UNDERTAKING J1.1

Reference:

Undertaking:

To provide an update to page 11 of the SEC compendium.

Response:

As indicated during Hydro One’s Oral Hearing Presentation on Monday October 21, 2019, the following undertaking response provides the updated revenue requirement table and other relevant tables from evidence, including:

1. Revenue Requirement
2. Summary of Revenue Requirement Components
3. Custom Cap Index (RCI) by Component
4. Revenue Requirement by Year
5. Summary of Transmission OM&A Expenditures
6. Bridge Year and Planning Year Capital Expenditure Summary
7. In-Service Capital Additions 2014 – 2022
8. Average Bill Impacts on Transmission and Distribution-connected Customers
9. Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts
10. Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

Table 1: Revenue Requirement ($ Millions)
Revised from Exhibit E, Tab 1, Schedule 1 – Table 1

Components	2018[1]	2019[2]	2020 Blue Page	2020 Accelerated CCA[4]	2020 Actual Debt Issuances[5]	2020 Updated Pension Valuation[6]	2020 OPEB ISA Assumptions[7]	2020 Oral Hearing Update
OM&A	394.3		375.8			(1.7)		374.1
Depreciation and Amortization	468.6		474.6			(0.1)	0.0	474.5
Income Taxes	57.2		48.3	(23.6)	0.1	1.3	0.1	26.3
Return on Capital	703.6		775.0		(8.3)	(0.2)	0.6	767.1
Total Revenue Requirement	**1,623.8**	**1,644.4**	**1,673.8**	**(23.6)**	**(8.2)**	**(0.7)**	**0.7**	**1,642.0**
Deduct External Revenues and Other [3]	(54.7)	(54.5)	(52.6)					(52.6)
Rates Revenue Requirement	**1,569.1**	**1,589.9**	**1,621.2**					**1,589.4**
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	6.8					6.8
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,510.7**	**1,552.3**	**1,628.0**					**1,596.2**

Note 1: Represents OEB approved 2018 revenue requirement from Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160
Note 2: Represents OEB approved 2019 revenue requirement in EB-2018-0130
Note 3: External Revenue and Other includes External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit
Note 4: As quantified in I-1-OEB-208
Note 5: I-04-LPMA-019 reflected a lower cost of debt for 2020 of 4.45% based on 2019 actual issuances relative to 4.57% presented in the blue-page update
Note 6: Updated JT-2.31 Attachment 1 (October 17, 2019) provided the updated pension valuation as of December 31, 2018
Note 7: As quantified in I-01-OEB-206 the revenue requirement impact related to OPEB ISA assumptions

Table 2: Summary of Revenue Requirement Components ($ Million)

Revised from Exhibit A, Tab 4, Schedule 1 – Table 2

Line		Reference	2020	2021	2022
1	Rate Base	C-1-1	12,407.0	13,130.2	13,951.7
2	Return on Debt	E1-1-1	322.5	342.1	363.5
3	Return on Equity	E1-1-1	444.6	471.6	501.2
4	Depreciation	F-6-1	474.5	503.4	528.9
5	Income Taxes	F-7-2	26.3	27.2	40.4
6	Capital Related Revenue Requirement		1,267.9	1,344.4	1,434.0
7	Less Productivity Factor (0.0%)			-	-
8	**Total Capital Related Revenue Requirement**		**1,267.9**	**1,344.4**	**1,434.0**
9	OM&A	F-1-1	374.1	379.4	384.7
10	**Total Revenue Requirement**		**1,642.0**	**1,723.7**	**1,818.7**
11	Increase in Capital Related Revenue Requirement			76.5	89.6
12	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.66%	5.20%
13	Less Capital Related Revenue Requirement in I-X			1.08%	1.09%
14	**Capital Factor**			**3.58%**	**4.11%**

Table 3: Custom Cap Index (RCI) by Component (%)

Revised from Exhibit A, Tab 4, Schedule 1 – Table 3

Custom Revenue Cap Index by Component	2021	2022
Inflation Factor (I)	1.40	1.40
Productivity Factor (X)	0.00	0.00
Capital Factor (C)	3.58	4.11
Custom Revenue Cap Index Total	4.98	5.51

Table 4: Revenue Requirement by Year

Revised from Exhibit A, Tab 4, Schedule 1 – Table 4

Year	Formula	Revenue Requirement
2020	Cost of Service	$1,642.0 million
2021	2020 Revenue Requirement x 1.0498	$1,723.7 million
2022	2021 Revenue Requirement x 1.0551	$1,818.7 million

** Calculations assume that Inflation Factor remains at 1.4% through term.*

Table 5: Summary of Transmission OM&A Expenditures ($ Millions) Revised from Exhibit F, Schedule 1, Tab 1 – Table 1

	Historical								Bridge	Test
	2015		2016		2017		2018		2019	2020
	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Forecast
Category Level										
Sustainment	233.6	238.7	215.1	241.1	218.1	241.2	229.4	238.5	200.6	214.2
Development	6.1	12.9	4.6	13.4	5.1	4.8	5.2	5.0	6.0	6.9
Operations	59.0	58.5	62.5	59.1	61.1	61.3	53.4	62.1	46.1	48.9
Customer Care	5.1	5.5	4.5	5.5	8.5	4.0	11.0	3.9	7.3	7.5
Common Corporate Costs and Other Costs	73.9	70.2	60.1	71.3	41.5	49.9	54.9	47.5	29.4	30.3
Property Taxes & Rights Payments	63.9	66.3	61.3	67.0	50.7	63.6	65.3	64.3	67.2	68.1
Adjustments										
EB-2014-0140 Settlement Reduction		-20.0		-20.0						
EB-2016-0160 Decision Reduction						-15.0		-15.0		
Removal of B2M Expense		-0.9		-0.7		-0.8		-2.1		
Pension Adjustment						-11.4		-9.9		
Directive[1]									-0.1	-0.1
Envelope Level										
Total Transmission OM&A	**441.6**	**431.2**	**408.1**	**436.8**	**385.0**	**397.7**	**419.2**	**394.3**	**356.5**	**375.8**
Pension Adjustment Dec 31, 2018 Valuation										-1.7
Updated Total Transmission OM&A	**441.6**	**431.2**	**408.1**	**436.8**	**385.0**	**397.7**	**419.2**	**394.3**	**356.5**	**374.1**

1: Directive refers to the Government Directive as detailed and defined in Exhibit F, Tab 4, Schedule 1.

Table 6: Bridge Year and Planning Year Capital Expenditure Summary ($ Millions)

Revised from Exhibit A, Tab 3, Schedule 1 – Table 7

OEB Category	Historical			Bridge	Forecast				
	2018			2019	2020	2021	2022	2023	2024
	OEB Approved	Actual	Var	F/Cast	Test	Test	Test	Plan	Plan
	$M	$M	%	$M	$M	$M	$M	$M	$M
System Access	24.3	33.7	39%	45.1	24.8	11.3	11.7	12.7	4.1
System Renewal	780.4	776.2	-1%	773.3	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	75.6	73.9	-2%	103.8	204.1	148.2	151.8	174.3	204.2
General Plant	119.7	83.6	-30%	116.3	115.4	94.4	94.7	83.6	58.9
Progressive Productivity	0.0	0.0	0%	0.0	-17.0	-39.0	-61.0	-78.0	-91.0
Directive[1]				-0.3	-0.3	-0.3	-0.4	-0.4	-0.4
Total	**1,000.0**	**967.3**		**1,038.2**	**1,192.2**	**1,317.7**	**1,369.6**	**1,369.6**	**1,369.6**
Pension Adjustment Dec 31, 2018 Valuation				-3.2	-4.2	-5.2	-5.4	-5.4	-5.4
Updated Total				**1,035.0**	**1,188.0**	**1,312.5**	**1,364.2**	**1,364.2**	**1,364.2**

1: Directive refers to the Government Directive as detailed and defined in Exhibit F, Tab 4, Schedule 1.

Table 7: In-Service Capital Additions 2014 – 2022 ($ Millions)
Revised from Exhibit C, Tab 2, Schedule 1 – Table 1

	Historical																				
	2014			**2015**			**2016**					**2017**			**2018**			**Bridge**	**Test**		
	Actual	**Plan**	**Variance**	**Actual**	**Plan**	**Variance**	**Actual**	**New Plan** [1]	**Plan**	**Variance (New Plan)**	**Variance (Plan)**	**Actual**	**Plan**	**Variance**	**Actual**	**Plan**	**Variance**	**2019**	**2020**	**2021**	**2022**
System Access	34.1	50.4	-32%	8.9	13.9	-36%	10.1	17.7	3.0	-43%	237%	51.2	1.8	2,744%	12.1	68.2	-82%	30.4	59.2	5.3	14.1
System Renewal	649.6	575.8	13%	559.8	563.3	-1%	635.7	595.4	472.0	7%	35%	657.8	717.0	-8%	852.3	761.4	12%	770.5	762.0	998.7	1,138.7
System Service	144.8	129.9	11%	18.7	120.7	-85%	174.2	192.4	116.6	-9%	49%	85.7	70.4	22%	218.0	244.8	-11%	54.5	155.1	175.2	137.7
General Plant	86.0	107.2	-20%	111.7	123.4	-9%	90.2	106.3	81.7	-15%	10%	77.5	78.5	-1%	77.9	104.0	-25%	95.6	76.9	155.1	59.5
Progressive Productivity Placeholder																			(15.8)	(36.3)	(56.7)
Total	**914.5**	**863.3**	**6%**	**699.1**	**821.3**	**-15%**	**910.2**	**911.7**	**673.3**	**-0.2%**	**35%**	**872.2**	**867.7**	**1%**	**1,160.4**	**1,178.4**	**-2%**	**951.0**	**1,037.4**	**1,298.0**	**1,293.3**
Directive[2]																		-0.3	-0.3	-0.3	-0.4
Total																		**950.7**	**1,037.1**	**1,297.7**	**1,293.0**
Pension Adjustment Dec 31, 2018 Valuation																		-3.2	-4.2	-5.2	-5.4
Updated Total																		**947.5**	**1,032.9**	**1,292.5**	**1,287.6**

1: New Plan represents the 2016 Bridge Year forecast from 2017-2018 Transmission Rate Application (EB-2016-0160)
2: Directive refers to the Government Directive as detailed and defined in Exhibit F, Tab 4, Schedule 1.

Table 8: Average Bill Impacts on Transmission and Distribution-connected Customers Revised from Exhibit I2, Tab 5, Schedule 1 – Table 2

	2019[1]	2020		2021		2022	
		Blue Page	**Oral Hearing Update**	**Blue Page**	**Oral Hearing Update**	**Blue Page**	**Oral Hearing Update**
Rates Revenue Requirement ($M)	**$1,552.3**	**$1,628.0**	**$1,596.2**	**$1,719.4**	**$1,677.4**	**$1,808.4**	**$1,773.2**
% Increase in Rates RR over prior year		4.9%	2.8%	5.6%	5.1%	5.2%	5.7%
% Impact of load forecast change		3.8%	3.8%	0.6%	0.6%	0.7%	0.7%
Net Impact on Average Transmission Rates		**8.7%**	**6.6%**	**6.2%**	**5.7%**	**5.9%**	**6.4%**
Transmission as a % of Tx-connected customer's Total Bill		*7.4%*	7.4%	*7.4%*	7.4%	*7.4%*	7.4%
Estimated Average Bill impact		**0.6%**	**0.5%**	**0.5%**	**0.4%**	**0.4%**	**0.5%**
Transmission as a % of Dx-connected customer's Total Bill		*6.2%*	6.2%	*6.2%*	6.2%	*6.2%*	6.2%
Estimated Average Bill impact		**0.5%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**

1 2019 rates revenue requirement as per the OEB's Decision and Order for Hydro One's 2019 Transmission Revenue Requirement application (EB-2018-0130), issued on 25th April, 2019.

Table 9: Typical Medium Density (R1) Residential Customer Bill Impacts
Revised from Exhibit I2, Tab 5, Schedule 1 – Table 3

	Typical R1 Residential Customer					
	Blue Page	**Oral Hearing Update**	**Blue Page**	**Oral Hearing Update**	**Blue Page**	**Oral Hearing Update**
	400 kWh	**400 kWh**	**750 kWh**	**750 kWh**	**1,800 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$83.40	$121.75	$121.75	$236.81	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$4.78	$8.96	$8.96	$21.50	$21.50
Estimated 2019 Monthly RTSR[2]	$5.10	$5.10	$9.56	$9.56	$22.95	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.13**	**$0.24**	**$0.24**	**$0.58**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$5.52	$5.42	$10.35	$10.16	$24.83	$24.39
2020 increase in Monthly Bill	**$0.42**	**$0.32**	**$0.79**	**$0.60**	**$1.89**	**$1.44**
2020 increase as a % of total bill	*0.5%*	*0.4%*	*0.6%*	*0.5%*	*0.8%*	*0.6%*
Estimated 2021 Monthly RTSR[3]	$5.84	$5.71	$10.96	$10.71	$26.29	$25.70
2021 increase in Monthly Bill	**$0.32**	**$0.29**	**$0.61**	**$0.55**	**$1.46**	**$1.31**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.5%*	*0.4%*	*0.6%*	*0.5%*
Estimated 2022 Monthly RTSR[3]	$6.17	$6.06	$11.56	$11.36	$27.76	$27.26
2022 increase in Monthly Bill	**$0.32**	**$0.35**	**$0.61**	**$0.65**	**$1.46**	**$1.56**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.5%*	*0.5%*	*0.6%*	*0.6%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).
[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's 2019 rates revenue requirement as shown in Table 8 above.
[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 8 above, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

Table 10: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts Revised from Exhibit I2, Tab 5, Schedule 1 – Table 4

	GSe Customer Monthly Bill					
	Blue Page	**Oral Hearing Update**	**Blue Page**	**Oral Hearing Update**	**Blue Page**	**Oral Hearing Update**
	1,000 kWh	**1,000 kWh**	**2,000 kWh**	**2,000 kWh**	**15,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$198.93	$198.93	$367.73	$367.73	$2,562.20	$2,562.20
RTSR included in 2017 GSe Customer's Bill (based on 2016 UTR)	$10.63	$10.63	$21.26	$21.26	$159.47	$159.47
Estimated 2019 Monthly RTSR[2]	$11.35	$11.35	$22.69	$22.69	$170.21	$170.21
2019 increase in Monthly Bill	**$0.29**	**$0.29**	**$0.58**	**$0.58**	**$4.33**	**$4.32**
2019 increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$12.28	$12.06	$24.56	$24.12	$184.20	$180.90
2020 increase in Monthly Bill	**$0.93**	**$0.71**	**$1.86**	**$1.43**	**$13.99**	**$10.69**
2020 increase as a % of total bill	*0.5%*	*0.4%*	*0.5%*	*0.4%*	*0.5%*	*0.4%*
Estimated 2021 Monthly RTSR[3]	$13.00	$12.71	$26.00	$25.42	$195.04	$190.63
2021 increase in Monthly Bill	**$0.72**	**$0.65**	**$1.44**	**$1.30**	**$10.84**	**$9.74**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.4%*	*0.4%*	*0.4%*	*0.4%*
Estimated 2022 Monthly RTSR[3]	$13.73	$13.48	$27.45	$26.96	$205.88	$202.21
2022 increase in Monthly Bill	**$0.72**	**$0.77**	**$1.45**	**$1.54**	**$10.85**	**$11.58**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.4%*	*0.4%*	*0.4%*	*0.4%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).
[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's 2019 rates revenue requirement as shown in Table 8 above.
[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 8 above, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

UNDERTAKING J1.2

Reference:

JT 2.25

Undertaking:

To explain the calculation in the capital program accomplishment composite index

Response:

The ***Capital Program Accomplishment (composite index)*** measure is calculated as follows:

$$Capital\ Program\ Accomplishment\ (composite\ index) = \frac{Weighted\ Index_{3,4,6,8,11,12}}{Weighthing_{3,4,6,8,11,12}} = \frac{18.0+8.3=16.2+7.9+1.6+2.6}{17.0+8.3+6.2+9.2+2.1+2.7} = 120.0\%$$

The ***Capital Program Accomplishment (composite index)*** is the sum of the TX Segment Weighted Index values divided by the sum of the TX Segment Weighting values.

