the same as 2022 rates 2021 and 2022 rate assumptions are provided in the footnotes below				
OEB Prescribed Rate (Quarterly Rates)[1]	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Transmission	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%
Distribution	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%
Weighted Average Cost of Debt (WACD)[2]	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Transmission	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
Distribution	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
Weighted Average Cost of Capital (WACC)[3]	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Transmission	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%
Distribution	5.51%	5.51%	5.51%	5.51%	5.51%	5.51%	5.51%
Bank of Canada Rate plus 150 basis points[4]	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Transmission	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
Distribution	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
Board approved short term debt rate[5]	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Transmission	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%
Distribution	2.29%	2.29%	2.29%	2.29%	2.29%	2.29%	2.29%
Rate for debt issued in the current year	Please refer to the response to LPMA IR #2, part f.						

[1] 2021 and 2022 assumptions are based on the most recent OEB prescribed rate
[2] 2021 and 2022 assumptions as per Exhibit A, Tab 1, Schedule 1, page 8
[3] 2021 and 2022 assumptions as per Exhibit A, Tab 1, Schedule 1, page 8
[4] 2021 and 2022 assumptions as per response to LPMA IR #2, part a
[5] 2021 and 2022 assumptions as per response to LPMA IR #2, part d

OPTION 1 – RECOVERY OVER 2021 AND 2022

Amounts are in millions of dollars	**2021**	**2022**	**Total**
OEB Prescribed Rate (Quarterly Rates)			
Transmission	0.8	0.3	1.1
Distribution	0.4	0.1	0.5
Weighted Average Cost of Debt (WACD)			
Transmission	6.0	2.0	8.0
Distribution	3.4	1.1	4.5
Weighted Average Cost of Capital (WACC)			
Transmission	7.3	2.5	9.8
Distribution	4.3	1.4	5.7
Bank of Canada Rate plus 150 basis points			
Transmission	2.9	1.0	3.9
Distribution	1.6	0.6	2.2
Board approved short term debt rate			
Transmission	3.8	1.3	5.1
Distribution	1.8	0.6	2.4

OPTION 2 – RECOVERY FROM 2021 TO 2024					
Amounts are in millions of dollars	**2021**	**2022**	**2023**	**2024**	**Total**
OEB Prescribed Rate (Quarterly Rates)					
Transmission	0.9	0.6	0.4	0.1	2.0
Distribution	0.5	0.4	0.2	0.1	1.2
Weighted Average Cost of Debt (WACD)					
Transmission	6.6	4.7	2.8	0.9	15.0
Distribution	3.7	2.7	1.6	0.5	8.5
Weighted Average Cost of Capital (WACC)					
Transmission	8.1	5.8	3.5	1.2	18.6
Distribution	4.7	3.4	2.0	0.7	10.8
Bank of Canada Rate plus 150 basis points					
Transmission	3.2	2.3	1.4	0.5	7.4
Distribution	1.8	1.3	0.8	0.3	4.2
Board approved short term debt rate					
Transmission	4.2	3.0	1.8	0.6	9.6
Distribution	2.0	1.4	0.8	0.3	4.5

OPTION 3 – RECOVERY FROM 2021 TO 2024								
Amounts are in millions of dollars	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
OEB Prescribed Rate (Quarterly Rates)								
Transmission	0.9	0.8	0.6	0.5	0.3	0.2	0.1	3.4
Distribution	0.5	0.4	0.4	0.3	0.2	0.1	0.0	1.9
Weighted Average Cost of Debt (WACD)								
Transmission	6.8	5.8	4.7	3.7	2.6	1.6	0.5	25.7
Distribution	3.8	3.3	2.7	2.1	1.5	0.9	0.3	14.6
Weighted Average Cost of Capital (WACC)								
Transmission	8.4	7.1	5.8	4.5	3.2	1.9	0.6	31.5
Distribution	4.9	4.1	3.4	2.6	1.9	1.1	0.4	18.4
Bank of Canada Rate plus 150 basis points								
Transmission	3.3	2.8	2.3	1.8	1.3	0.8	0.3	12.6
Distribution	1.9	1.6	1.3	1.0	0.7	0.4	0.1	7.0
Board approved short term debt rate								
Transmission	4.3	3.7	3.0	2.4	1.7	1.0	0.3	16.4
Distribution	2.0	1.7	1.4	1.1	0.8	0.5	0.2	7.7

LPMA INTERROGATORY #4

Reference:

Exhibit A, Tab 1, Schedule 1, pages 12 – 14

Interrogatory:

Tables 5, 6 & 7 show the dollar impact on a typical R1 residential customer served by Hydro One. Is the expected impact on a typical residential customer served by non-Hydro One distributors resulting from the recovery of the transmission component of the Misallocated Tax Savings expected to be similar to the values shown in Tables 5, 6 & 7? If not, please explain.

Response:

While Hydro One would expect that the impacts on a typical residential customer served by non-Hydro One distributors resulting from the recovery of the transmission component of the Misallocated Tax Savings would be similar to that shown on Tables 5, 6 and 7, there could be some differences related to how each distributor allocates the collection of transmission costs across their rate classes.

LPMA INTERROGATORY #5

Reference:

Exhibit A, Tab 1, Schedule 1, pages 12 – 14

Interrogatory:

Is there any reason why the recovery periods need to be the same for the transmission and distribution components of the Misallocated Tax Savings? For example, could the transmission portion be recovered over the 2021 to 2022 period while the distribution portion could be recovered over the 2021 to 2027 period? If yes, please fully.

Response:

No, there is no reason that the recovery periods need to be the same for transmission and distribution components of the Misallocated Tax Savings.

LPMA INTERROGATORY #6

Reference:

Exhibit A, Tab 1, Schedule 1, pages 12 – 15

Interrogatory:

a) Do the transmission related bill impacts shown in Tables 5, 6 and 7 include the impacts included in Table 9 related to the 2022 revenue requirement adjustment or are the figures in addition to the rate impact noted in page 15?

b) Please explain the footnote to Table 9. In particular, please explain why the 2022 transmission rate increase will not impact distribution customers until 2023. Does this statement apply only to Hydro One distribution customers or does it also apply to distribution customers of other Ontario distributors?

Response:

a) No, the impacts shown in Tables 5, 6 and 7 do not include the impacts in Table 9 related to the 2022 revenue requirement adjustment.

b) The footnote is in reference to the fact that the timing of the OEB's approval and setting of Uniform Transmission Rates (UTRs) in Ontario does not typically provide sufficient time for Distributors to reflect the change in UTR rates for a given year in the calculation of the Retail Transmission Service Rates (RTSR) as part of their distribution rates application for that same year. Yes, this is typically the case for Distributors that reset their rates on January 1, and could also apply to Distributors that reset their rates on May 1 of each year.

LPMA INTERROGATORY #7

Reference:
Exhibit A, Tab 1, Schedule 1, pages 15

Interrogatory:
Would Hydro One be amenable to the Board transferring the balance of the Misallocated Tax Savings for each of the Transmission and Distribution effective the recovery date for the remainder of the recovery period to be determined by the Board and having the Board approved deferral and variance account interest rate applied to the balances in the accounts after the recovery period begins? If not, please explain fully why not.

Response:
Please see response to Staff-02(d) and (e).

SEC INTERROGATORY #1

Reference:
General

Interrogatory:
Please provide, for each of the distribution rates and transmission revenue requirement orders related to the Applicant covering any part of the period from and after January 1, 2017, the Board order, or citation thereof:

a) Declaring the Applicant's rates interim; or

b) Establishing a deferral or variance account with respect to the Misallocated Tax Savings Amounts, or any portion of those amounts.

Response:
By way of background, Hydro One observes that the two topics raised by SEC of interim rates and use of deferral or variance accounts are exceptions to the general regulatory principle against retroactive ratemaking. Hydro One interprets SEC's question to effectively ask whether the recovery of the Misallocated Tax Savings is inconsistent with this general regulatory principle.

As recently discussed by the Alberta Utilities Commission and upheld by the Alberta Court of Appeal[1], the general principle against retroactive or retrospective ratemaking has five well understood exceptions. These are: (1) where rates have been declared to be interim; (2) where deferral or variance accounts are used; (3) where the rate issue involves a utility that is subject to a negative disallowance scheme (i.e. complaint based regulation); (4) the knowledge exception; and (5) the nullity exception.

In the present circumstances, Hydro One acknowledges that none of the prior decisions involving these circumstances cumulating with the Ontario Divisional Court Decision resulted in Hydro One's rates being placed or approved on an interim basis in respect of the Misallocated Tax Savings. Further, Hydro One acknowledges that the amounts of the Misallocated Tax Savings have not been accounted for through an approved deferral or

[1] Capital Power Corporation v Alberta Utilities Commission, 2018 ABCA 437.

variance account. Hydro One also acknowledges, that its scheme of regulation is a positive allowance scheme as opposed to a negative disallowance scheme.

The applicable exceptions to the general prohibition against retroactive and retrospective ratemaking concern the fourth and fifth categories, namely, the knowledge exception and the nullity exception.

The knowledge exception applies when parties knew or ought to have known that the approved rates in effect were the subject-matter of a challenge and could reasonably be expected to change. In this light, Hydro One notes that throughout the appeal process from the Original Decision, parties involved either knew or ought to have known that steps had been taken to seek: (a) a review and variance of the Original Decision; (b) a rehearing of the Original Decision; and (c) an appeal to the Divisional Court. SEC certainly had knowledge of these steps as they actively participated in all proceedings along with Board Staff. In the transmission and distribution rates proceedings that took place between the Original Decision and the date of the Divisional Court Decision, Hydro One further notes that references were made to the fact that the allocation of deferred tax assets was under review and/or appeal. A chronology which makes references to such information is provided in the attachment to this response. Given these circumstances, Hydro One submits that it has taken the necessary steps to ensure parties have had knowledge or ought to have received such knowledge of the appeal process and the potential risk of changes in rates.

The nullity exception applies when a decision is found to be made based on errors of law or jurisdiction.[2] As noted in *Telus Communications Inc. v Canadian Radio-Television and Telecommunication Commission*[3] at paragraphs 35-48, a decision that lacks legal foundation is properly characterized in law as no decision at all or a nullity.

Once that is accepted, it follows that if the duty of the decision-maker is to what is, in law, no decision at all, then, in law, the duty to make a decision remains unperformed. Thus, not only is there no legal impediment under the general law to a decision maker making such a decision but, as a matter of strict legal principle, he or she is required to do so. [4]

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[2] Chandler v. Alberta Association of Architects, 1989 2 SCR 848 [Chandler]
[3] 2004 FCA 365.
[4] See Chandler and Bhardwaj.

Hydro One submits that the nullity exception also applies to the present circumstances. The Divisional Court Decision found that the Rehearing Decision (which upheld the Original Decision), was made based on errors of law in which decisions were taken without evidence to support the conclusions reached.[5] The general prohibition against retroactive and retrospective ratemaking has no application because, in law, the Original Decision as it relates to the allocation of tax savings, was no decision at all. The Board's duty to establish just and reasonable rates by correcting the errors remains unperformed, which is why the matter has been remitted by the Divisional Court so that the Board can carry out the necessary corrections and fulfil its duties.

[5] Hydro One Networks Inc. v. Ontario Energy Board, 2020 ONSC 4331.

APPENDIX 1
Chronology Hydro One Rate Cases Involving Tax Savings Allocations

1. Background

On May 31, 2016, Hydro One applied under s. 78(7) of the OEB Act for approval of the 2017 and 2018 rate revenue requirements for its transmission business ("**Original Application**"). The applied-for amounts included the recovery of forecast income taxes calculated based on the provincial payment in lieu of taxes regime ("**PILS Scheme**") that applied when Hydro One was owned outright by the Government of Ontario.

This approach was used despite the fact that Hydro One had exited the PILS Scheme given the Ontario Government's decision to sell a portion of its ownership interest. The effect of this decision caused Hydro One to become subject to the federal income tax scheme. Exiting the PILS Scheme and entering the Canadian federal income tax scheme resulted in Hydro One being obligated to pay an amount referred to as the PILS Departure Tax. As an offset to this cost, entering into the federal income tax scheme caused Hydro One to have a higher capital asset value which is used to calculate capital cost allowance ("**CCA**"). CCA is a taxable deduction and thus a tax savings. The accumulated (i.e. net present value) of all future tax savings arising from the change in income tax schemes approximates to the value of the PILS Departure Tax payment made by Hydro One ("**Tax Savings**").

Given that the PILS Departure Tax was solely caused by Hydro One's shareholder's decision to sell a portion of its ownership interests, and this cost did not relate to Hydro One's rate regulated services, Hydro One did not seek to recover any of the PILS Departure Tax from ratepayers in its Original Application and, in turn, Hydro One did not seek to provide any allocation of future Tax Savings to ratepayers.

On September 28, 2017, the Board disposed of the application in the Original Decision, as subsequently revised by the Board on October 11 and November 1, 2017. The Original Decision found that future Tax Savings could be allocated to ratepayers. The effect of the Original Decision was to reduce the amount of income tax Hydro One was allowed to recover in its transmission rates for the period January 1, 2017 to December 31, 2018, and without ratepayers being allocated costs for the recovery of the PILS Departure Tax. On October 18, 2017 Hydro One filed a Notice of Motion to Review and Vary portions of Board Decision and Order in EB-2016-0160 under Rules 40 and 42 of the OEB's *Rules of Practice and Procedure*. This Motion included a review and variance to the reduction in income tax recovery due to allocations of future Tax Savings to ratepayers ("**R&V Proceeding**").

Electronic copies of the Motion were distributed to all parties who participated in the EB-2016-0160 proceeding. The OEB assigned case number EB-2017-0336 to R&V Proceeding.

On October 27, 2017, Hydro One filed its Notice of Appeal to the Ontario Divisional Court in respect of the OEB's tax-related findings in the Original Decision. A copy of this Notice was provided to the OEB.

On November 9, 2017, the OEB issued its decision and order regarding Hydro One's draft rate order related to the Original Decision. Additional reasons were provided in the DRO Decision regarding the allocation of Future Tax Savings. On November 29, 2017 counsel for Hydro One requested that the R&V Motion and R&V Proceeding be inclusive of the DRO Decision. Copies of this correspondence were provided to all parties involved in the EB-2016-0160 proceeding.

On December 1, 2017, the OEB released a Decision on Issues List, Interim Rates and Procedural Order No. 2 ("**PO2 Decision**") in respect of Proceeding EB-2017-0049 ("**Distribution Rates Proceeding**"). This proceeding concerned Hydro One's application for approval of distribution rate revenue requirements for a five-year period effective January 1, 2018 to December 31, 2022. Substantively, all parties who had participated in the Original Decision were the same parties involved in the Distribution Rates Proceeding and were notified of the PO2 Decision.

Commencing at page 3 of the PO2 Decision, the Board observed that Hydro One's R&V Motion and Notice of Appeal regarding the Tax Savings Determination were directly relevant to the Distribution Rates Proceeding. The Board found that it would not permit the Tax Savings Determinations that were the subject matter of the R&V Motion and Notice of Appeal to be re-litigated or addressed in the Distribution Proceeding, pending the outcomes of the Hydro One R&V Motion and Notice of Appeal.

No party challenged the Board's P02 Decision in deferring consideration of the Tax Savings Determinations pending the outcomes of the Hydro One R&V Motion and Notice of Appeal.

On December 19, 2017, the Board issued Procedural Order No. 1 into the R&V Proceeding and determined that the R&V Motion had met the threshold for review and that the DRO Decision would be included as part of the R&V Proceeding. All parties who had been granted intervenor status in the Original Decision process (i.e. EB-2016-0160) were granted this same status for the R&V Proceeding and were served with Procedural Order No. 1.

Also on December 19, 2017, the Divisional Court made an order, the effect of which was to hold the appeal in abeyance pending the outcome of the R&V Proceeding and allowing Hydro One to perfect the appeal up to 30 days after the date on which the OEB issued its decision into the EB-2016-0160 R&V Proceeding.

On August 31, 2018 the Board issued its Decision into the R&V Proceeding. Hydro One's Motion to Review and Vary the Original Decision was granted, in part. The Board ordered that the Original Decision was returned to the original panel to reconsider the Future Tax Savings Determination in light of the findings made in the R&V Proceeding Decision.

On October 26, 2018, Hydro One filed a one-year transmission rate filing application with the Board ("**EB-2018-0130**") for the period January 1, 2019 to December 31, 2019. The outstanding nature of the R&V Proceeding and the subsequent Ontario Divisional Court Appeal were matters known to parties participating in this proceeding.

On March 7, 2019, the Board issued its Decision into the Distribution Rates Proceeding. As noted in the P02 Decision, Tax Savings Determinations were not addressed in the Distribution Rates Proceeding and were pending the outcome of the Hydro One R&V and Notice of Appeal to the Divisional Court.

Also on March 7, 2019, the Board issued Reconsideration Decision EB-2018-0269 into 2018 Transmission Revenue Requirement and Charge Determinants regarding Future Tax Savings ("**Reconsideration Decision**"). The Board determined that the method of allocating tax savings as determined in the Original Decision was reasonable.

On March 21, 2019, Hydro One filed its transmission rates revenue requirement application for the period Jan 1, 2020 to December 31, 2022 ("**2020-2022 Tx Rates Proceeding**"). The Board established Proceeding EB-2019-0082 to hear this application. Hydro One's applied-for income tax methodology was consistent with the Reconsideration and Original

Decisions but this methodology was noted as being subject to the October 27, 2017 Notice of Appeal made to the Divisional Court of Ontario.
On April 5, 2019, Hydro One filed its Draft Rate Order Application into the Distribution Rates Proceeding. At Page 20 of 36 of this Application Hydro One reiterated that the Reconsideration Decision regarding Future Tax Savings remained the subject-matter of an appeal to the Ontario Divisional Court and that the final amount of tax savings allocated to ratepayers remains in dispute and uncertain. Tax calculations amounts included in the Application regarding the allocation of future tax savings were assumed to be based on the correctness of the Reconsideration and Original Decisions. The correctness of this assumption was expressly stated as one not admitted and denied. No party participating in the DRO Application took issue with Hydro One's ongoing uncertainty as to the correctness of the Reconsideration and Original Decisions.

Also on April 5, 2019, Hydro One notified the Board of its decision to recommence its Appeal to the Divisional Court regarding the correctness of the Reconsideration and Original Decisions.

On April 25, 2019, the Board issued its Decision into EB-2018-0130. The pending Divisional Court appeal were matters described in this proceeding. [6]

On June 6, 2019 as revised on June 11, 2019, the Board issued its DRO Decision into the Distribution Rates Proceeding and accepted the information provided in support of Hydro One's proposed DRO Tariff of Rates and Charges. On June 7, 2019, Hydro One wrote to the Board clarifying that: "Hydro One assumes that the Board's June 6, 2019 decision is not intended to preclude adjustments to distribution rates that may arise from [the DTA appeal] taking affect as of the commencement of the rate period. If Hydro One's assumption is not shared by the Board, we would kindly request further clarification on this subject."[7] The Board did not provide the requested clarification and no statements of concern were expressed regarding the ongoing uncertainty and challenges underway to the Divisional Court regarding the correctness of the Reconsideration and Original Decisions and as the related to the allocation of tax savings.

[6] See Decision EB-2018-0130 at page 12.
[7] See letter at Attachment 1 to the response.

On November 21, 2019, the Ontario Divisional Court heard Hydro One's Appeal of the Reconsideration and Original Decisions. The Court heard oral submissions from Hydro One, Power Workers' Union, Board Staff and Schools Energy Coalition.

On April 23, 2020 the Board issued Decision EB-2019-0082 into the 2020-2022 Tx Rates Proceeding. At page 117 of the Decision, the OEB directed Hydro One to provide an updated set of detailed regulatory tax calculations that underpin the regulatory income tax expense amounts as part of its Draft Rate Order Application.
On May 28, 2020 Hydro One filed its Draft Rate Order application concerning the 2020-2022 Tx Rates proceeding and included updated detailed regulatory tax calculations that underpin the regulatory income tax expense amounts.[8]

On July 6, 2020, the Ontario Divisional Court determined that Board decisions having the effect of allocating tax savings amounts to rate payers had been made in error. In the Court's opinion, no part of the benefit of the Future Tax Savings is allocable to ratepayers and should instead be paid to the shareholders in its entirety, and further ordered that the matter be remitted back to the Board.

On July 16, 2020, the Board issued its Decision and Order approving transmission rates established for the 2020-2022 period and in accordance with the Board's 2020-2022 Tx Rates Proceeding Decision ("DRO Decision"). The DRO Decision did not address impacts arising from the Ontario Divisional Court's Decision.

[8] Hydro One Draft Rate Order Application, page 22; see also Exhibits 1.5, 1.5.1 and 1.5.2.

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June 7, 2019

VIA RESS, EMAIL AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

RE: EB-2017-0049 – Interim Rate Order dated June 6, 2019

We are writing on behalf of Hydro One Networks Inc. (**"Hydro One"**) regarding the above-matter.

In the referenced Decision, the Board has found that Hydro One's rates for the period May 1, 2018 to December 31, 2022 are to remain interim until the conclusion of the EB-2016-0315 proceeding.

As a matter of clarification, Hydro One notes two other matters are also underway, and the outcomes of which could result in additional adjustments to rates calculated and recovered from the commencement of this rate period. These matters concern Hydro One's Motion to Review and Vary pension cost disallowances (EB-2019-0122) and the future tax savings appeal now before the Ontario Divisional Court (Divisional Court File No. 200/19).

Hydro One assumes that the Board's June 6, 2019 Decision is not intended to preclude adjustments to distribution rates that may arise from these additional matters taking effect as of the commencement of the rate period. If Hydro One's assumption is not shared by the Board, we would kindly request further clarification on this subject.

Please contact the undersigned with any questions in regards to the foregoing.

Yours truly,

McCarthy Tétrault LLP

Gordon M. Nettleton

GMN

cc: EB-2017-0049 All Parties

SEC INTERROGATORY #2

Reference:

Ex. A/1/1, p. 6, 7, 14

Interrogatory:

Please provide, in Excel format, a table showing, with relevant dates, and covering the period from 2016 until the remaining amount of the Deferred Tax amount included in the Applicant's financial statements is expected to be less than the Applicant's materiality threshold:

a) The original Deferred Tax amount booked in the financial statements as a result of the change in tax status, and any additions to the Deferred Tax amount as a result of acquisitions or any other factors, in each case including the calculation of that amount;

b) The maximum drawdown of the Deferred Tax amount as a result of the availability of the FMV Bump in each year, divided between transmission and distribution businesses; and

c) If the drawdown of the Deferred Tax amount in any year was or is expected to be less than the maximum, because of limited taxable income or for any other reason, the actual or forecast drawdown of the Deferred Tax amount as a result of the FMV Bump in each year, divided between transmission and distribution businesses.

Response:

Hydro One declines to provide the requested information as it is not relevant to the issues in this proceeding. The amounts which Hydro One is seeking recovery for (excluding carrying costs) are described in Exhibit A, Tab 1, Schedule 1, Table 1 at page 7 of 20. Each of the amounts shown in Table 1 have been cross-referenced to the Proceeding in which Board approval was received and in which the referenced amount was allocated to rate-payers.[1] As it is these amounts that have been determined by the Divisional Court to

[1] For ease of reference, the income tax exhibits from the draft rate orders in the relevant proceedings showing the total regulatory income tax less the DTA sharing amount are attached to this response as follows: Attachment 1 – EB-2016-0160 Tx 2017; Attachment 2 – EB-2016-0160 Tx 2018; Attachment 3 – EB-2017-0049 – Dx 2018-2022; Attachment 4 – EB-2019-0082 – Tx 2020-2022

not be a matter pertaining to the provision of rate regulated service, Hydro One is seeking their recovery through this application.

In its Procedural Order, the Board stated the following:

> *The findings in the Original Decision with respect to the tax savings allocations for the 2017-2018 period have subsequently been incorporated by the OEB into transmission revenue requirements and charge determinants for the years 2019 to 2022 as well as into distribution revenue requirements and rates for the 2018 to 2022 period. The OEB has determined that as a first step it will require Hydro One to file evidence on such matters as the total amount that Hydro One is entitled to recover for the 2017 to 2022 period as a result of the Court's decision. The information should be divided between the transmission business and the distribution business, along with detailed supporting calculations and potential customer bill impacts. Hydro One should also file one or more proposed implementation options for the recovery of the amounts owed through rates, and the annual forecast of rate impacts for these various options. Hydro One may also include any other information related to this matter that it believes would be useful.*

Hydro One's evidence and its proposals are not based upon the information or type of analysis that is requested in this interrogatory. The scope and focus of this proceeding is intended to be narrow in nature and focus. Requiring Hydro One to conduct this analysis and those included in the subsequent interrogatories (i.e. 3 to 6) appear more of an attempt to expand the issues, allow reconsideration of allocation approaches, and, in so doing seek information not relevant to this proceeding. The time and effort required to prepare any tables, reconciliations and calculations are disproportionate to any probative value to the Board in its consideration or understanding of (a) calculations Hydro One has used to calculate the Misallocated Tax Savings for the 2017-2022 period; (b) the justification which Hydro One has used in support of its calculations (see Table 1 "Proceeding" References); and (c) implementation options that Hydro One has proposed for the recovery of these amounts.

a-c) N/A. See above.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Income Tax

($ millions)	Supporting Reference	Hearing Update 2017	Hearing Update 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Income Taxes	*See supporting details below*	81.9	89.6	(30.9)	(34.5)	51.0	55.1

Income Tax Supporting Details			Hydro One Proposed 2017	Hydro One Proposed 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Rate Base	Exhibit 1.2	a	$ 10,554.4	$ 11,225.5	$ (31.7)	$ (77.5)	$ 10,522.7	$ 11,148.0
Common Equity Capital Structure		b	40.0%	40.0%			40.0%	40.0%
Return on Equity	Exhibit 1.4	c	8.78%	8.78%	0.00%	0.00%	8.78%	8.78%
Return on Equity		d = a x b x c	370.7	394.2	(1.1)	(2.7)	369.6	391.5
Regulatory Income Tax		e = l	81.9	89.6	0.3	(0.8)	82.2	88.8
Regulatory Net Income (before tax)		f = d + e	452.6	483.8	(0.8)	(3.5)	451.8	480.3
Timing Differences *(Note 1)*		g	(140.3)	(142.6)	2.0	0.5	(138.3)	(142.1)
Taxable Income		h = f + g	312.2	341.2	1.3	(3.0)	313.5	338.2
Tax Rate		i	26.5%	26.5%			26.5%	26.5%
Income Tax		j = h x i	82.7	90.4	0.3	(0.8)	83.1	89.6
less: Income Tax Credits		k	(0.8)	(0.8)	-	-	(0.8)	(0.8)
Regulatory Income Tax		l = j + k	81.9	89.6	0.3	(0.8)	82.2	88.8
less: Deferred Tax Asset Sharing *[Note 2]*		m	-	-	(31.2)	(33.7)	(31.2)	(33.7)
Income Taxes		n = l + m	81.90	89.60	(30.9)	(34.5)	51.0	55.1

Note 1. Book to Tax Timing Differences	Hydro One Proposed 2017	Hydro One Proposed 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Depreciation	435.7	470.7	(1.3)	(2.1)	434.4	468.6
CCA	(516.0)	(547.9)	3.4	2.6	(512.7)	(545.4)
Other Timing Differences	(60.0)	(65.4)	-	-	(60.0)	(65.4)
Total Timing Differences	(140.3)	(142.6)	2.0	0.5	(138.3)	(142.1)

Note 2: As per EB-2016-0160 Decision and Order on September 28, 2017.