The scorecard has been updated as per JT 2.25.

Witness: Andrew Spencer

	Work Item	Segment	Units	Budget (n)	Weighting (n)	Units Planned (n)	Units Forecasted (n)	Completion (n)	Weighted Index (n)
(n)					**Budget (n) ÷ Budget Total**			**Units Forecasted (n) ÷ Units Planned (n)**	**Completion (n) × Weighting (n)**
1	End of Life Replacement of Wood Poles	Dx	# of poles	$73.8	19.9%	9,600	6,088	63.4%	12.6%
2	Residential, Subdivision, Expansion	Dx	# of connects	$65.5	17.7%	14,724	17,321	117.6%	20.8%
3	Tx Lines Insulator Replacement Program	Tx	# of circuit structures	$63.2	17.0%	3,700	3,905	105.5%	18.0%
4	Steel Structure Coating Program	Tx	# of structures	$30.8	8.3%	1,050	1,051	100.1%	8.3%
5	Dx Capital Trouble Call Poles & Equipment	Dx	# of poles/equipment	$24.0	6.5%	3,376	2,842	84.2%	5.5%
6	Purchase of Spare Transformers Program	Tx	# of transformers	$23.1	6.2%	5	13	260.0%	16.2%
7	Customer Upgrade	Dx	# of upgrades	$17.5	4.7%	4469	3,958	88.6%	4.2%
8	Tx Wood Pole Replacement	Tx	# of structures	$34.1	9.2%	850	735	86.5%	7.9%
9	PCB Overhead Equipment Replacement	Dx	# of transformers	$11.6	3.1%	2152	1,744	81.0%	2.5%
10	DS Station Refurbishment Program	Dx	# of stations	$9.3	2.5%	5	2	40.0%	1.0%
11	Tx Lines Foundation Assess/Clean	Tx	# of structures	$7.7	2.1%	800	628	78.5%	1.6%
12	Shieldwire Replacement Program	Tx	# of KM of shieldwire replaced	$10.1	2.7%	220	209	95.1%	2.6%
		Budget Total		**$370.7**					

UNDERTAKING J1.3

Reference:

JT-1.16

Undertaking:

To provide the forecasts that have targets and what those targets are.

Response:

The table below expands on the metrics provided in JT 1.16 to differentiate between those metrics that have targets and those that are reported upon for informational and ongoing trending purposes.

Witness: Andrew Spencer

Metric	Report vs Target	Objective
On-time: Project In-Service Date Forecast versus Current Approved	Report	Completed consistently with approved schedule to achieve benefits
On-time: Project In-Service Date Forecast versus Original Approved	Report	
On-budget: Gross Project Total Forecast versus Current Approved	Report	Complete within AACE Estimate Class Range documented in original approval assuming no material changes in scope.
On-budget: Gross Project Total Forecast versus Original Approved	Report	
Portfolio Level Metrics:		
In-Service Additions: Annual Forecast versus Budget	Target: 100%	Completion of portfolio commitments against plan to achieve investment benefits
Capital Expenditures: Annual Forecast versus Budget	Target: 100%	
Portfolio Risk: Number of Projects Forecasting a Major Variance (+/- 10%) to Budget	Report	1 – Ensure oversight and project control effectiveness 2 - To identify significant variances (+/- 10%) to budget where a variance approval is required 3 - Strive for year over year improvements
Portfolio Risk: Value of Projects Forecasting a Major Variance (+/- 10%) to Budget	Report	
Project Cost Performance: Number of Projects complete within AACE Estimate Class Range documented in original approval	Target: 100%*	Demonstrated effectiveness of Project Definition and Execution Processes
Project Cost Performance: Value of Projects complete within AACE Estimate Class Range documented in original approval	Target: 100%*	
Cost Variance Distribution: Portion of Project Portfolio Delivered On Budget, Over Budget, Under Budget	Report	1 - Demonstrated effectiveness of Project Definition and Execution Processes 2 - Strive for a balanced distribution of projects over and under budget
Cost Variance Distribution: Standard Deviation of Project Cost Performance represented as a percentage of original Budgets	Report	1 - Demonstrated effectiveness of Project Definition and Execution Processes 2 - Strive for year over year improvements by reducing standard deviation of variances overtime
Schedule Variance Distribution: Portion of Project Portfolio Delivered On-time, Late, Early	Report	
Schedule Variance Distribution: Standard Deviation of Schedule Variance in Days	Report	

**Assuming no material changes in scope*

UNDERTAKING J1.4

Reference:
B-1-1, TSP Section 1.5, Figure 1

Undertaking:
To update the scorecard to include trend lines up to 2018 for the System Reliability measures.

Response:
The proposed Electricity Transmitter Scorecard, originally filed in Exhibit B, Tab 1, Schedule 1, TSP Section 1.5, Figure 1, and subsequently updated in JT-2.25 is provided below with directional trend arrows for the System Reliability results for 2018, relative to the 2018 targets.

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Trend	Targets 2018
Customer Focus	Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)		86	92	89	94	85		85
		Overall Customer Satisfaction (% Satisfied)		77	85	78	88	90		86
	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs		11.8	14.3	9.7	9.5	10.1		13.0
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		1.8	1.7	1.1	1.2	1.1		1.1
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.60	0.59	0.46	0.65	0.83		0.58
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.48	0.50	0.33	0.47	0.50		0.53
		T-SAIDI (Ave minutes of interruptions per Deliver Point)		36.7	43.9	80.8	42.8	70.0		46.5
		System Unavailability (%)		0.48	0.63	0.70	0.69	0.83		0.42
		Unsupplied energy (minutes)		12.2	11.8	11.4	13.2	19.5		12.6
	Asset & Project Management	Transmission System Plan Implementation Progress (%)		99	105	100	94	99		100
		CapEx as % of Budget		90	106	105	100	97		100
		OM&A Program Accomplishment (composite index)			97	99	108	107		100.0
		Capital Program Accomplishment (composite index)			122	59	88	120		100.0
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		8.4	9.0	8.6	7.9	7.7		7.7
		OM&A per Gross Fixed Asset Value (%)		2.7	2.9	2.5	2.3	2.3		2.2
		Line Clearing Cost per kilometer ($/km)		2,495	2,234	1,966	2,100	2,797		2,295
		Brush Control Cost per Hectare ($/Ha)		1,624	1,566	1,542	1,356	1,539		1,625
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments		100	100	100	100	100		100
	Regional Infrastructure Planning (RIP) &	Regional Infrastructure Planning progress - Deliverables met, %		100	100	100	100	100		100
	Long-Term Energy Plan (L-TEP) Right-Sizing	End-of-Life Right-Sizing Assessment Expectation					Met	Met		Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.69	0.13	0.20	0.13	0.12		
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.16	1.39	1.43	1.47	1.53		
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.36	9.30	9.19	8.78	9.00		
			Achieved	13.12	10.93	10.02	9.03	11.08		

Legend: 5-year trend
up down flat
Current year
target met target not met

1 Witness: Bruno Jesus

UNDERTAKING J1.5

Reference:

I-02-13 p 2 line 6

Undertaking:

To clarify the clarington numbers.

Response:

	Original Business Case Approval	As Filed EB-2016-0160 ($M)	As a result of the DRO**	Current Forecast ($M)*
Reference Date	Jun 2013	May 2016	Nov 2017	Sep 2019
Project Total (Net)	$ 296.6	$ 280.7	$ 244.1	$ 242.3
2017 Net Capex		$ 68.6	$ 29.9	$ 29.8
2018 Net Capex		$ 14.8	$ 21.9	$ 14.6
Contingency* **	$ 59.9	$ 59.9	$ 3.3	$ 0.0

**The values for 2017 and 2018 capex in the Current Forecast are actuals*
*** DRO = Draft Rate Order filed*
**** Contingency is included in the Project Total*

The lower forecast results primarily from unused contingency funds originally allocated to potential risks which did not materialize.

The original approval for Clarington TS occurred in 2013; since then there have been considerable improvements to contingency definition and management practices as per 2019-03-21, B-2-1, pages 12-13.

Witness: Andrew Spencer

UNDERTAKING J2.1

Reference:

Exhibit A, Tab 7, Schedule 2, Attachment 3, Slide 7

Undertaking:

With reference to slide 7, 2016 performance trend, to provide details on threshold of increasing versus stable trend

Response:

The term “trend” reflects the status of 2016 performance of delivery points serving First Nations communities, relative to the Customer Delivery Point Performance Standard, as detailed in Exhibit D, Tab 2, Schedule 1, Attachment 1.

The following outlines the threshold associated with the trend designations, based on 2016 performance:

- **Increasing duration of interruptions**: Delivery point is an outlier from a Duration perspective (Individual or Group)
- **Increasing frequency of interruptions**: Delivery point is an outlier from a Frequency perspective (Individual or Group)
- **BOTH**: Delivery point is an outlier from both a Frequency (Individual or Group) and Duration (Individual or Group) perspective
- **STABLE**: Delivery point is neither a group or individual outlier

UNDERTAKING J2.2

Reference:

Exhibit B-1-1, TSP Section 1.4, Attachment 4, Figure 2-1.

K-2.3 – OEB Staff Compendium, Capital Expenditures and Transmission System Plan Issues.

Undertaking:

Re: EPRI report, page 23, conductor replacements between 1998 and 2017, to describe the circumstances for each removal, including for example conductor age or condition assessment

Response:

As noted in the EPRI Conductor Report, Hydro One provided a total of 126 historical replacement records from 48 unique circuits, spanning the period from January 1988 to January 2017.

This data, listed below, consisted of segments from line sections that were replaced as a result of deteriorated condition or a service requirement, which necessitated an upgrade. Duplicated line sections reflect different replacements within the same line sections.

#	Circuit	Line Section	Length (km)	Installation Date	Replacement Date	Age
1	P5M	PORT ARTHUR TS #1 X CONMEE JCT	33	11/28/1943	1/1/1988	44
2	P5M	PORT ARTHUR TS #1 X CONMEE JCT	33	11/28/1943	1/1/1988	44
3	W12W	BUCHANAN TS X INGERSOLL TS	31.7	6/16/1905	1/1/1989	84
4	P5M	PORT ARTHUR TS #1 X CONMEE JCT	33	11/28/1943	1/1/1990	46
5	P5M	PORT ARTHUR TS #1 X CONMEE JCT	33	11/28/1943	1/1/1990	46
6	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	1/1/1990	69
7	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	1/1/1990	69
8	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	1/1/1990	69
9	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	1/1/1990	69
10	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	1/1/1990	69
11	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	1/1/1990	69
12	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	1/1/1990	69
13	B8W	BRANT TS X WOODSTOCK TS	35.3	11/1/1910	1/1/1990	79
14	B8W	BRANT TS X WOODSTOCK TS	35.3	11/1/1910	1/1/1990	79
15	56M1	RED ROCK JCT X NORAMPAC CTS	2.9	9/21/1937	1/1/1990	52
16	56M1	NIPIGON JCT X RED ROCK JCT	5.2	4/29/1921	1/1/1990	69
17	W8T	BUCHANAN TS X EDGEWARE JCT	17.1	12/1/1910	1/1/1990	79
18	B12	BURLINGTON TS-DUNDAS #2 JCT	12	6/30/1910	6/30/1991	81

19	B13	BURLINGTON TS-DUNDAS #2 JCT	12	6/30/1910	6/30/1991	81
20	57M1	RESERVE JCT X NIPIGON JCT	4.5	9/9/1924	1/1/1992	67
21	D10H	WATERLOO JCT X WALLENSTEIN JCT	18.6	8/1/1930	1/1/1994	63
22	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	1/31/1994	83
23	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	1/31/1994	83
24	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	1/31/1994	83
25	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	2/28/1994	73
26	H2JK	MANBY TS X RIVERSIDE JCT	5.5	7/4/1951	4/30/1994	43
27	H2JK	MANBY TS X RIVERSIDE JCT	5.5	7/4/1951	4/30/1994	43
28	H2JK	MANBY TS X RIVERSIDE JCT	5.5	7/4/1951	4/30/1994	43
29	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	5/31/1994	83
30	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	5/31/1994	83
31	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	5/31/1994	83
32	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	6/30/1994	84
33	A1N	VANESSA JCT X NORFOLK TS	12	1/28/1940	7/31/1994	55
34	W8T	BUCHANAN TS X EDGEWARE JCT	17.1	12/1/1910	9/30/1994	84
35	W8T	BUCHANAN TS X EDGEWARE JCT	17.1	12/1/1910	9/30/1994	84
36	Q4N	BECK GS #1 X PORTAL JCT	4.6	1/1/1922	9/30/1994	73
37	A1N	VANESSA JCT X NORFOLK TS	12	1/28/1940	9/30/1994	55
38	P33C	IPB OTTAWA RIVER JCT X CHATS FALLS JCT	6.7	10/1/1928	4/30/1995	67
39	P33C	IPB OTTAWA RIVER JCT X CHATS FALLS JCT	6.7	10/1/1928	4/30/1995	67
40	A1N	VANESSA JCT X NORFOLK TS	12	1/28/1940	6/30/1995	55
41	D10H	PALMERSTON TS X HANOVER TS	41.4	8/1/1930	7/31/1995	65
42	D10H	PALMERSTON TS X HANOVER TS	41.4	8/1/1930	7/31/1995	65
43	H2JK	MANBY TS X RIVERSIDE JCT	5.5	7/4/1951	7/31/1995	44
44	H2JK	MANBY TS X RIVERSIDE JCT	5.5	7/4/1951	7/31/1995	44
45	P33C	IPB OTTAWA RIVER JCT X CHATS FALLS JCT	6.7	10/1/1928	8/31/1995	67
46	D10H	WALLENSTEIN JCT X PALMERSTON TS	29.2	8/1/1930	2/29/1996	66
47	D10H	WATERLOO JCT X WALLENSTEIN JCT	18.6	8/1/1930	2/29/1996	66
48	Q3L	BECK GS #1 X PORTAL JCT	4.6	1/1/1922	5/1/1996	74
49	D8S	LEONG JCT X ST.MARYS TS	56.9	12/1/1910	6/24/1996	86
50	L1MB	MILLE ROCHES JCT X LUNENBURG JCT	8.4	7/29/1934	10/15/1997	63
51	D10H	WATERLOO JCT X WALLENSTEIN JCT	18.6	8/1/1930	6/15/1998	68
52	B1S	BARRETT CHUTE #2 JCT X ARDOCH JCT	38.5	7/20/1937	9/9/1998	61
53	B1S	BARRETT CHUTE #2 JCT X ARDOCH JCT	38.5	7/20/1937	10/1/1998	61
54	B1S	BARRETT CHUTE #2 JCT X ARDOCH JCT	38.5	7/20/1937	10/1/1998	61
55	L1S	CRYSTAL FALLS TS X VERNER JCT	20.2	8/28/1937	12/10/1998	61
56	L1S	CRYSTAL FALLS TS X VERNER JCT	20.2	8/28/1937	12/10/1998	61
57	B1S	BARRETT CHUTE #2 JCT X ARDOCH JCT	38.5	7/20/1937	5/20/1999	62
58	Q2AH	Beamsville TS x Saltfeet Jct	23.6	10/1/1922	2/7/2002	79