	2017	2018
Income Tax from OEB Decision (Pre-DTA Sharing)	82.2	88.8
Deferred Tax Asset Sharing	31.2	33.7

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2016-0160

Income Tax

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Income Taxes	*See supporting details below*	55.1	2.2	57.2

Income Tax Supporting Details			**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Rate Base	Exhibit 1.2	a	$ 11,148.0	$ -	$ 11,148.0
Common Equity Capital Structure		b	40.0%		40.0%
Return on Equity	Exhibit 1.4	c	8.78%	0.22%	9.00%
Return on Equity		d = a x b x c	391.5	9.8	401.3
Regulatory Income Tax		e = l	88.8	3.54	92.3
Regulatory Net Income (before tax)		f = d + e	480.3	13.35	493.7
Timing Differences *(Note 1)*		g	(142.1)	-	(142.1)
Taxable Income		h = f + g	338.2	13.35	351.5
Tax Rate		i	26.5%		26.5%
Income Tax		j = h x i	89.6	3.54	93.2
less: Income Tax Credits		k	(0.8)	-	(0.8)
Regulatory Income Tax		l = j + k	88.8	3.54	92.3
less: Deferred Tax Asset Sharing *[Note 2]*		m	(33.7)	(1.34)	(35.1)
Income Taxes		n = l + m	55.1	2.2	57.2

Note 1. Book to Tax Timing Differences	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Depreciation	468.6	-	468.6
CCA	(545.4)	-	(545.4)
Other Timing Differences	(65.4)	-	(65.4)
Total Timing Differences	(142.1)	-	(142.1)

Note 2: As per EB-2016-0160 Decision and Order on September 28, 2017.

Income Tax from OEB Decision (Pre-DTA Sharing)	88.8	92.3
Deferred Tax Asset Sharing	33.7	35.1

Filed: 2020-12-04
EB-2020-0194
Exhibit I-3-2
Attachment 3

Filed: 2019-04-05
EB-2017-0049
Draft Rate Order
Exhibit 1.5

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2017-0049

Income Tax

	Supporting Reference		Hydro One Proposed					OEB Decision Impact					OEB Approved				
($ millions)			2018	2019	2020	2021	2022	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
Income Taxes	*See supporting details below*		65.2	68.8	71.4	78.7	79.3	(22.1)	(18.8)	(20.2)	(24.1)	(14.8)	43.1	50.0	51.1	54.5	64.5
Income Tax Supporting Details																	
Rate Base	Exhibit 1.2	(a)	$ 7,648.1	$ 8,004.2	$ 8,403.4	$ 8,928.8	$ 9,291.1	$ (11.2)	$ (110.1)	$ (228.3)	$ (411.7)	$ (478.3)	$ 7,636.9	$ 7,894.1	$ 8,175.1	$ 8,517.1	$ 8,812.8
Common Equity Capital Structure		(b)	40.0%	40.0%	40.0%	40.0%	40.0%						40.0%	40.0%	40.0%	40.0%	40.0%
Return on Equity	Exhibit 1.4	(c)	9.00%	9.00%	9.00%	9.00%	9.00%						9.00%	9.00%	9.00%	9.00%	9.00%
Return on Equity		(d) = a x b x c	275.3	288.2	302.5	321.4	334.5	(0.4)	(4.0)	(8.2)	(14.8)	(17.2)	274.9	284.2	294.3	306.6	317.3
Regulatory Income Tax		(e) = l	65.2	68.8	71.4	78.7	79.3	6.8	7.5	4.0	(1.6)	6.2	72.0	76.4	75.4	77.1	85.5
Regulatory Net Income (before tax)		(f) = d + e	340.5	357.0	373.9	400.1	413.8	6.4	3.6	(4.2)	(16.4)	(11.1)	346.9	360.6	369.7	383.7	402.7
Timing Differences *(Note 1)*		(g)	(89.8)	(92.1)	(99.5)	(98.2)	(109.5)	19.3	24.9	19.3	10.4	34.3	(70.5)	(67.3)	(80.2)	(87.8)	(75.2)
Taxable Income		(h) = f + g	250.8	264.8	274.4	301.9	304.3	25.6	28.4	15.1	(6.0)	23.2	276.4	293.3	289.5	295.9	327.5
Tax Rate		(i)	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Income Tax		(j) = h x i	66.5	70.2	72.7	80.0	80.6	6.8	7.5	4.0	(1.6)	6.2	73.3	77.7	76.7	78.4	86.8
less: Income Tax Credits		(k)	(1.2)	(1.3)	(1.3)	(1.3)	(1.3)						(1.2)	(1.3)	(1.3)	(1.3)	(1.3)
Regulatory Income Tax		(l) = j + k	65.2	68.8	71.4	78.7	79.3	6.8	7.5	4.0	(1.6)	6.2	72.0	76.4	75.4	77.1	85.5
Max CCA													(221.4)	(201.7)	(185.7)	(172.8)	(160.7)
Tax Effected (26.5%)													(58.7)	(53.5)	(49.2)	(45.8)	(42.6)
Less: DTA Sharing (36.2%)													(21.2)	(19.3)	(17.8)	(16.6)	(15.4)
Less: DTA Sharing - G/up													(7.7)	(7.0)	(6.4)	(6.0)	(5.6)
Total Deferred Tax Asset Sharing													(28.9)	(26.3)	(24.2)	(22.5)	(21.0)
Income Taxes			65.2	68.8	71.4	78.7	79.3	(22.1)	(18.8)	(20.2)	(24.1)	(14.8)	43.1	50.0	51.1	54.5	64.5
Note 1. Book to Tax Timing Differences																	
Depreciation			398.1	419.0	433.7	452.6	466.2	(0.4)	(4.0)	(8.2)	(10.2)	(10.6)	397.8	415.0	425.5	442.4	455.6
CCA			(435.3)	(456.8)	(474.8)	(481.6)	(504.0)	(0.1)	9.3	8.0	0.8	24.0	(435.5)	(447.5)	(466.8)	(480.9)	(480.0)
Other Timing Differences			(52.6)	(54.4)	(58.4)	(69.1)	(71.7)	19.8	19.6	19.5	19.8	20.9	(32.8)	(34.8)	(38.9)	(49.3)	(50.8)
Total Timing Differences			(89.8)	(92.1)	(99.5)	(98.2)	(109.5)	19.3	24.9	19.3	10.4	34.3	(70.5)	(67.3)	(80.2)	(87.8)	(75.2)

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Income Tax

($ millions)	Supporting Reference	Hydro One Proposed			OEB Decision Impact			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
Income Taxes	*See supporting details below*	18.1	18.5	31.2	12.1	22.4	8.5	30.1	40.9	39.7

Income Tax Supporting Details

			Hydro One Proposed 2020	2021	2022	OEB Decision Impact 2020	2021	2022	OEB Approved 2020	2021	2022
Rate Base	Exhibit 1.2	(a)	$ 12,407.0	$ 13,130.2	$ 13,951.7	$ (47.4)	$ (202.9)	$ (310.8)	$ 12,359.6	$ 12,927.3	$ 13,640.9
Common Equity Capital Structure		(b)	40.0%	40.0%	40.0%				40.0%	40.0%	40.0%
Return on Equity	Exhibit 1.4	(c)	8.52%	8.52%	8.52%				8.52%	8.52%	8.52%
Return on Equity		(d) = a x b x c	421.9	447.5	475.5	(0.7)	(6.9)	(10.6)	421.2	440.6	464.9
Regulatory Income Tax		(e) = l	50.8	49.0	59.6	12.1	22.4	8.5	62.9	71.4	68.1
Regulatory Net Income (before tax)		(f) = d + e	472.7	496.5	535.0	11.4	15.5	(2.1)	484.1	512.0	533.0
Timing Differences *(Note 1)*		(g)	(279.6)	(310.2)	(308.9)	34.1	69.0	34.2	(245.4)	(241.2)	(274.7)
Taxable Income		(h) = f + g	193.1	186.3	226.1	45.5	84.5	32.1	238.7	270.8	258.2
Tax Rate		(i)	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Income Tax		(j) = h x i	51.2	49.4	59.9	12.1	22.4	8.5	63.2	71.8	68.4
less: Income Tax Credits		(k)	(0.3)	(0.4)	(0.3)				(0.3)	(0.4)	(0.3)
Regulatory Income Tax		(l) = j + k	50.8	49.0	59.6	12.1	22.4	8.5	62.9	71.4	68.1
Max CCA			(251.2)	(233.7)	(217.3)				(251.2)	(233.7)	(217.3)
Tax Effected (26.5%)			(66.6)	(61.9)	(57.6)	-	-	-	(66.6)	(61.9)	(57.6)
Less: DTA Sharing (36.2%)			(24.1)	(22.4)	(20.8)	-	-	-	(24.1)	(22.4)	(20.8)
Less: DTA Sharing - G/up			(8.7)	(8.1)	(7.5)	-	-	-	(8.7)	(8.1)	(7.5)
Total Deferred Tax Asset Sharing			(32.8)	(30.5)	(28.4)	-	-	-	(32.8)	(30.5)	(28.4)
			(32.8)	(30.5)	(28.4)						
Income Taxes			18.1	18.5	31.2	12.1	22.4	8.5	30.1	40.9	39.7
Note 1. Book to Tax Timing Differences											
Depreciation			474.5	503.4	528.9	(1.0)	(3.2)	(4.4)	473.4	500.2	524.5
CCA			(681.4)	(732.6)	(752.8)	5.7	42.1	7.6	(675.7)	(690.5)	(745.2)
Other Timing Differences			(72.7)	(81.1)	(85.0)	29.5	30.2	31.0	(43.1)	(50.9)	(54.0)
Total Timing Differences			(279.6)	(310.2)	(308.9)	34.1	69.0	34.2	(245.4)	(241.2)	(274.7)

SEC INTERROGATORY #3

Reference:

Ex. A/1/1, p. 7

Interrogatory:

Please add to Table 1 columns for each of transmission and distribution showing the total tax savings amounts available in each year, the total tax savings claimed or expected to be claimed in the year, the amount allocated to the shareholders, and the remaining amount (already shown) originally allocated to the customers.

Response:

Refer to Hydro One's response to SEC Interrogatory #2 for more details.

SEC INTERROGATORY #4

Reference:
Ex. A/1/1, throughout

Interrogatory:
With respect to the calculation of the impact of the FMV Bump:

a) Please provide, in Excel format, a full CCA continuity schedule for all depreciable assets subject to the FMV Bump, whether at the time of the IPO, or as a result of any subsequent event, all broken down by CCA class, from 2016 until the Deferred Tax amounts are below the materiality threshold.

b) Please provide an identical CCA continuity schedule, calculated on the assumption that the FMV Bump was not applicable, and that the assets continued to be subject to CCA based on their previous undepreciated capital costs.

c) Please reconcile the differences between those continuity schedules to the initial and any additional calculations of the Deferred Tax amounts included or to be included in the financial statements.

d) In the event that any of the assets are amortized pursuant to the CEC rules, please provide similar continuity schedules with and without the FMV Bump, and a similar reconciliation.

Response:
a-d) Refer to Hydro One’s response to SEC Interrogatory #2 for more details.

SEC INTERROGATORY #5

Reference:
Court Decision, p. 4

Interrogatory:
Please provide, in Excel format, the full calculation of the net present value figure of $1.2 billion related to the Future Tax Savings referred to in note 4 of the Court's Decision, and originally alleged by the Applicant in its Factum in that proceeding, at page 5. Please include the annual amount of tax savings for each year from 2016 onward, including the calculation of that tax savings amount, and the discounting calculations used including all assumptions.

Response:
Refer to Hydro One's response to SEC Interrogatory #2 for more details.

SEC INTERROGATORY #6

Reference:
Ex. A/1/1, throughout

Interrogatory:
Please provide the accountants' working papers for the original and any subsequent calculations of the deferred taxes as recognized for financial statement purposes.

Response:
Refer to Hydro One's response to SEC Interrogatory #2 for more details.

SEC INTERROGATORY #7

Reference:
General

Interrogatory:
Please provide an explanation of how the gross-up rule applies, if at all, in the case of the recovery of the Deferred Tax amounts from customers in rates, and provide examples.

Response:
The gross-up rule does not impact the recovery of the Misallocated Tax Savings Amounts. This is because the total amount Hydro One seeks to recover is the aggregate of the Misallocated Tax Savings that Hydro One provided to ratepayers during 2017-2021 excluding carrying costs. See Hydro One Evidence Exhibit A, Tab 1, Schedule 1, Table 1 at page 7 of 20. These Misallocated Tax Savings which were shared with ratepayers included a tax grossed up with the exception of the amounts relating to 2017 and 2018 Transmission which were based on the OEB's suggested approach.

SEC INTERROGATORY #8

Reference:
Ex. A/1/1, p. 12-15

Interrogatory:
With respect to the rate impacts of the Applicant's proposals:

a) Please provide the full calculations behind Tables 5, 6, 7, and 9.

b) Please provide similar tables to 5, 6, 7, and 9 showing the rate impacts for commercial customers with a 100kw monthly demand and a monthly volume of 40,000 kwh.

Response:
a) The calculations used to derive the values shown in Tables 5, 6, 7 and 9 are provided in Appendix 1 below.

b) The rate and bill impacts for a commercial customer with 100kw monthly demand and monthly volume of 40,000 kWh are provided in Appendix 2 below.

Appendix 1
Rate and Bill Impact Calculation Details

Assumptions for Estimating Rate and Bill Impacts

Assumed DTA Amounts to be Recovered:	Value	Reference ID for Calculations
2017-2021 Tx Misallocated Tax Savings Amount ($M)	183.3 [1]	A
2018-2021 Dx Misallocated Tax Savings Amount ($M)	100.2 [1]	B
2022 Tx Tax Impact on Revenue Requirement ($M)	28.4 [2]	C
2022 Dx Tax Impact on Revenue Requirement ($M)	21.0 [2]	D
Rates Revenue Requirement		
Tx 2021 Rates Revenue Requirement	1656.6 [3]	E
Dx 2021 Rates Revenue Requirement	1540.6 [4]	F
Bill-related Assumptions		
Tx Charges as share of Tx Bill	7.6% [5]	G
Tx Charges as share of typical R1 residential bill (excl. DRP, before OER)	6.2% [6]	H
Dx Charges as share of typical R1 residential bill (excl. DRP, before OER)	28.7% [6]	I
Dx Charge on typical R1 residential customer bill (excl. DRP)	$ 57.61 [6]	J
Tx Charge on typical R1 residential customer bill	$ 12.51 [6]	K

[1] Per Table 4 in DTA submission EB-2020-0194
[2] Per Table 8 in DTA submission EB-2020-0194
[3] Per Table 5 in 2021 Annual Transmission Application EB-2020-0202
[4] Per Exhibit 2.0 in 2021 Annual Distribution Application EB-2020-0030
[5] Per Table 4 in Annual Tx Application EB-2020-0202
[6] Derived from R1 Bill Impact Sheet in Exhibit 6.0 of Dx Application EB-2020-0030

Table 5: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2022

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx Residential Customer *	Tx Customer	
	L=(B/2)/F	M=(A/2)/E	L*I + M*H	M*G	L*J + M*K
2021	3.3%	5.5%	0.9%	0.4%	$1.87
2022	0.0%	0.0%	0.3%	0.0%	$0.69

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 6: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2024

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx Residential Customer *	Tx Customer	
	L=(B/4)/F	M=(A/4)/E	L*I + M*H	M*G	L*J + M*K
2021	1.6%	2.8%	0.5%	0.2%	$0.94
2022	0.0%	0.0%	0.2%	0.0%	$0.35

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 7: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2027

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx Residential Customer *	Tx Customer	
	L=(B/7)/F	M=(A/7)/E	L*I + M*H	M*G	L*J + M*K
2021	0.9%	1.6%	0.3%	0.1%	$0.54
2022	0.0%	0.0%	0.1%	0.0%	$0.20

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 9: Bill Impacts of the 2022 Revenue Requirement Adjustment to Regulatory Income Tax

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx Residential Customer *	Tx Customer	
	L=D/F	M=C/E	L*I + M*H	M*G	L*J + M*K
2022	1.4%	1.7%	0.5%	0.1%	$1.00

* The 2022 Transmission rate increase will not impact Distribution customer bills until 2023, and as such, the impact amounts shown for a typical R1 residential customer include a bill impact of 0.1% and a dollar impact of $0.22 that will not affect distribution customer bills until 2023.

Appendix 2
Impacts on GSd Customer

The estimated impacts in the tables below are calculated using the same methodology illustrated in Appendix 1 above, but with the following bill-related assumptions for a GSd customer with a 100 kW monthly demand and a monthly volume of 40,000 kWh. The bill-related assumptions were determined by inputting the assumed demand and consumption levels into the GSd bill impact sheet provided in Exhibit 6.0 of the Annual Distribution Application EB-2020-0030.

Bill-related Assumptions

Tx Charges as share of assumed GSd residential customer bill	4.4%
Dx Charges as share of assumed GSd residential customer bill	20.2%
Dx Charge in assumed GSd residential customer bill	$ 1,736.59
Tx Charge in assumed GSd residential customer bill	$ 374.27

Table 5: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2022

Year	Rates Increase		Bill Impact		$ Impact on GSd Customer *
	Dx	Tx	GSd Customer *	Tx Customer	
2021	3.3%	5.5%	0.7%	0.4%	$56.47
2022	0.0%	0.0%	0.2%	0.0%	$20.71

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 6: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2024

Year	Rates Increase		Bill Impact		$ Impact on GSd Customer *
	Dx	Tx	GSd Customer *	Tx Customer	
2021	1.6%	2.8%	0.3%	0.2%	$28.24
2022	0.0%	0.0%	0.1%	0.0%	$10.35

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 7: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2027

Year	Rates Increase		Bill Impact		$ Impact on GSd Customer *
	Dx	Tx	GSd Customer *	Tx Customer	
2021	0.9%	1.6%	0.2%	0.1%	$16.14
2022	0.0%	0.0%	0.1%	0.0%	$5.92

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 9: Bill Impacts of the 2022 Revenue Requirement Adjustment to Regulatory Income Tax

Year	Rates Increase		Bill Impact		$ Impact on GSd Customer *
	Dx	Tx	GSd Customer *	Tx Customer	
2022	1.4%	1.7%	0.4%	0.1%	$30.09

* The 2022 Transmission rate increase will not impact Distribution customer bills until 2023, and as such, the impact amounts shown include a bill impact of 0.1% and a dollar impact of $6.42 that will not affect distribution customer bills until 2023.

ENERGY PROBE INTERROGATORY #1

Reference:
Exhibit A, Tab 1, Schedule 1, Page 5

Preamble:
"On July 16, 2020, the Ontario Divisional Court determined that Board decisions having the effect of allocating tax savings amounts to rate payers had been made in error. In the Court's opinion, no part of the benefit of the Future Tax Savings is allocable to ratepayers and should instead be paid to the shareholders in its entirety. The Court ordered that the matter be remitted back to the Board for implementation."

Interrogatory:
Please file a Copy of the Ontario Divisional Court Decision.

Response:
Please see attached for the Decision and Order of the Ontario Divisional Court.

Divisional Court File No. 200/19

ONTARIO
SUPERIOR COURT OF JUSTICE
DIVISIONAL COURT

THE HONOURABLE JUSTICE CORBETT	)	
	)	THURSDAY, THE 16th
THE HONOURABLE JUSTICE DUCHARME	)	
	)	
	)	DAY OF JULY, 2020
THE HONOURABLE JUSTICE GOMERY	)	

B E T W E E N :

HYDRO ONE NETWORKS INC.

Appellant

\- and -

ONTARIO ENERGY BOARD

Respondent

ORDER

THIS APPEAL by HONI (as defined in para. 1) for an order setting aside the Rehearing Decision (as defined in para. 1), was heard on November 21, 2019, at Osgoode Hall, 130 Queen Street West, Toronto, Ontario.

ON READING the notice of appeal, the record before the OEB (as defined in para. 1), and the factums of HONI, the OEB and the intervenors Ontario Education Services Corp. and Power Workers' Union, on hearing the oral submissions of the lawyers for HONI, the lawyers for the OEB, the lawyers for Ontario Education Services Corp., and the lawyers for Power Workers' Union, and on reading the supplementary written submissions of the parties and intervenors filed in March 2020 in light of the decision of the Supreme Court of Canada in *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65:

1. **THIS COURT ORDERS** that in this order the following terms have the following meanings:

(a) "**Future Tax Savings**" means the future tax savings of HONI in the amount of $2.595 billion addressed in the Original Decision.

(b) "**HONI**" means Hydro One Networks Inc.

(c) "**OEB**" means the Ontario Energy Board.

(d) "**Original Decision**" means the order of the OEB dated September 28, 2017 (OEB File No. EB-2016-0160).

(e) "**Rehearing Decision**" means the order of the OEB dated March 7, 2019 (OEB File No. EB-2018-0269).

(f) "**Review Decision**" means the order of the OEB dated August 31, 2018 (OEB File No. EB-2017-0336).

(g) "**Review Panel**" means the panel of the OEB that rendered the Review Decision.

2. **THIS COURT ORDERS** that, pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, s. 33(4), the Divisional Court certifies its opinion to the OEB as follows and the OEB shall make an order in accordance with this opinion:

(a) No portion of the Future Tax Savings should be allocated to ratepayers, when the evidence is clear that HONI paid all of its costs under the stand-alone utility principle.

(b) Under the long-established benefits follow costs principle, no part of the benefit of the Future Tax Savings is allocable to ratepayers and should instead be paid to the shareholders in its entirety.

(c) The application of this principle is not affected by the OEB's mandate to approve "just and reasonable rates" or to achieve a reasonable balance between the interests of utility ratepayers and the interests of shareholders.

3. **THIS COURT ORDERS** that:

(a) The Rehearing Decision is set aside.

(b) The matter shall be remitted back to the OEB and:

(i) A new panel of the OEB shall consider and make an appropriate order varying the tax savings allocation in the Original Decision by correcting the errors identified in it by the Review Panel.

(ii) In doing so, the OEB shall apply and give effect to the findings of the Review Decision and each of the errors it identified in the Original Decision, including in respect of the applicable ratemaking principles.

Registrar / Clerk

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LE / DANS LE REGISTRE NO.: 76
SEP 21 2020
PER / PAR: K.S.

HYDRO ONE NETWORKS INC. and **ONTARIO ENERGY BOARD**
Appellant and Respondent

Divisional Court File No. 200/19

ONTARIO
SUPERIOR COURT OF JUSTICE
DIVISIONAL COURT

Proceeding commenced at Toronto

ORDER

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CITATION: Hydro One Networks Inc. v. Ontario Energy Board, 2020 ONSC 4331
DIVISIONAL COURT FILE NO.: 200/19
DATE: 20200716

ONTARIO
SUPERIOR COURT OF JUSTICE
DIVISIONAL COURT

CORBETT, DUCHARME and GOMERY JJ.

B E T W E E N:	
HYDRO ONE NETWORKS INC.	*Geoff R. Hall, Gordon M. Nettleton* and *Brandon Kain* for the Appellant
Appellant	
- and -	
ONTARIO ENERGY BOARD	*Fred Cass*, for the Respondent
Respondent	*Mark Rubenstein*, for the Intervenor Ontario Education Services Corp.
	Richard Stephenson and *Hailey Bruckner* For the Intervenor Power Workers' Union
	Heard: November 21, 2019[1]

REASONS FOR DECISION

Ducharme J.:

PART I: NATURE OF PROCEEDING

[1] Hydro One Networks Inc. ("HONI") appeals from the March 7, 2019, decision (the "Rehearing Decision") of the Ontario Energy Board (the "OEB" or "the Board") affirming its

[1] The Court also considered written argument provided by the parties in March 2020 in light of the decision of the Supreme Court of Canada in *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65.

September 2017 decision (the "Original Decision") with respect to the allocation of Future Tax Savings of $2.595 billion (the "Future Tax Savings"). HONI argued throughout the Board's proceedings that all of the Future Tax Savings should be allocated to its shareholders. In the Rehearing Decision, the OEB ordered, as it had in the Original Decision, that 38% of the Future Tax Savings (or roughly $900 million) should instead be used to reduce HONI's revenue requirements for 2017 and 2018, with the result that HONI's customers would pay lower rates.

[2] HONI argues that the Rehearing Decision cannot stand because it fails to address errors in the Original Decision. It was these errors, identified by the OEB review panel (the "Review Panel") in August 2018, that led to a rehearing on the allocation issue and the Rehearing Decision. HONI asks this Court to set aside the Rehearing Decision and substitute an order requiring the Future Tax Savings be allocated entirely to HONI's shareholders or, in the alternative, directing that OEB should reconsider the allocation in light of errors in the Original Decision identified by the Review Panel.

PART II: OVERVIEW

[3] This appeal concerns nearly $900 million in Future Tax Savings that the Rehearing Decision allocated to HONI's ratepayers instead of HONI's shareholders. The Future Tax Savings arose after HONI's ultimate shareholder, the Province of Ontario, made a public offering of its indirect parent company's shares in 2015. HONI was then required to pay $2.271 billion (the "PILs Departure Tax") to exit the provincial payments in lieu of taxes ("PILs") regime. This increased the tax value of HONI's assets, and thus its deductions in computing future federal/provincial income tax.

[4] HONI did not seek to recover the PILs Departure Tax from its ratepayers, as it was not a cost incurred to provide them with regulated utility services. The PILS Departure Tax instead arose from a transaction involving HONI's unregulated indirect parent for the purchase of shares by Ontario. HONI submits that as it, and not its ratepayers, paid the cost of the PILs Departure Tax, HONI's shareholders and not its ratepayers are entitled to the benefit of the Future Tax Savings flowing from this transaction.

[5] In the Original Decision on September 28, 2017, an OEB panel (the "Original Panel") held that the PILs Departure Tax was not a real cost to HONI, as it was variable in the Province's discretion and was funded by Ontario. The Original Panel therefore concluded that some of this money should benefit HONI's ratepayers. It directed that HONI's revenue requirements, and by extension its rates, should be reduced by 38% of the Future Tax Savings that the PILs Departure Tax produced or nearly $900 million. The remaining 62% of the Future Tax Savings could be paid to HONI's shareholders.

[6] In the Review Decision on August 31, 2018, however, a different OEB panel (the "Review Panel") found numerous errors with this reasoning. In particular, the Review Panel held that the Original Panel's failure to treat the PILs Departure Tax as a real cost to HONI was contrary to both the evidence and the stand-alone utility principle, which distinguishes a utility corporation,

like HONI, from its shareholders and limits its business activities and recoverable costs to the provision of regulated services. The Review Panel also found that the methodologies the Original Panel applied in allocating the Future Tax Savings to HONI's ratepayers were flawed. It thus directed that the Original Decision should be "reconsider[ed] in light of these findings and all the evidence and argument the original panel and the reviewing panel heard".

[7] The OEB panel that reheard the matter (the "Rehearing Panel") failed to address the errors in the Original Decision identified by the Review Panel. The Rehearing Panel instead simply recited the arguments made by the parties and then concluded that the Original Panel's allocation of Future Tax Savings was "within the realm of reasonable outcomes." It also specifically failed to explain what methodology, if any, it relied on for this conclusion.

[8] As a result, pursuant to the Rehearing Decision, 38% of the Future Tax Savings, or nearly $900 million, was once again allocated for the benefit of HONI's ratepayers instead of its shareholders. HONI submits that for two reasons, the Rehearing Decision must be set aside.

[9] First, HONI argues that once the Review Panel found that the PILs Departure Tax was a real cost to HONI based on the evidence and the stand-alone utility principle, the only reasonable decision possible was that HONI's shareholders were entitled to all of the Future Tax Savings. The fundamental regulatory principle that "benefits follow costs" dictates that all Future Tax Savings be allocated to HONI's shareholders, because HONI rather than its ratepayers incurred all the expenses necessary to generate them. Similarly, the stand-alone utility principle prevented HONI from recovering any costs for non-rate regulated activities from its ratepayers, so ratepayers cannot be allocated any benefits that these costs produce. In fact, the Review Panel found that the Original Panel's failure to follow these principles was found to result in an "inappropriate allocation of the future tax savings". HONI submits that there was no logical basis on which the Rehearing Panel could depart from these principles, and its reasons did not even attempt to explain why it did so.

[10] Second, HONI submits that the Rehearing Panel applied the wrong legal test. It held that the reconsideration motion required it to determine only whether the Original Decision would be "reasonable" if the errors found by the Review Panel were accepted. The Rehearing Panel failed to address the flaws identified by the Review Panel. It thus misapprehended its role and fettered its statutory discretion to vary the Original Decision without deference to the Original Panel.

[11] HONI therefore requests that the Rehearing Decision be set aside, and that the Court substitute an order that none of the Future Tax Savings be applied to reduce HONI's transmission revenue requirements for 2017 and 2018. Alternatively, HONI requests that the Court remit the matter back to the OEB with the directions that: (a) the OEB shall consider and make an appropriate order varying the tax savings allocation in Original Decision by correcting the errors identified in it by the Review Panel; and (b) in doing so, the OEB shall apply and give effect to the findings in the Review Decision and each of the errors it identified in the Original Decision, including in respect of the applicable ratemaking principles.

PART III: THE FACTUAL CONTEXT

[12] HONI is an electric utility corporation that is regulated by the OEB. As of 2017, its transmission system accounted for about 98% of Ontario's electricity transmission capacity, and it is also the Province's largest electricity distributor.

[13] Currently, HONI is a wholly owned subsidiary of Hydro One Inc. ("HOI"), which is itself a wholly owned subsidiary of Hydro One Limited ("HOL"). Unlike HONI, neither HOI nor HOL is regulated by the OEB, because only HONI provides regulated electric transmission and distribution services.

[14] In 2015, the Province of Ontario, which until then had been the sole owner of HONI's parents, undertook an initial public offering (the "IPO") to begin divesting itself of HOL's shares. The IPO had two interrelated tax consequences for HONI.

[15] First, HONI was required to immediately pay the PILs departure tax of $2.271 billion in exiting the PILs regime established by the *Electricity Act* (Ontario) and the *Payments in Lieu of Corporate Taxes Regulation* (the "*PILs Regulation*").

[16] Prior to the IPO, HOL and its subsidiaries, including HONI, were exempt from federal income taxes pursuant to s. 149(1) of Canada's *Income Tax Act*, which in turn made them exempt from provincial corporate income taxes under s. 27(2) of Ontario's *Taxation Act, 2007*. So long as HONI was exempt from these taxes, it was required by ss. 88-89 of the *Electricity Act* to make PILs to the Ontario Electricity Financial Corporation in amounts equivalent to the federal and provincial taxes it would have paid were it a taxable entity.

[17] The IPO changed this. The province's sale of more than 10% of HOL's shares terminated HONI's exemption from federal and provincial income taxes, such that the PILs regime ceased to apply to it. For tax purposes, this triggered a deemed disposition and reacquisition of all HONI's assets at fair market value ("FMV") under s. 149(10)(b) of the *Income Tax Act* ("*ITA*") (the "Deemed Transaction"). The Deemed Transaction, in turn, triggered HONI's liability to pay the PILs Departure Tax under s. 16.1 of the *PILs Regulation* in an amount equal to the tax under the *ITA* where an entity sells or is deemed to sell its assets at FMV.

[18] Second, the Deemed Transaction also provided HONI with Future Tax Savings of $2.595 billion.[2] The Future Tax Savings arose because the Deemed Transaction increased the tax value of certain of HONI's assets by $9.794 billion, which increased the capital cost allowance and

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[2] The $2.595 billion figure represents the book value of the Future Tax Savings, but the present value of the Future Tax Savings (taking into account the time value of money over the approximately 20-year period when HONI can use them, by using an average weighted cost of capital of 9% and average annual tax depreciation of 5.5% on a declining balance) is only $1.2 billion. The PILS Departure Tax paid by HONI was therefore materially greater than the amounts it may recover back by the Future Tax Savings over time.

cumulative eligible capital claims that HONI could deduct in computing its taxable federal and provincial income in years after 2015.

[19] It is important to note that the Future Tax Savings do not represent a windfall for HONI. In order to receive the Future Tax Savings, HONI had to exit the PILs regime and pay the PILs Departure Tax as a result of the Deemed Transaction. In effect, the Future Tax Savings are a recovery over time of the PILs Departure Tax paid by HONI and funded by its shareholders.

1. The Transmission Approval Application

[20] In Ontario, utility rates are regulated through a process by which a utility seeks approval from the OEB for costs it has incurred or expects to incur in a specified period of time. Where the OEB approves of such costs as just and reasonable, it incorporates them into the utility's rates pursuant to s. 78(3) of the *OEB* Act, so that the utility has a reasonable opportunity to recover them and earn a fair return during a rate period.[3]

[21] On May 31, 2016, HONI applied under s. 78(7) of the *OEB Act* for approval of the 2017 and 2018 "revenue requirements" for its transmission business, i.e., "the total revenue that is required by the company to pay all of its allowable expenses and also to recover all costs associated with its invested capital", which once approved are "allocated to customers in the form of just and reasonable rates".[4]

[22] In doing so, HONI did not seek to recover any part of the PILs Departure Tax applicable to its transmission business from ratepayers. The rationale for this decision was that the PILS Departure Tax was not a cost that pertained to the provision of rate-regulated utility services; rather, it arose from a transaction involving its unregulated indirect parent. HONI therefore paid the PILs Departure Tax itself, using funds it obtained by issuing shares to HOI as part of a trickle-down recapitalization of the corporation by its ultimate shareholder, the Province.

[23] Consistent with this decision, HONI took the position, supported by OEB staff, that all of the Future Tax Savings should be retained by its shareholders, and not be allocated to reduce its revenue requirement so as to lower the regulatory taxes that HONI's ratepayers pay. It did so on the basis of rate-making principles accepted by the OEB in the Original Decision, including the "stand-alone or pure utility" and "benefits follow costs" principles. The Original Panel described these principles as follows:

> 3.3 STAND ALONE OR PURE UTILITY PRINCIPLE
>
> This principle limits the amounts recoverable in utility rates to costs related to the

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[3] *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 at paras. 1, 15-20 and 76.
[4] *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2015 SCC 45, at para. 3.

provision of regulated utility services. For ratemaking purposes, costs related to unregulated or non-utility business activities are excluded from the ambit of the "standalone" or "pure" utility activities.

The business activities of a "stand-alone" or "pure" utility are limited to the provision of regulated services. For regulatory purposes, a "pure" utility is distinguishable from a holding company parent that already controls and is actively acquiring several other subsidiary enterprises.

...

3.5 BENEFITS FOLLOW COSTS

If a cost, not included in the utility's revenue requirement, causes or produces a benefit, then, for ratemaking purposes, that benefit is allocated to utility shareholders and not to its ratepayers. This principle of allocation is considered in the determination of issues related to the allocation of tax benefits between utility ratepayers and shareholders.

Charitable donations are an example of costs not recoverable from ratepayers that produce a tax benefit. A portion of the donation can be used as a tax credit when calculating taxes payable. The utility's actual income tax is lower because of the tax credit produced by the charitable donation. However, ratepayers do not receive the benefit of this lower tax amount because they did not pay the costs that caused it. The tax benefit is allocated to the shareholders who are responsible for the donation costs.

The taxes collected from ratepayers will be a notional sum that is higher than the actual amount paid by the utility. The notional sum will be calculated on the basis of a taxable income amount that excludes the charitable donation expense and its related tax credit.

2. The Original Decision

[24] On September 28, 2017, the Original Panel disposed of the application in the Original Decision, as subsequently revised by it on October 11 and November 1, 2017.

[25] The Original Panel rejected HONI's position with respect to the Future Tax Savings. It determined that they should not be allocated in their entirety to HONI's shareholders, but instead be divided between its shareholders and ratepayers, with the ratepayer portion being applied to reduce HONI's transmission revenue requirements for 2017 and 2018 (the "Future Tax Savings Determination").

[26] The Original Panel reached this conclusion upon finding that HONI was entitled to the second, or more favourable, of the following two methodologies:

(a) one by which HONI's shareholders would receive 52.5% of the Future Tax Savings, which represented amounts that could be considered recapture of amounts credited to ratepayers in prior rate applications, leaving ratepayers 47.5% (the "Recapture Methodology"); and

(b) one by which HONI's shareholders would receive 62% of the Future Tax Savings, representing the part of the PILs Departure Tax that contributed to increasing the FMV of the HOL shares subsequently sold on the IPO, leaving ratepayers 38% (the "Actual FMV Sales and Payments Methodology").

[27] The crux of the Original Panel's reasoning was its finding that the PILs Departure Tax was not a real cost to HONI, because it was variable at the Province's discretion and was funded by a payment from Ontario to HONI for the purchase of additional shares.

[28] As a result of this finding, the Original Panel declined to apply the benefits follow costs and stand-alone utility principles adopted in HONI's proposed methodology. Under that methodology, 100% of the Future Tax Savings would have been allocated to HONI's shareholders, because they were a benefit for which HONI paid the entirety of the cost via the PILs Departure Tax, and this cost was not related to HONI's provision of regulated service, nor recovered by it from ratepayers.

[29] In declining to apply HONI's proposed methodology, the Original Panel referred to its Distribution Rate Handbook Report (the "2005 Report"). There, the OEB allocated to ratepayers the tax savings that arose when Ontario utilities received an increase in the tax value of their assets through a deemed sale arising from a mandatory directive by Ontario's Minister of Finance. As the Original Panel noted, however, the 2005 Report reached this conclusion only because the utilities in that case incurred no costs to receive the tax benefit:

> [In the 2005 Report] [t]he OEB concluded that, where no costs relating to an actual sale at FMV had been incurred, the CCA tax benefits associated with the FMV Bump should be allocated, in their entirety, to utility ratepayers.
>
> ...[T]ax benefits related to increases in the prevailing tax values of utility assets to FMV that are "costless" are allocated to ratepayers...[5]

[30] Based on this, because the Original Panel found that the PILS Departure Tax was not a real cost to HONI, it concluded that "the Benefits follow Costs principle does not apply to the proportion of the FMV Bump that remains attributable to the 'deemed' sale".

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[5] Original Decision, pp. 87, 11-12, 86, 95, 168 and p.92-93, 167, 176.

3. The Review Procedural Order

[31] On October 18, 2017, HONI filed a motion with the OEB to review and vary the Original Decision under Rules 40 and 42 of the OEB's *Rules of Practice and Procedure* (the "OEB Rules"), including with respect to the Future Tax Savings Determination. These OEB Rules implement the review and variance jurisdiction conferred upon the OEB by ss. 21.2(1) and 25.1(1) of Ontario's *Statutory Powers Procedure Act* (the "*SPPA*").[6]

[32] On December 19, 2017, the OEB made an order (the "Review Procedural Order") finding that HONI's motion "met the threshold for review as defined in section 43 of the OEB's Rules" and that it would "hear the motion on its merits".[7] OEB Rule 43.01 allows the OEB to determine, in respect of motions to review and vary, the "threshold question of whether the matter should be reviewed before conducting any review on the merits".

4. The Review Decision

[33] On August 31, 2018, the OEB disposed of the review and variance motion through the Review Decision. In it, the Review Panel concluded that the Original Decision suffered from four interrelated errors with respect to the Future Tax Savings Determination.

[34] First, the Original Decision was contrary to the stand-alone utility principle:

> 1. The Decision does not follow the stand-alone utility principle and is inconsistent with prior OEB applications of the stand-alone utility principle.
>
> In EB-2007-0905… the OEB found that a utility would have no greater or lesser rights and obligations simply because it is government owned.
>
> The Decision treated Hydro One Networks differently because its shareholder is the Province. The OEB agrees with Hydro One Networks submission at the Motion hearing that:
>
> > If the shareholder, who had provided the equity and [in]fusion for shares, had been anybody other than the province, it could have been any third party, then…you can infer from the decision that the cost would not have been treated as variable or anything less than the full true cost… The determination of a cost should not turn on who provides the equity…
>
> This finding in the Decision, which considered the PILs departure tax from the

[6] Review Decision, pp. 1-2, 28-29.
[7] Procedural Order No. 1, December 19, 2017, EB-2017-0336, p. 2.

Province's perspective and not from the utility's stand-alone perspective, led to an inappropriate allocation of the future tax savings…

[35] Second, the Original Panel erred in finding the PILs Departure Tax was "variable" and could have been waived by the Province:

> 2. The Decision found that the PILs departure tax was "variable".
>
> …
>
> The PILs departure tax and the PILs payments paid by Hydro One Networks were established by the PILs legislation. All municipally and provincially owned regulated utilities (including Hydro One Networks and OPG) pay PILs on the same basis and recover those payments from ratepayers.
>
> There has never been any question on whether Hydro One Networks should be allowed to recover its ongoing PILs payments from ratepayers, even though its shareholder and taxing authority, the Province, has the power to amend the PILs legislation to allow it to waive the PILs payments.
>
> There was no evidence presented to the OEB that suggested that the PILs departure tax should be treated any differently than PILs payments and that the Province ever contemplated amending the PILs legislation to waive the departure tax for Hydro One Networks, which it did not do.
>
> The Decision erred in speculating or assuming that the Province could have or should have made changes to the PILs legislation. The evidence should have been considered only in the context of the legislation that was and is in effect.

[36] Third, the Original Panel erred in finding the PILs Departure Tax was not a real cost to HONI but a payment by the Province to itself:

> 3. The Decision did not accept that Hydro One Networks paid the departure tax in substance and that it was a real cost to the utility.
>
> The Decision finding that the departure tax was a "payment from itself to itself" by the Province is inconsistent with the evidence on the record. The testimony… show[s] how the departure tax liability and the future tax savings, which has been dedicated to the Trillium Trust, have been recorded.
>
> The Decision considered the payment of the departure tax from the perspective of the Province, not the utility's stand-alone perspective. The Decision inappropriately considered potential transactions involving the shareholder, beyond the regulated business.

[37] Fourth, both allocation methodologies considered in the Original Decision were flawed, including the Actual FMV Sales and Payments Methodology ultimately used by the Original Panel to allocate 38% of the Future Tax Savings to ratepayers:

> 4. The two allocation methodologies used in the Decision appear to be inappropriate. In particular:
>
> a. Recapture Ratio methodology – did not recognize the real cost of the departure tax liability paid by Hydro One Networks.
>
> b. Actual FMV Sales and Payment methodology – treats shares of Hydro One Networks that continue to be owned by the Province differently than those owned by other shareholders, even though Hydro One Networks has only one class of shares. This methodology is also inconsistent with other findings in the Decision (e.g. making allowance for departure tax payment by the Province even though the Decision found that this departure tax was not a real cost to the utility).
>
> c. None of the parties, including Hydro One Networks, had the opportunity to consider the applicability of these methodologies, review the calculations or make submissions on whether or how they should be applied.

[38] Finally, the Review Panel found the Future Tax Savings were a benefit that followed directly from the PILs Departure Tax, which, as noted above, it held was a real cost to HONI:

> The OEB does not accept the argument by some of the intervenors that the departure tax payment and the future tax savings are unrelated. They both arise as a result of the same transaction. PILs are payable because the ITA does not apply to municipally and provincially owned entities. It is only because of the change in Hydro One Network's tax status as a result of shares being sold that any of these payments and savings occur.

[39] Given all the foregoing, the Review Panel ordered that the Original Decision be returned to the Original Panel so that it could be "reconsider[ed] in light of these findings and all the evidence and argument the original panel and the reviewing panel heard".

5. The Rehearing Decision

[40] On March 7, 2019, the OEB purported to reconsider the Original Decision in the Rehearing Decision. The Rehearing Panel consisted of two members of the Original Panel and one member of the Review Panel.

[41] In a procedural order released on November 6, 2018 (the "Rehearing Procedural Order"),[8] the OEB held that the Review Panel had applied only the first step of its threshold "NGEIR Decision"[9] test for determining if a review and variance proceeding should be heard (i.e., the Original Decision contained an error), and not the second step as well (i.e., that the error was material to the Original Decision's outcome), thereby misstating the Review Panel's actual finding at paragraph 34 above that the Original Decision produced "an inappropriate allocation of the future tax savings":

> ... What is unique about the current proceeding is that, in the OEB's view, the threshold test is being applied in two stages with only the first stage having been performed by the Review Panel. The Review Panel determined that errors were made but did not determine whether these errors, if corrected, would change the outcome of the Original Decision. The reconsideration of the Original Decision by the Original Panel in view of the identified errors, in the OEB's view, represents the second stage of the threshold test as articulated by the NGEIR decision. ...
>
> ...
>
> In response to the Review Panel's direction and in alignment with the threshold test first articulated in the NGEIR Motion Decision, the OEB will consider, in addition to all previously filed pertinent evidence and arguments, submissions on the following question:
>
> If the errors identified by the Review Panel are accepted, and with due consideration given to the May 2005 Report and any other matters argued in the original case, would the Original Decision be reasonable regarding the allocation of future tax savings between shareholders and ratepayers? If not, what is the appropriate outcome?

[42] The Rehearing Panel therefore applied this second step of its threshold test in the Rehearing Decision itself, without acknowledging that the same test had already been applied in the Review Procedural Order. The result was that the Rehearing Panel fettered its reconsideration discretion and applied only a standard of "reasonableness" to the Original Decision, as if on appeal or judicial review:

> ...[T]he original decision making panel is entitled to deference, and... the appropriate standard of review is what is known before the courts as "reasonableness".

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[8] Procedural Order No. 1, November 6, 2018, EB-2018-0269, p. 1, 22.

[9] EB-2006-0322/EB-2006-0338/EB-2006-0340, *Decision With Reasons: Motions To Review The Natural Gas Electricity Interface Review Decision*, May 22, 2007.

> ...[T]he review is being conducted in two stages with only the first stage having been performed by the Review Panel. The Review Panel determined that errors were made but did not determine whether these errors, if corrected, would change the outcome of the Original Decision. The reconsideration of the Original Decision by the current panel in view of the identified errors, in the OEB's view, represents the second stage of the review. In PO#1, the OEB found the following determinations of the NGEIR decision to be relevant to this proceeding.

[43] In applying this test, the Rehearing Panel accepted that the Original Panel erred in not treating the PILs Departure Tax as a real cost to HONI:

> The Review Panel found that the Decision of the Original Panel did not follow the standalone principle and was inconsistent with prior OEB applications of the stand-alone principle. ...
>
> This finding of error in treating Hydro One differently because its shareholder is the Province is intrinsically related to the determination that the Original Panel erred in finding that the payment was from itself to itself. The two errors, if corrected, would have the payment be recognized as a true cost to Hydro One.
>
> The correction of the error that the departure tax was variable and that the Province could have or should have changed the PILs legislation also results in the payment being recognized as a real cost to Hydro One.

[44] However, the Rehearing Panel held that the Original Decision should continue to stand. In gave no meaningful reasons for this conclusion. Instead, it simply recited the submissions of the parties and then baldly concluded that the Original Decision was "reasonable". It did so even though the only argument put against HONI was that the SEC's submission that the PILs Departure Tax is not recoverable from ratepayers, which argument supports HONI's claim to the benefit of the Future Tax Savings that followed from this cost:

> Hydro One has argued that 100% of the Future Tax Savings should be allocated to shareholders. The OEB sees merit in this argument based on Hydro One's assertions that it should get the benefit of the Future Tax Savings resulting from the IPO transaction because it paid for it through the Departure Tax.
>
> SEC has argued that based on the just and reasonable principle, 100% of the Future Tax Savings should be allocated to customers. The OEB sees merit in this argument based on SEC's assertions that costs caused by non-regulated activities (i.e. Departure Tax resulting from the IPO) are not recoverable from customers in regulated rates. Although SEC submits that the Review Panel did not discuss how this rule should be applied, SEC argues that this outcome would still be consistent with the findings of the Review Panel.
>
> As stated earlier, the current panel has retained the determination made by the

> Original Panel with respect to the wide level of discretion available to the OEB in making its determination with respect to the treatment of the Future Tax Savings. In consideration of all the above, the OEB finds that the Original Decision results in an allocation of the Future Tax Savings (62% to shareholders and 38% to the ratepayers) that is within the realm of reasonable outcomes.

[45] The Rehearing Panel did not identify the allocation methodology it used to reach this result. Despite accepting that both methodologies in the Original Decision were flawed – including the Actual FMV Sales and Payments Methodology that produced the very 68/32% split which the Rehearing Panel confirmed – it found it unnecessary to consider the matter once it held the 68/32% "outcome" to be "reasonable":

> The Review Panel had determined that both allocation methodologies used by the Original Panel "appeared to be inappropriate" for reasons related to errors that had been identified. ... The OEB has determined that, given its balance of interest approach and the range of reasonableness of outcomes that stems from the application of the principles contained in 2005 Report, it need not pursue the identification of a more appropriate allocation methodology. Further, the consideration of the appropriateness of one method over the other is not required if both would result in a reasonable outcome. The purpose of this exercise is as stated earlier, to consider the reasonableness of the outcome of the Original Decision in view of the Review Panel's determinations. The OEB considers the outcome of the Original Decision to be reasonable. The motion is dismissed and the original decision upheld.

[46] In the result, a nearly $900 million issue was decided in a handful of paragraphs based on a recitation of the parties' arguments followed by the bald conclusion that the Original Decision was reasonable, despite the errors that the Review Panel identified in the Original Decision. There was no assessment of the merits and no application of expertise; the Rehearing Panel did not identify or rationalize a methodology supporting the allocation of some of the Future Tax Savings to the ratepayers and some to HONI's shareholders.

PART III: LEGAL ISSUES

1. Court's Jurisdiction

[47] Pursuant to ss. 33(1)(a) and 33(2) of the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Sched. B, ["the *OEB Act*"] an appeal lies to the Divisional Court from an order of the Board, but only on a question of law or jurisdiction. According to ss. 33(4) of the same act, "The Divisional Court shall certify its opinion to the Board and the Board shall make an order in accordance with the opinion, but the order shall not be retroactive in its effect."

[48] HONI argues that the OEB erred in law by applying the wrong legal test to the Original Decision. After identifying the errors made by the Original Panel, the Review Panel ordered that

its decision be remitted back to it so that it could be "reconsider[ed] in light of these findings and all the evidence and argument the original panel and the reviewing panel heard". The Rehearing Panel did not do so. Rather than reconsidering the issue as directed by the Review Panel, the Rehearing Panel held that the reconsideration motion required it to determine only whether the Original Decision would be "reasonable" if the errors found by the Review Panel were accepted. It thus asked itself the wrong question and fettered its statutory discretion to vary the Original Decision without deference to the Original Panel.

[49] The OEB submits that the issues raised in this appeal are not properly viewed as errors of law or of jurisdiction. I disagree. The issue of whether the Rehearing Panel applied the correct legal test presents a clear question of law.[10]

2. The Standard of Review

[50] As the Legislature has granted a right to appeal on a question of law or jurisdiction, the standard of review in this case is correctness: *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65 at para. 37.

3. Was the Decision of the Rehearing Panel Correct?

[51] The Rehearing Panel was directed to reconsider the Original Decision in light of the findings of the Review Panel and all the evidence and argument the original panel and the reviewing panel heard. The Rehearing Panel did not do so. It instead applied a standard of reasonableness to the Original Decision. This was central to its conclusion that the original decision was "within the realm of reasonable outcomes." A failure to apply the correct legal test is clearly an error in law. Therefore the decision of the Rehearing Panel was not correct, and it must be quashed.

[52] I would note that, even if the standard of review was the more deferential reasonableness standard, the decision of Rehearing Panel could not be upheld. *Vavilov* emphasizes the importance of the justification of an administrative decision. At para 15 the Chief Justice stated:

> In conducting a reasonableness review, a court must consider the outcome of the administrative decision in light of its underlying rationale in order to ensure that the decision as a whole is transparent, intelligible and justified. [Emphasis added.]

The Chief Justice continued at paras 85, 95, 102 and 103:

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[10] *Németh v. Canada (Justice)*, 2010 SCC 56 at paras. 10 and 115.