59	Q2AH	Saltfleet Jct. x Beach TS	3.9	10/1/1922	2/27/2002	79
60	Q2AH	Louth Jct x Beamsville TS	17.5	10/1/1922	3/4/2002	79
61	D1A	Hoopers Jct x St. John Valley	3.3	9/14/1943	4/21/2002	59
62	P3S	Sidney TS x Dale Jct	57.2	8/7/1928	7/26/2002	74
63	P3S	Sidney TS x Dale Jct	57.2	8/7/1928	7/29/2002	74
64	P3S	Sidney TS x Dale Jct	57.2	8/7/1928	7/30/2002	74
65	H27H	Hinchinbrooke TS x Havelock TS - South Phase	98.2	11/26/1929	8/1/2002	73
66	H27H	Hinchinbrooke TS x Havelock TS - North Phase	98.2	11/26/1929	8/1/2002	73
67	C25H	Chats Falls x Havelock TS - Centre Phase	171.7	10/1/1928	8/7/2002	74
68	C25H	Chats Falls x Havelock TS - South Phase	171.7	10/1/1928	8/7/2002	74
69	A6P	RESERVE JCT X PORT ARTHUR TS -Bottom Phase	91.1	11/20/1920	9/24/2002	82
70	A6P	RESERVE JCT X PORT ARTHUR TS #1	91.1	11/20/1920	9/26/2002	82
71	C25H	Chats Falls x Havelock TS - North Phase	171.7	10/1/1928	10/1/2002	74
72	C25H	Chats Falls x Tower #209	6.6	10/1/1928	2/10/2004	75
73	C25H	Chats Falls x Tower #209 - 1/4 span from tower #15	6.6	10/1/1928	2/10/2004	75
74	A5RK	RIVERDALE JCT-OVERBROOK TS	2.1	6/15/1947	6/15/2004	57
75	Q2AH	LOUTH JCT-CHERRY JCT	12.3	12/31/1921	12/31/2005	84
76	Q2AH	CHERRY JCT-BEAMSVILLE TS	5.2	12/31/1921	12/31/2005	84
77	Q5G	LOUTH JCT-CHERRY JCT	12.3	12/31/1921	12/31/2005	84
78	Q5G	CHERRY JCT-BEAMSVILLE TS	5.2	12/31/1921	12/31/2005	84
79	Q2AH	WEST LINCOLN CSS-WINONA TS	17.3	12/21/1921	12/21/2007	86
80	Q2AH	WINONA TS-SALTFLEET JCT	4.5	12/21/1921	12/21/2007	86
81	Q2AH	SALTFLEET JCT-Q2AH 254 JCT	3.5	12/21/1921	12/21/2007	86
82	Q5G	BEAMSVILLE TS-WEST LINCOLN CSS	1.9	12/21/1921	12/21/2007	86
83	A4K	CYRVILLE MTS-CYRVILLE JCT	1.9	7/15/1954	7/15/2008	54
84	L1S	CONISTON TS-SUDBURY JCT	8.8	6/14/1949	6/14/2009	60
85	L1S	SUDBURY JCT-MARTINDALE TS	2.1	7/10/1948	7/10/2009	61
86	M31W	INGERSOLL JCT-KARN TS	11.2	10/7/1909	10/7/2010	101
87	M32W	INGERSOLL JCT-KARN TS	11.2	10/7/1909	10/7/2010	101
88	K12	KARN TS-WOODSTOCK TS	2.3	10/7/1909	10/7/2010	101
89	K4	MACASSA #3 JCT-MATACHEWAN JCT	47.2	6/1/1924	6/1/2011	87
90	N21W	LUCASVILLE JCT-BOSTWICK ROAD JCT	26.9	9/15/1959	9/15/2011	52
91	N22W	LUCASVILLE JCT-BOSTWICK ROAD JCT	26.9	9/15/1959	9/15/2011	52
92	L14W	LEASIDE 2 JCT-BAYVIEW JCT	0.5	6/23/1928	6/23/2012	84
93	L14W	LEASIDE 2 JCT-BAYVIEW JCT	0.7	6/23/1928	6/23/2012	84
94	L14W	LEASIDE 2 JCT-LEASIDE TS	0.5	6/23/1928	6/23/2012	84
95	L14W	BIRCH JCT-BRIDGMAN JCT	1.4	6/24/1928	6/24/2012	84
96	L20D	KIPLING GS-HARMON JCT	4.5	12/13/1966	12/13/2012	46
97	A6P	RESERVE JCT-PORT ARTHUR TS #1	19	12/21/1920	12/21/2012	92
98	A6P	RESERVE JCT-PORT ARTHUR TS #1	15.9	12/21/1920	12/21/2012	92

Witness: Donna Jablonsky

99	A6P	RESERVE JCT-PORT ARTHUR TS #1	29.6	12/21/1920	12/21/2012	92
100	A6P	RESERVE JCT-PORT ARTHUR TS #1	5.3	12/21/1920	12/21/2012	92
101	D3A	HOOPER'S JCT-ST.JOHNS VALLEY JCT	3.4	5/20/1943	5/20/2013	70
102	D1A	HOOPER'S JCT-ST.JOHNS VALLEY JCT	3.4	6/28/1943	6/28/2013	70
103	M2W	MANITOUWADGE JCT B-MANITOUWADGE DS #1	0.1	10/7/1955	10/7/2013	58
104	M2W	MANITOUWADGE JCT B-MANITOUWADGE DS #1	0.1	10/7/1955	10/7/2013	58
105	D1A	DECEW FALLS SS-HOOPER'S JCT	0.2	10/17/1954	10/17/2013	59
106	L24L	LAMBTON TS #2-LAMBTON JCT	3.1	1/17/1970	1/17/2014	44
107	H3L	HEARN SS-BASIN TS	0.2	3/20/1959	3/20/2014	55
108	D3A	DECEW FALLS SS-HOOPER'S JCT	0.2	4/19/1943	4/19/2014	71
109	C27P	CHATS FALLS SS-GALETTA JCT	12.9	6/1/1932	6/1/2014	82
110	H27H	BANNOCKBURN JCT-HAVELOCK TS	30	11/26/1929	11/26/2014	85
111	D10S	VANSICKLE TS-LOUTH JCT	0.9	11/8/1952	11/8/2015	63
112	D9HS	VANSICKLE TS-LOUTH JCT	0.9	11/8/1952	11/8/2015	63
113	61M18	CONSTANCE DS-GODERICH TS	0.1	12/10/1959	12/10/2015	56
114	61M18	CONSTANCE DS-GODERICH TS	0	12/10/1959	12/10/2015	56
115	D10S	LOUTH JCT-GLENDALE TS	0.1	1/19/1922	1/19/2016	94
116	D9HS	LOUTH JCT-GLENDALE TS	6.1	1/19/1922	1/19/2016	94
117	D9HS	LOUTH JCT-GLENDALE TS	0.1	1/19/1922	1/19/2016	94
118	D9HS	LOUTH JCT-GLENDALE TS	6.1	1/19/1922	1/19/2016	94
119	C25H	CHATS FALLS SS-HAVELOCK TS	170.9	3/31/1932	3/31/2016	84
120	C25H	CHATS FALLS SS-HAVELOCK TS	170.9	3/31/1928	3/31/2016	88
121	S2B	ESPANOLA A JCT-ESPANOLA TS	0.2	5/8/1975	5/8/2016	41
122	S2B	EDDY TAP A JCT-ESPANOLA TS	0.1	5/8/1951	5/8/2016	65
123	H9W	WEST LINCOLN CSS-WINONA TS	17.3	5/26/1922	5/26/2016	94
124	H24C	MARINE JCT-OSHAWA NORTH JCT	54.5	11/4/1929	11/4/2016	87
125	Q12S	BECK #1 SS-WARNER ROAD JCT	0.3	1/1/1922	1/1/2017	95
126	B20P	BRUCE A TS-BRUCE HW PLANT D JCT	0.3	1/27/1975	1/27/2017	42

UNDERTAKING J3.1

Reference:
JT-2.28

Undertaking:
To look for and file available reports on unit cost benchmarking.

Response:
Power Systems Engineering ("PSE") included a total cost benchmarking report at Exhibit A, Tab 4, Schedule 1, Attachment 1. PSE determined that Hydro One's total factor productivity has consistently been greater than that of the transmission industry as a whole. This was further confirmed by PSE's findings from the total cost benchmarking study, which shows that Hydro One's actual costs are well below benchmarked costs.

In EB-2016-0160, Hydro One submitted an independent Transmission Total Cost Benchmarking Study ("Navigant TCB study")[1] that compared Hydro One's performance against a group of peer utilities. In respect of costs, the Navigant TCB study concluded as follows:

- In 2014, Hydro One's total transmission expenditure (OM&A and CAPEX) was below the median of the peer group, 9.1% of the gross book value of in-service transmission assets ("gross asset value") compared to a median value of 13.9%
- In 2014, Hydro One's direct transmission expenditure (O&M and CAPEX) was among the lowest in the peer group, 6.5% of gross asset value compared to a median value of 9.7%
- Hydro One's direct transmission O&M was at the median of the peer group in 2014, 1.6% of gross asset value compared to a median value of 1.8%
- Hydro One's CAPEX was among the lowest in the peer group in 2014, 4.8% of gross asset value compared to a median value of 6.6%

Hydro One does not have any further reports on unit cost benchmarking. Hydro One's work program is divided into projects and programs. Unit cost analysis is relevant for programs that contain high volumes and generally repeatable units (e.g. insulator

[1] The TCB study was submitted as Exhibit B2, Tab2, Schedule 1, Attachment 1 in EB-2016-0160

replacements, wood pole replacements). Programs of this nature generally account for 20%-30% of the transmission capital expenditure.

The remainder of the transmission capital expenditure is comprised of projects. Benchmarking project costs from one utility to the next, or even one project to the next in the same utility is not a meaningful measure due to the variability between projects. This is because each project will have unique scope, engineering requirements, construction means and methods, equipment requirements, etc., which will inform the budget and schedule.

Instead, project definition and governance processes are the most effective way to deliver projects in an efficient and economic manner. Project definition and governance facilitate a robust project execution plan which captures scope, schedule and cost requirements and which identify potential risks to executing the project per plan. Hydro One has a robust project definition and governance process that has been developed and improved in recent years, and which is detailed in Exhibit B, Tab 2, Schedule 1. These enhancements were made in part to address the recommendations in the Navigant TCB Study. In addition, Hydro One has implemented enhanced project and portfolio reporting capabilities and has identified a number of relevant metrics. These are listed in JT-1.16, with objectives and if applicable, targets as presented in J-1.3.

UNDERTAKING J3.2

Reference:

JT-1.3 & K-3.3

Undertaking:

To update the table provided at JT-1.3, breakdown of sustainment OM&A, to include a column showing the average for 2015-2019.

Response:

The following table provides a breakdown of the subset of sustainment OM&A costs provided in Undertaking JT-1.03. The average for 2015 to 2019 is based on 2015-2018 actuals and 2019 forecasted spend. Detailed explanations for 2019 and 2020 are included in Undertaking JT-1.03.

Sustainment OM&A ($ millions)	**2015-2018 Actual**	**2015-2018 Actual & 2019 Forecast**	**2019 Forecast**	**2020 Forecast**
	A	D=(A x 4+B)/5	B	C
Power equipment preventative maintenance	20.6	19.5	15.2	17.6
Transformer refurbishments	4.7	4.2	2.4	3.9
Site infrastructure maintenance	23.0	22.3	19.8	21.3
Vegetation management	32.6	31.9	29.7	31.9
Overhead lines maintenance	17.1	16.5	14.0	17.2
Total	**98.0**	**94.4**	**81.1**	**91.9**

Witness: Donna Jablonsky

UNDERTAKING J3.3

Reference:

I-01-OEB-185
Oral Hearing Volume 3, Page 65, Line 14 – Page 67, Line 9

Undertaking:

With reference to IR OEB STAFF 185, to provide, if possible, a value for management of maintenance cycles related to the 2018 plan; if not possible, to explain why

Response:

As summarized in Exhibit F, Tab 1, Schedule 1 in Table 1, "Plan" totals also referred to as OEB-approved amounts reflect as-filed budgets and not revised OM&A amounts after incorporating any of the following adjustments:

- reductions that Hydro One has made throughout the proceedings (for example reductions due to updated pension valuation or adjustment to exclude certain B2M operating costs);
- settlement approved reductions; and
- OEB-directed envelope cut.

All reductions appear in the subsequent lines in the chart and are applied at the envelope level. Relative to Hydro One's actuals, it appears as though Hydro One has consistently underspent under the sustainment OM&A category in all four historical years (2015-2018). This is not in fact the case. The "Plan" or OEB-approved amounts were then reduced to accommodate the reductions discussed above. When you add the aggregate "Plan" amounts, including all reductions and compare them to the aggregate actuals, Hydro One has actually spent over 99% of the OEB-approved values on an aggregate level for the last four historical years.

Accordingly, a calculation of the impact of 'management of maintenance cycles' on 2020 revenue requirement relative to 2018 OEB approved expenditure levels is not possible nor is it a meaningful metric given that 2018 OEB approved OM&A includes several high level adjustments discussed above. From an envelope perspective, Hydro One's approved 2018 OM&A included in revenue requirement was $27M below the originally proposed amount. As category level OM&A was not restated to reflect the decision and other adjustments, the comparison would overstate the effect of management of maintenance cycles and would not reflect a reasonable comparison. As such, Hydro One provided the impact of ‘management of maintenance cycles’ relative to 2018 actuals in response to OEB IR 185.