> a reasonable decision is one that is based on an internally coherent and rational chain of analysis and that is justified in relation to the facts and law that constrain the decision maker.
>
> ...
>
> the exercise of public power must be justified, intelligible and transparent, not in the abstract, but to the individuals subject to it. It would therefore be unacceptable for an administrative decision maker to provide an affected party formal reasons that fail to justify its decision
>
> ...
>
> To be reasonable, a decision must be based on reasoning that is both rational and logical. It follows that a failure in this respect may lead a reviewing court to conclude that a decision must be set aside. ... However, the reviewing court must be able to trace the decision maker's reasoning without encountering any fatal flaws in its overarching logic, and it must be satisfied that "there is [a] line of analysis within the given reasons that could reasonably lead the tribunal from the evidence before it to the conclusion at which it arrived.
>
> ...
>
> a decision will be unreasonable if the reasons for it, read holistically, fail to reveal a rational chain of analysis or if they reveal that the decision was based on an irrational chain of analysis ... A decision will also be unreasonable where the conclusion reached cannot follow from the analysis undertaken ... or if the reasons read in conjunction with the record do not make it possible to understand the decision maker's reasoning on a critical point
> [Emphases added.]

[53] The Rehearing Panel wrongly stated that the Review Panel did not conclude that the errors it identified "would change the outcome of the Original Decision." It also failed to address any of the four significant errors identified by the Review Panel and simply concluded that the Original Decision fell "within the realm of reasonable outcomes." The Rehearing Panel's decision lacks an internally coherent and rational chain of analysis that leads from the evidence to the conclusion it reached. Indeed, given the brevity of the reasons, one cannot say whether the panel's reasoning is logical or rational.

[54] In sum, the decision cannot be said to be transparent, intelligible, and justified. It therefore cannot be found to be reasonable.

4. What is The Appropriate Remedy?

[55] Pursuant to s. 33(4) of the *OEB Act* on the hearing of an appeal under the *Act*, "The Divisional Court shall certify its opinion to the Board and the Board shall make an order in accordance with the opinion, but the order shall not be retroactive in its effect."

[56] HONI submits that the proper remedy in this case is for the court to substitute for the decision of the Rehearing Panel an order that none of the Future Tax Savings will be applied to reduce HONI's transmission revenue requirements for 2017 and 2018. In this regard, HONI relies on s. 134(1)(a) of the *Courts of Justice Act* which makes clear that the Court's opinion to the OEB can be in substitution for the one given in the Rehearing Decision:

> 134 (1) Unless otherwise provided, a court to which an appeal is taken may, (a) make any order or decision that ought to or could have been made by the court or tribunal appealed from;

HONI submits that this is the appropriate remedy as this is the only reasonable decision that was available on the evidence, given the findings of the Review Panel.

[57] In the alternative, HONI submits that this court should remit the matter back to the OEB with the directions that: (a) the OEB shall consider and make an appropriate order varying the tax savings allocation in Original Decision by correcting the errors identified in it by the Review Panel; and (b) in doing so, the OEB shall apply and give effect to the findings in the Review Decision and each of the errors it identified in the Original Decision, including in respect of the applicable ratemaking principles.

[58] The OEB submits that s. 33(4) of the *OEB Act* does not confer on the court a statutory right to substitute its decision in place of the decision of the Rehearing Panel. The OEB submits that 134(1)(a) of the *Courts of Justice Act* does not apply in this appeal, because s. 33(4) of the OEB Act "provides otherwise" by limiting the available remedy to the certification of the Divisional Court's opinion. The OEB points out that there are no cases where the Divisional Court has simply substituted its own decision for the OEB's decision under appeal.

[59] In the alternative, the OEB submits that this court should not substitute its opinion for that of the Board since that should only be done in "exceptional circumstances" which do not exist here. The OEB argues that remitting the case to the Board would not be pointless and that this is not a case where there is only one reasonable outcome that can be reached if the matter is sent back. Rather the OEB submits that this Court should certify its opinion about any errors of law or jurisdiction so that the Board can reconsider the matter in view of that opinion, applying its expertise and experience to that task.

[60] I agree that s. 33(4) of the OEB Act precludes us from simply issuing the ruling that we think the Rehearing Panel should have issued. Rather we must certify our opinion to the Board. But I also agree with the submissions of HONI that no portion of the Future Tax Savings should be allocated to ratepayers when the evidence is clear that HONI paid all of its costs under the stand-alone utility principle. Therefore, under the long-established benefits follow costs principle, no part of the benefit of the Future Tax Savings is allocable to ratepayers and should instead be paid to the shareholders in its entirety. The application of this principle is not affected by the Board's mandate to approve "just and reasonable rates" or to achieve a reasonable balance between the interests of utility ratepayers and the interests of shareholders.

PART IV: FINAL ORDER

[61] The Court therefore orders that the matter be remitted back to the Board and (a) a new panel of the OEB shall consider and make an appropriate order varying the tax savings allocation in Original Decision by correcting the errors identified in it by the Review Panel; and (b) in doing so, the OEB shall apply and give effect to the findings of the Review Decision and each of the errors it identified in the Original Decision, including in respect of the applicable ratemaking principles.

Ducharme J.

I agree: D.L. Corbett J.

I agree: Gomery J.

Released: July 16, 2020

CITATION: Hydro One Networks Inc. v. Ontario Energy Board, 2020 ONSC 4331
DIVISIONAL COURT FILE NO.: 200/19
DATE: 20200716

ONTARIO

SUPERIOR COURT OF JUSTICE
DIVISIONAL COURT

D.L. Corbett, Ducharme and Gomery JJ.

BETWEEN:

HYDRO ONE NETWORKS INC.

Appellant

- and -

ONTARIO ENERGY BOARD

Respondent

REASONS FOR DECISION

Ducharme J.

Released: July 16, 2020

ENERGY PROBE INTERROGATORY #2

Reference:
Exhibit A, Tab 1, Schedule 1, Page 7, Table 1

Interrogatory:

a) Please detail what costs has Hydro One incurred as a result of the Misallocated Tax Savings Amounts (MTSA) that are not shown in Table 1, e.g. legal costs.

b) Did the Court make an award of costs? If so please provide details.

Response:
These amounts are not relevant as they are not sought for recovery.

ENERGY PROBE INTERROGATORY #3

Reference:
Exhibit A, Tab 1, Schedule 1, Page 8, Table 2

Interrogatory:
Please Update the Carry Cost Rates to reflect the OEB November 9, 2020 Letter regarding Rates for Debt and Equity.

Response:
Please refer to response to Staff-02 (a), iv.

ENERGY PROBE INTERROGATORY #4

Reference:
Exhibit A, Tab 1, Schedule 1, Page 10, and Table 4

Preamble:
"In the present circumstances, Hydro One submits that its weighted average cost of debt ("WACD") is an appropriate rate used to calculate all carrying costs and the bill impacts included herein reflect that rate. As a result of the Original Decision, Hydro One incurred a higher level of debt, than it otherwise would have. The WACD is the most appropriate carrying charge because the Misallocated Tax Savings Amounts were funds otherwise expected to be received by Hydro One in its normal operations. The cost to finance this shortfall would reasonably attract Hydro One's WACD given that it was over a four year period."

Interrogatory:
a) Please provide a schedule that shows in the OEB approved format for each of the historic years up to 2020 Hydro One debt issues and the detailed data on terms, rates etc. for each issue.

b) Please compare the amount and type of debt issued in 2015-2017 period to the amounts of debt issued in the 2018-2020 period.

c) Provide the average historic Cost of Debt 2015-2017 and the recent cost of debt 2018-2020.

d) Please provide a schedule that shows the sources and uses of funds for each year from 2017 to 2019. Please show the dividends paid for each year.

e) Are the carrying cost amounts shown for each year in Table 4 calculated as simple interest or are they compounded? If the carrying costs are compounded please explain why that is appropriate.

Response:

a) As shown in the response to Staff-02, the WACD is comprised of the OEB approved long-term debt rate and the short-term debt rate. The details of the OEB approved long-term debt rates can be found in the following exhibits.

<table>
<tr><th colspan="7">OEB Case Numbers</th></tr>
<tr><th></th><th colspan="3">Transmission</th><th colspan="3">Distribution</th></tr>
<tr><th>Year</th><th>DRO Number</th><th>Reference</th><th>Attachment</th><th>DRO Number</th><th>Reference</th><th>Attachment</th></tr>
<tr><td>2017</td><td>EB-2017-0280</td><td>Exhibit 1.4.1, page 1</td><td>1</td><td colspan="3">No tax savings in the 2017 Distribution rates</td></tr>
<tr><td>2018</td><td>EB-2017-0359</td><td>Exhibit 1.4.1, page 1</td><td>2</td><td rowspan="5">EB-2017-0049</td><td rowspan="5">Exhibit 1.4.1, page 1</td><td rowspan="5">4</td></tr>
<tr><td>2019</td><td colspan="3">N/A*</td></tr>
<tr><td>2020</td><td rowspan="3">EB-2019-0082</td><td rowspan="3">Exhibit 1.4.1, page 1</td><td rowspan="3">3</td></tr>
<tr><td>2021</td></tr>
<tr><td>2022</td></tr>
</table>

*No DRO for 2019 due to Transmission Revenue Cap Index adjustment to determine Hydro One's 2019 revenue requirement

b) The amount of long-term debt issued, as per the approved debt schedules in the DROs referenced in part a) are as follows:

		Long Term Debt ($M)*	
	DRO Number	**2015-2017**	**2018-2020**
Distribution	EB-2017-0049	850	596
Transmission	EB-2019-0082	940	2,060

c) Hydro One's rationale for using approved rates is discussed in the response Staff-02(a) iv.

d) Please refer to Attachment 5.

e) Please refer to response in Staff-02(b).

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2017)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/2016 ($Millions)	Total Amount Outstanding: at 12/31/2017 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.4	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.8	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.6	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.2	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.3	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.2	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.9	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.5	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.2	5.62%	228.9	228.9	228.9	12.9	
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.7	5.45%	187.5	187.5	187.5	10.2	
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.3	5.04%	30.0	30.0	30.0	1.5	
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.4	4.93%	240.0	240.0	240.0	11.8	
13	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.6	5.23%	225.0	0.0	173.1	9.0	
14	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.7	4.95%	180.0	0.0	138.5	6.9	
15	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.4	6.07%	195.0	195.0	195.0	11.8	
16	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.4	5.53%	210.0	210.0	210.0	11.6	
17	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.6	5.45%	120.0	120.0	120.0	6.5	
18	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.5	4.46%	180.0	180.0	180.0	8.0	
19	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.2	4.98%	150.0	150.0	150.0	7.5	
20	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.3	4.43%	205.0	205.0	205.0	9.1	
21	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.5	4.03%	70.0	70.0	70.0	2.8	
22	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.5	3.26%	154.0	154.0	154.0	5.0	
23	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	101.0	3.08%	165.0	165.0	165.0	5.1	
24	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.5	4.02%	68.8	68.8	68.8	2.8	
25	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.5	3.81%	52.5	52.5	52.5	2.0	
26	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.2	3.83%	141.0	141.0	141.0	5.4	
27	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.4	4.63%	239.3	239.3	239.3	11.1	
28	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.6	2.87%	412.5	412.5	412.5	11.8	
29	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.4	4.32%	30.0	30.0	30.0	1.3	
30	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.4	4.21%	198.0	198.0	198.0	8.3	
31	24-Feb-16	3.910%	23-Feb-46	175.0	1.1	173.9	99.4	3.95%	175.0	175.0	175.0	6.9	
32	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.6	2.82%	245.0	245.0	245.0	6.9	
33	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.6	1.92%	250.0	250.0	250.0	4.8	
34	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.5	3.75%	270.0	270.0	270.0	10.1	
35	15-Mar-17	3.670%	15-Mar-47	219.1	1.1	218.0	99.5	3.70%	0.0	219.1	168.5	6.2	
36	15-Jun-17	2.606%	15-Jun-27	109.6	0.5	109.0	99.5	2.66%	0.0	109.6	59.0	1.6	
37	15-Jun-17	3.670%	15-Jun-47	109.6	0.5	109.0	99.5	3.70%	0.0	109.6	59.0	2.2	
38	15-Sep-17	2.606%	15-Sep-27	219.1	1.1	218.0	99.5	2.66%	0.0	219.1	67.4	1.8	
39		**Subtotal**							5489.1	5741.4	5749.5	262.4	
40		Treasury OM&A costs										1.8	
41		Other financing-related fees										4.1	
42		**Total**							5489.1	5741.4	5749.5	268.3	4.67%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2018)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/2017 ($Millions)	Total Amount Outstanding: at 12/31/2018 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
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2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
13	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
14	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
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16	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
17	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
18	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
19	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
20	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
21	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
22	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
23	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
24	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
25	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
26	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	0.0	317.3	9.1	
27	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.44	4.32%	30.0	30.0	30.0	1.3	
28	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.40	4.21%	198.0	198.0	198.0	8.3	
29	24-Feb-16	3.910%	23-Feb-46	175.0	1.1	173.9	99.4	3.95%	175.0	175.0	175.0	6.9	
30	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.6	2.82%	245.0	245.0	245.0	6.9	
31	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.6	1.92%	250.0	250.0	250.0	4.8	
32	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.5	3.75%	270.0	270.0	270.0	10.1	
33	15-Mar-17	3.670%	15-Mar-47	0.0	0.0	0.0	100.0	3.67%	0.0	0.0	-	0.0	Note 1
34	15-Jun-17	2.606%	15-Jun-27	0.0	0.0	0.0	100.0	2.61%	0.0	0.0	-	0.0	Note 1
35	15-Jun-17	3.670%	15-Jun-47	0.0	0.0	0.0	100.0	3.67%	0.0	0.0	-	0.0	Note 1
36	15-Sep-17	2.606%	15-Sep-27	0.0	0.0	0.0	100.0	2.61%	0.0	0.0	-	0.0	Note 1
37	15-Mar-18	4.185%	15-Mar-48	296.6	1.5	295.2	99.50	4.21%	0.0	296.6	228.2	9.6	Note 2
38	15-Jun-18	3.377%	15-Jun-28	296.6	1.5	295.2	99.50	3.44%	0.0	296.6	159.7	5.5	Note 2
39	15-Sep-18	2.824%	15-Sep-23	296.6	1.5	295.2	99.50	2.93%	0.0	296.6	91.3	2.7	Note 2
40		**Subtotal**							5084.1	5561.5	5468.1	249.8	
41		Treasury OM&A costs										2.0	
42		Other financing-related fees										4.1	
43		**Total**							5084.1	5561.5	5468.1	255.8	4.68%

Note 1: Updated to reflect actual 2017 debt issuance

Note 2: Updated to reflect the forecast coupon rates for 2018 as per Hydro One Inc. Spreads and Consensus Forecast (3 and 12 month 10 year Government Bond Yield average), both from September 2017

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2020)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: 1/1/2019 at 12/31/19 ($Millions)	Total Amount Outstanding: 1/1/2020 at 12/31/20 ($Millions)	1/1/2020 Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates	
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.400	20.8		
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.272	7.7		
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.000	3.9		
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.000	8.1		
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.000	9.6		
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.000	4.6		
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.000	2.4		
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.000	2.4		
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.900	12.9		
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.500	10.2		
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.000	1.5		
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.000	11.8		
13	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8		
14	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6		
15	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5		
16	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	0.0	83.1	3.7		
17	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5		
18	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1		
19	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8		
20	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0		
21	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1		
22	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8		
23	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0		
24	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4		
25	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1		
26	29-Jan-14	4.310%	29-Jan-64	30.0	0.2	29.8	99.44	4.34%	30.0	30.0	30.0	1.3		
27	3-Jun-14	4.190%	3-Jun-44	198.0	1.2	196.8	99.40	4.23%	198.0	198.0	198.0	8.4		
28	24-Feb-16	3.910%	24-Feb-46	175.0	1.1	173.9	99.36	3.95%	175.0	175.0	175.0	6.9		
29	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.56	2.82%	245.0	245.0	245.0	6.9		
30	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.63	1.92%	250.0	250.0	250.0	4.8		
31	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.50	3.75%	270.0	270.0	270.0	10.1		
32	26-Jun-18	3.630%	25-Jun-49	468.0	2.4	465.6	99.48	3.66%	468.0	468.0	468.0	17.1		
33	26-Jun-18	2.970%	26-Jun-25	218.4	0.9	217.5	99.60	3.03%	218.4	218.4	218.4	6.6		
34	5-Apr-19	3.640%	5-Apr-49	147.5	0.8	146.7	99.43	3.67%	147.5	147.5	147.5	5.4		
35	5-Apr-19	3.020%	5-Apr-29	324.5	1.4	323.1	99.57	3.07%	324.5	324.5	324.5	10.0		
36	5-Apr-19	2.540%	5-Apr-24	413.0	1.6	411.4	99.62	2.62%	413.0	413.0	413.0	10.8		
37	15-Nov-19	3.205%	15-Nov-49	0.0	0.0	0.0	100.00	3.21%	0.0	0.0	0.0	0.0		Note 1
38	15-Nov-19	2.555%	15-Nov-29	0.0	0.0	0.0	100.00	2.56%	0.0	0.0	0.0	0.0		Note 1
39	15-Nov-19	2.226%	15-Nov-24	0.0	0.0	0.0	100.00	2.23%	0.0	0.0	0.0	0.0		Note 1
40	15-Mar-20	3.305%	15-Mar-50	163.0	0.8	162.2	99.50	3.33%	0.0	163.0	125.4	4.2		
41	15-Jun-20	2.655%	15-Jun-30	163.0	0.8	162.2	99.50	2.71%	0.0	163.0	87.8	2.4		
42	15-Sep-20	2.326%	15-Sep-25	163.0	0.8	162.2	99.50	2.43%	0.0	163.0	50.2	1.2		
43	**Subtotal**								6243.0	6552.0	6409.4	276.4		
45	Treasury OM&A costs											1.9		
46	Other financing-related fees											5.3		
47	**Total**								6243.0	6552.0	6409.4	283.6	4.42%	

Note 1: Updated 2020 ECD – AIC debt schedule prepared in November 2019, to reflect actual debt issuance in 2019 which only occurred in April 2019, and the removal of forecasted November 2019 issuances which did not occur, as stated in Reply Argument, page 213, lines 16 to 17, " As stated in Exhibit G, Tab 1, Schedule 1 and consistent with prior practice, Hydro One intends to update the rate at the Draft Rate Order stage to reflect actual debt issuances for 2019."

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Test Year (2018)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	1/1/2017 Total Amount Outstanding at 12/31/17 ($Millions)	1/1/2018 Total Amount Outstanding at 12/31/18 ($Millions)	1/1/2018 Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.600	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.728	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.000	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.000	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.000	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.000	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.000	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.000	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.100	5.5	
10	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.500	3.4	
11	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.000	2.3	
12	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.000	7.9	
13	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
14	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
15	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
16	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
17	13-Sep-10	2.950%	11-Sep-15	100.0	0.4	99.6	99.62	3.03%	0.0	0.0	0.0	0.0	
18	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
19	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
20	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
21	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
22	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
23	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
24	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
25	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
26	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	195.8	195.8	195.8	9.1	
27	9-Oct-13	2.780%	9-Oct-18	337.5	1.4	336.1	99.59	2.87%	337.5	0.0	259.6	7.4	
28	29-Jan-14	4.310%	29-Jan-64	20.0	0.1	19.9	99.44	4.34%	20.0	20.0	20.0	0.9	
29	3-Jun-14	4.170%	3-Jun-44	132.0	0.8	131.2	99.40	4.21%	132.0	132.0	132.0	5.6	
30	24-Feb-16	3.910%	24-Feb-46	175.0	1.1	173.9	99.36	3.95%	175.0	175.0	175.0	6.9	
31	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.56	2.82%	245.0	245.0	245.0	6.9	
32	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.63	1.92%	250.0	250.0	250.0	4.8	
33	18-Nov-16	3.720%	18-Nov-47	180.0	0.9	179.1	99.50	3.75%	180.0	180.0	180.0	6.7	
34	15-Mar-17	3.692%	15-Mar-47	0.0	0.0	0.0	100.00	3.69%	0.0	0.0	-	0.0	
35	15-Jun-17	2.929%	15-Jun-27	0.0	0.0	0.0	100.00	2.93%	0.0	0.0	0.0	0.0	
36	15-Jun-17	3.692%	15-Jun-47	0.0	0.0	0.0	100.00	3.69%	0.0	0.0	0.0	0.0	
37	15-Sep-17	2.929%	15-Sep-27	0.0	0.0	0.0	100.00	2.93%	0.0	0.0	0.0	0.0	
38	15-Mar-18	4.185%	15-Mar-48	198.8	1.0	197.8	99.50	4.21%	0.0	198.8	152.9	6.4	
39	15-Jun-18	3.377%	15-Jun-28	198.8	1.0	197.8	99.50	3.44%	0.0	198.8	107.0	3.7	
40	15-Sep-18	2.824%	15-Sep-23	198.8	1.0	197.8	99.50	2.93%	0.0	198.8	61.2	1.8	
41		**Subtotal**							3524.9	3783.7	3768.1	164.7	
42		Treasury OM&A costs										1.1	
43		Other financing-related fees										2.8	
44		**Total**							3524.9	3783.7	3768.1	168.5	4.47%

HYDRO ONE LIMITED
AMENDED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2018 and 2017

Year ended December 31 *(millions of Canadian dollars)*	2018	2017
Operating activities		
Net income (loss)	(65)	682
Environmental expenditures	(22)	(24)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 5)*	747	727
Regulatory assets and liabilities	35	112
Deferred income taxes	890	85
Unrealized loss (gain) on foreign exchange contract	(25)	3
Other	38	18
Changes in non-cash balances related to operations *(Note 28)*	(23)	113
Net cash from operating activities	**1,575**	**1,716**
Financing activities		
Long-term debt issued	1,400	—
Long-term debt repaid	(753)	(602)
Short-term notes issued	4,242	3,795
Short-term notes repaid	(3,916)	(3,338)
Convertible debentures issued *(Note 16)*	—	513
Dividends paid	(560)	(536)
Distributions paid to noncontrolling interest	(8)	(6)
Other *(Note 16)*	(6)	(27)
Net cash from (used in) financing activities	**399**	**(201)**
Investing activities		
Capital expenditures *(Note 28)*		
Property, plant and equipment	(1,418)	(1,467)
Intangible assets	(120)	(80)
Capital contributions received *(Note 28)*	7	9
Other	15	(2)
Net cash used in investing activities	**(1,516)**	**(1,540)**
Net change in cash and cash equivalents	458	(25)
Cash and cash equivalents, beginning of year	25	50
Cash and cash equivalents, end of year	**483**	**25**

See accompanying notes to Amended Consolidated Financial Statements.

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2019 and 2018

Year ended December 31 *(millions of Canadian dollars)*	2019	2018
Operating activities		
Net income (loss)	802	(65)
Environmental expenditures	(25)	(22)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 5)*	777	747
Regulatory assets and liabilities	(48)	35
Deferred income tax expense (recovery)	(30)	890
Unrealized loss (gain) on Foreign-Exchange Contract *(Note 4)*	22	(25)
Derecognition of deferred financing costs *(Note 4)*	24	—
Other	37	38
Changes in non-cash balances related to operations *(Note 30)*	55	(23)
Net cash from operating activities	**1,614**	**1,575**
Financing activities		
Long-term debt issued	1,500	1,400
Long-term debt repaid	(730)	(753)
Short-term notes issued	4,217	4,242
Short-term notes repaid	(4,326)	(3,916)
Convertible debentures redeemed	(513)	—
Dividends paid	(588)	(560)
Distributions paid to noncontrolling interest	(9)	(8)
Contributions received from sale of noncontrolling interest *(Note 4)*	12	—
Common shares issued	6	—
Costs to obtain financing	(8)	(6)
Net cash from (used in) financing activities	**(439)**	**399**
Investing activities		
Capital expenditures *(Note 30)*		
Property, plant and equipment	(1,513)	(1,418)
Intangible assets	(115)	(120)
Capital contributions received *(Note 30)*	3	7
Other	(3)	15
Net cash used in investing activities	**(1,628)**	**(1,516)**
Net change in cash and cash equivalents	(453)	458
Cash and cash equivalents, beginning of year	483	25
Cash and cash equivalents, end of year	**30**	**483**

See accompanying notes to Consolidated Financial Statements.

ENERGY PROBE INTERROGATORY #5

Reference:

Exhibit A, Tab 1, Schedule 1, Page 11, Section 3.1.2

Preamble:

"Carrying costs will also be incurred during the period in which the Misallocated Tax Savings Amounts remain outstanding within the recovery period. Calculation of this amount will be dependent upon (a) the commencement date of the recovery of the Misallocated Tax Savings Amount; (b) the length of time over which those amounts are recovered; and (c) the effective rate."

Interrogatory:

a) Is Hydro One proposing to establish one or more deferral accounts to facilitate the disposition of the MTSA? Please explain the proposal(s) in this regard.

b) Please explain why the DTB amount to be recovered is not a Regulatory Asset and accordingly, the balance attracts the OEB prescribed interest rate for deferral accounts from January 1, 2021 forward?

c) Please provide a schedule that shows for each of the recovery options the annual recovery from the DTB:
   i. 2017-2020 using WACD
   ii. 2021 onward using the Board-prescribed interest rates for Regulatory Assets.(at current rates)

Response:

a) Please see response to Staff-02(e).

b) Please see response to Staff-02(d).

c) Please see response to LMPA-02 and LPMA-03.

ENERGY PROBE INTERROGATORY #6

Reference:
Exhibit A, Tab 1, Schedule 1, Page 11

Preamble:
In 2023, rates will be impacted by new distribution and transmission revenue requirement that will be established through a *common joint rate application and rebasing process.* This approach mitigates rate impacts to customers by staggering rate increases over time.

Interrogatory:

a) Please confirm if the OEB has accepted/directed a common rate application for transmission and distribution. Please provide references.

b) Please provide details on the rationale/basis for such an Application, including how it fits within the RRFE.

c) What are the benefits to customers of "staggering rate increases over time". Please discuss.

Response:

a) The OEB directed Hydro One to file a joint rate application for 2023-2027 rates for transmission and distribution in a letter dated March 16, 2018, attached.

b) Please see the rationale in the OEB's letter, attached.

c) In general, the benefit to customers of spreading the recovery of costs over multiple years is that it limits customer bill impacts in a given year. This issue is particularly important at this time as many customers look to recover from the economic impacts of COVID-19. The specific reference cited is also referring to staggering the rate impacts associated with starting recovery of the Misallocated Tax Savings Amounts and the rate impacts that will be associated with the 2023 joint rate application.