Furthermore, the testimony given by Mr. Jesus on Thursday October 24[1] discussing the productivity initiatives relative to 2018 plan year should be clarified to state that the impact of productivity initiatives on 2020 revenue requirement listed in OEB Staff IR 185 (including reduction in vacancies, limiting of consulting and contract engagement, sustained productivity initiatives, and Inergi renegotiations) are calculated relative to their applicable baselines as shown in JT-2.28, which range from 2015 to present, depending upon when the initiative was conceived and implemented.

[1] Oral Hearing Transcript, Day 3, October 24, 2019 page 64 line 23, page 66 line 4:

MR. SIDLOFSKY:
Now, in response to OEB Staff 185 […] in looking at the table that you provided as part of that response, first of all, I am going to ask you to confirm that that table shows the impacts on the 2020 revenue requirement versus 2018 plan, with the exception of the first item, management of maintenance cycles, which is relevant to -- which relates to 2018 actuals. Am I correct when I read this table that it's only the management of maintenance cycles item that relates to 2018 actuals, and all of those other items are related to the 2018 plan?

MR. JESUS: That's correct.

UNDERTAKING J3.4

Reference:
I-02-EP-12

Undertaking:
To reconcile line clearing costs per kilometer and brush control costs per hectare as those numbers appear in the evolved transmission scorecard targets for 2019-2024 on the one hand and in I-02-EP-12 (a) on the other.

Response:
The line clearing and brush control unit costs provided in response to I-02-EP-12 are the latest forecast of 2020-2024 unit costs, relative to the forecast provided in the scorecard at TSP 1.5, p. 5, to perform vegetation management on Hydro One's transmission system. Notwithstanding this forecast, the scorecard targets have not been updated.

Cost increases included in I-02-EP-12 reflect:

- An augmented notification system developed in 2018 and 2019 for vegetation management on urban right-of-ways ("ROW"), where greater communication with affected communities is, in the long run, a more efficient and effective way of coordinating and executing vegetation work in urban areas and prevents costly misunderstandings with adjacent landowners.
- Increased labour costs required to treat overgrowth on ROWs.

Forecast line clearing costs for 2020-2024 relative to 2018-2019 decrease slightly as a result of a reduction of urban ROWs scheduled for maintenance which require the more costly notification process.

UNDERTAKING J3.5

Reference:
I-02-EP-12

Undertaking:
To reconcile Brush Control Cost per Hectare and Hectares Completed Annually as those numbers appear in the evolved transmission scorecard targets for 2019-2024 on the one hand and in I-02-EP-12 (a) on the other.

Response:
The line clearing and brush control unit costs provided in response to I-02-EP-12 are the latest forecast of 2020-2024 unit costs, relative to the forecast provided in the scorecard at TSP 1.5, p. 5, to perform vegetation management on Hydro One's transmission system. Notwithstanding this forecast, the scorecard targets have not been updated.

Cost increases included in I-02-EP-12 reflect:

- An augmented notification system developed in 2018 and 2019 for vegetation management on urban right-of-ways ("ROW"), where greater communication with affected communities is, in the long run, a more efficient and effective way of coordinating and executing vegetation work in urban areas and prevents costly misunderstandings with adjacent landowners.
- Increased labour costs required to treat overgrowth on ROWs.

Forecast line clearing costs for 2020-2024 relative to 2018-2019 decrease slightly as a result of a reduction of urban ROWs scheduled for maintenance which require the more costly notification process.

UNDERTAKING J3.6

Reference:
TSP 2.2 p 4

Undertaking:
To provide the data for the tier 3 metric, percentage of forced outages caused by equipment type for the last five years

Response:
The tier 3 metric identified in the previous rate application relates to equipment outages, irrespective of whether there is a customer interruption. The following table reflects the percent distribution of the tier 3 metric for forced outage frequency based on major equipment type over the last five years:

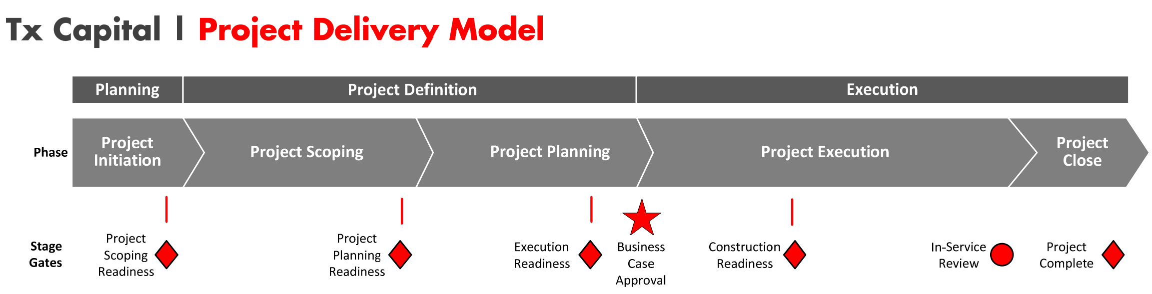
	2014	**2015**	**2016**	**2017**	**2018**	**5-Year Total Ave**
Line	23.1%	27.0%	41.5%	35.9%	44.7%	35.3%
Breaker	57.1%	47.3%	41.5%	45.7%	33.5%	44.1%
Transformer	16.4%	21.6%	13.5%	14.7%	18.4%	17.0%
Other	3.3%	4.0%	3.5%	3.6%	3.2%	3.6%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

UNDERTAKING J3.7

Reference:
JT 1.16

Undertaking:
To provide data supporting success rate in terms of projects delivered on budget, over budget, under budget, and on time, late, or early.

Response:
Hydro One measures a project from the Business Case Approval at the end of the Project Definition Phase (shown in the figure below).



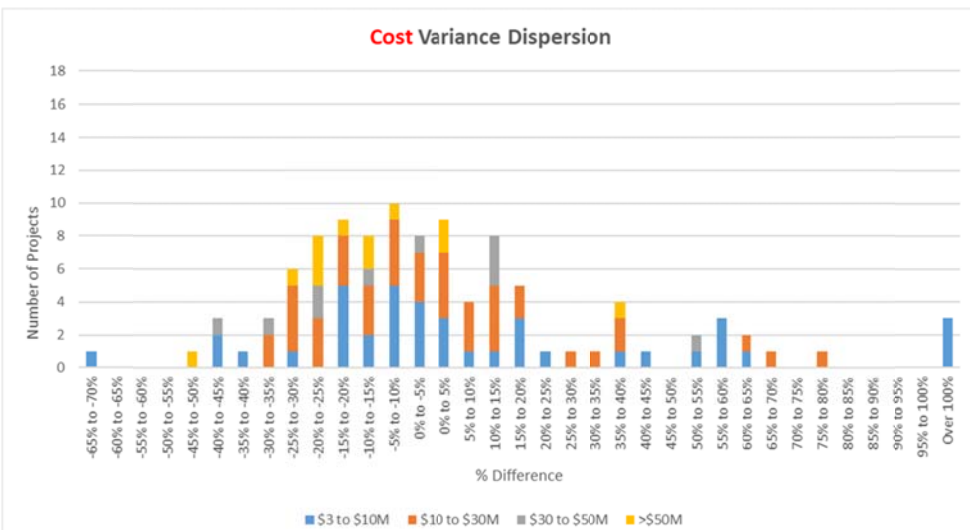
Hydro One's Planning and Project Definition processes are designed to produce an effective project execution plan capturing scope, schedule and cost requirements and identifying any potential risks likely to arise and change project scope, schedule and cost.

During Project Definition, a cross-functional project team is formed and the project execution plan is developed. During this phase all major material is identified and engineering studies and surveys are complete and basic layout drawings including the phasing of work are determined. In addition, a preliminary outage staging plan, comprehensive schedule, and risk registry are produced.

Key internal and external stakeholders are consulted during the Project Definition phases including but not limited to: Indigenous Relations, Community Relations, Customer Solutions, Regulatory Affairs, and Real Estate. This ensures that proper consultation, engagement, and risk identification and mitigation actions can be incorporated into the project execution plan.

At the culmination of the Project Definition phases, the project execution plan is subject to a stage gate panel review and ultimately, Business Case Approval. At this point the scope, schedule and cost of a project are firm and a baseline is created and reported against. For more information on the project planning process please refer to the Capital Work Execution Strategy (Exhibit B, Tab 2, Schedule 1).

The graph below provides cost performance relative to the approved business case for projects that were completed over the 5-year period between 2014 and 2018.[1] The majority of projects were completed at[2] or below their approved business case budget. This demonstrates that at the portfolio level there are a balanced number of projects above and below the approved budget, which is consistent with Hydro One's objectives. With one exception, all large projects that had an approved business case budget greater than $50 million were completed on or below budget.



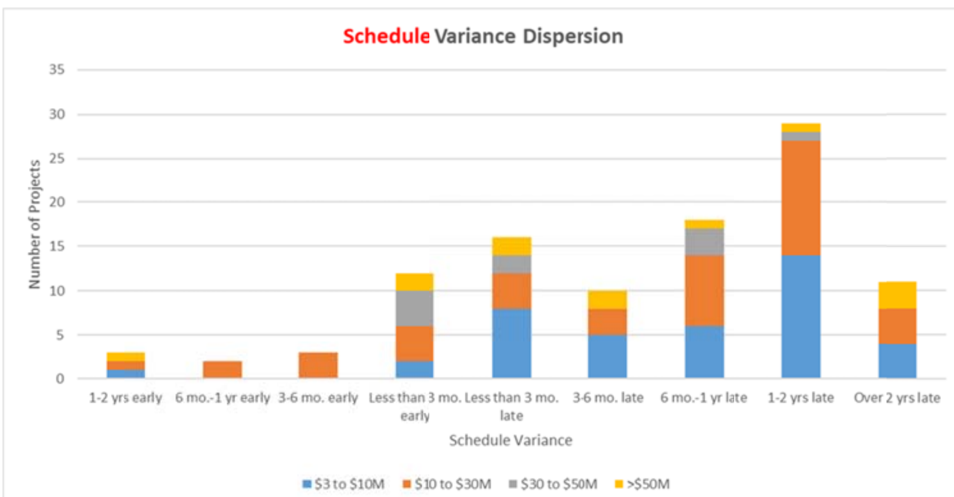
---

[1] The data set includes the majority of Transmission Capital Power System projects completed between 2014 and 2018 in the System Access, System Renewal and System Service categories. Excludes projects with business case approved budgets <$3M and excludes projects where approved budget values were not readily available.

[2] On Budget refers to projects that had a cost variance between -10% and +10% relative to the business case approved budget which aligns with Hydro One's criteria for a major variance.

The graph below provides schedule performance relative to the approved schedule for projects that were completed between the 5-year period of 2014 and 2018. Almost half of the projects were completed early or on time[3] relative to their approved business case schedules. This analysis uses the final project in-service date to indicate total project completion, however many projects have substantial phases completed and are in-use well before this point in time, and therefore a negative skew is not a major concern in and of itself.

Hydro One is continually learning and enhancing project planning, definition, and execution practices so that the projects are delivered safely and efficiently against the plan.



[3] On Time refers to projects that have a schedule variance between -6 months and +6 months relative to business case approved schedule.

UNDERTAKING J3.8

Reference:
SR-11

Undertaking:
To provide a status update on the SONET system replacement project

Response:
In 2020, the SONET system replacement project will continue in the development and estimation phase. In 2021, project execution will begin, consistent with the plan included in this Application.

Witness: Donna Jablonsky, Bruno Jesus

UNDERTAKING J4.1

Reference:

TSP 3.3
Oral Hearing Volume 4, Page 1, Line 12 – Page 2, Line 5

Undertaking:

To update the Table 2 in the TSP 3.3, page 3 to include a column showing 2018 Q2 actuals and 2019 Q2 actuals.

Response:

2019 Q2 actual results are not indicative of 2019 full year results as overall expenditures are not necessarily incurred uniformly through the year. As evident from the table below, 2018 Q2 expenditures reflect 44% of the total capital expenditures for 2018. In 2019, Q2 expenditures represent 43% of the total capital expenditures forecasted for 2019.

OEB Category (in $ millions)	Historical	Historical	Bridge	Bridge	Forecast				
	2018 Q2	2018	2019 Q2	2019	2020	2021	2022	2023	2024
	Actual	Actual	Actual	F/Cast	Test	Test	Test	Plan	Plan
System Access	12.8	33.7	13.6	45.1	24.8	11.3	11.7	12.7	4.1
System Renewal	359.8	776.2	372.5	773.3	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	33.6	73.9	36.7	103.8	204.1	148.2	151.8	174.3	204.2
General Plant	23.7	83.6	22.6	116.3	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder				0.0	-17.0	-39.0	-61.0	-78.0	-91.0
Directive[1]				**-0.3**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.4**
Total	**430.0**	**967.3**	**445.4**	**1,038.2**	**1,192.2**	**1,317.7**	**1,369.6**	**1,369.6**	**1,369.6**
Pension Adjustment Dec 31, 2018 Valuation[2]				-3.2	-4.2	-5.2	-5.4	-5.4	-5.4
Updated Total				**1,035.0**	**1,188.0**	**1,312.5**	**1,364.2**	**1,364.2**	**1,364.2**

[1] The Directive adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.
[2] As per J1.1

Witness: Andrew Spencer

UNDERTAKING J4.2

Reference:
I-07-SEC-27, JT-1.12

Undertaking:
To provide a list of the test-year projects.

Response:
Attachment 1 provides a listing of the 563 investments which are referenced in the interrogatory response for I-07-SEC-27 and presented in a similar format as undertaking JT-1.12. As discussed during the hearing, only investments greater than $3M have been described and investments less than $3M have been consolidated into a single line item.

Witness: Bruno Jesus

Grouping	Category	Type	Less than $3M	Description	Project Count	Test Year Total ($ in millions, NET)	Risk Mitigation ($)
Test Year Expenditures	1. System Access	Mandatory		Connect New DESN near Halton TS	1	6	-
				Horner TS - Build 230-28-28kV Station	1	4	-
				IAMGOLD - 115 kV Connection	1	10	-
				Tx Load Connection Plans	1	10	-
			Less than $3M		23	16	-
			Less than $3M		2	3	-
	2. System Renewal	Mandatory		Telecom Capital Lease Renewals (Fiber IRU Agreements)	1	11	3,190,264
				Nanticoke ABCB Station Refurbishment Project	1	45	5,269,590
				Cherrywood TS 230kV - Phase 1 ABCB (12) & AC/DC SS	1	44	5,628,346
				Tx Lines Emergency Replacement	1	29	1,992,879
				N21W/N22W, Sarnia Scott TS-Buchanan TS, Str. Refurb.	1	5	293,216
				Detweiler TS: T2, T4 & Component Replacement	1	14	251,406
				Line Refurbishment - D2L, Upper Notch JCT x Martin River JCT	1	3	145,930
				B5/6C, BurlingtonTS X WestoverCTS, Tx Line Refurb.	1	5	145,930
				Pine Portage SS: Component Replacement	1	6	62,270
				Strachan TS: T12 & Component Replacements	1	4	21,487
				Bridgman TS: T11, T12, T13, M/C & Component Replacements	1	30	43,746
				Leaside TS: 27.6kV Yard & Component Replacements	1	10	21,795
				Kenilworth TS: T1, T3, T4 & Switchyard Refurbishment and Reconfiguration	1	16	23,632
				Sheppard TS: T3, T4, PCT, LV Yard & Component Replacements	1	5	29,239
				Beck 2 TS 230 kV ABCB Replacement	1	33	-
				Bruce A TS 230 kV ABCB Station Refurbishment	1	6	-
				CIPv6 Transient Cyber Assets Project (SFAD)	1	3	-
				Elgin TS T1/T2/T3/T4; T1,T2,T3,T4 MVGI and Component Replacement	1	10	-
				Hanmer TS: Northern Station Replacement Project	1	8	-
				Hawthorne TS - ISCR	1	3	-
				Lennox TS BULK: ABCB component replacement	1	16	-
				Martindale TS: T21/T23 & Component Replacement	1	18	-
				Physical Security ISL Application Replacement	1	6	-
				Transformer Protection Replacement due to 2nd Harmonic Misoperations	1	4	-
			Less than $3M		62	65	4,657,419
				Trafalgar TS: Component Replacements	1	18	22,774,659
				Milton SS: Component Replacements	1	10	12,748,846
				Claireville TS: Component Replacements	1	22	12,177,368
				Fort Frances TS: Component Replacement	1	12	7,475,555
				Essa TS BULK; ABCB & Component Replacement	1	27	16,490,443
				Bruce B SS ABCB Replacement project	1	50	14,448,901
				Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement	1	31	5,197,186
				Tillsonburg TS: Component Replacement	1	6	849,325
				Middleport TS; ABCB Station Refurbishment	1	61	11,839,484
				Wawa TS: Component Replacement	1	4	3,315,152
				Q25BM/Q29HM ADSS Replacement	1	4	484,854
				Cherrywood TS 230 & 500 kV: Phase 3 ABCB (26)	1	24	14,060,530
				Mackenzie TS: Component Replacement	1	11	1,735,950
				Rabbit Lake SS: Component Replacement	1	7	641,267
				Runnymede TS: T3, T4 & Switchyard Replacement	1	13	1,923,339
				Bunting TS: MV Switchgear & Component Replacement	1	6	1,294,240
				Beck 1 SS 115kV ABCB Replacement	1	10	2,240,565
				Otto Holden TS: T3/T4 & Component Replacement	1	25	2,988,313
				Sarnia Scott TS: T5 & Component Replacement	1	13	1,799,180
				Fairbank TS: T1, T2, T3, T4, PCT & LV Yard Replacements	1	56	4,665,254
				Murray TS: T11, T12 & Component Replacement	1	14	1,280,770
				Carlton TS: T1, T4 & Switchyard Refurbishment and Reconfiguration	1	12	1,365,519
				Near-Term Deteriorated Asset Replacement Program	1	15	2,029,402
				Wingham TS: T1, T2, PCT & Component Replacement	1	18	1,229,358
				Kirkland Lake TS: Component Replacement	1	12	708,734
				Tower Foundations - L0- Vulnerable	1	57	6,374,390
				Arnprior TS: T1/T2 and PCT and Component Replacment	1	23	1,534,825
				Manby TS: T7, T9, T12, T13 & Component Replacements	1	4	3,029,988
				Demand Capital - Power Transformers	1	18	1,959,698
				Gage TS: T3,T4,T5,T6, PCT & Switchyard Reconfiguration	1	31	1,827,573
				Wood Pole Structure Replacements - Publicly Accessible, High Criticality	1	78	6,891,178
				Wood Pole Structure Replacements - Publicly Accessible, High Criticality	1	78	6,891,178
				Lauzon TS: T6, T8 & Component Replacement	1	17	1,449,796
				Moose Lake TS: Component Replacement	1	13	981,875
				Glendale TS: T1, T3, T4 & Switchyard Refurbishment and Reconfiguration	1	40	1,874,052
				Telecom Performance Improvements	1	11	442,416
				Hanover TS: T2 & Component Replacement	1	5	1,163,104
				Port Colborne TS: T61, T62 & Switchyard Refurbishment	1	30	1,133,007
				Hunta SS: Component Replacement	1	6	263,121
				Wonderland TS: T5, PCT & Component Replacement	1	23	885,994
				Minor Component Demand Capital	1	27	2,029,402
				Rexdale TS: Metalclad Switchgear & Component Replacement	1	19	681,515
				Hanlon TS: T1, T2 & Component Replacement	1	19	574,339
				Kingsville TS: T1, T2, T3, T4 & Component Replacement Phase 2	1	20	594,206
				Telecom Performance Improvements	1	6	281,883
				Finch TS: Component Replacements	1	18	678,375
				Lambton TS: T5 & Component Replacement	1	26	893,869
				Stanley TS: T2, PCT & Component Replacement	1	23	696,627
				Thorold TS: T1, MV Switchyard & Component Replacement	1	16	374,269
				King Edward TS T3 and PCT Replacement	1	8	226,767
				Halton TS: Breakers, PCT & Component Replacements	1	7	187,080
				Marathon TS: Component Replacement	1	17	358,549
				Tx Line Refurb. K1/K2 | Kirkland Lake TS-Holloway Holt JCT (Copper)	1	3	107,473
				Tx Lines Insulator Replacement Program - Non-Publically Accessible, High Criticality	1	102	3,068,769
				John Transformer Station Reinvestment	1	40	1,447,792
				Tx Lines Insulator Replacement Program - Non-Publically Accessible, High Criticality	1	102	3,068,769
				Q2AH, ROSEDENE JCT X ST.ANNS JCT, Tx Line Refurb	1	8	114,674
				Ottawa Ring 9 Fibre Infrastructure Development	1	9	139,421
				Bruce A TS: 500kV ABCB replacement and Yard Reconfiguration	1	47	1,857,193
				Mobile Radio System Replacement	1	15	201,590
				Campbell TS: PCT & Component Replacement	1	5	155,249
				H24S Martindale x Widdifield Completion of OPGW Path	1	5	45,201
				Replace Legacy SONET Systems	1	58	1,008,208
				Tx Line Refurb. B3/B4 | Horning Mountain JCT-Glanford JCT (Copper)	1	4	156,191
				Buchanan TS: 115 kV Switchyard & Component Replacement	1	4	199,544
				Metalclad Breaker Replacement Program - Carryover	1	5	31,652
				Tx Line Refurb. H1L/H3L/H6LC/H8LC | Bloor Street JCT-Leaside 34 JCT (EoL)	1	18	114,674
				Tx Line Refurb: Placeholder, Expected EoL Line Discoveries	1	98	1,065,455
				Tx Line Refurb. D6 | Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT (Close EoL)	1	12	104,636
				Porcupine TS: Component Replacement	1	11	250,626
				Keith TS: T11,T12 & Component Replacement	1	32	159,937
				Tx Lines Shieldwire Replacement - Non Publically Accessible, High Criticality	1	14	107,721
				Purchase of Transformer Operating Spares	1	43	311,494
				Tx Line Refurb. D2/3H & D4 & D6T, Hunta SS X Abitibi Canyon SS (EoL)	1	27	113,546
				Elliot Lake TS: Component Replacement	1	5	65,423
				Tx Line Refurb. A8K/A9K | A8K Str. 141 JCT-A8K Str. 277 JCT-Ramore JCT (Copper)	1	24	99,074
				Tx Lines Shieldwire Replacement - Non Publically Accessible, High Criticality	1	24	107,721
				Orangeville TS: T1, T2, T3, T4 & Component Replacements	1	36	93,363
				Bridgman TS: Building Renewal, HL A1/A2 & A7/A8 Swgr Replacement	1	10	27,304
				N5K, Sarnia Scott TS X Kent TS, Tx Line Refurb.	1	5	62,536
				Slater TS T1/T2/T3 and component replacement	1	12	20,814
				Tx Line Refurb. E1C | Ear Falls TS-Slate Falls DS (EoL) + Etruscan JCT-Crow River DS (Near EoL) - EOL, PA	1	33	75,810
				Duplex TS: T1, T2 & Component Replacements	1	4	52,799
				Tx Line Refurb. A4H/A5H | C.P. Tunis JCT-Fournier JCT (Close EoL)	1	18	27,031
				HV UG Cable - Replace C5E/C7E	1	63	176,963
				Minden TS T1, T2, PCT & Component Replacements	1	18	39,690
				Tx Line Refurb. M6E/M7E | Cooper's Falls JCT-Orillia TS (Near EoL)	1	24	32,870
				Cedar TS: T7, T8 & Component Replacement	1	9	14,585
				Tx Line Refurb. A7L/R1LB & 57M1 Alexander B JCT-Lakehead TS & Nipigon JCT Copper	1	56	89,257
				Tx Line Refurb. A4L | Roxmark Mines CTS-Beardmore JCT/DS #2 (Near EoL)	1	14	24,987
				Tx Line Refurb. B5QK | Barrett Chute #2 JCT-Sharbot JCT (Near EoL)	1	17	32,552
				Birmingham TS: MV Switchgear Replacement	1	4	27,193
				Tx Line Refurb. L22H Easton JCT-Hinchinbrk N JCT Near EoL	1	20	37,517
				Crowland TS: T5, T6 & Component Replacement	1	16	18,587
				Belleville TS- Station Refurbishment	1	10	8,519
				Newton TS: T1, T2, PCT & Switchyard Refurbishment	1	6	13,268
				Algoma TS: T5/T6 & Component Replacement	1	7	23,273
				Tx Line Refurb. E8V/E9V | Orangeville TS-Essa JCT (Near EoL)	1	18	21,990
				Tx Line Refurb. C27P | Galetta JCT-Bannockburn JCT (Near EoL)	1	79	31,293
				Tx Line Refurb. T2R/T61S | Timmins JCT-Wawaitin JCT-Shiningtree JCT (Close EoL)	1	32	12,814
				Parry Sound TS: Component Replacement	1	14	4,913
				Main TS: T3, T4 & Component Replacements	1	26	7,309
				Tx Line Refurb. D1M/D2M/D3M/D4M | Otter Creek JCT-Minden TS (Close EoL)	1	4	17,814
				Tx Line Refurb. C28C, Complete Line, Chats Falls SS X Cherrywood TS Near EoL	1	4	17,814
				CIP-014 Implement Remaining 24 sites	1	54	-
				Steel Structure Coating Program	1	55	-
			Less than $3M		108	234	49,623,429
	3. System Service	Mandatory		Aylmer Tillsonburg Area Tranmission Reinforcement	1	29	-
				Customer Power Quality (Tx) - Capital - Cap Switcher	1	10	-
				East-West Tie Connection	1	102	-
				Kapuskasing area reinforcement - Kapuskasing TS	1	10	-
				Leamington Area Transmission Reinforcement	1	74	-
				Lennox 500kV Shunt Reactors	1	30	-
				Local Area Supply - Regional Plans	1	25	-
				M30A/M31A Conductor Upgrade	1	23	-
				Northwest Bulk Transmission Line Project - Construction	1	30	-
				Richview Manby Transmission Reinforcement -Station	1	7	-
				Southwest GTA Transmission Reinforcement	1	18	-
				St. Lawrence TS: Replace Phase shifters PS33/PS34	1	18	-
				Upgrade Barrie TS and Line E3/4B to 230 kV	1	69	-
				Watay Line_to_Pickle Lake Connection	1	26	-
			Less than $3M		21	32	-
			Less than $3M		1	0	-
	4. General Plant	Mandatory		Operating Hardware Refresh	1	6	1,244,481
				NMS Capital Sustainment	1	30	119,119
				Integrated System Operations Centre - New Facility Development	1	45	-
				IVCT Refresh	1	5	-
			Less than $3M		14	20	4,769,810
				SAP Foundation Phase 1 - HR/Pay - CAP	1	6	203,672
				SAP Foundation Phase 2 - Finance -CAP	1	7	287,872
				Local PSMC Network Sustainment	1	12	404,981
				Non-Operational Data Mgmt System New	1	16	25,420
				Transport and Work Equipment (TWE) Capital Requirements - Priority 2 - Heavy PTO	1	28	24,249
				Accomodations and Interior Fixtures and Equipment	1	14	4,020
				TS Facilities & Site Improvements	1	29	-
			Less than $3M		51	85	2,081,813
No Test Year Expenditures					122	-	5,924,415
Grand Total					**563**	**3,992**	**291,648,598**

UNDERTAKING J4.3

Reference:
SR-19 LakeheadTS & Nipigon JCT

Undertaking:
To advise if there are enhancements being made on any projects in anticipation of the potential of a corridor being built up to the Dryden TS.

Response:
There are no enhancements included in any of the System Renewal projects identified in this Transmission System Plan in anticipation of the Waasigan (Northwest Bulk) Transmission Line Project. As such, the System Renewal investments proposed on existing assets with this filing are not affecting that potential forward-looking project for which the variance account has been established.

Witness: Mark Brodie

UNDERTAKING J4.4

Reference:
GP-01 p. 32 and K-4.2, ISD-GP-18, p. 23 of 24

Undertaking:
To confirm the exchange rate data in GP-01, and advise whether a correction is needed.

Response:
The exchange rate shown on line 2 of ISD-GP-01, p.32 of 33 is shown as a rounded value of \$1.3 CAD, however the calculation was based on \$1.3366 CAD.[1] The exchange rate shown on line 2 of ISD-GP-18, p.23 of 24 is also shown as a rounded value of \$1.3 CAD, however the calculations was based on \$1.3310 CAD.[2]

As such, no correction is needed, on this particular point. However, on a related note in respect of this evidence, a correction is required to the calculation of the *Adjusted 2016 Industry Comparator Average Cost* value of \$996/ft^2 CAD on page 23 of 24 in ISD-GP-18, as follows:

The BC Transmission Corporation project is split into three values:

i. the actual project, and for further analysis, two sub-components were broken out;
ii. Control Centre (building only); and
iii. Backup Control Centre (building only).

There were only eight control facility projects (NYISO, AEP, ISO-New England, PG&E's three control centres, First Energy, and BC Transmission Corp) in the comparator table. The BC Transmission Corporation costs were calculated three times, when it should have only been the actual project costs of \$133M or \$1,310 CAD/ft^2 included in the weighted average calculation.

The corrected *Adjusted 2016 Industry Comparator Average Cost* for ISD-GP-18 is \$1,072 CAD/ft^2 as shown below.

[1] Bank of Canada Daily Exchange Rate, March 21, 2019, https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates-lookup/
[2] Ibid, March 31, 2017

$$\frac{\$950 + \$789 + \$742 + \$1,395 + \$1,582 + \$936 + \$874 + \$1,310}{8} = \$1,072\ CAD/ft\char`^2$$

This was corrected in the table in EB-2019-0082, ISD-GP-01, p.32 by utilizing only the full project cost of the BC Transmission Corporation project of $133M when calculating the overall average cost of the eight control facility projects, resulting in the **2018 cost of $1,141 CAD/ft^2**, a 6% increase after readjusting for inflation. This table featured industry comparator projects which were placed into service pre-2015.