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL AND WEB POSTING

March 16, 2018

To: All Participants in EB-2016-0160
All Participants in EB-2017-0049
All Participants in EB-2017-0051
All Other Interested Parties

Re: Incentive Rate-setting for Hydro One Networks Inc. Distribution and Transmission Businesses

This letter addresses the OEB's expectations regarding future applications for Hydro One distribution rates and transmission revenue requirement.[1]

Under the current practice Hydro One's applications are filed separately for the distribution business and for the transmission business, and generally in alternating years. Hydro One also files separate applications for Hydro One Remote Communities Inc. (Hydro One Remotes).

The OEB believes that it is appropriate to consider rates for the distribution businesses (including Hydro One Remotes) and transmission business in a single application. Matters such as corporate costs, taxes, pensions and benefits can be considered as a whole in a single application resulting in regulatory consistency and efficiency.

Hydro One filed a 2018 to 2022 Custom IR application for distribution rates, on March 31, 2017.[2] Hydro One Remotes filed a cost of service application in 2018,[3] and is expected to file its next cost of service application for 2023 rates. The OEB anticipates that Hydro One will file its next transmission revenue requirement application later this year under the Custom IR framework[4] for the five-year test period 2019 to 2023. In order to align the applications and the test periods, the OEB expects Hydro One to file

[1] The revenue requirement for transmitters is approved by the OEB and this is used to set uniform transmission rates that apply throughout the province.
[2] OEB File Number EB-2017-0049.
[3] OEB File Number EB-2017-0051.
[4] Decision and Order, Hydro One Networks Transmission, EB-2016-0160, page 109.

the transmission revenue requirement application for a four-year test period from 2019 to 2022.

The OEB further expects Hydro One to file a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027. Although the matter will be heard as a single application, the OEB's final determination will result in separate revenue requirements for the distribution businesses and the transmission business. This approach will be similar in many respect to the OEB's determination of OPG hydroelectric and nuclear payment amounts which are based on separate revenue requirements.[5]

The commencement of the period for the combined application may be affected by the outcomes of the (current) distribution and (upcoming) transmission proceedings.

The OEB requests Hydro One to inform OEB staff of any issues pertaining to technical filing requirements of a single application or any other process matters that may arise as it prepares for the combined application. The OEB will determine how best to obtain stakeholder input on filing requirement or process matters, and provide its guidance as the need arises.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

[5] OEB Proceedings EB-2007-0905, EB-2010-0008, EB-2013-0321.

ENERGY PROBE INTERROGATORY #7

Reference:
Exhibit A, Tab 1, Schedule 1, Page 11, Tables 5, 6 and 7

Preamble:
In 2023, rates will be impacted by new distribution and transmission revenue requirement that will be established through a *common joint rate application and rebasing process.* This approach mitigates rate impacts to customers by staggering rate increases over time.

Interrogatory:
a) For both Transmission and Distribution, for each of the options please provide for each class, the incremental revenue requirement(s) and calculations for the prospective DTB rate increases and rate riders.

b) Please show the total rates and bill impacts if the applicable Revenue Requirements are escalated by the approved IRM amounts.

Response:
a) The incremental revenue requirement, rate riders and specific rate increases by rate class can only be determined once the OEB approves the appropriate methodology, and time period, for recovery of the Misallocated Tax Savings Amounts. The estimated impacts on a typical R1 residential customer for disposition of the Misallocated Tax Savings Amounts included in the submission allows for a relative comparison of the three options. The specific impacts for every rate class are not necessary to evaluate the disposition options. In the response to Staff-05, Hydro One has also provided the estimated impacts for the other residential classes, as well as for a general service demand customer in the response to SEC-08.

b) The reference to IRM adjustments in the question is not clear, but Hydro One confirms that the Misallocated Tax Savings revenue requirement amounts shown in the submission are the amounts to be recovered and will not be subject to any IRM adjustments. See response to Staff-01 for further discussion.

ENERGY PROBE INTERROGATORY #8

Reference:

Exhibit A, Tab 1, Schedule 1, Page 14

Preamble:

As discussed under Option 1, Hydro One expects that R1 and R2 distribution customers will be protected from distribution rate increases associated with the recovery of Misallocated Tax Savings Amounts (i.e. the $0.54 impact shown in Table 7) as a result of the DRP program.

Interrogatory:

Please explain this offset in more detail for each of the options.

Response:

Ontario Regulation 198/17 provides for a government program – referred to as Distribution Rate Protection or “DRP” – that applies to residential customers served by eight specified distributors, including the R1 and R2 residential customers served by Hydro One. DRP limits the recovery of base distribution charges for these eight distributors to a specified amount (currently $36.86), with any base distribution charges in excess of the amount recovered through the DRP program. As the base distribution charges for R1 and R2 customers are already capped at $36.86, any increase in base distribution charges due to the recovery of the Misallocated Tax Savings Amounts would be absorbed by the DRP program. In the reference cited in the preamble to this question, the $0.54 represents the bill increase associated with the change in base distribution rates due to the recovery of the Misallocated Tax Savings Amounts, and as such would be absorbed by the DRP.

ENERGY PROBE INTERROGATORY #9

Reference:
No Reference

Interrogatory:

a) Will Hydro One amend/restate its Utility Income/Earnings Statements for 2017-2020? Please provide details.

b) Will Hydro One amend its Income Tax filings for 2017-2020? Please indicate in detail what steps will be taken.

c) What other financial issues will Hydro One address as a result of the MTSA? Please provide information on matters such as dividends, deferral of debt issues etc.

Response:

a) Hydro One will reflect the Ontario Divisional Court's decision in respect of the tax savings matter in the 2020 standalone Transmission and Distribution financial statements. Previous years financial statements will not be amended/restated.

b) There is no need to amend the Income Tax filings for 2017-2020. The tax returns determine the quantum of tax savings arising from the Future Tax Savings permitted per year and are not affected by the Court Decision. The Court Decision addressed the allocation of the tax savings between the shareholders and the rate payers and specified that all tax savings should be allocated to the shareholders. The current OEB proceeding addresses how the MTSA should be recovered based on the decision made by the Court.

c) Financial issues such as dividends and deferrals of debt issues arising as a result of the Divisional Court decision are not relevant to the scope of this proceeding.

CCC INTERROGATORY #1

Reference:
No Reference

Interrogatory:
Please provide all materials provided to HON’s Board of Directors regarding this Application.

Response:
This question is not relevant to the scope of this proceeding.

CCC INTERROGATORY #2

Reference:
No Reference

Interrogatory:
On July 16, 2020, the Divisional Court determined that no part of the benefit of the Future Tax Savings is allocable to ratepayers and should instead be paid to the shareholders in its entirety.

Did Hydro One Networks Inc. (HON) make any submissions in the Divisional Court proceeding or any of the other OEB proceedings regarding carrying costs? If so, what were those submissions?

Did the Divisional Court make any findings regarding carrying costs? If so, what were those findings?

Response:
Please see response to LPMA-01.

CCC INTERROGATORY #3

Reference:
Ex. A/T1/S1/p. 8

Interrogatory:
Please explain how the WACD rates were derived.

Response:
Please see response to Staff-02(a)(i) for how the WACD rates were derived.

CCC INTERROGATORY #4

Reference:

Ex. A/T1/S1/pp. 10-11

Interrogatory:

The Alberta Utilities Commission in a previous case determined that a rate of interest equal to the Bank of Canada rate plus 150 basis points was an appropriate rate. Please recast Tables 2 and 3 to include this option. Why has HON not considered this option?

Response:

Please see response to LPMA-02 for the Bank of Canada rate plus 150 basis points included in Tables 2 and 3. Please also see response to Staff-02(d) and AMPCO-01.

Hydro One has not considered this option because the line loss issue that was decided by the Alberta Utilities Commission related to a cost category that was part of the provision of rate regulated services. Line losses were never disputed as a cost which ratepayers were responsible for. The issue concerned the proper calculation and allocation of these costs as between ratepayers. Further, the party responsible for implementing the line loss formula, the Alberta Electric System Operator, was not affected by the impugned calculation. In other words, unlike the present circumstances all of the matters fell within the rate setting paradigm and did not impact the rate regulated utility or its unregulated shareholders.

Hydro One considered application of the OEB's prescribed rate of interest. The Alberta Utility Commission's equivalent to this metric is found in Rule 23 of its Rules of Practice and Procedure. The similarity with each of the OEB and the AUC's Rules are that they apply to circumstances involving the calculation of regulated rates which are paid by regulated utility customers.

The circumstances in the present case are different and unique. The underlying cost category has been determined as not properly within the rate setting paradigm. Hydro One never sought approval for recovery of either the PILS Departure Tax or inclusion of the offsetting tax savings as its position was then and is now that neither amounts related to the provision of rate regulated service, a position which has now been upheld by the Divisional Court.

In light of these unique circumstances, Hydro One views it is appropriate to have the Board apply an interest rate that is equivalent to the approved cost of debt as that is more reflective of the cost Hydro One has notionally incurred and will incur during the 2017-2021 period, as well as the period in which any unrecovered portion of the Misallocated Tax Savings balance remains outstanding.

CCC INTERROGATORY #5

Reference:

Ex. A/T1 pp. 12-13

Interrogatory:

The evidence states that HON "expects" that R1 and R2 distribution customers will be protected from distribution rate increases associated with the recovery of Misallocated Tax Savings Amounts as a result of the distribution rate protection program. Under what circumstances would they not be protected?

Response:

The Distribution Rate Protection (DRP) program would not protect R1 and R2 customers if Misallocated Tax Savings Amounts are not treated as distribution base rate amounts subject to protection under the DRP program.

CCC INTERROGATORY #6

Reference:
Ex. A/T1/S1/pp. 12-15

Interrogatory:
Please confirm that the bill impacts are monthly impacts.

Response:
Confirmed.

CCC INTERROGATORY #7

Reference:

Ex. A/T1/S1/pp. 12-15

Interrogatory:

Please provide the rate and bill impacts for HON's Seasonal customers.

Response:

Please see the responses to Staff-05 and Staff-06.

CCC INTERROGATORY #8

Reference:

No Reference

Interrogatory:

Is HON developing a communication strategy regarding the Misallocated Tax Savings Amounts? If not, why not? If so, please explain how HON intends to explain the recovery of the amounts to its customers.

Response:

Hydro One will notify customers by bill message that their delivery rates are changing along with a link to a dedicated webpage to learn more. Included on this webpage will be background information and bill impacts. In addition, we will provide scripting for our customer service representatives who work at our contact centre.

CCC INTERROGATORY #9

Reference:
Ex. A

Interrogatory:
Did HON consider an option whereby the carrying costs would be shared between HON's shareholders and HON's customers? If not, why not?

Response:
Hydro One's options reflect a measured approach to the recovery of the Misallocated Tax Savings. Hydro One considered using the OEB's approved rate of equity to determine the carrying cost. It also considered seeking approval of compound interest treatment on these amounts, consistent with the law of compensation of placing parties in the position that they would reasonably have expected, but for the making of the erroneous decision.

Hydro One decided not to pursue either approach in an effort to minimize rate impacts on customers, notwithstanding that these attributes (ROE and compound interest) would theoretically place Hydro One and its shareholder in the closest no harm position. The selection of a carrying cost using (a) approved cost of debt values; (b) simple interest; and (c) use of an extended seven-year recovery period over which (a) and (b) would be applied, were again, considered as concessions that would reduce rate shock/rate impacts and effectively reflect a shared outcome as between Hydro One and its customers.

PWU INTERROGATORY #1

Reference:

Exhibit A Tab 1 Schedule 1 Page 12 of 20 (Section 3.1.4)

Interrogatory:

In the reference, Hydro One proposes three options for recovering misallocated tax savings, adding that Hydro One's recommendation from customer-rate-impact perspective is Option 3. The three options are:

OPTION 1 – RECOVERY OVER 2021 AND 2022
OPTION 2 – RECOVERY FROM 2021 TO 2024
OPTION 3 – RECOVERY FROM 2021 TO 2027

Please provide a chart that shows the total amount of misallocated tax savings (including carrying cost) that would be collected from customers under each of the three options, indicating the assumptions and methodology used to calculate the carrying cost.

Response:

Tables 1, 2, and 3 in the Submission show the total amount of Misallocated Tax Savings (including historical carrying cost) requested for recovery from ratepayers.

For estimated carrying charges incurred during recovery in each of the 3 options - please refer to the response to LPMA-03.

AMPCO INTERROGATORY #1

Reference:

EB-2009-0038 OPG Motion to vary part of the Ontario Energy Board's EB-2007-0905 Decision with Reasons made November 3, 2008, P15.

EB-2010-0008 OPG PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012, DECISION WITH REASONS March 10, 2011, P131, P135.

Interrogatory:

In the above Decision, the Board varied the OPG Payments Decision to link the revenue requirement reduction and regulatory tax losses, and ordered the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the re-calculation of those tax losses. OPG established the variance account to be called the Tax Loss Variance Account to be effective as of April 1, 2008.

With respect to the Tax Loss Variance Account, the EB-2010-0008 Decision states, "The difference between the revenue requirement reduction ($342 million) and the remaining tax loss ($50.3 million), being $290.9 million, was booked to the account for the period April 1, 2008 through December 31, 2009. OPG forecast the amount for 2010 to be $195 million, being an annualized grossed-up amount of the $342 million revenue requirement reduction during the original 21 month test period. To these amounts OPG also applied interest at the Board prescribed levels." At page 135, the Decision states "The Board approved recovery of the balance in the Tax Loss Variance Account in accordance with OPG's proposal."

Given that Board approved the Board's prescribed interest levels as the appropriate carrying cost for the above OPG tax losses, please explain why the Board's prescribed interest levels should not applied in Hydro One's circumstances regarding the Misallocated Tax Savings Amounts.

Response:

The facts in the OPG case are materially different from Hydro One's circumstances in the following three regards: (1) the matter at hand concerns amounts which, from the outset of the Original Decision, were contested but now have been determined not to be part of the provision of rate regulated services and thus to be included in the calculation of Hydro One's regulated rates; (2) in the present case, there is no uncertainty regarding the calculation of a cost category; and (3) in the present case, there is no uncertainty with the rate treatment of the future tax savings amounts. As a result, application of the Board's prescribed interest levels are distinguishable to the present circumstances.

(1) Underlying Non-Regulatory Nature of Impugned Cost

With respect to the first difference, the OPG's case concerned regulated rate and regulated payment treatment of prior period regulatory tax losses incurred by OPG and the regulatory treatment of these past amounts to customers in the test period. Importantly in the OPG's case, there was no dispute whether the underlying costs (regulatory tax losses) were an item properly included in the calculation of rates charged for the provision of regulated services.[1] The OPG case concerned the accounting and calculation of cost items recognized by all parties as being part and parcel of the payments consumers were obligated to pay to OPG. It was not a case pertaining to misapprehension of a regulated cost category, but rather, the proper calculation and rate treatment afforded within the regulatory rate setting paradigm (EB-2009-0038, p. 11).

In contrast to the OPG's case, the present case involves the recovery of monies that were erroneously determined to be included in the regulatory rate setting paradigm. The injured parties are Hydro One's shareholders; parties who are not directly involved in the rate setting process. The Board's prescribed interest rates as determined in EB-2006-0117, were expressly described to apply to costs that are properly the subject-matter of rate regulation and which are accounted for in approved regulatory accounts under the Uniform System of Accounts for natural gas utilities and electricity distributors. The prescribed interest rates also apply to the regulatory accounts of other rate or payment regulated entities when authorized by the OEB to use these rates and involve deferral and variance accounts or construction work in progress. The EB-2006-0117 Decision establishing these prescribed rates did not contemplate circumstances rates of interest or methods of

[1] This characteristic was also the case in AUC Decision 790-D04-2016 wherein line losses were also never in dispute as being a cost of providing rate regulated services.

calculating carrying charges (i.e. simple or compound interest) on categories of costs erroneously determined to be part of a rates revenue requirement.

The effect of the Divisional Court's decision in this case is that the Original Decision which ordered the unlawful misallocation of tax savings, is a nullity. The task now at hand is how the Board should exercise its discretion to place parties in the position that they would have been, but for the error committed in first instance. Hydro One's proposal of using its weighted average cost of debt (as opposed to a higher rate based on the Board approved return on equity) and use of simple and not compounded interest is intended to achieve objectives of neither providing windfalls nor creating punishments. This approach is consistent with the principles applied in awards of pre-judgment and post-judgment interest in accordance with ss. 128-130 of the *Courts of Justices Act*. See also *Hislop*, 2004 CanLII 43774 (ONCA) para 145; *Pilon* 2006 CanLII 6190 (ONCA) para 27*; Cobb*, 2017 ONCA 717 para 86.

Having the Board exercise discretion by approving a carrying cost charge based on Hydro One's approved weighted average cost of debt is analogous to the discretion courts have used to award simple interest at higher rates than statutorily prescribed rates, or for longer periods than the statutorily described period, if it considers it just to do so under s. 130(1). Section 130(2) prescribes seven factors courts should take into account in making this determination:

(a) changes in market interest rates;
(b) the circumstances of the case;
(c) the fact that an advance payment was made;
(d) the circumstances of medical disclosure by the plaintiff;
(e) the amount claimed and the amount recovered in the proceeding;
(f) the conduct of any party that tended to shorten or to lengthen unnecessarily the duration of the proceeding; and
(g) any other relevant consideration.

By allowing courts discretion to depart from a default rate, s. 130 ensures courts can provide fair compensation to a plaintiff for injury (without over-compensation or under-compensation) in light of economic realities: *Cobb*, 2017 ONCA 717, para 86-88. Similar circumstances apply in these unique circumstances.

(2) Certainty of the Calculation of the Impugned Amount

Regarding the second difference, in the OPG case, the OPG noted in its argument the uncertainty regarding the OEB's decision that it was not satisfied there were any regulatory tax losses, or that they had not been correctly calculated, or that there was not sufficient evidence to determine the amount of those regulatory tax losses. As a result of this uncertainty regarding the calculation of a cost category, the relief sought by OPG was the establishment of a deferral variance account for regulatory tax losses (EB-2009-0038, p. 13). In view of this, use of the Board's prescribed interest rate was appropriate as Decision EB-2006-0117 expressly contemplates use of its prescribed rate formula where regulatory deferral and variance accounts are contemplated.

In the matter at hand, the overall amount of the Misallocated Tax Savings is known with certainty and calculated based on transparent disclosures filed with the OEB. Thus, in the present case, there is no need for a deferral or variance account similar to the approach taken in the OPG case.

(3) <u>Certainty of Rate Treatment of Future Tax Savings Amounts</u>

Finally, in the OPG case, the OEB varied the Payments Decision in a manner that linked the revenue requirement reduction and regulatory tax losses, and ordered the establishment of a tax loss variance account to record any annual variance between the tax loss mitigation amount which underpins the rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in the Payments Decision as to the re-calculation of those losses. Further, the OEB found that clearance of the Tax Loss Variance Account would be reviewed at the next OPG payment application and any issues related to tax calculations would be dealt with at that future proceeding. In OPG's circumstances, rate order treatment of future tax loss amounts were intended to be used in a differential calculation such that actual tax loss amounts would be treated in OPG's rate order and passed on to, or recovered by, consumers. (EB-2009-0038, p. 15).

In the present case, the Decision of the Ontario Divisional Court is clear: none of the tax savings amounts – past, present or future – arising from the IPO transaction are to be allocated to rate payers but are instead for the benefit of Hydro One's shareholders. This finding precludes the need for regulatory accounting treatment of the tax savings in a manner consistent with the OPG case.

AMPCO INTERROGATORY #2

Reference:
Exhibit A Tab 1 Schedule 1, P9.

Interrogatory:
The evidence states:

> *"Matters involving the payment of monies made under errors of law and impacted by lengthy appeal periods are distinguishable from normal utility operation circumstances. To that end, Hydro One is unaware of similar fact circumstances where this Board has had to implement Court decisions requiring the recovery or payment of amounts determined to be for the benefit or cost of the regulated utility's shareholders."*

Please provide further evidence to support Hydro One's claim that "Matters involving the payment of monies made under errors of law and impacted by lengthy appeal periods are distinguishable from normal utility operation circumstances."

Response:
Please see response to Staff-03.

AMPCO INTERROGATORY #3

Reference:
Exhibit A Tab 1 Schedule 1 P12-P14

Interrogatory:
Please recalculate the impacts of recovering Misallocated Tax Savings Amounts in Tables 5, 6 and 7 (Options, 1, 2 and 3) based on the Board's prescribed interest levels as the carrying cost.

Response:
Using the Board's prescribed interest rates, the total Misallocated Tax Savings Amounts to be collected would be $170.4M for Transmission and $94.5M for Distribution. Updated Tables 5, 6, and 7 using these amounts are provided in Appendix 1.

Appendix 1
Estimated Impacts Assuming Prescribed Interest Rates

Table 5: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2022

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx R1 Residential Customer *	Tx Customer	
2021	3.1%	5.1%	0.9%	0.4%	$1.77
2022	0.0%	0.0%	0.3%	0.0%	$0.64

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 6: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2024

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx R1 Residential Customer *	Tx Customer	
2021	1.5%	2.6%	0.4%	0.2%	$0.88
2022	0.0%	0.0%	0.2%	0.0%	$0.32

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 7: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2027

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx R1 Residential Customer *	Tx Customer	
2021	0.9%	1.5%	0.3%	0.1%	$0.50
2022	0.0%	0.0%	0.1%	0.0%	$0.18

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

AMPCO INTERROGATORY #4

Reference:
Exhibit A Tab 1 Schedule 1 P12-P14

Interrogatory:
Please provide the impacts of recovering Misallocated Tax Savings Amounts in Tables 5, 6 and 7 (Options, 1, 2 and 3) if no interest charges are applied.

Response:
Assuming no interest charges, the total Misallocated Tax Savings Amounts to be collected would be $165.0M for Transmission and $92.4M for Distribution. Updated Tables 5, 6, and 7 using these amounts are provided in Appendix 1.

Appendix 1
Estimated Impacts Assuming No Interest Charges

Table 5: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2022

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx R1 Residential Customer *	Tx Customer	
2021	3.0%	5.0%	0.9%	0.4%	$1.73
2022	0.0%	0.0%	0.3%	0.0%	$0.62

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 6: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2024

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx R1 Residential Customer *	Tx Customer	
2021	1.5%	2.5%	0.4%	0.2%	$0.86
2022	0.0%	0.0%	0.2%	0.0%	$0.31

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

Table 7: Impacts of Recovering Misallocated Tax Savings Amounts over 2021-2027

Year	Rates Increase		Bill Impact		$ Impact on Typical R1 Residential Customer *
	Dx	Tx	Dx R1 Residential Customer *	Tx Customer	
2021	0.9%	1.4%	0.2%	0.1%	$0.49
2022	0.0%	0.0%	0.1%	0.0%	$0.18

* Transmission rate increases are assumed to impact Dx bills in subsequent year given timing of setting RTSR

AMPCO INTERROGATORY #5

Reference:

Exhibit A Tab 1 Schedule 1 P6

Interrogatory:

The applications states:

> *"Commencing in 2021, prior period Misallocated Tax Savings Amounts would be recovered through a rate rider (or similar base rate adjustment mechanism) applied to Hydro One's existing approved rates, as discussed further under Section 3.1."*

Please define other similar base rate adjustment mechanisms that could be applied.

Response:

In the case of Transmission-related amounts, prior period Misallocated Tax Savings Amounts would be recovered via an adjustment to Hydro One's rates revenue requirement to be included in the calculation of Uniform Transmission Rates (UTRs).

In the case of Distribution-related amounts, the base rate adjustments required to recover the prior period Misallocated Tax Savings Amounts could be recovered in approved Tariffs as either a separate line item for each rate class (e.g. rate rider) or the adjustments could be included in the base rate fixed and volumetric rates for each rate class.

BOMA INTERROGATORY #1

Reference:

Exhibit A, Tab 1, Schedule 1, Page 7 of 20

HONI submits that it is a principle of the law of compensation that – so far as possible by means of a monetary award – just compensation requires that a party be put in the position it would have been in had it not suffered the wrong complained of and cites Reeves v. Arsenault *(1998), 1998 Carswell 97 (PEICA) as an example.*

Interrogatory:

a) Please provide the paragraph citation for the principle described.

b) Please advise whether an example of the application of this principle in the electricity regulatory context can be provided.

c) Please advise whether an example of the application of this principle in any other regulatory context can be provided.

Response:

a) The PEI Court of Appeal discusses the equitable principle that just compensation requires a party be put in the position it would have been in had it not suffered the wrong complained of at paragraphs 14-18 of the decision.[1]

b) The application of this principle was raised in the Alberta Utilities Commission proceeding, with respect to a complaint regarding the methodology and allocation of line loss charges.[2] In this decision, the AUC exercised its discretion by including a carrying charge amount (i.e. interest) in addition to the re-determined methodology and allocations. The Alberta Utilities Commission stated that due to the time associated with the over or under-charging of market participants in respect of line losses, some parties had funds at their disposal that they otherwise should not have had, while other parties were without these funds. The Alberta Utilities Commission awarded interest

[1] 1998 CarswellPEI 97 at paras 14-18 (PEICA).
[2] AUC Decision 790-D-04-2016.

in this instance to rectify the issue of the time value of money that was unjustly at the disposal of various market participants and denied to the aggrieved parties.[3]

The Alberta Utilities Commission's Decision to award interest was upheld by the Alberta Court of Appeal.[4] The Alberta Utilities Commission utilized the tools available to put the aggrieved party back in the position it would have been in, had it not suffered or been charged the unlawful line loss charges.

c) Hydro One is not aware of further specific instances in either the electricity or regulatory context in which the principle of making a party whole has been cited. Circumstances involving the recovery of a cost category amount that is judicially determined to fall outside of the rate regulation context and to the detriment of parties who are not ratepayers appear to be unique circumstances. However, as noted, this principle is well-established within the law of compensation and has been applied in other contexts.[5]

The Ontario Energy Board has broad powers and discretion in making determinations of just and reasonable rates. The Board's enabling legislation does not preclude the Board from taking into account the principle of making parties whole as part of its public interest mandate. The present circumstances are unique, particularly given that the underlying Misallocated Tax Savings were determined to not properly be part of the ratemaking exercise, and the aggrieved parties in these circumstances are Hydro One's shareholders as opposed to the ratepayers. In that respect, the present situation is more analogous to a commercial context and the circumstances where pre and post-judgment interest are applied pursuant to sections 128 and 129 of the *Courts of Justice*

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[3] AUC Decision 790-D-04-2016 at paras 78-82.
[4] 2019 ABCA 437.
[5] See for example in the context of expropriation. 2013 SCC 51 at para 37, in which the Supreme Court of Canada sated that there is a statutory presumption that legislation permits parties the right to full compensation for expropriation unless it clearly states the contrary. The British Columbia Court of Appeal has stated that compensation in the context of expropriation and the legislative scheme means to make the owner "economically whole" and in doing so, one must consider all the elements of compensation, one of which, is interest. The Supreme Court of Canada in [1997] 1 SCR 32 stated the whole purpose of the *Expropriations Act* is to provide full and fair compensation to the person whose land has been expropriated (as cited by the Ontario Municipal Board in 2013 CarswellOnt 10709, at para 25). See also [1980] 2 SCR 283 in which the Supreme Court of Canada confirmed an award of interest made by the arbiter in fixing the compensation for expropriated land pursuant to the statute. The above noted principles have been carried out by surface rights boards across the country.