Using the pre-2015 dataset from ISD-GP-01, the analysis demonstrates that the estimated cost of the ISOC of $1,266 CAD/ft^2 is comparable[3] with the average cost of $1,141 CAD/ft^2 for facilities evaluated in the study. The marginally higher cost/ft^2 is primarily due to the impact of new foreign tariffs and market pressures for labour resources (e.g. a 20% increase to the cost of steel, a 25% increase to the cost of labour, and a 30% increase to the cost of rebar).

[3] In J-4.05, Attachment 1, Hydro One provided the Board of Directors' approved business case. The business case had a lower total cost, the reason for which is explained in the undertaking, and therefore a lower cost of $1,224 per sq. ft. is presented in the business case.

Further and by way of update to provide a more recent comparison of industry comparator costs, we have updated below the industry comparator table (relative to the table at ISD-GP-01, Appendix B, p.32). This includes investments in facilities and data centre development projects constructed after 2015.[4] The costs associated with these projects are more current than the ones included at ISD-GP-01and thus provide a more useful comparison to the ISOC costs. Updating the industry comparator table for post-2015 projects, results in a *2018 Industry Comparator Average Cost* of $2,215 CAD/ft^2 as shown below (in comparison to the estimated cost of the ISOC, which is $1,266 CAD/ft^2).

Industry Comparator	**Cost ($M)**	**Size (ft^2)**	**Year Built**	**Adj. Cost to 2018 $ (CPI)**	**Cost (2018 $/ft^2)**
Project 1	191.6	167,000	2017	197.2	1,181
Project 2	184.0	115,000	2019	184.0	1,600
Project 3	46.5	35,833	2016	48.3	1,348
Project 4	75.8	51,000	2015	80.0	1,569
Project 5	345	175,000	Construction Underway	345	1,971
Project 6	250.4	110,000	2018	250.4	2,276
Average Cost, USD					**1,658**
Average Cost, CAD[5]					**2,215**
Proposed ISOC Cost Comparison	**159.8**	**126,200**	**2021**	**159.8**	**1,266**

[4] Costs have been provided to Hydro One on an anonymized basis.
[5] Using the $1.3366 CAD exchange rate used in ISD-GP-01.

UNDERTAKING J4.5

Reference:
GP-01

Undertaking:
To provide the approved business case for the ISOC.

Response:
Attachment 1 of this undertaking provides the business case for the ISOC, as approved by Hydro One's Board of Directors.

Witness: Godfrey Holder

Integrated System Operating Centre: New Facility Development

Overview of Recommended Alternative:

Request for full approval of $154.5M to begin construction and complete the final phase of the new Integrated System Operating Centre (ISOC) in the City of Orillia. This total includes $18.5 million of expenditures previously approved for the needs assessment, engineering design, and land acquisition.

Investment Details:

In-service: Multiple I/S in 2021

The entire Hydro One transmission grid and major distribution assets are monitored and controlled 24/7 from the Ontario Grid Control Centre (OGCC) located in Barrie, Ontario with a Backup Control Center (BUCC) located within the Richview Transformer Station near Pearson International Airport. The current state of the OGCC and BUCC facilities could result in a loss of grid monitoring and controlling capability which could impact public and employee safety and cause widespread transmission grid outages impacting the whole province and neighbouring interconnected transmission systems in Canada and the United States. Prolonged unavailability of the OGCC would inhibit Hydro One's ability to deliver its T&D capital and maintenance programs and lessens the quality of customer outage communications.

In 2003, the OGCC was built to replace and centralize the thirteen (13) T&D operating centres. At the same time the BUCC was established at the Richview Transformer Station, built in 1956, to meet the minimum backup control centre requirements at that time. This investment will allow the ISOC to be the primary control centre for Hydro One and the existing OGCC will be converted into the new backup, replacing the existing Richview BUCC.

The OGCC facility has a high risk of a prolonged forced evacuation due to the following issues:

- A broken and leaking sewage pipe under the control room that requires regular vacuuming and will require an extended control room evacuation for repair.
- The data centre is approaching critical cooling limits during the summer which could trigger a shutdown.
- Cooling loop and heat rejection risks due to shared infrastructure; a single point of failure on the HVAC system requiring an extended shutdown to remediate.

The above OGCC issues will be remediated under separate investments and may only be completed once the ISOC is in serviced.

The BUCC facility also has a series of issues that prevent it from being used for a prolonged period of time if the OGCC is evacuated. The BUCC is an adaptation of rooms at a transmission station, not designed or intended for grid control use. In addition, Richview TS is a single point vulnerability for the overall Hydro One telecommunication network that is instrumental for T&D grid monitor and control. In 2013 the BUCC data centre and telecommunication network equipment rooms flooded, breaking the telecommunication link between both control facilities and grid assets, resulting in an extended outage to over 1,000,000 Hydro One and LDC customers. The current BUCC data centre facility is capacity constrained and no longer mirrors that of the OGCC data center. In the event of activation, the BUCC cannot deliver the same functionality as the OGCC. The BUCC also has office space constraint that will not be able to accommodate the required staffing level from support functions such as Operating Technology Operations, Operating Planning, and Operating Engineering in support of the real-time control room operations.

NERC Mandatory Reliability Standard for Emergency Operations Planning "Loss of Control Centre Functionality" is a set of requirements that are designed to "ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable". It specifically describes the timing requirement for the full activation of the backup control center as follows: "A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours." This requirement is ranked as "Severe" on the NERC Violation Severity Levels scale which has a financial penalty of up to $1M per day for a non-compliance. In addition, the IESO Market Rules list the BUCC as one of the key facilities to the Ontario Basic Minimum Power System which is required to maintain minimum operating reliability of the Ontario electric grid.

Population and business growth in the area has created external factor challenges at BUCC beyond the ability of Hydro One to remediate. BUCC activation testing conducted in recent years in the early hours of a Saturday morning recorded full-activation time at just under 2 hours. In addition to the non-compliance risks there are external factors driving additional risks beyond Hydro One's ability to mitigate:

- Adjacent to the BUCC building is a multi-level self-storage facility, a situation rated as a high security risk.
- The BUCC is accessible by a single secondary street which has been in the past rendered inaccessible by emergencies in the area.
- In proximity to the BUCC is the main aviation fuel pipeline for the Pearson Airport.
- A Pearson Airport flight path goes over the property.

The Integrated Telecommunications Management Centre (ITMC), currently located in the same building as the BUCC in Richview TS, is a critical 24/7 operating center for Hydro One's telecommunication network to ensure that the telecommunication network is functioning to facilitate monitoring and control of the electric grid. The current Backup Integrated Telecommunications Management Centre (BUITMC), located in Detweiler TS and in-serviced in 1950, is a temporary single shared room, requires extensive technical setup for activation, cannot accommodate all necessary operating staff, and does not meet necessary security requirements. This adds further risk to grid monitoring and control.

Hydro One Security Operations is reliant on a single external third party for primary and backup physical security monitoring services. Having internal control of all security management software and servers, via the Security Operations Centre at ISOC, would improve security management performance and reduce the risk of NERC Critical Infrastructure Protection standards non-compliance with clearer accountability on risk assessment, operational controls and compliance management. Furthermore, recent trends indicate more stringent NERC security requirements are likely, which will result in material escalation of third party security expenditures. Consolidating the Security Operations Centre within ISOC and supplying this service in-house will allow Hydro One to better control these costs and potential cost escalation, which will partially offset the capital costs of this component allocated to the ratepayer.

In the 2018-2022 Dx Rate Filing Hydro One filed with the OEB the above operational risks and challenges. In its decision the OEB directed Hydro One to setup an asymmetric variance account to be offset by the revenue requirement at the actual cost for the ISOC. Hydro One has also filed a similar ISOC justification in the 2020-2022 transmission rate application, currently before the OEB.

This ISOC investment, as filed with the OEB, will build the Integrated System Operating Centre (ISOC), to accommodate the following functions:

- Primary Transmission and Distribution Operating Control Centre;
- Backup Integrated Telecommunication Management Centre (BUITMC);
- Security Operations Centre;
- General back office areas; and
- Integrated Data Centre to support the above functionalities.

After the 2013 GTA flood, Hydro One conducted a planning needs assessment and determined that it was prudent to replace the BUCC and build a new BUITMC. It was also determined that building a new integrated facility to house security operations and telecommunications operations would offer improved operational effectiveness and synergies for Hydro One. The location assessment was initiated and it considered various alternatives including building on a new site, leasing a suitable site, acquiring and retrofitting an existing facility, and building a new facility on an existing Hydro One owned site. The assessment concluded that no leasing site was available. Of all the viable site alternatives studied, the preferred alternative was to build a new facility at an Orillia site.

Orillia was chosen over other municipalities, because of its ideal proximity to the OGCC and accessibility via multiple highway routes and access roads. Local development fees have been waived. The land acquisition costs were materially less expensive compared to other available sites within the two (2) hour mandated full activation limit, and the site is already serviced with municipal water and other utilities.

The final phase of this investment consists of the following:

- The contract awarded for a full-service general contractor to build the ISOC, hardened to withstand EF3 Tornado wind, on the 16.57 acres Orillia site, that was acquired in the Development Phase. The ISOC will have a gross floor area of 126,200 square feet. The two-storey building will consist of control rooms, data centre space, and common office space. The ISOC office area has been designed for higher employee workspace density when compared to the OGCC setup;
- Construct new circuits to connect the ISOC to the existing Hydro One Telecommunication System, resolving the existing telecom network single point vulnerability issue;
- Construct and configure the distribution system to provide multiple redundant utility power services to the site;
- Complete the Operations Technology/Information Technology infrastructure servicing the ISOC;
- Provision of furnishing throughout the ISOC facility; and
- Facility designed for future enhancements which will provide scalability to continue expanding Hydro One’s future operating capabilities in Advance Metering Infrastructure operation, Distribution Automation, grid asset condition monitoring and diagnostics to extend asset lifecycle as technology matures.

The ISOC will satisfy all safety-related and emergency preparedness requirements for both physical and cyber security. This investment is essential in maintaining adequate redundancy for operation of the T&D grid and the Telecommunication Network as mandated by NERC Emergency Operations Planning standards and Critical Infrastructure Protection standards, and the IESO Market Rules.

Architect rendering of ISOC.

Benefits:

The ISOC provides for the follow benefits:

1) **Mitigate current operation challenges:** Provide a facility capable of long-term BES operation, designed to address emergency preparedness, and technical and business continuity challenges that currently exist at the OGCC, BUCC and BUITMC. Furthermore, will allow Hydro One to address current OGCC deficiencies with minimal disruption to real-time BES operations.

2) **Improve real-time capabilities to increase reliability and efficiency:** Allows for enhanced collaboration between System Operations, telecommunication, security operations, Smart Meter Infrastructure operations, Distribution Automation, and asset condition monitoring and diagnostics, realizing real-time operational effectiveness and synergies.

3) **Compliance with Regulatory Requirements:** The new ISOC will improve Hydro One's ability to maintain compliance with existing and future IESO Market Rules requirements, NERC Reliability Standards requirements and Hydro One's Reliability Standards.

4) **Increase Physical Security Protection with cost reduction:** The Security Operations Centre at the ISOC will allow for better cost management, proactive monitoring of critical facilities and additional operational synergies from being in a single location.

Estimated Costs & In-service:

This is a multi-year project with expenditures planned to 2021. The asset will be placed in-service as each project component is completed. This Investment is included in the Board approved 2019-2024 Business Plan with total funding of $159.8M. The total cost breakdown is as follows:

Category	Cost ($M)
Total Development Phase*	$11.2
Construction Phase:	
General Contractor Construction **	$91.9
Telecommunication and Dual Power	$9.7
Data Centre and other IT equipment	$9.1
Furnishing	$3.6
Project Management and Commissioning	$1.4
Contingency	$6.7
Decommissioning of BUCC	$0.5
Interest and Overhead	$20.4
Total Project Cost	$154.5

**While $18.5M had previously been approved for the Development Phases, the actual/forecasted cost is $11.2M. This is due to the negotiated Detailed Engineering Design cost reductions and deferral to construction phase to the IT Proof of Concept work.*

***$78.5M of the General Contractor Construction category is comprised of a fixed-price contract following a competitive multi-staged procurement, based on complete and comprehensive owner's requirements, with multiple proponent submissions .*

The underlying project definition work has been completed to a Class 2 level in accordance with the Association for Advancement of Cost Engineering, and based on the work completed on this project the cost estimate has a range of outcomes between -4% and +6%, and an expected cost of $154.5M. The estimate range is based on a sensitivity analysis performed on each of the cost categories, taking into account both potential risk and saving opportunities. The contingency is based on a project risk review workshop and allocates $6.7M, 4.7% of the remaining project costs, to cover known-unknowns and allowance deviation in procurement, construction, and commissioning costs during execution from the original owner's requirements and design.

After the ISOC is commissioned, the annual OM&A cost will be $3.4M, which includes facilities, Operations Technology/Information Technology and telecommunication maintenance. For the first 18 months of ISOC operations, there would also be $6.6M incremental charges related to employee relocation of System Operations staff to the ISOC and OGCC

The OM&A savings with the ISOC in service are;

- End of Barrie external data centre lease, $700k per year.
- The following existing office space will no longer be required. These opportunities will be operationalized in the Real Estate Optimization Strategy which can be repurposed for office space;
  - Approximately 50 workstations at the leased Barrie Corporate Office (BCO).
  - 2,000 square feet of training room space at the leased BCO.
  - 8,800 square feet of space (control room + office space) at the Richview TS.

Hydro One has conducted a benchmarking cost comparison to other utilities' new control centre builds in North America. The total ISOC cost, including fitting out, is $1,224 per sq ft. This cost is in-line with other control centre build costs ranging from $783 per sq ft to $1,669 per sq ft. Costs are affected by data centre (i.e. Uptime Tier Institute level) design, building structure (based on local weather history), environmental impact considerations, site servicing needs, and employee relocation impacts. The 2003 Hydro One OGCC build cost was $2,271 per sq ft (after inflation adjustments), as poor soil quality at the site increased the foundation requirements. Leveraging the lessons learned from the OGCC, Hydro One and the engineering consultants have completed advance testing and staking work to proactively mitigate issues with the ISOC build. The Altus Group 2018 Canadian construction cost guide shows Tier 3 data centre facilities with extensive redundancies in the infrastructure to be at $1,000/square feet before fitting out.

Hydro One Telecom will lease 4% of the space in the ISOC facility to provide for a BUITMC. Hydro One Telecom will be required to pay lease payments to Hydro One Networks Inc. in accordance with the OEB's Affiliate Relationship Code. The lease payments will include a component of the required return of capital and incremental OM&A of the facility and will reduce the revenue requirement impact of the new facility to rate payers.

Other Alternatives Considered

Alternative 1: Status Quo / Use Offsite Leased Space

This alternative is to lease space for office for support staff, data centre and BUITMC, to mitigate the data centre flood risk and to accommodate space requirements for support staff but does not address any of the other identified risks. The total cost of this alternative is estimated to be $83.1M, or 54% of the requested capital while leaving numerous risks unresolved (e.g. risk to NERC mandatory reliability standards non-compliance, single point of failure of telecommunications system, single access road, hazards associated with a Transformer Station, fuel pipeline, flight path). Therefore, this alternative was rejected.

Alternative 2: Build a modified version of ISOC on the preferred Orillia Site

This alternative would build a smaller facility in Orillia excluding Backup Telecom Control Centre and/or Security Operations Centre. There are multiple build configurations which were considered as alternatives to the recommended facility:

1. Removing the Backup Telecom Control Centre (reduction of $21.1M), and/or
2. Removing the Security Operation Centre(reduction of $11M),

Depending on which scenario(s) are selected, the estimate for these alternatives ranges from $122.4M to $143.5M. These alternatives were rejected as they do not address risks identified with ITMC (equipment room flood risk and single point of failure for the telecommunication network) and BUITMC (activation concerns) and do not create the operational effectiveness and synergies with Security Operation Centre colocation.

Alternative 3: Acquire an existing facility or use Hydro One owned sites

While Hydro One considered using existing sites or leasing a facility for the ISOC, there were no feasible facilities available for lease in the geographic zone that will satisfy the NERC backup activation requirements.

Regulatory Considerations

This common capital investment was included in the 2018 to 2022 distribution rate application (EB-2017-0049) at a cost of $138.4M. The updated estimate of $154.4M was included in the 2020-2022 transmission rate application (EB-2019-0082). The new ISOC is currently scheduled for completion in 2021 which will result in an estimated total addition to rate base of $154.4M, with 50.07% being allocated to distribution rate base and 49.93% to transmission rate base.

Current estimated project costs are $154.4 million which is $16.1 million more than the total estimated cost included in the recent distribution rate application (EB-2017-0049) for the 2018 to 2022 period.

On March 7, 2019 the OEB issued its Decision on Hydro One’s 2018-2022 distribution rate application and directed Hydro One to create an asymmetric variance account to track the actual cost of the distribution portion of the ISOC against the forecast total cost of $69.3 million[1]. The basis for this amount was the estimated total addition to rate base in the distribution rate

[1] As filed in I-29-Staff-173 and I-29-Staff-173, Attachment 1

application of $138.4M, with 50.07% or $69.3M allocated to distribution rate base and 49.93% or $69.1M allocated to transmission rate base. If the revenue requirement at the actual cost is lower than the revenue requirement at the forecast cost, Hydro One will be required to return the difference to its customers. Therefore, in an extraordinary scenario where Hydro One does not build the ISOC, the revenue requirement portion associated with the distribution-allocated cost of $69.3 million would have to be returned to rate payers.

As part of the Draft Rate Order filed on April 5, 2019, Hydro One was directed to file an accounting order for the variance account. The balance in the account will be considered for disposition during the next rebasing application.

If at the time that the ISOC is deemed to be in-service, the distribution portion of the total costs exceeds $69.3 million, the revenue requirement portion associated with the excess will not be immediately recoverable in rates. At rebasing, there will be an opportunity for Hydro One to request recovery of the excess amount, however any such request will be subject to a prudence review and recovery is not guaranteed.

Based on the OEB's Decision on Hydro One's 2018-2022 distribution rate application, there is a strong likelihood that Hydro One will be directed to implement a similar asymmetric variance account as part of the 2020-2022 transmission rate application (EB-2019-0082), to account for the transmission-allocated cost of the ISOC.

Due to the nature of the asymmetric variance account, any cost-savings or under-spending associated with the ISOC, as realized through value engineering or other initiatives, cannot be used in re-direction. These cost-savings or under-spending must be brought forward as cost reductions in future updates or rate applications.

Hydro One Telecom will lease the ITMC portion of the ISOC. The lease costs will be subject to an Affiliate Agreement, allocated using OEB-approved methodology and compliant with the Affiliate Relationship Code. Lease revenues will reduce the revenue requirement for the facility collected from Hydro One Transmission and Distribution ratepayers.

Risks and Mitigation

Regulatory Risks (Medium Risk) – If the ISOC is not built, the revenue requirement portion associated with the distribution-allocated cost of $69.3 million has to be returned to rate payers. In addition, the revenue requirement portion associated with the transmission-allocated cost of $79.8 million will likely also have to be returned to rate payers, assuming that the OEB institutes a similar asymmetric variance account for transmission. This risk can be mitigated by proceeding with the construction of the ISOC.

Regulatory Risk (Low Risk) - Amounts in excess of the distribution-allocated cost of $69.3 million will be subject to a prudence review and must be applied for recovery in future applications. As discussed earlier, it is likely that the OEB will create a similar account under transmission, which would then require a similar treatment, i.e. any amounts in excess of $79.8 million would be subject to a prudence review and must be applied for recovery in future applications. This risk can be mitigated by working within the distribution and transmission-allocated rate base amounts as filed with the OEB, and noted above.

Technology Changes (Low-to-Medium Risk) – This risk is assessed as low-to-medium as there has been rapid technology advances in the Data Centre and computer industry. Design and estimates have been based on current available technology. Final device and material selection will be based on cost, performance, and lifecycles consideration. Part of the data centre technological design has been deferred to maximize flexibility and allow for best selection of technology while avoiding redesign costs.

First Nations (Low Risk) – As part of the site selection process, First Nation risks were considered. The preferred Orillia site was selected in part as there are no First Nations claims/issues anticipated.

This Approval ($M): $136.0	**Previous Approval ($M):** $18.5	**Total Approval ($M):** $154.5
Signature Block:		
Approved by: Darlene Bradley	**Title:** Acting Chief Operating Officer	**Date:** July 23, 2019
Approved by: Chris Lopez	**Title:** Chief Financial Officer	**Date:** July 23, 2019
Approved by: Mark Poweska	**Title:** President & Chief Executive Officer	**Date:** August 1, 2019
Approved by:	**Title:** Board of Directors Advice	**Date:**

Appendix: Required information for SAP data input

Yearly Expenditures ($M)	2015-2018	2019	2020	2021	Total
Capital* and MFA	11.3	57.1	64.5	21.1	154.0
Removals*	-	-	-	0.5	0.5
OM&A	-	-	-	-	-
Gross Investment Cost*	**11.3**	**57.1**	**64.5**	**21.6**	**154.5**
Recoverable	-	-	-	-	-
Net Investment Cost	**11.3**	**57.1**	**64.5**	**21.6**	**154.5**

**Includes capitalized interest and overhead at current rates*

Rate base additions ($M)	2015-2018	2019	2020	2021	Total
2018 – 2022 Dx Rate Filing	-	-	69.3	-	69.3
2020 – 2022 Tx Rate Filing	-	-	-	79.8	79.8
Total Rate Filing	**-**	**-**	**69.3**	**79.8**	**149.1**
Business Case (As Per Estimate)	-	-	-	154.0	154.0
Variance	**-**	**-**	**69.3**	**(74.2)**	**(4.9)**

Rate base additions ($M)	2015-2018	2019	2020	2021	Total
2019 – 2024 BP	-	-	-	159.8	159.8
Business Case (As Per Estimate)	-	-	-	154.0	154.0
Redirection Available	**-**	**-**	**-**	**5.8**	**5.8**

In-service Date:	Multiple I/S in 2021
Business Case Summary #:	51001897
Appropriation Request #:	23555
Subject ID #	80830
Investment Driver:	N.C.C.3.01
Investment Summary Document	GP18 and GP1
Redirection Required?	No
Supporting Documents: 1. Estimate 2. Investment Planning Scorecard 3. Risk Assessment Questionnaire	ISOC Full Estimate
Director	Godfrey Holder
Planner	Daniel Lam

Scientific Research & Experimental Development Tax Credits (SR&ED):

- Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

UNDERTAKING J4.6

Reference:
GP-01

Undertaking:
To confirm that the amount being sought for approval in this application for the ISOC – the revenue requirement and in-service addition – is not based on the transmission-allocated portion of $159.8 million.

Response:
In this application, the total cost for the ISOC is $159.8 million as shown on p.28 of ISD-GP-01. The transmission-allocated portion of this total cost being sought for recovery in this application is $79.8 million or 49.93%, which will be recognized as a transmission in-service addition in 2021 and which is reflected in the proposed 2021 and 2022 revenue requirements as part of the test year rate base.

The total cost for the ISOC as shown in the Hydro One Board of Directors approved business case filed in undertaking response J-4.05, Attachment 1 is $154.5 million. ISD-GP-01 was filed on March 21, 2019 and the business case was approved on August 16, 2019. The total cost savings of approximately $5.3 million during this period was achieved primarily through value engineering – the transmission-allocated portion of the total cost savings is approximately $2.7 million.

Hydro One will update the transmission-allocated costs and hence the revenue requirement and in-service addition being sought for recovery in this application to reflect the lower Hydro One Board of Directors approved business case total cost as part of the Draft Rate Order process in this application.

UNDERTAKING J4.7

Reference:

Undertaking:

To produce a list of material ISDs from the last proceeding and what the forecast was, and the new forecast for those going into service in this term.

Response:

The table below lists project ISDs from the 2017-2018 transmission application with a net project total >$20M and the subsequent values for those projects in the 2020-2024 transmission application. At an aggregate level, the net project total for projects in the 2020-2024 transmission application is 7% higher than in the 2017-2018 transmission application, which is to be expected as projects transition over time from a planning stage to an execution stage and have more refined and detailed cost estimates. Some projects in the 2017-2018 transmission application will be substantially complete and are therefore not included in the 2020-2024 transmission application; in those cases the latest cost forecast has been provided in the 2020-2024 transmission application column.

17/18 ISD	20/24 ISD	17/18 ISD Description	2017 - 2018 Filing			2020 - 2024 Filing		
			Project Phase	Net Project Total ($M)	In-Service Year	Project Phase	Net Project Total ($M)	In-Service Year
D01	N/A	Clarington TS: Build new 500/230kV Station	Execution	280.7	2018	Substantially Complete	242.3	2019
D03	SS-06	M30A/M31A Conductor Upgrade	Planning	20.0	2020	Planning	24.1	2022
D04	SS-04	East-West Tie - Station Expansion	Planning	166.1	2020	Planning	155.0	2022
D05	SS-07	Milton TS and 230kV Lines	Planning	250.1	2022	Planning	238.5	2024
D07	N/A	York Region – Increase Transmission Capability for B82V/B83V Circuits	Execution	31.8	2017	Substantially Complete	35.4	2017
D11	SS-14	Southwest GTA Transmission Reinforcement	Planning	30.0	2020	Planning	20.6	2022
D12	SS-09	Upgrade Barrie TS and Line E3/4B to 230	Planning	80.0	2020	Planning	83.2	2020
D14	N/A	Supply to Essex County Transmission Reinforcement	Planning	50.4	2018	Substantially Complete	52.0	2018
D19	N/A	Runnymede TS -115-28kV Station - plus KxW upgrades	Planning	25.2	2019	Substantially Complete	0.3	2018
O01	GP-01	Integrated System Operations Centre - New Facility	Planning	137.4	2020	Planning	159.8	2021
S01	SR-01	Air Blast Circuit Breaker Repalcement - Beck #1 SS	Planning	24.1	2019	Planning	30.7	2026
S02	SR-01	Air Blast Circuit Breaker Replacement - Beck #2 TS	Execution	90.7	2021	Execution	110.2	2022
S03	SR-01	Air Blast Circuit Breaker Replacement - Bruce A TS	Execution	104.9	2019	Execution	111.2	2020
S04	SR-01	Air Blast Circuit Breaker Replacement - Bruce B SS	Planning	65.2	2020	Planning	85.5	2024
S05	SR-01	Air Blast Circuit Breaker Repalcement - Cherrywood TS	Planning	60.6	2020	Execution	88.9	2023
S06	SR-01	Air Blast Circuit Breaker Repalcement - Lennox TS	Execution	83.7	2020	Execution	88.1	2023
S07	SR-01	Air Blast Circuit Breaker Replacement - Richview TS	Execution	95.5	2018	Execution	94.9	2020
S08	N/A	Integrated Station Component Replacements - Beach TS	Execution	76.5	2019	Execution	70.5	2019
S09	N/A	Integrated DESN Investments - Centralia TS	Execution	20.7	2018	Substantially Complete	31.7	2018
S10	N/A	Integrated Station Component Replacements - Dryden TS	Execution	31.0	2017	Substantially Complete	31.5	2018
S11	SR-02	Power Transformer Replacements	Execution	58.2	2019	Execution	68.9	2020
S12	N/A	Integrated DESN Replacement - Espanola TS	Execution	24.9	2016	Substantially Complete	28.8	2017
S13	N/A	End of Life Station Reconfiguration - Gage TS	Planning	36.0	2019	Planning	50.4	2021
S15	N/A	London Nelson TS	Execution	22.5	2019	Execution	25.0	2021
S16	N/A	Station Re-Investment - Palmerston TS	Planning	25.1	2018	Execution	30.7	2019
S17	N/A	Wanstead TS	Planning	28.5	2018	Substantially Complete	27.1	2018
S18	N/A	Station Re-Investment - Alexander SS	Planning	24.0	2018	Execution	21.2	2020
S19	N/A	Integrated Station Component Replacements - Allanburg TS	Execution	32.8	2018	Substantially Complete	50.9	2018
S20	N/A	Integrated DESN Investments - Aylmer TS	Execution	23.4	2017	Substantially Complete	23.1	2017
S22	N/A	Station Re-Investment - Birch TS	Planning	30.5	2019	Execution	32.2	2019
S23	N/A	Station Re-Investment - Bronte TS	Planning	33.1	2019	Execution	28.5	2019
S24	SR-05	Bridgman TS Reinvestment	Planning	39.9	2022	Planning	33.8	2023
S25	N/A	Buchanan TS BULK	Execution	29.7	2017	Substantially Complete	28.3	2017
S30	N/A	Station Re-Investment - Dufferin TS	Planning	21.7	2019	Execution	27.1	2019
S33	SR-02	Station Re-Investment - Hanmer TS	Execution	63.5	2019	Execution	77.4	2020
S34	SR-05	Integrated Station Component Replacements - Hawthorne TS	Execution	27.0	2019	Execution	41.2	2020
S35	N/A	Station Re-Investment - Horning TS	Planning	36.6	2018	Substantially Complete	39.2	2018
S36	N/A	Station Re-Investment - Leaside TS	Execution	31.1	2018	Execution	46.0	2019
S37	SR-06	Integrated DESN Replacement - Leaside TS	Planning	21.1	2019	Execution	35.7	2020
S38	SR-05	Station Re-Investment - Main TS	Planning	24.8	2019	Planning	29.8	2021
S40	SR-02	Station Re-Investment - Martindale TS	Planning	64.7	2020	Execution	71.8	2021
S43	N/A	Integrated DESN Replacement – National Research Council TS	Execution	30.8	2017	Execution	36.5	2019
S45	N/A	Richview TS	Execution	25.1	2017	Substantially Complete	27.2	2018
S46	SR-02	Sheppard TS	Planning	28.1	2019	Execution	40.9	2020
S47	N/A	Station Re-Investment - St. Isidore TS	Execution	26.1	2017	Execution	32.8	2019
S48	SR-05	Stanley TS; Station Centric Investment	Planning	24.5	2020	Planning	33.5	2021
S55	SR-11	SONET Systems Replacement	Planning	111.9	2024	Planning	119.3	2024
S62	N/A	Line Refurbishment - C22J/C24Z/C21J/C23Z	Execution	47.3	2018	Substantially Complete	34.4	2017
S63	N/A	Line Refurbishment - D2L - Dymond TS x Upper Notch Jct and Martin River Jct x Crystal Falls SS	Execution	31.6	2017	Substantially Complete	33.0	2019
S65	SR-19	Line Refurbishment - N21W/N22W	Planning	23.6	2019	Execution	27.7	2019
S67	SR-19	Line Refurbishment - D2L - Upper Notch Jct x Martin River Jct	Planning	43.2	2019	Execution	28.3	2019
S70	SR-19	Tx Line Refurb. A7L/R1LB & 57M1	Planning	69.1	2021	Planning	76.9	2022
S72	SR-19	Tx Line Refurb. E1C	Planning	39.2	2020	Planning	52.0	2024
S74	SR-19	Tx Line Refurb. D2H/D3H	Planning	25.9	2019	Planning	36.0	2022
S83	N/A	H7L/H11L Cable Replacement	Planning	25.3	2018	Execution	39.3	2019
				2,975.5			**3,188.9**	

Note: Cancelled projects have been excluded from the above table.