Act ("**CJA**").[6] Refer to AMPCO Interrogatory No. 1 (I-07-01) for a full discussion on the CJA and its application.

[6] RSO 1990, c C43.

ANWAATIN INTERROGATORY #1

Reference:
Exhibit A, Tab 1, Schedule 1, pp. 6-17

Interrogatory:
Have any of Hydro One's Indigenous ratepayers been subject to higher rates or additional taxation as a result of the Misallocated Tax Savings Amounts? If so, please explain how any related recovery or refund will be managed by Hydro One in respect of Indigenous customers. If not, please explain why not.

Response:
No. The Misallocated Tax Savings Amounts represent an increase to the revenue requirement that should have been collected from ratepayers and therefore did not contribute to higher rates in the past for any rate classes, some which include Indigenous ratepayers.

VECC INTERROGATORY #1

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

Interrogatory:
a) Please file the Decision of the Ontario Divisional Court with respect to the tax savings.

b) Did Hydro One make any submissions in that case as to the appropriate carrying charges that should apply should it be (as it was) successful? If so please provide those arguments.

Response:
a) Please see response to Energy Probe-01

b) Please see response to LPMA-01

VECC INTERROGATORY #2

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

Interrogatory:
Please file the Alberta Utilities Commission Decision 790-D04-2016 -September 28, 2016.

Response:
Please find the Alberta Utilities Commission Decisions 24805-D01-2020 provided as attachment 1 and the Alberta Utilities Commission Decision 790-D04-2016 -September 28, 2016 here.

Filed: 2020-12-04
EB-2020-0194
Exhibit I-10-2
Attachment 1
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Alberta Utilities Commission

ATCO Electric Ltd.

2018-2019 General Tariff Application Compliance Filing – Information Technology Common Matters

July 6, 2020

Alberta Utilities Commission
Decision 24805-D01-2020
ATCO Electric Ltd.
2018-2019 General Tariff Application Compliance Filing –
Information Technology Common Matters
Proceeding 24805

July 6, 2020

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The Commission may, within 30 days of the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

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1 Decision summary

1. This decision provides the Alberta Utilities Commission's finding on the compliance of ATCO Electric Ltd. (AET) with Decision 20514-D02-2019 (IT Common Matters decision),[1] for information technology common matters and the associated costs. This decision refers to both AET and to ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. (referred to as AP), the two transmission utilities that were the subject of the IT Common Matters decision. The Commission will collectively refer to AET and AP as the ATCO Transmission Utilities. A separate decision was concurrently issued by the Commission for AP in Proceeding 24817.[2]

2. ATCO Gas, a division of ATCO Gas and Pipelines Ltd., and ATCO Electric's distribution function also incur IT common matters costs, which will be addressed separately under performance-based regulation (PBR). The two distribution utilities will be referred to as the ATCO Distribution Utilities.

3. In this decision, the Commission has approved the majority of AET's IT common matters compliance application but there are outstanding items that will require a second compliance filing. A summary of Commission directions can be found in Appendix 3 of this decision.

4. The Commission's determinations on AET's compliance with non-IT common matters directions issued in Decision 22742-D01-2019[3] and the directions issued in Decision 22742-D02-2019,[4] both of which relate to the 2018-2019 general tariff application (GTA), will be the subject of a future decision to be issued in this proceeding.

2 Introduction

5. AET filed an application with the Commission on August 8, 2019, requesting approval of its compliance filing to Direction 1 in the IT Common Matters decision, Decision 22742-D01-2019 and Decision 22742-D02-2019. This decision solely addresses AET's compliance to Decision 20514-D02-2019, the ATCO Utilities IT Common Matters decision and the IT common matters directions in Decision 22742-D01-2019.

1 Decision 20514-D02-2019: The ATCO Utilities (ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.), Information Technology Common Matters, Proceeding 20514, June 5, 2019.

2 Proceeding 24817, ATCO Pipelines, 2019-2020 GRA Compliance Filing, leading to Decision 24817-D01-2020: ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., 2019-2020 General Rate Application Compliance Filing, Proceeding 24817, July 6, 2020.

3 Decision 22742-D01-2019: ATCO Electric Ltd., 2018-2019 Transmission General Tariff Application, Proceeding 22742, July 4, 2019.

4 Decision 22742-D02-2019: ATCO Electric Ltd., 2018-2019 Transmission General Tariff Application, Proceeding 22742, October 2, 2019.

3 Process summary

6. The Commission issued a notice of the application on August 9, 2019, that required parties to provide a statement of intent to participate (SIP) by August 22, 2019. SIPs were filed by The City of Calgary, the Consumers' Coalition of Alberfta (CCA), and the Office of the Utilities Consumer Advocate (UCA).

7. A detailed description of the regulatory process of the current proceeding is provided in Appendix 2 of this decision.

8. The Commission considers the close of record for the IT common matters portion of Proceeding 24805 to be April 7, 2020, the deadline date for filing reply argument on IT common matters.

9. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

4 Background

10. In the IT Common Matters decision, the ATCO Transmission Utilities were directed to apply:

(i) a reduction of 13 per cent in pricing in year one (2015) of the master service agreements (MSAs); and

(ii) a glide path that reduces prices on a weighted average across towers by 4.61 per cent in each of years two through 10 of the MSAs, as approved by the Commission.

11. The ATCO Transmission Utilities were directed to file their compliance applications to the IT Common Matters decision in the compliance filings to their general rate application (GRA) or GTA. Separate directions were issued for the ATCO Distribution Utilities.

12. In Proceeding 24817 and Proceeding 24805, the Commission must determine whether AP and AET, respectively, have complied with the findings and directions issued by the Commission in Decision 23793-D01-2019,[5] Decision 22742-D01-2019, Decision 22742-D02-2019, and the IT Common Matters decision. The Commission addresses AET's compliance with the IT Common Matters decision in the sections that follow. The Commission's decision on AP's compliance with the IT Common Matters decision has been issued concurrently with this decision. The Commission's findings on AET's compliance with the remaining GTA directions from decisions 22742-D01-2019 and 22742-D02-2019 will be issued in a separate decision in due course.

[5] Decision 23793-D01-2019: ATCO Pipelines, 2019-2020 General Rate Application, Proceeding 23793, June 25, 2019.

5 Discussion of issues

5.1 Directions related to IT common matters costs

13. This decision includes the following Commission directions on IT common matters costs for the ATCO Transmission Utilities, which includes AET, that are contested or otherwise require findings from the Commission in this proceeding.

14. Direction 17 of Decision 22742-D01-2019 stated:

> 223. Further, on June 5, 2019, the Commission issued Decision 20514-D02-2019 regarding the ATCO Utilities IT common matters proceeding. AET is directed to reflect any changes arising from the directions in that decision in its compliance filing to this decision. AET is further directed to provide schedules detailing how the determinations from Decision 20514-D02-2019 are reflected in its compliance filing.

15. Direction 33 of Decision 22742-D01-2019 stated:

> 595. Further, on June 5, 2019, the Commission issued Decision 20514-D02-2019 in the ATCO Utilities IT common matters proceeding. With respect to USA 934, AET is directed to reflect any changes arising from the directions in that decision in its compliance filing to this decision. AET is further directed to provide schedules detailing how the determinations in Decision 20514-D02-2019 are reflected in the compliance filing to this decision.

16. Direction 1 of the IT Common Matters decision stated:

> 379. In summary, to account for the considerations listed above and to achieve just and reasonable rates, adjustments to the MSA pricing are required. The ATCO Utilities are directed to apply (i) a reduction of 13 per cent in MSA pricing in year 1 (which automatically flows through to all subsequent years as in the example shown above); and (ii) a glide path reduction in MSA pricing of 4.61 per cent (on a weighted average across towers) in each of years 2 through 10.

17. Direction 4 of the IT Common Matters decision stated:

> 398. Similar to the IT and CC&B disallowance determined in the Evergreen II decision and related compliance filings, ATCO Pipelines and ATCO Electric Transmission will apply a first-year disallowance for 2015 and a glide path reduction as set out in Section 6 of this decision. ATCO Pipelines and ATCO Electric Transmission are directed to file their compliance applications to this decision in the compliance filings to their ongoing GRA/GTAs, clearly showing the directed IT disallowance on an annual basis by capital, indirect capital and O&M.

ATCO Transmission Utilities responses to the directions

18. In accordance with directions 1 and 4 of the IT Common Matters decision, the ATCO Transmission Utilities provided schedules[6] referencing the placeholder dollars for capital, indirect capital, and O&M from the previous GTA proceedings on a total dollar basis per annum. The schedules included in AET's compliance filing detailed the first-year pricing reduction of

[6] Exhibit 24805-X0015.01, Other matters response 04 Attachment 1.

13 per cent and glide path reductions, which are calculated as the difference between the 4.61 per cent as approved in the IT Common Matters decision and the average glide path set out in the MSA.[7]

19. For the years 2015-2020, the ATCO Transmission Utilities calculated the amounts owed by AET and AP to customers because of IT rate adjustments from the IT Common Matters decision in the following two tables:

Table 1. Summary of net amounts owed by ATCO Electric Transmission (2015-2019)[8]

	2015	2016	2017	2018	2019	Total
	($ million)					
O&M (Sch 2)	(0.9)	(1.2)	(1.5)	(1.3)	(1.2)	(6.1)
Direct Capital (Sch 3)	-	-	(0.1)	-	(0.1)	(0.2)
Other Capital (Sch 4)	0.2	0.1	0.1	(0.1)	0.1	0.4
Total	(0.7)	(1.1)	(1.5)	(1.4)	(1.2)	(5.9)
Interest per (Sch 8)						(0.2)
Total amounts owed by ATCO Electric Transmission						(6.1)

Table 2. Summary of net amounts owed by ATCO Pipelines (2015-2020)[9]

	2015	2016	2017	2018	2019	2020	Total
	($000)						
O&M (Sch 2)	(463)	(594)	(674)	(686)	(582)	(602)	(3,601)
Direct Capital (Sch 3)	8	7	(23)	(98)	(83)	(118)	(307)
Other Capital (Sch 4)	56	55	70	11	124	72	388
Total	(399)	(532)	(627)	(773)	(541)	(648)	(3,520)
Interest per (Sch 8 & 9)							(207)
Total amounts owed by ATCO Pipelines							(3,727)

20. While the IT Common Matters decision did not require a line-by-line or tower-by-tower assessment, the ATCO Transmission Utilities submitted an alternative approach to their original IT placeholder adjustment.[10] In a November 15, 2019, supplementary filing, the ATCO Transmission Utilities provided a detailed back-up for a Service ID-by-Service ID analysis, which applied the 13 per cent reduction on the first-year pricing and the 4.61 per cent glide path for years two to 10 to the individual Service IDs and approved volumes.[11]

21. Table 3 shows the incremental differences in applying the first-year pricing adjustment of 13 per cent and glide path for years two to 10 using the total dollar approach compared with applying the IT adjustments on a Service ID-by-Service ID approach:

7 Exhibit 24805-X0001.01, AET 2018-2019 GTA Compliance Filing.
8 Exhibit 24805-X0015.01, Other matters response 04 Attachment 1.
9 Proceeding 24817, Exhibit 24817-X0008.01, Attachment C.
10 Exhibit 24805-X0015.01, Other matters response 04 Attachment 1.
11 Exhibit 24805-X0150, AET argument - IT matters, paragraph 14.

Table 3. Total dollar approach versus the Service ID-by-Service ID approach[12]

Utility	Total dollar approach	Service ID-by- Service ID approach	Variance
	($ million)		
ATCO Electric Transmission	6.1	5.9	**0.2**
ATCO Pipelines	3.7	3.7	**0.0**
ATCO Gas	10.3	10.3	**0.0**
ATCO Electric Distribution	6.4	6.4	**0.0**

22. A discussion of specific issues regarding AET's compliance with directions on IT common matters costs is provided in the subsections below. Where the submissions and findings are applicable to both AET and AP, the subsections refer to the ATCO Transmission Utilities collectively.

5.1.1 Placeholders

Calgary

23. Calgary argued that IT costs must be adjusted to realize just and reasonable rates. Calgary stated that although the ATCO Transmission Utilities have provided two models showing IT adjustments and refunds, the amounts and methods used to demonstrate compliance contain a number of deficiencies.

24. Calgary noted that the IT Common Matters decision discussed placeholders and the finalization of IT rates and revenue requirement, as follows:[13]

> 19. A placeholder is created when specific costs for a utility are not finalized because those costs are contingent upon some other event or proceeding. The IT costs included in the revenue requirement for those utilities affected by the IT common matters proceeding have been treated as a placeholder until the MSA prices are determined in this proceeding. The approved IT rates will be multiplied by utility-specific IT volumes to determine costs that will be approved for inclusion in revenue requirement in a future rate proceeding. The IT costs for each of the ATCO Utilities will then be finalized and included in revenue requirement and rates.

25. While Proceeding 20514 tested IT rates contained in the MSAs, Calgary argued the proceeding did not test IT prices/rates or dollar amounts that are contained in the ATCO Transmission Utilities' placeholders and proposed adjustments. Calgary also argued that some of the ATCO Transmission Utilities placeholders contain Service ID numbers, service descriptions and IT service prices that do not exist in the MSA price schedule. If Service ID numbers, service descriptions and IT service prices are presented in the placeholders but do not exist in the tested MSA price schedule, then those items were not tested in Proceeding 20514 and should not be adjusted, or even included in the costs to be recovered from ratepayers. Calgary argued that untested prices included in the placeholders must, therefore, be treated as zero amounts for placeholder purposes and, therefore, zero amounts for compliance purposes. Calgary also suggested that the ATCO Transmission Utilities should be required to provide the volumes that are associated with the Service IDs.[14]

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12 Exhibit 24805-X0150, AET argument - IT matters, Table 1, paragraph 14.
13 Decision 20514-D02-2019, paragraph 19.
14 Exhibit 24805-X0151, Calgary argument - redacted, paragraph 18.

26. In addition, Calgary argued that the ATCO Transmission Utilities' approach included applying the Commission directed glide path for all towers. The compliance process should utilize individual glide paths by tower as recommended by PA Consulting (PAC). Calgary asked that the ATCO Transmission Utilities be ordered to recalculate all price adjustments after 2015, applying the specific tower glide path recommended by PAC for both (i) contractual labour arbitrage; and (ii) automation, as was accepted by the Commission in the IT Common Matters decision.

27. Calgary recommended that the ATCO Transmission Utilities be directed to make adjustments to customer rates and refunds based on the method used in the Evergreen compliance filing, in Proceeding 3378.[15]

28. Consistent with the method used in Proceeding 3378, Calgary recommended the use of net present value (NPV) to account for the payment of adjusted property, plant and equipment (PP&E) balances going forward as it offers a simple, transparent and easy-to-understand approach to ensure the adjustments required from the IT Common Matters decision are implemented.[16] Calgary estimated that the use of a one-time present value payment for disallowed actual capital would equate to an additional refund to customers of $9.4 million.

29. Calgary's comparison of the refund to customers using the method from Proceeding 3378 and the ATCO Transmission Utilities' proposed method is provided in Table 4, below:[17]

Table 4. Customer refunds from directed adjustments

Proceeding	Refund using ATCO Transmission Utilities' method as filed	Refund using Proceeding 3378 method	Difference
	($000)		
24817 – AP	(3,460)	(7,217)	(3,757)
24805 – AET	(5,279)	(14,106)	(8,826)
Total refund	**(8,739)**	**(21,323)**	**(12,583)**

UCA

30. With respect to the adjustments to placeholders, the UCA agreed with Calgary that the ATCO Transmission Utilities should adjust IT rates using price multiplied by quantity and not dollar value adjustments to placeholders when computing its compliance amounts, consistent with the Commission's findings in the IT Common Matters decision.[18]

ATCO Transmission Utilities

31. The ATCO Transmission Utilities stated that placeholder volumes and dollars have not been altered or adjusted, as previously ruled by the Commission and that the placeholder IT forecast rates and volumes, used to determine the placeholder true-up from the IT Common Matters decision, have not changed. AET provided a detailed IT forecast volume by Service ID for 2018 and 2019 in its 2018-2019 GTA.

15 Proceeding 3378, ATCO Utilities Evergreen Compliance Filing.
16 Exhibit 24805-X0113, Calgary evidence - redacted, A.40, PDF page 39.
17 Exhibit 24805-X0113, Calgary evidence - redacted, A.25, PDF page 28.
18 Exhibit 24805-X0156, UCA reply argument on IT Matters, paragraph 17.

32. The ATCO Transmission Utilities argued that it would be inappropriate to make any adjustments to the approved Service IDs and volumes or to seek to eliminate these approved Service IDs and volumes in a true-up application.[19] Where a Service ID identified in the approved placeholder schedules is not traced to the price schedules or where the Service ID is not volume based, the ATCO Transmission Utilities indicated that they had applied the 13 per cent first-year reduction and the 4.61 per cent glide path to the placeholder rate or dollar value consistent with the directions from the IT Common Matters decision.[20]

33. In response to an IR, the ATCO Transmission Utilities explained that they utilized the total IT placeholder spend for O&M, indirect capital and capital in service, and applied the first-year pricing reduction and glide path difference between the glide path that was embedded in the MSA and the approved glide path percentage. Given the directions in the IT Common Matters decision, a line-by-line model was not utilized or necessary in determining the true-up amounts, as the direction from the Commission requires an across the board first-year pricing adjustment and an approved average glide path for years two to 10.[21] ATCO Transmission Utilities submitted that a line-by-line review, as conducted in Proceeding 3378 was not required or warranted and has proven to cause significant regulatory burden.

Commission findings

34. In the IT Common Matters decision, the Commission approved an adjustment to IT rates on a weighted-average tower basis. The Commission is of the view that the placeholder adjustment, when compared with the detailed line-by-line adjustment results in the same refund amounts. The more detailed line-by-line Service ID approach offers greater transparency into how the ATCO Transmission Utilities applied the first-year pricing reduction of 13 per cent and the 4.61 per cent glide path to years two to 10 of the MSA prices. The Commission notes that, in the circumstances, the variance between the two methods was not material. However, the Commission is mindful of its comments in the IT Common Matters decision, regarding placeholders and the finalization of IT rates and revenue requirement, which are reproduced below:

> The approved IT rates will be multiplied by utility-specific IT volumes to determine costs that will be approved for inclusion in revenue requirement in a future rate proceeding. The IT costs for each of the ATCO Utilities will then be finalized and included in revenue requirement and rates.[22]

35. The Commission is of the view that to properly assess adjustments to IT placeholders the ATCO Transmission Utilities must show their adjustments to MSA rates based on the IT rates being multiplied by volumes and the resulting adjustments to IT placeholders. The Commission considers that the proposed adjustment to IT rates by applying the 13 per cent first-year reduction and the 4.61 per cent glide path thereafter to the placeholder rate or dollar value is reasonable for Service IDs not traced to the price schedules or where the Service ID is not volume based.

36. In the IT Common Matters decision, the Commission did not approve the use, or direct the application, of the true-up methodology from Proceeding 3378 in other proceedings and the

19 Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, paragraph 20.
20 Exhibit 24805-X0135-CONF, ATCO rebuttal evidence, paragraph 20.
21 Exhibit 24805-X0058, AET Responses to CAL, AET-CAL-2019OCT07-002(f)(i), PDF pages 10-11.
22 Decision 20514-D02-2019, paragraph 19.

Commission sees insufficient reason or merit for doing so here. The Commission approved a specific approach to lowering the first-year rate followed by applying a 4.61 per cent glide path annually to simplify the reductions to IT costs and reduce the regulatory burden associated with those IT costs. In view of the evidence on alternative approaches provided by the ATCO Transmission Utilities, the Commission is satisfied that the ATCO Transmission Utilities' proposed IT adjustments are consistent with the Commission's directions in the IT Common Matters decision, and are supported by the analysis and summary information provided in Table 1.

37. With respect to Calgary's submissions on NPV, a determination on whether the ATCO Transmission Utilities should adopt the NPV approach to account for the payment of adjusted PP&E balances going forward is provided in Section 5.1.8 of this decision.

5.1.2 Custom unit rates

Calgary

38. Calgary argued that the ATCO Transmission Utilities compliance approach for custom unit rates is inappropriate for the following reasons:

- ATCO Transmission Utilities denies the propriety of using a P x Q [price times quantity] approach for Custom Unit Rate adjustments.
- ATCO Transmission Utilities applies the Commission's 13% first year reduction to Placeholder dollars and/or Placeholder prices/rates rather than the specific prices/rate provided in the MSA.
- ATCO Transmission Utilities uses hard coded IT prices/rates and/or dollar amounts.
- ATCO's Transmission Utilities compliance filing contains numerous errors in Service ID numbers and Service Descriptions, which confounds the compliance process.
- ATCO Transmission Utilities has included, in its 2015 Placeholders, Custom Unit Rates services which were not contained in the MSA.[23]

39. Calgary asserted that since the IT common matters proceeding did not test IT prices/rates or dollar amounts that are contained in the placeholders, the Commission should require the ATCO Transmission Utilities to compute the 2015 adjustments for custom unit rates by applying the Commission's required reduction of 13 per cent to MSA rates rather than placeholder rates.

[23] Exhibit 24805-X0151, Calgary argument - redacted, PDF page 16, paragraph 51.

40. Calgary argued that all approved volumes from the MSA are in units, with the exception of pass-through, usage-based and serviced-based items[24] and it provided more detail in its confidential evidence on this issue.[25]

41. Calgary added that the ATCO Transmission Utilities' unsupported claim that price times quantity (i) does not apply to custom unit rates; and (ii) is contrary to the facts of their own compliance filings with respect to the Commission's findings in Decision 3378-D01-2016, relates to the Evergreen II compliance filings. In that compliance proceeding, the reductions to IT prices/rates for many Custom Unit Rate Services used a price times quantity approach.[26] As a result, Calgary argued that the 2015 custom unit rate provided in the price schedules should be reduced by 13 per cent. For each of the years subsequent to 2015, the foregoing adjusted 2015 rate should be adjusted by the glide path reduction required by the IT Common Matters decision.

ATCO Transmission Utilities

42. The ATCO Transmission Utilities argued that the custom rate table from the MSAs shows there are no billing metrics, demonstrating that custom rates do not follow the common rates approach where the rate is set in the first year and a glide path/inflation is applied to subsequent years. The ATCO Transmission Utilities argued that custom rates are similar to "service-based" or "usage-based" services, and Calgary has not taken issue with this position. In AP/AET-CAL-2019DEC03-003 CONF, the ATCO Transmission Utilities explained the treatment of custom unit rates, charges and changes to services. They also explained the true-up of services reflecting custom unit rates.[27]

43. The ATCO Transmission Utilities stated that they applied the IT common matters directions to the placeholder dollar amounts for custom rates, consistent with past decisions related to truing-up placeholder costs.

Commission findings

44. In the IT Common Matters decision, the Commission directed the ATCO Transmission Utilities to apply (i) a reduction of 13 per cent in MSA pricing in year one (which automatically flows through to all subsequent years); and (ii) a glide path reduction in MSA pricing of 4.61 per cent (on a weighted average across towers) in each of years two through 10. The decision did not provide any specific direction with regard to custom unit rates or new services. The Commission has determined that, in compliance with the Commission's directions, the ATCO Transmission Utilities have multiplied the approved placeholder dollar amounts by the first-year pricing reduction and applied the difference in the annual glide path between the MSA and the approved

[24] Exhibit 24805-X0113, Calgary evidence - redacted, PDF pages 9-10. There are numerous examples of units for Custom Service Rates for each of the following Service IDs: Service ID 348 has a billing metric of "Per IDS Device"; Service ID 548 has a billing metric of "Per Device/ Month"; Service ID 583 has a billing metric of "Per Site/Month"; Service IDs 706, 707, 815, 816, 817, 818, 820 and 830 all have billing metrics of "Per Application/Month"; Service ID 732 has a billing metric of "Per PC/Month"; Service IDs 744 and 764 have billing metrics of "Per Firewall/Month"; Service ID 763 has a billing metric of "Per User/Month"; and Service IDs 814, 821, 822, 823, 824, 825, 826 and 827 (all of which are "Fixed Overhead Charges," for each tower) have billing metrics of "Fixed Fee/Month."

[25] Exhibit 24805-X0113, Calgary conf evidence, PDF pages 10-11.

[26] Proceeding 20514, Exhibit 20514-X0222.05, CONF ATCO-CAL CONF-2017MAR31-007(b) Attachment-AET 3378 July 10, and Exhibit 20514-X0222.01 CONF, ATCO-CAL CONF-2017MAR31-004(d) Attachment-AP 3378 July 10.

[27] Exhibit 24805-X0097 CONF, PDF pages 12-13.

IT common matters' glide path. This approach is consistent with the adjustments to IT rates required as a result of the Commission's directions in the IT Common Matters decision.

45. The Commission denies Calgary's request to reduce by 13 per cent the 2015 custom unit rate provided in the price schedules. Instead, the Commission accepts the ATCO Transmission Utilities' explanation that custom unit rates are more like a fixed charge than a service-based charge using IT volumes. The Commission notes, moreover, that the ATCO Transmission Utilities have reduced the placeholder dollar amounts by both the first-year pricing reduction and the difference in the annual glide path. No further reduction is required for the ATCO Transmission Utilities to comply with the directions in the IT Common Matters decision.

46. The Commission finds that the ATCO Transmission Utilities' proposed IT adjustments to custom unit rates demonstrate a reasonable approach to ensure these utilities have complied with the directions in the IT Common Matters decision. The Commission accepts the ATCO Transmission Utilities' method to adjust custom unit rates, as filed.

5.1.3 New services

Calgary

47. Calgary noted that although there was no guidance in the IT Common Matters decision for new services, there is a need for IT price/rate adjustments to apply to all IT rates including new service rates. Calgary indicated that while the ATCO Transmission Utilities have reduced the IT price/rate by 13 per cent in the year each new service was introduced, these new services were not tested for fair market value (FMV).

48. In addition, Calgary stated that the ATCO Transmission Utilities have implemented the glide path for years after new services were introduced. For new services introduced in years after 2015, Calgary proposed a "reverse engineering" process to reflect the Commission's two adjustments to new services, which would apply (i) the initial year reduction of 13 per cent to new services; and (ii) the required glide path for that new service. Calgary provided the following steps, for its proposed adjustment to new services:

> Determine a 2015 price:
>
> 1) Establish the Wipro price of the New Service (from a year after the initial 10 year in the MSA that ATCO has used in its Placeholder).
>
> 2) For that service, ascertain the glide path inherent in the MSA, the Inflation Factor for each year for that service, together with the Commission required adjustments for each of 2015 initial year and the glide path.
>
> 3) For 2017 remove the Inflation Factor to get back to the uninflated price in 2017.
>
> 4) Using that 2017 uninflated price, remove the glide path factor inherent in the MSA to get back to the inflated price that would have been in place in 2016.
>
> 5) For 2016, remove the 2016 Inflation Factor to get back to the uninflated price in 2016.
>
> 6) For 2016, remove the glide path factor inherent in the MSA to get back to the price that would have been in place in 2015.
>
> 7) The above noted steps would place the [sic] of the New Service to a price that would have been in place had the service been included in the 2015 Price Schedule.

Apply Commission Ordered Adjustments.

8) Adjust that newly found 2015 price by the Commission's 2015 adjustment factor of 13%.

9) Then proceed with the application of the allowed glide path factors and inflation factors for each year until the year of the introduction of the New Service is reached.

10) Subtract the resulting price in Step 9 from the price of the New Service introduced by ATCO to determine the price adjustment for the introduction year of the New Service. [28]

49. In the absence of the above adjustments, Calgary submitted that prices for new services would not lead to just and reasonable rates.

UCA

50. The UCA stated that prices for any new services had not been tested in Proceeding 20514. Further, the UCA indicated that there was no evidence that the prices for such new services would not be affected by the sale of ATCO I-Tek Inc. (ATCO I-Tek) to Wipro Solutions Canada Limited (Wipro) as found in the IT Common Matters decision. The UCA submitted that where the ATCO Transmission Utilities have introduced new services, new Service IDs and new custom unit prices, any amounts should be treated as a zero-dollar entry for the placeholder.[29]

ATCO Transmission Utilities

51. The ATCO Transmission Utilities stated they ensured that all new services were priced at FMV. While the IT Common Matters decision was silent on new services, the ATCO Transmission Utilities applied the same 13 per cent reduction to the actual pricing of new services (since the MSAs commenced in 2015) when the service was introduced to be consistent with the Commission's directions. Further, they applied the glide path of 4.61 per cent for years thereafter.[30] If the Commission considers that future new services should be tested further on a go-forward basis, the ATCO Transmission Utilities submitted that any of the new services should be tested in the respective GTA/GRA of the utility that is using those services.

52. The ATCO Transmission Utilities stated that Calgary's additional recommended adjustment of using a "reverse engineering" process to determine what prices would have been in 2015 and to then apply a glide path to that hypothetical 2015 rate is entirely inappropriate. New services were never part of the directions contained in the IT Common Matters decision, as they were not subject to the tender process that the Commission determined affected first-year pricing.[31]

Commission findings

53. In the IT Common Matters decision, the Commission provided no specific direction with respect to new services. The Commission accepts that new services may be required over the term of the MSA and similar to custom unit rates, the ATCO Transmission Utilities' approach of applying a 13 per cent adjustment in year one and then a glide path adjustment for years two to 10 from the date service begins is reasonable to account for new services. Calgary's methodology to calculate the price of new services based on a hypothetical start date of 2015

28 Exhibit 24805-X0113, Calgary evidence - redacted, PDF pages 29-31.
29 Exhibit 24805-X0156, UCA reply argument on IT matters, paragraphs 19-20.
30 Exhibit 24805-X0135, and Proceeding 24817, Exhibit 24817-X0094.
31 Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, paragraphs 62-63.

followed by the application of the first-year reduction and glide path from that point onward is inconsistent with the start date for a new service and when new IT services are required by the utility. The Commission considers that the ATCO Transmission Utilities' method for adjusting IT rates for new services complies with the Commission's general direction in Direction 1 of the IT Common Matters decision. On this basis, the Commission rejects Calgary's proposed adjustment to IT rates for new services.

54. In addition, the Commission considers that although new services have not been tested for FMV, the IT price adjustments from the IT Common Matters decision are a reasonable proxy for IT services and rates, absent an FMV being determined for every new service. Continual assessment of the FMV of new services is both inefficient and unnecessary, especially given that a reasonable and effective process already exists to reduce over the term of the MSA the prices of IT services that were the subject of the IT Common Matters decision. For these reasons, the Commission will not adopt the recommendations of Calgary and the UCA. The Commission considers that the ATCO Transmission Utilities should apply the first-year reduction of 13 per cent and the approved glide path from the start date for any new service.

55. Based on these findings, the Commission approves the ATCO Transmission Utilities' approach to calculating the IT rates for new services and the resulting prices.

5.1.4 True-up for capital amounts for 2018 and 2019

Calgary

56. Calgary submitted that the ATCO Transmission Utilities have not included adjustments to property, plant and equipment (PP&E) to account for actual amounts for direct capital and other capital and the impacts of those adjustments with respect to 2018 and 2019. Based on the current dates of the compliance filings, adjustments to actual amounts and their impacts for years after 2017 should be provided. Calgary recommended that the ATCO Transmission Utilities update their actual filings for both 2018 and 2019 so that the adjustments which are currently known can be addressed in the current proceedings.[32]

UCA

57. The UCA agreed with Calgary that actual adjusted amounts for 2018 and 2019 should be included in the current compliance proceedings.[33]

ATCO Transmission Utilities

58. The ATCO Transmission Utilities indicated they have trued up actual IT capital spend up to 2017, as the 2017 closing rate base was the latest year incorporated into the revenue requirement calculations.

59. The ATCO Transmission Utilities submitted that 2018 and 2019 actual PP&E will be trued-up in the next GRA for AP and the next GTA for AET. For 2018 and beyond, actual rate base will reflect IT capital allowed for ratemaking purposes. Including 2018 and 2019 in these compliance filings would be inconsistent with how revenue requirement has been calculated for the years being trued up.

[32] Exhibit 24805-X0113, Calgary evidence - redacted, A. 22, PDF pages 24-25.
[33] Exhibit 24805-X0156, UCA reply argument on IT matters, paragraph 23.

Commission findings

60. The Commission accepts the ATCO Transmission Utilities' explanation that for both AP and AET, the true-up of non-IT rate base items in the original AP and AET GRA/GTA proceedings included actual amounts up to 2017.

61. For AET, capital true-up of 2018 and 2019 should be addressed in AET's next GTA. Otherwise, there would be an inconsistency in calculating closing rate base for IT capital-related costs and non-IT capital-related costs. Calgary's request for further information is denied. However, the Commission directs AET to clearly show any rate base related impacts from the IT Common Matters decision when truing up its 2018 and 2019 actuals in its next GTA filing.

5.1.5 Opening rate base and accumulated depreciation

Calgary

62. Calgary noted that the ATCO Transmission Utilities' calculations in Schedule 3 (Impact of Direct IT) and Schedule 4 (Impact of Other Capital) do not properly or fully track accumulated depreciation, such that revenue requirement impacts and refunds are understated for both direct and indirect capital. Calgary submitted that the formulas included on line 4 of each schedule are incorrect in a number of cases, because the formula is missing the depreciation effects of prior years.

63. Calgary noted that in Proceeding 3378 for the Evergreen II compliance filing, a separate schedule was filed for each test year, which allowed full visibility and confirmation of annual and accumulating depreciation charges for each year that IT capital was included in rate base. Applying the method from Proceeding 3378 to the compliance filing test period, Calgary calculated the potential loss of customer refunds, due to the ATCO Transmission Utilities' proposed calculation on accumulated depreciation, to be over $650,000.[34]

64. Calgary submitted that the UCA's recommendation in this proceeding supports Calgary's request for the ATCO Transmission Utilities to file separate schedules for each year, consistent with Proceeding 3378, so that accumulated depreciation and opening rate base can be properly tracked in compliance with the IT Common Matters decision.

UCA

65. In its argument, the UCA noted, by way of example, that AP had included an "opening rate base" balance of zero for 2019 in both Schedule 3 and Schedule 4. It argued that this approach was incorrect and non-compliant with the Commission's direction in the IT Common Matters decision, and recommended that the ATCO Transmission Utilities be required to "reduce the actual volumes from the placeholder prices to the approved prices and carry that figure forward into the opening balance of rate base for the new test period."[35]

[34] Exhibit 24805-X0151, Calgary argument - redacted, paragraphs 104-111.
[35] Exhibit 24805-X0149, UCA argument (IT Matters), paragraph 23.

66. The UCA made a similar recommendation in its argument concerning AET's compliance with the IT Common Matters decision, in respect of AET's opening balances for 2018 in Proceeding 24805.[36]

ATCO Transmission Utilities

67. The ATCO Transmission Utilities argued that they calculated accumulated depreciation using the methodology that was put forth and accepted in Proceeding 3378.[37] The ATCO Transmission Utilities stated that Calgary's assumption that both accumulated depreciation and previous opening rate base are continued into the future test periods/rate applications when calculating the impact on the forecast test periods is incorrect and results in a double counting, first in the original forecast opening rate base and, subsequently, in the updated adjustment of the actual opening rate base put forward in the next test period.

68. The ATCO Transmission Utilities stated that schedules 3 and 4 calculate the revenue requirement true-up on the forecast IT capital in the applicable test period and that after a test period is completed, the forecast accumulated depreciation is not continued to future test periods, which would be the case if Calgary's incorrect assertions were used. The ATCO Transmission Utilities indicated that after each forecast test period is complete, the forecast opening rate base is zeroed out, including the accumulated depreciation, and the previous opening rate base would be replaced with actual going-in rate base for the new test period, as is calculated in Schedule 5 (Revenue Requirement Calculation by Year – Direct Capital) and Schedule 6 (Revenue Requirement Calculation by Year – Indirect Capital).[38] As a result, the ATCO Transmission Utilities submitted that no changes are required to the refund schedules.

Commission findings

69. The Commission finds that the ATCO Transmission Utilities have calculated the rate base adjustments, and depreciation amounts to be refunded or collected, in a manner consistent with Decision 3378-D01-2016.

70. Unlike Decision 3378-D01-2016, which calculated placeholder and actual adjustments to prior GRA or GTA revenue requirement periods, the IT Common Matters decision affects prior periods (2015-2018 for AP, and 2015-2017 for AET), current periods (2019-2020 for AP, and 2018-2019 for AET), and future GRA and GTA test periods.

71. In Decision 23793-D01-2019, the Commission provided the following direction regarding IT disallowances on an annual basis for capital, indirect capital and O&M:

> 336. As set out by the Commission in Decision 20514-D02-2019 and reproduced below, ATCO Pipelines is directed to incorporate the adjustments to the IT disallowances on an annual basis by capital, indirect capital and O&M, resulting from the MSA in a compliance filing to this decision:
>
> > Similar to the IT and CC&B (customer care and billing) disallowance determined in the Evergreen II decision and related compliance filings, ATCO Pipelines and ATCO Electric Transmission will apply a first-year disallowance for 2015 and a glide path reduction as set out in Section 6. ATCO Pipelines and ATCO Electric

36 Exhibit 24805-X0149, paragraphs 8-10.
37 Exhibit 24805-X0135, and Proceeding 24817, Exhibit 24817-X0094.
38 Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, paragraph 44.

> Transmission are directed to file their compliance applications to this decision in the compliance filings to their ongoing GRA/GTAs, clearly showing the directed IT disallowance on an annual basis by capital, indirect capital and O&M. [footnote removed]

72. And in Decision 22742-D01-2019, the Commission gave the following directions:

> 223. Further, on June 5, 2019, the Commission issued Decision 20514-D02-2019 regarding the ATCO Utilities IT common matters proceeding. AET is directed to reflect any changes arising from the directions in that decision in its compliance filing to this decision. AET is further directed to provide schedules detailing how the determinations from Decision 20514-D02-2019 are reflected in its compliance filing.
>
> …
>
> 595. Further, on June 5, 2019, the Commission issued Decision 20514-D02-2019 in the ATCO Utilities IT common matters proceeding. With respect to USA [Uniform System of Accounts] 934, AET is directed to reflect any changes arising from the directions in that decision in its compliance filing to this decision. AET is further directed to provide schedules detailing how the determinations in Decision 20514-D02-2019 are reflected in the compliance filing to this decision.

73. In Proceeding 24805, the Commission asked where prior period adjustments to the 2018 opening balances and current GTA test periods were reflected, and why AET had separately calculated and included a 2018 and 2019 revenue requirement adjustment for the effects of the IT Common Matters decision, when the adjustments for those years could be incorporated into the GTA minimum filing requirement (MFR) compliance schedules.[39]

74. AET provided the following response to these IRs:[40]

> (b-d) AET has calculated the impact related to the IT Common Matters separately for simplicity and ease of review, as the IT Common Matters Decision impacts and trues-up [*sic*] multiple placeholder years, spanning multiple proceedings. The true-up includes the forecast years 2015 to 2019 and 2015 to 2017 actual rate base. It was determined at the time of the IT Common Matters Decision that the separate calculation would make it most efficient to show the total impact of the IT Common Matters Decision, without the added complexities that are associated to trueing up [*sic*] balances for multiple years which span multiple proceedings. For example, absent a separate calculation, AET would have shown parts of the adjustments through a separate calculation, specifically for the forecast years 2015 to 2017 and 2015 to 2016 actual rate base. Then, it would have incorporated these adjustments and the adjustments for the forecast years 2018 to 2019 into the GTA schedules as referenced in Exhibit 24805-X0005.01. This lack of continuity and flipping from separate calculations to the GTA schedules was determined to be overly complex and difficult to follow.
>
> The separate calculations have also proven beneficial throughout the proceeding, as AET has received hundreds of information requests on the IT Common Matters true-up specifically. These IRs have included the request to recalculate the refund and revise calculations using a service ID-by-service ID approach (AP-AET-AUC2019NOV07-001) and various alternative calculations that have been requested (AP-AET-CAL-2019DEC03-002), to name a few. The separate calculations made it easier to run the

[39] Exhibit 24805-X0120, AET-AUC-2019DEC06-004(b)-(d).

[40] Exhibit 24805-X0120, Response to AET-AUC-2019DEC06-004(b)-(d), PDF pages 200-201.

various scenarios and requests, as well as display the overall refund under these scenarios. Absent the separate calculation, multiple workbooks and GTA schedules would have been required to be uploaded to the eFiling system.

75. The Commission agrees with the ATCO Transmission Utilities that the true-up of the IT Common Matters decision includes adjustments to prior period forecasts and to actual rate base adjustments, which will require the refund or collection amounts to be settled outside of the current compliance filing test period revenue requirements. The Commission finds that the opening 2018 rate base balance and the revised 2018, 2019 and 2020 capital expenditures and capital additions should be directly adjusted in the MFR schedules, consistent with the schedule previously filed for AP in the 2019-2020 GRA in Proceeding 23793 and for AET in the 2018-2019 GTA for Proceeding 22742. The IT service volumes for AP's 2019-2020 GRA and AET's 2018-2019 GTA (subject to any adjusted FTE amounts) were approved in decisions 23793-D01-2019 and 22742-D01-2019, respectively, and were to be adjusted by the revised IT services pricing approved in the IT Common Matters decision. Thus, the forecast amounts included in the MFR schedules were to be adjusted in the compliance filing and the forecasts were not adjusted by AET or AP.

76. Accordingly, the ATCO Transmission Utilities have not complied with directions provided in Decision 23793-D01-2019 and Decision 22742-D01-2019 to reflect changes relating to the IT Common Matters decision. To ensure that the proper adjustments are made in accordance with previous compliance filing directions for AP and AET, and for consistency amongst the ATCO Transmission Utilities, the Commission directs the ATCO Transmission Utilities to provide the following in their second compliance filing MFR schedules:

- the adjusted opening 2018 rate base balance;
- the opening 2018 undepreciated capital expenditures balance;
- the 2018 opening future income tax reserve balance for the adjustments related to the IT common matters 2015 to 2017 actual rate base adjustment;
- the adjusted 2018, 2019 and 2020 forecasted capital expenditures and rate base;
- the 2018, 2019 and 2020 undepreciated capital expenditure balance adjustments;
- the 2018, 2019 and 2020 tax adjustments for the purposes of calculating current tax and future tax; and
- the 2018 and 2019 future income tax reserve adjustments related to the IT Common Matters decision in each of the ATCO Transmission Utilities individual second compliance filings.

5.1.6 Tax deductions

Calgary

77. Calgary argued that the ATCO Transmission Utilities are claiming the reversal of two tax deductions: (i) for capital cost allowance on the amount of reversed capital additions; and (ii) for the total amount of reversed capital under the heading "running costs." In Calgary's view, the ATCO Transmission Utilities have not explained why there are two reversals of tax deductions

pertaining to the same capital amount, nor have the ATCO Transmission Utilities referenced any tax law that allows two deductions for the same capital amount. Calgary submitted that the ATCO Transmission Utilities should be required to remove the double counting for the reversal of tax deductions that currently exists in their calculations of revenue requirement impacts.

78. In its evidence, Calgary stated that the ATCO Transmission Utilities have altered the methodology for other capital rate adjustments in Schedule 4 to include the tax impact of "running costs" from schedules 5 and 6, and that they have included the revenue requirement impact for the initial forecast year for the actual opening PP&E adjustment for direct capital and other capital, for each of 2015, 2016 and 2017.

79. Calgary provided adjusted calculations in the attachments to its evidence to supports its position. However, in response to Calgary-AUC-2020FEB03-004, Calgary stated it was unaware that a full capital amount, capitalized as an overhead, is deductible for income taxes purposes. Calgary noted that the ATCO Transmission Utilities were taking capital cost allowance, for income tax purposes, as a separate line item.

80. Calgary also noted that each of the utilities appeared to be using inconsistent income tax rates, both between years and between AP and AET:[41]

Table 5. Income tax rates used by ATCO Transmission Utilities in their current compliance filings

	AP						AET				
	2015	2016	2017	2018	2019	2020	2015	2016	2017	2018	2019
Federal	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Provincial	11.1%	12.0%	12.0%	12.0%	12.0%	12.0%	11.01%	12.0%	12.0%	12.0%	11.5%

81. Noting that AET and AP are using different provincial income tax rates for each of 2015 and 2019, Calgary recommended that they be directed to use consistent and correct statutory income tax rates.

ATCO Transmission Utilities

82. The ATCO Transmission Utilities argued that the tax treatments used are the same as those found in each of the respective GTAs and GRAs and that there is no overlap or double counting as the schedules clearly show each component for tax purposes. The ATCO Transmission Utilities further submitted that Calgary has not properly accounted for all of the years that comprise the test periods covered by the applications. Instead, Calgary has simply removed the first year, with no explanation as to why, apparently in order to create a higher customer refund, which is against the well-established revenue requirement methodology that has been used for decades in the utility industry.

83. The ATCO Transmission Utilities submitted that the tax rates used in the compliance filings of AP and AET mirror the tax rates approved in the various proceedings covering the specific test years. The ATCO Transmission Utilities indicated that their approach is correct as the IT common matters schedules calculate the refund related to those specific test periods. The ATCO Transmission Utilities stated that changing the income tax rates to rates that were not approved in the original proceeding, and where the placeholders were established, would create

41 Exhibit 24805-X0113, Calgary evidence - redacted, PDF page 8.

a difference between the test period calculations and the IT common matters refund and that such a change to the income tax rates is inappropriate.[42]

84. As a result, the ATCO Transmission Utilities submitted that there are no changes required to the refund schedules filed on the record due to tax deductions.[43]

Commission findings

85. The Commission has reviewed the provincial income tax rates used and the adjustments made to calculate net income for tax purposes, for direct capital and indirect capital, and agrees with the ATCO Transmission Utilities that they are consistent with the provincial tax rates and the method used to calculate taxable income as approved in Decision 23793-D01-2019 for AP and in Decision 22742-D01-2019 for AET. The Commission denies Calgary's request to apply different statutory income tax rates because no adjustment to the tax rates and the net income is required for the ATCO Transmission Utilities to comply with the Commission's directions.

86. The Commission notes that AET has a tax deferral account should a tax rate change in the future and, therefore, further comment on AET's application is required.

87. As stated in a Commission IR response, quoted below, AET did not include the refund of previously collected future income tax in its calculated refund amounts to customers:

> AET has not included the revenue requirement effects of future income tax (FIT). FIT is collected based on forecast tax inputs (e.g. CCA [capital cost allowance] and depreciation) at the time of the rate application, which are not subsequently trued-up. Therefore, AET did not consider it necessary to adjust FIT as a result of the IT Common Matters directions.[44]

88. AET calculated future income tax (FIT) expenses as part of its 2015, 2016 and 2017 revenue requirement amounts. As explained by AET, FIT is calculated based on forecast tax inputs[45] (e.g., capital cost allowance, depreciation and "running costs"). These inputs include IT costs, which have been adjusted in response to the IT Common Matters decision. As a result, the amount of future income tax that was collected for 2015, 2016 and 2017 should also be adjusted for the change in the tax inputs. AET estimated that a total of $0.5 million of FIT was overcollected for the years 2015 to 2017 as a result of tax inputs being adjusted to comply with the IT Common Matters decision.[46] AET is directed to refund the FIT amounts for the years 2015, 2016 and 2017 that it should not have collected from customers as a result of its adjusted IT costs. Consistent with the direction in paragraph 76 above, AET is also directed to reflect the effects of the 2018 and 2019 test period adjustments in its corresponding MFR schedules.

5.1.7 Carrying costs

89. Calgary argued that the unique circumstances of Proceeding 20514 for IT common matters warrants the use of weighted average cost of capital (WACC) for determining carrying

[42] Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, paragraph 13.
[43] Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, PDF pages 21-22.
[44] Exhibit 24805-X0120, response to AET-AUC-2019DEC06-004(a), PDF page 200.
[45] Exhibit 24805-X0120, AET responses to AUC requests – Round 2, AET-AUC-2019DEC06-004.
[46] Exhibit 24805-X0120, AET responses to AUC requests – Round 2, AET-AUC-2019DEC06-004.

charges,[47] consistent with the Commission's findings from Decision 3378-D01-2016. In that decision, the Commission directed the use of WACC for carrying costs:

> 162. In the present case, final approved pricing was applied to both O&M and capital projects and the resulting adjustments by the ATCO Utilities were all in the form of refunds to customers. Consequently, the use of WACC to determine carrying costs would not be unreasonable in the circumstances. Calgary's argument that the ATCO Utilities had earned a return on projects incorporating MSA pricing prior to their approval or adjustment in Decision 2014-169 (Errata) is also of some merit.
>
> 163. The Commission is satisfied that in these specific circumstances, the ATCO Utilities' use of WACC to calculate the carrying charges is acceptable. Accordingly, the ATCO Utilities are directed to calculate these amounts using WACC.[48]

UCA

90. The UCA agreed with Calgary that the use of WACC for carrying costs was warranted.[49]

ATCO Transmission Utilities

91. Absent some special circumstances, the ATCO Transmission Utilities argued the AUC has traditionally applied Rule 023[50] to both refunds to and collections from customers. The ATCO Transmission Utilities noted that Rule 023 has been used in previous decisions, such as the past IT benchmark proceeding,[51] Decision 2012-237[52] for Y factor true-up under PBR, and decisions related to the true-up of capital trackers,[53] and Decision 2010-496 regarding the removal of carbon-related assets from utility service.[54] These examples clearly indicate that Rule 023 is appropriate in the true-up of IT common matters costs.[55]

Commission findings

92. The Commission has discretion to apply Rule 023 or WACC in the individual circumstances that are applicable to a GRA or GTA. In Decision 3378-D01-2016,[56] the Commission found:

> 162 In the present case, final approved pricing was applied to both O&M and capital projects and the resulting adjustments by the ATCO Utilities were all in the form of

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47 Exhibit 24805-X0151, Calgary argument - redacted, paragraph 133.
48 Decision 3378-D01-2016, paragraphs 162-163.
49 Exhibit 24805-X0156, UCA reply argument on IT matters, paragraphs 24-26.
50 Rule 023: *Rules Respecting Payment of Interest.*
51 Proceeding 32, ATCO Utilities, 2003-2007 Benchmarking and I-Tek Placeholders True Up.
52 Decision 2012-237: Rate Regulation Initiative Distribution Performance-Based Regulation, Proceeding 566, September 12, 2012.
53 Decision 20385-D01-2015: ATCO Gas, 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast Compliance Application, Proceeding 20385, August 24, 2015; Decision 20369-D01-2015 (Errata): ATCO Electric Ltd., 2013-2015 Capital Trackers Compliance Filing, Proceeding 20369, August 31, 2015; and Decision 20351-D01-2015: FortisAlberta Inc., 2013-2015 Capital Tracker Compliance Filing, Proceeding 20351, September 23, 2015.
54 Decision 2010-496: ATCO Gas South, Removal of Carbon Related Assets from Utility Service, Proceeding 87, Application 1579086-1, October 19, 2010.
55 Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, paragraph 75.
56 Proceeding 3378, ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), Evergreen II Application Compliance Filing to Decision 2014-169 (Errata) Confidential.

> refunds to customers. Consequently, the use of WACC to determine carrying costs would not be unreasonable in the circumstances. Calgary's argument that the ATCO Utilities had earned a return on projects incorporating MSA pricing prior to their approval or adjustment in Decision 2014-169 (Errata) is also of some merit.
>
> 163. The Commission is satisfied that in these specific circumstances, the ATCO Utilities' use of WACC to calculate the carrying charges is acceptable. Accordingly, the ATCO Utilities are directed to calculate these amounts using WACC.

93. The Commission is of the view that the ATCO Transmission Utilities have failed to provide persuasive reasons why Rule 023 should apply given the express wording of the rule and the circumstances of the refund directed in the IT Common Matters decision. Other AUC decisions that apply Rule 023 for performance-based regulation and the carbon refund[57] are not determinative of the refund applied to both O&M and capital projects for IT carrying costs. Consistent with the method used in Decision 3378-D01-2016, which is the most recent IT common matters decision that applied interest for carrying costs, the Commission finds that WACC should be used when calculating interest on IT refund balances.

94. The Commission directs the ATCO Transmission Utilities to recalculate the balances using its WACC as the interest rate applied to its carrying costs, and to file the resulting refund and regulatory schedules for AET and AP in the compliance filing to this decision.

5.1.8 Net present value

Calgary

95. Calgary recommended the use of net present value (NPV) to account for the payment of adjusted PP&E balances going forward because it offers a simple, transparent and easy-to-understand approach to ensure the adjustments required from the IT Common Matters decision are fully captured. Calgary estimated that the use of a one-time present value payment for disallowed actual capital equates to an additional refund to customers of $9.4 million.[58]

ATCO Transmission Utilities

96. The ATCO Transmission Utilities considered that it should be up to the utility to determine and justify the appropriateness of using a one-time NPV methodology in specific circumstances, as opposed to adopting this approach as a normal course of action.

97. In Proceeding 3378, the ATCO Utilities (AP, AET and the ATCO Distribution Utilities) outlined the benefits of the one-time payment for IT costs in that proceeding. The circumstances in the current proceeding are dissimilar to Proceeding 3378. Particularly, the I-Tek MSA, contemplated in Proceeding 3378, was at the end of its term and did not affect future proceedings and costs, unlike the situation with the current proceeding.

98. The use of the NPV methodology in Proceeding 3378 was the result of a prudency review, which was not intended to continue beyond Decision 3378-D01-2016. In contrast, the Wipro MSAs are in the middle of their contract term, creating different accounting treatments of

[57] Decision 2010-496, paragraph 242.
[58] Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, paragraph 38.

the costs prior to and after the issuance of the decision. For example, after July 2019, only the portion allowed to be included in rate base will be capitalized for accounting purposes.

99. The ATCO Transmission Utilities submitted that although the short term administrative burden to remove the past costs is higher, given the impact to future years and different accounting treatment required, the use of the NPV methodology would not alleviate the overall administrative burden as was the case in Proceeding 3378.

100. The ATCO Transmission Utilities argued that their approach fully and appropriately captures the impact of disallowed capital. These utilities explained that they have not requested nor are they requesting to utilize the NPV methodology in this compliance filing.[59] The directions contained in the IT Common Matters decision span future years (to cover the entire 10-year MSA) and, as such, the circumstances are not the same as in Proceeding 3378. Therefore, the ATCO Transmission Utilities are not proposing an NPV of future PP&E reductions because they have removed from rate base the portion of the reductions disallowed for ratemaking purposes related to the directions in the IT Common Matters decision. In future rate applications, the ATCO Transmission Utilities confirmed that they will exclude from rate base the IT portion of costs that is affected by the IT Common Matters decision.[60]

Commission findings

101. In Decision 3378-D01-2016, the Commission approved the use of the NPV method to refund IT balances and explained that one of the reasons for approving this approach was that it was more efficient than directing the utility to make annual rate base adjustments. NPV calculations are often used to apply an adjustment instead of removing costs of assets from rate base. Although the NPV method was used in some prior decisions,[61] the Commission considers that whenever possible, costs should be removed from rate base consistent with the method traditionally applied to PP&E - capital project disallowances. Further, the Commission finds that Calgary failed to offer compelling reasoning for the continued use of the NPV methodology beyond referencing that it was used in Proceeding 3378.

102. The Commission agrees that the ATCO Transmission Utilities' approach fully captures the impact of disallowed capital, without any added concerns associated with the inputs required to be used in an NPV calculation. The Commission further agrees with the ATCO Transmission Utilities that the findings in the IT Common Matters decision reflected the entire 10-year period of the MSA and, therefore, is distinguishable from the findings of the prudency review for a more limited time span in Decision 3378-D01-2016. As cost-of-service regulated utilities, AP and AET are able to exclude IT costs from rate base as a result of the IT Common Matters decision.

103. On this basis, the Commission rejects Calgary's NPV proposal. The Commission directs the ATCO Transmission Utilities to remove all IT directed adjustments to direct and indirect capital from rate base in compliance with the IT Common Matters decision in the compliance

59 Exhibit 24805-X0135, ATCO rebuttal evidence - redacted, paragraphs 40-41.
60 Proceeding 24817, Exhibit 24817-X0034, AP-CAL-2019OCT07-006(d)-(e).
61 For example, Decision 2010-102: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up, Proceeding 32, Application 1562012-1, March 8, 2010; and Decision 3378-D01-2016.

filing to this decision and in future IT common matters, GRA, GTA or other relevant transmission proceedings and compliance proceedings.

104. The ATCO Distribution Utilities were subject to different directions for complying with the Commission's findings in the IT Common Matters decision, as follows:.

> ATCO Gas and ATCO Electric Distribution shall incorporate the Commission determined reduction of 13 per cent to the first year of the master services agreements, 2015, and apply a glide path that reduces prices on a weighted average basis across towers by 4.61 per cent for the purposes of recalculating their notional 2017 revenue requirement and base K-bar.
>
> …
>
> ATCO Gas and ATCO Electric Distribution are to file their compliance applications to this decision in their next annual performance-based regulation filings.[62]

105. The full directions to the distribution utilities are set out in the Commission's findings in Section 7 of the IT Common Matters decision.

106. A determination of how the ATCO Distribution Utilities apply their directed IT adjustments or disallowances from the IT Common Matters decision is a matter to be determined at the relevant PBR-related proceeding or proceedings.[63] In this decision, the Commission has not evaluated the NPV methodology as it would apply to either of the ATCO Distribution Utilities under the PBR framework. This decision is not determinative of whether the Commission would find acceptable any NPV methodology, or NPV-based adjustment, as might be proposed by the two distribution utilities in a PBR proceeding in order for them to comply with directions in the IT Common Matters decision. In other words, the Commission's directions in this decision are not intended to bind or preclude in any way any future panel from making such findings as it considers just and reasonable, and warranted in the public interest, related to the application of directed IT adjustments or disallowances in the context of PBR.

5.1.9 Future rate proceedings

Calgary

107. Calgary identified several principles that should guide the Commission and the ATCO Transmission Utilities in reflecting the adjustments from the IT Common Matters decision in future rate proceedings, which are reproduced below:

> - the ordered reductions to the Wipro MSA prices must be readily identifiable and fully transparent to the Commission and interested parties through appropriate filing requirements;
> - IT prices used by ATCO [Transmission Utilities] in test year forecasts and in PP&E reconciliations must be demonstrated, through appropriate filing requirements, to comply with the formulas set out in paragraphs 371 and 372 of Decision 20514-D02-2019 to show the application of the initial year (2015) reduction as well as the compounding glide path effect;

62 Decision 20514-D02-2019, paragraph 399.
63 Decision 20514-D02-2019, paragraph 395.

- regulatory efficiency and burden should be pursued where possible in the adoption of the previous principles; and
- the recommended changes to methodologies and accounting set out in the Calgary Evidence should be applied.[64]

108. Calgary explained that future rate filings of the ATCO Transmission Utilities must demonstrate full compliance with the adjustments ordered in the IT Common Matters decision. Calgary argued that the ATCO Transmission Utilities' proposed concepts of year-over-year comparisons and average cost reductions do not appear to lessen regulatory burden or promote efficiency.

109. Calgary recommended that to comply with the directions from the IT Common Matters decision:

- each ATCO [Transmission] Utility should be required to file with its GRA/GTA application a workbook, similar to the attachments filed in these Compliance Proceedings, showing the adjusted MSA prices for each test year included in the application, which would be applied against the corresponding forecast volumes. The resultant forecasted IT costs in each application would then be reconciled to these prices. Given the filing of the adjusted MSA prices, the reconciliation would be relatively simple and efficient to conduct as they would be based on the current templates already used.[65]

110. Calgary also recommended that for direct and other capital, a calculation of the NPV of future rate adjustments could be performed against the forecast projects with the NPV period beginning after the last test year. Reconciliations to actual PP&E balances could be performed in the next GRA or GTA.[66]

UCA

111. The UCA agreed with Calgary that detailed information and workbooks should be filed in future applications to efficiently assess IT costs, in a transparent manner.[67]

ATCO Transmission Utilities

112. For future rate applications, the ATCO Transmission Utilities submitted that year-over-year comparisons and average cost per user forecasts should be utilized to avoid an overly burdensome regulatory process. To ensure transparency to the IT Common Matters decision, the ATCO Transmission Utilities proposed to show the total costs, for example, O&M at Wipro rates and the overall reduction on a total cost approach.[68] The ATCO Transmission Utilities argued that this approach is appropriate considering that within this proceeding and AET's current 2020-2022 GTA,[69] it has been demonstrated that this methodology renders the same result as the extensive line-by-line analysis. The ATCO Transmission Utilities submitted that if the Commission determines that it requires a detailed line-by-line analysis, there would be no need

64 Exhibit 24805-X0151, Calgary argument - redacted, paragraph 139.
65 Exhibit 24805-X0151, Calgary argument - redacted, paragraph 145.
66 Exhibit 24805-X0151, Calgary argument - redacted, paragraph 145.
67 Exhibit 24805-X0156, UCA reply argument on IT matters, paragraph 4.
68 Exhibit 24805-X0153, ATCO reply argument (IT Matters), paragraph 46.
69 Proceeding 24964, AET 2020-2022 General Tariff Application.

to show the costs using Wipro rates. Rather, the rates per the IT Common Matters decision, as presented in the line-by-line workbooks, should be sufficient. For usage-based rates, the ATCO Transmission Utilities submitted that the same formula would be applied on a go-forward basis, as within this compliance filing.[70]

Commission findings

113. The Commission is of the view that the placeholder and line-by-line adjustments that were provided in this proceeding offer greater transparency into the ATCO Transmission Utilities' compliance with directions from the IT Common Matters decision than any of the other alternatives the Commission was asked to consider. Although the total cost approach delivers the same result as the line-by-line analysis, the Commission agrees with the principles articulated by Calgary regarding (i) the need for transparency; (ii) the need to ensure reductions to the MSA prices are readily identifiable; and (iii) the need to allow interested parties to review test year forecasts and PP&E reconciliations. As the ATCO Transmission Utilities have already provided both placeholder and detailed line-by-line adjustments in the current proceedings, the Commission considers that populating Excel worksheets with forecast and actual volumes, new services and approved IT rates in future proceedings, as recommended by Calgary, should not be overly burdensome. For future rate applications, the Commission directs the ATCO Transmission Utilities to provide the following information, to comply with directions from the IT Common Matters decision and this decision:

- Each of AP and AET is required to file with its GRA/GTA a workbook, in a manner similar to the attachments filed in Proceeding 24817,[71] showing the adjusted MSA prices for each test year, that would be applied against the corresponding forecast volumes. The resultant forecasted IT costs in each application must be reconciled to these prices.

- For direct and other capital, a calculation of the NPV of future rate adjustments must be performed against the forecast projects with the NPV period beginning after the last test year. Reconciliations to actual PP&E balances are to be included in the next GRA and GTA, or in a related compliance filing.

6 Order

114. It is hereby ordered that:

(1) ATCO Electric Ltd. is directed to file a second compliance filing in accordance with the findings and directions in this decision. The Commission will provide the filing deadline for the IT Common Matters second compliance filing in its decision addressing non-IT common matters, which will be issued on or before August 12, 2020.

[70] Exhibit 24805-X0153, ATCO reply argument (IT Matters), paragraph 46.
[71] Proceeding 24817, Exhibit 24817-X0095 CONF for AP, Exhibit 24817-X0096 CONF for AET.

Dated on July 6, 2020.

Alberta Utilities Commission

(original signed by)

Kristi Sebalj
Panel Chair

(original signed by)

Bill Lyttle
Acting Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Electric Ltd. (AET) Bennet Jones LLP
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP
Consumers' Coalition Advocate (CCA) Bema Enterprises Ltd.

Alberta Utilities Commission

Commission panel
K. Sebalj, Panel Chair
B. Lyttle, Acting Commission Member
B. Romaniuk, Acting Commission Member

Commission staff
A. Sabo (Commission counsel)
C. Strasser
F. Alonso
J. Cameron
D. Cherniwchan

Appendix 2 – Detailed description of the regulatory process of the current proceeding

(return to text)

1. On August 26, 2019, Calgary filed a request that the Commission address a number of concerns and preliminary matters regarding the ATCO Transmission Utilities compliance with directions from the IT Common Matters decision. Calgary raised procedural matters for the Commission's consideration that affect both Proceeding 24817 for AP and Proceeding 24805 for AET (collectively, the compliance proceedings). Calgary requested the Commission to direct that certain documents be placed on the record of the compliance proceedings. The documents in question had earlier been filed in Proceeding 3378, a compliance filing for IT common matters costs. The decision for Proceeding 3378 was issued on March 4, 2016.[72]

2. In a letter dated September 17, 2019, the Commission ruled that it would not require the information filed in Proceeding 3378 to be placed on the records of the compliance proceedings. For the filings on IT common matters issues, the Commission agreed with Calgary's recommendation that common process schedule deadlines for these issues be established in the compliance proceedings.

3. On October 7, 2019, the Commission granted confidential treatment to certain information related to the compliance proceedings.

4. By letter dated October 25, 2019, AET asked the Commission to confirm that its approach to IT placeholder adjustments complies with directions from the IT Common Matters decision and that the information requested by interveners was outside the scope of the compliance filing for IT common matters. Both AP and AET submitted that the schedules within their respective applications and information request (IR) responses clearly show the calculations of the directed IT disallowances.

5. In response to AET's submission, Calgary filed letters,[73] [74] asserting that the request for an omnibus ruling from the Commission to be applied to the four proceedings[75] was inappropriate, unfair and contrary to the provisions of Rule 001: *Rules of Practice*. Calgary submitted that the substance of the directions, and the methodologies to test compliance, go to the core of the compliance matters. Further, Calgary submitted that the directions in the IT Common Matters decision are not the only directions related to placeholder adjustments, indicating that AP and AET are subject to additional directions in each of Decision 23793-D01-2019 and Decision 22742-D01-2019 that relate to implementing the disallowances ordered in the IT Common Matters decision. Calgary submitted that AET's request should be denied.

6. Calgary submitted that the ATCO Transmission Utilities possess all the data required to effect the necessary IT adjustments to each service line item, as demonstrated by the evidence

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72 Decision 3378-D01-2016: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), Evergreen II Application Compliance Filing to Decision 2014-169 (Errata), Proceeding 3378, March 4, 2016.

73 Proceeding 24817, Exhibit 24817-X0037, Calgary Response to ATCO per Compliance Proceedings and IR Responses.

74 Exhibit 24805-X0043, Calgary Response to ATCO per Compliance Proceedings and IR Responses.

75 Proceeding 24817: ATCO Pipelines, 2019-2020 General Rate Application Compliance Filing;
Proceeding 24805: ATCO Electric Transmission, 2018-2019 General Tariff Application Compliance Filing;
Proceeding 24880: ATCO Gas, 2020 Annual Performance-Based Regulation Rate Adjustment;
Proceeding 24881: ATCO Electric Distribution, 2020 Annual Performance-Based Regulation Rate Adjustment.

filed in Proceeding 20514 and the calculations to support the permission to appeal application. Calgary argued that AP and AET should answer all of Calgary's IRs.

7. In a ruling dated November 7, 2019, the Commission, following a review of the directions from the IT Common Matters decision, found that AP and AET, in their respective compliance proceedings, have applied the directed first-year and subsequent glide path adjustments to the existing IT placeholders. However, the Commission indicated that the information provided by AP and AET failed to show how adjustments were made to IT rates and the glide path on a weighted tower basis. The Commission considered that information at this level was required for it to assess compliance with the directions from Decision 23793-D01-2019 and Decision 22742-D01-2019.

8. With respect to Calgary's request that AP and AET be directed to answer all of its IRs, the Commission found that the information requested by Calgary on a line-by-line basis or at the tower-by-tower level related to past proceedings, and was not required for the purposes of the compliance proceedings. However, the Commission issued supplemental IRs to address information gaps with respect to compliance with Commission directions on IT common matters. The Commission stated that while the supplemental IRs were required to complete the record, they were not designed to retest information provided in past proceedings.

9. On December 6, 2019, the Commission issued a ruling on a motion filed by AET on December 4, 2019, regarding the scope of the proceedings and the relevance of certain Calgary IRs. The Commission also extended the deadline for filing responses to additional IRs from December 9, 2019, to December 12, 2019.

10. In a December 18, 2019, letter, Calgary requested that the Commission revise its process schedule to permit Calgary to file evidence on IT common matters issues.

11. On December 20, 2019, the Commission approved Calgary's request to file evidence. The Commission confirmed that it would not consider evidence that sought to relitigate issues previously determined in the IT Common Matters decision or that would, in any way, expand the scope of the compliance proceedings for AP and AET.

12. Calgary requested an extension for filing its evidence from the original date of January 10, 2020, to January 13, 2020, and the time extension was granted by the Commission.

13. By letter dated January 17, 2020, the Commission set the remainder of the process schedule for the IT common matters:

Process step	Deadline date
Argument (on all matters for Proceeding 24817 and on IT common matters only for Proceeding 24805)	March 16, 2020
Reply argument (on all matters for Proceeding 24817 and on IT common matters only for Proceeding 24805)	March 30, 2020

14. On March 5, 2020, Calgary filed a letter concerning the ATCO Transmission Utilities' updated workbooks filed in rebuttal evidence. Although the rebuttal evidence explained these adjustments, Calgary submitted that the revisions were not clearly identified in the workbooks as required by Section 22.3 of Rule 001. Calgary requested that the Commission order each of the

ATCO Transmission Utilities to refile its rebuttal evidence attachments in compliance with Section 22.3 of Rule 001. Calgary further requested that the process schedule be revised.

15. On March 10, 2020, the Commission found that it was not necessary to direct AP and AET to refile the information using a blacklined format for the Excel worksheets, as set out in Section 22.3 of Rule 001. However, the ATCO Transmission Utilities were directed to update their respective compliance filing applications to make clear the amounts for which they were seeking approval and to update certain exhibits related to IT common matters. The Commission granted Calgary's request for an extension to the deadlines for filing argument and reply argument.

16. Due to the time extension request by the ATCO Transmission Utilities, the Commission also amended the deadline for reply argument.

Appendix 3 – Summary of Commission directions

(return to text)

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. For AET, capital true-up of 2018 and 2019 should be addressed in AET's next GTA. Otherwise, there would be an inconsistency in calculating closing rate base for IT capital-related costs and non-IT capital-related costs. Calgary's request for further information is denied. However, the Commission directs AET to clearly show any rate base related impacts from the IT Common Matters decision when truing up its 2018 and 2019 actuals in its next GTA filing. .... paragraph 61

2. Accordingly, the ATCO Transmission Utilities have not complied with directions provided in Decision 23793-D01-2019 and Decision 22742-D01-2019 to reflect changes relating to the IT Common Matters decision. To ensure that the proper adjustments are made in accordance with previous compliance filing directions for AP and AET, and for consistency amongst the ATCO Transmission Utilities, the Commission directs the ATCO Transmission Utilities to provide the following in their second compliance filing MFR schedules:

   - the adjusted opening 2018 rate base balance;
   - the opening 2018 undepreciated capital expenditures balance;
   - the 2018 opening future income tax reserve balance for the adjustments related to the IT common matters 2015 to 2017 actual rate base adjustment;
   - the adjusted 2018, 2019 and 2020 forecasted capital expenditures and rate base;
   - the 2018, 2019 and 2020 undepreciated capital expenditure balance adjustments;
   - the 2018, 2019 and 2020 tax adjustments for the purposes of calculating current tax and future tax; and
   - the 2018 and 2019 future income tax reserve adjustments related to the IT Common Matters decision in each of the ATCO Transmission Utilities individual second compliance filings.

   .... paragraph 76

3. AET calculated future income tax (FIT) expenses as part of its 2015, 2016 and 2017 revenue requirement amounts. As explained by AET, FIT is calculated based on forecast tax inputs (e.g., capital cost allowance, depreciation and "running costs"). These inputs include IT costs, which have been adjusted in response to the IT Common Matters decision. As a result, the amount of future income tax that was collected for 2015, 2016 and 2017 should also be adjusted for the change in the tax inputs. AET estimated that a total of $0.5 million of FIT was overcollected for the years 2015 to 2017 as a result of tax inputs being adjusted to comply with the IT Common Matters decision. AET is directed to refund the FIT amounts for the years 2015, 2016 and 2017 that it should not have collected from customers as a result of its adjusted IT costs. Consistent with the direction

in paragraph 76 above, AET is also directed to reflect the effects of the 2018 and 2019 test period adjustments in its corresponding MFR schedules. .... paragraph 88

4. The Commission directs the ATCO Transmission Utilities to recalculate the balances using its WACC as the interest rate applied to its carrying costs, and to file the resulting refund and regulatory schedules for AET and AP in the compliance filing to this decision. .... paragraph 94

5. On this basis, the Commission rejects Calgary's NPV proposal. The Commission directs the ATCO Transmission Utilities to remove all IT directed adjustments to direct and indirect capital from rate base in compliance with the IT Common Matters decision in the compliance filing to this decision and in future IT common matters, GRA, GTA or other relevant transmission proceedings and compliance proceedings. .... paragraph 103

6. The Commission is of the view that the placeholder and line-by-line adjustments that were provided in this proceeding offer greater transparency into the ATCO Transmission Utilities' compliance with directions from the IT Common Matters decision than any of the other alternatives the Commission was asked to consider. Although the total cost approach delivers the same result as the line-by-line analysis, the Commission agrees with the principles articulated by Calgary regarding (i) the need for transparency; (ii) the need to ensure reductions to the MSA prices are readily identifiable; and (iii) the need to allow interested parties to review test year forecasts and PP&E reconciliations. As the ATCO Transmission Utilities have already provided both placeholder and detailed line-by-line adjustments in the current proceedings, the Commission considers that populating Excel worksheets with forecast and actual volumes, new services and approved IT rates in future proceedings, as recommended by Calgary, should not be overly burdensome. For future rate applications, the Commission directs the ATCO Transmission Utilities to provide the following information, to comply with directions from the IT Common Matters decision and this decision:

   - Each of AP and AET is required to file with its GRA/GTA a workbook, in a manner similar to the attachments filed in Proceeding 24817, showing the adjusted MSA prices for each test year, that would be applied against the corresponding forecast volumes. The resultant forecasted IT costs in each application must be reconciled to these prices.
   - For direct and other capital, a calculation of the NPV of future rate adjustments must be performed against the forecast projects with the NPV period beginning after the last test year. Reconciliations to actual PP&E balances are to be included in the next GRA and GTA, or in a related compliance filing. .... paragraph 113

7. It is hereby ordered that:

   (1) ATCO Electric Ltd. is directed to file a second compliance filing in accordance with the findings and directions in this decision. The Commission will provide the filing deadline for the IT Common Matters second compliance filing in its decision addressing non-IT common matters, which will be issued on or before August 12, 2020.

   .... paragraph 114

VECC INTERROGATORY #3

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

Interrogatory:

a) Please explain what survey of Ontario Energy Board Decisions Hydro One made with respect to carrying costs to be applied for the recovery of monies collected by Utilities in error and later refunded to customers. Over what period was searched did Hydro One search for any precedent?

b) Is Hydro One aware of any OEB regulated utilities who have made accounting errors (e.g. accounting for Group 1 deferrals, etc.) for which refunds to customers were later required? If so, what carrying charge was applied in those circumstances?

c) In Hydro One's view should there be a difference as between the carrying charges applied by the OEB in the case where a regulated utility has made an error that requires a refund to customers and the carrying charge to be applied in these circumstances? If yes, please explain what principles apply and distinguishes as between these two circumstances.

Response:

a) The cases canvassed focused on a fact pattern where carrying costs were applied to amounts that had initially been included in the regulated rate calculations, but which were subsequently determined to fall outside of the regulated rate-setting paradigm and returned to shareholders. Hydro One was unable to locate other OEB cases involving this specific fact pattern.

b) Please see part (a)

c) Please see responses to AMPCO-01 and AMPCO-02.

   Different principles are applicable and turn on the question of whether the cost category was, at all times, disputed to be a cost related to the provision of rate regulated services. Where the cost has been upheld as not being part of the costs of providing rate regulated service, it is appropriate to consider the impacts to the parties aggrieved and to keep such parties whole through application of a reasonable carrying cost that takes into account the time value of money during the period required to refund such amounts. The present circumstances are materially different from those which would involve forecast risks associated with cost items that typically receive deferral and variance account treatment. In each of these cases, the expectation is that the amount which interest would be calculated upon, would be expected to be "cleared" within a short period of time, as opposed to an extended period. See Staff-02 for related discussion.

VECC INTERROGATORY #4

Reference:

Exhibit A, Tab 1, Schedule 1, page 10

Interrogatory:

a) What are the incremental annual carrying costs (based on Hydro One's carrying charge proposal) in a one-year recovery as compared to the three recovery options presented at section 3.14?

Response:

The carrying costs associated with a one-year recovery of the Misallocated Tax Savings are as follows:

- Hydro One Transmission - $4.5M
- Hydro One Distribution - $2.5M

These amounts were calculated using the following assumptions:

1. 2021 WACD rate is used.
2. Commencement date of the recovery for the Misallocated Tax Savings and effective date of 2021 rates is April 1, 2021;
3. The monthly recovery of misallocated tax savings is assumed to be equal; however, the actual monthly amount may fluctuate slightly due to consumption.

For the carrying costs calculations under the three recovery options, please refer to the response in LPMA-03.

VECC INTERROGATORY #5

Reference:

Exhibit A, Tab 1, Schedule 1, Section 3.1.4, Table 5

Interrogatory:

a) Under recovery Option 1 in year 2022 Table 5 shows no Dx rate increase (0.0%) but a 0.3% Dx residential customer Bill Impact and a $0.69 ($) Impact. Similarly, in Tables 6 and 7 there are columns showing no rate impacts (for Dx and Tx) and yet for the same years there are Bill and $ Impacts. Please explain why.

Response:

As noted in the footnote for Tables 5, 6 and 7, "Transmission rate increases are assumed to impact Distribution customer bills in subsequent year given the timing of implementing changes to transmission rates in the setting of distribution Retail Transmission Service Rates (RTSR)."

As such, the residential customer bill impact (in % and $ terms) for years where no "rate" impacts are shown result from flowing through to distribution customers the transmission rate impact from the prior year. As an example, the 0.3% and $0.69 distribution customer bill impact in 2022 shown in Table 5 is the estimated impact resulting from the average 5.5% transmission rate impact in 2021.