UNDERTAKING J4.8

Reference:
I-07-SEC-55
Oral Hearing Volume 4, Page 120, Line 20 – Page 2, Line 5
Oral Hearing Volume 4, Page 131, Line 2 – Page 132, Line 2

Undertaking:
On a best-efforts basis, to look at the 5.5-million-dollar OM&A reduction to classify it into categories

Response:
This undertaking was satisfied on the record. Please see below:

Oral Hearing Volume 4, Page 120, Line 20 – Page 2, Line 5

MR. DUMKA: Okay. So looking at this table, which has assorted adjustments, the pension reduction OM&A, the OPEB reduction OM&A, et cetera, where, amongst all of these values -- perhaps it is the very first one, the Mercer median TX OM&A figure -- where would the increased pension contribution cost in the rate year be reflected? Is there any specific adjustment for that?

[Witness panel confers]

MR. JODOIN: Our understanding is that would be included, correct, in the 5.5 pension reduction that you have outlined. But not only that. I know you have it on the next page, but we have actually updated that recently and have provided an updated pension reduction on, I guess, page 14 of your compendium, right at the top. So those two line items.

MR. DUMKA: Okay. So basically what you're telling me, by making these adjustments, they were not baked into the compensation cost for 2020, because you have to make these adjustments. Is that what we're seeing? Or are you saying -- maybe I have misinterpreted -- that in the 5.5 million, for example, you're saying a chunk of that is increased employee pension contributions?

[Witness panel confers]

MR. CHHELAVDA: So perhaps I can try to answer the question. I mean, there probably are multiple factors that would give rise to the reductions. So one would be -- one would be the increased employee contributions, and there would be other factors as well. It would be part of the reasons for the reduction.

Does that answer your question?

MR. DUMKA: Okay. So basically you are confirming that the increased employee pension contributions are reflected in the pension reduction OM&A figure of 5.5 million? Is that what you're saying? It is completely captured in there?

MR. CHHELAVDA: That is our understanding, yes.

MR. DUMKA: Okay. Unless you want to take an undertaking to confirm. I realize you spent a bit of time discussing it.

[Witness panel confers]

MR. CHHELAVDA: So on a best efforts basis, we will look at the 5.5 million OM&A reduction and try to classify it into categories, like what's causing the 5.5 million.

MS. DJURDJEVIC: We will make that undertaking J4.8.

UNDERTAKING NO. J4.8: ON A BEST-EFFORTS BASIS, TO LOOK AT THE 5.5-MILLION-DOLLAR OM&A REDUCTION TO CLASSIFY IT INTO CATEGORIES

<u>Oral Hearing Volume 4, Page 131, Line 2 – Page 132, Line 2</u>

MR. DUMKA: Right. So this is just like -- the 10 million is just the transmission OM&A, as opposed to the overall reductions in Hydro One compensation to bring it to market median.

So my question is, if I look at it, the $10 million reduction in OM&A takes into account that in 2017 employee pension contributions were lower.

So I just want to clarify, then, that the pension reduction that we see, I think it is -- I should open up SEC 55. I think it is about $5 million, is the first --

MR. JODOIN: 5.5 million.

MR. DUMKA: 5.5 million. So are we saying, then, that the 5.5 million reduction for pension takes into account the increased employee pension contributions? Is that what we're seeing? Is that what the inference is of that?

MR. CHHELAVDA: Yes. So it would be included in that 5.5.

MR. DUMKA: So it is definitely in there.

MR. CHHELAVDA: Yes.

MR. DUMKA: Okay, thanks.

MR. JODOIN: Does that satisfy the need and we no longer have to produce the undertaking that we agreed to? Just so that we're clear.

MR. DUMKA: Yes. If you're confident that the -- that that reduction is there or the impact of the employee pension contributions going up is reflected in the 5.5, that's fine.

MR. JODOIN: Fair enough.

MR. DUMKA: Yes, thanks.

UNDERTAKING J4.9

Reference:

I-07-SEC-58

Oral Hearing Volume 4, Page 132, Line 26 – Page 136, Line 15

Undertaking:

To update the chart (payroll table) at exhibit K4.5, page 4, to reflect the pension valuation update.

Response:

Please refer to attachment 1 to this undertaking, provided in an Excel format.

Attachment 1 includes the updated payroll table from Exhibit I, Tab 07, Schedule SEC-58 Attachment 1 including:

1. the impact of the updated pension valuation as of December 31, 2018; and

2. the allocation percentages between the Transmission and Distribution, OM&A and Capital, as further explained in J5.5.

Witness: Sabrin Lila

UNDERTAKING J4.10

Reference:

F-4-1

Oral Hearing Volume 4, Page 164, Line 23 – Page 166, Line 4

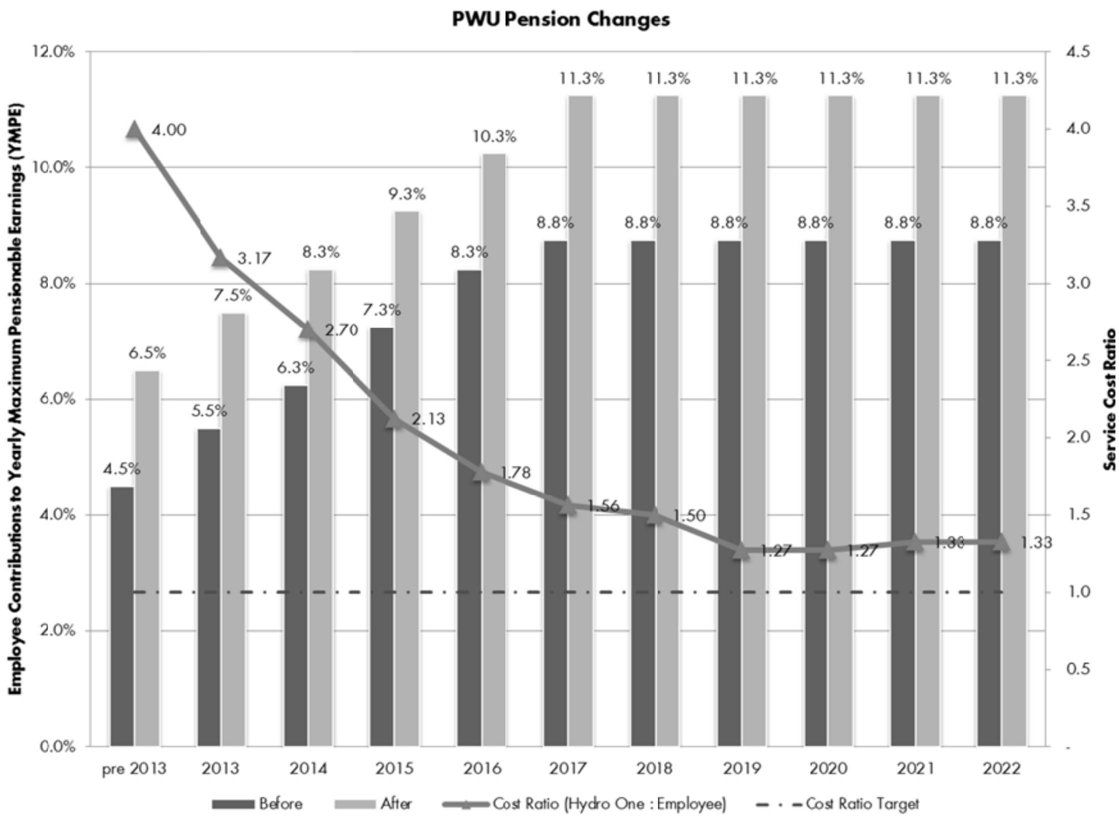
Undertaking:

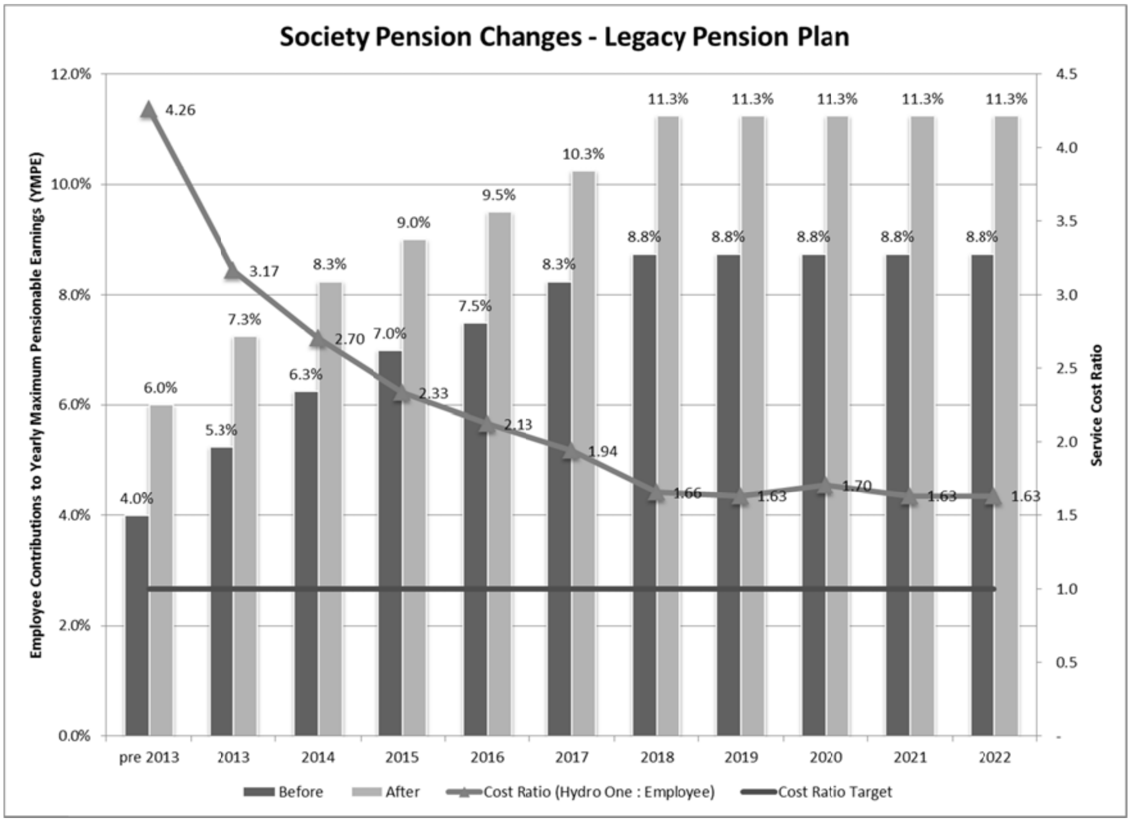
To update the employee pension contributions charts based on December 31, 2018 pension valuation.

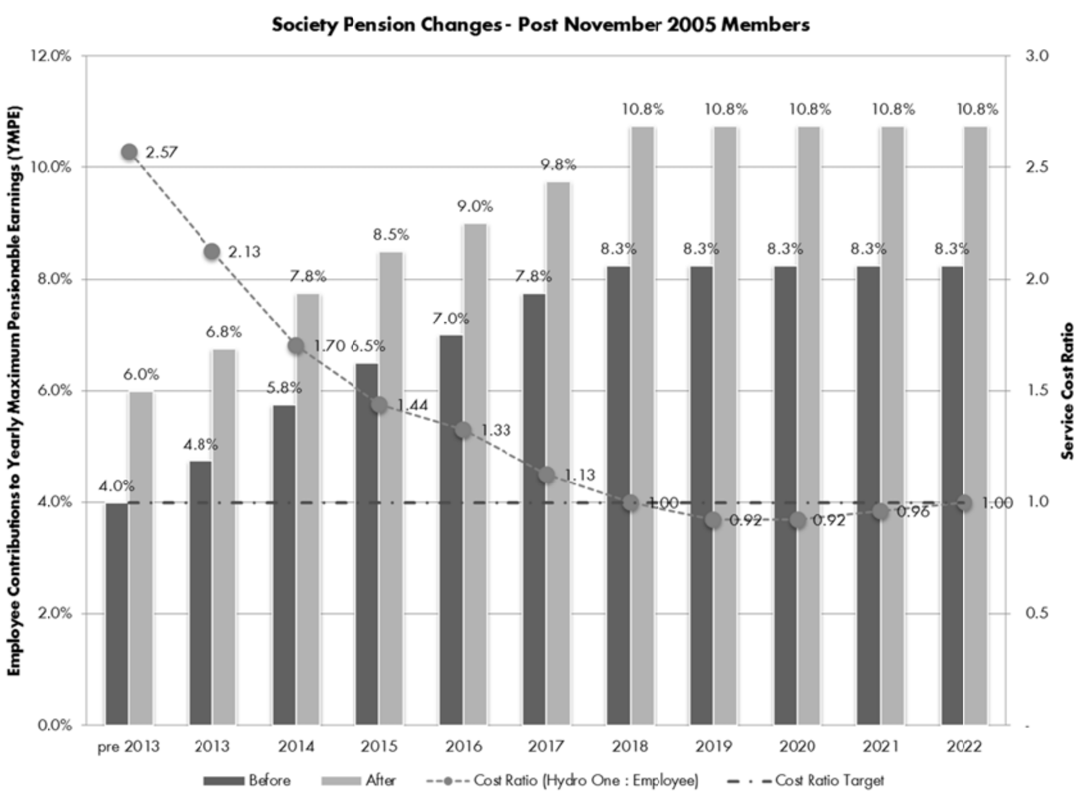
Response:

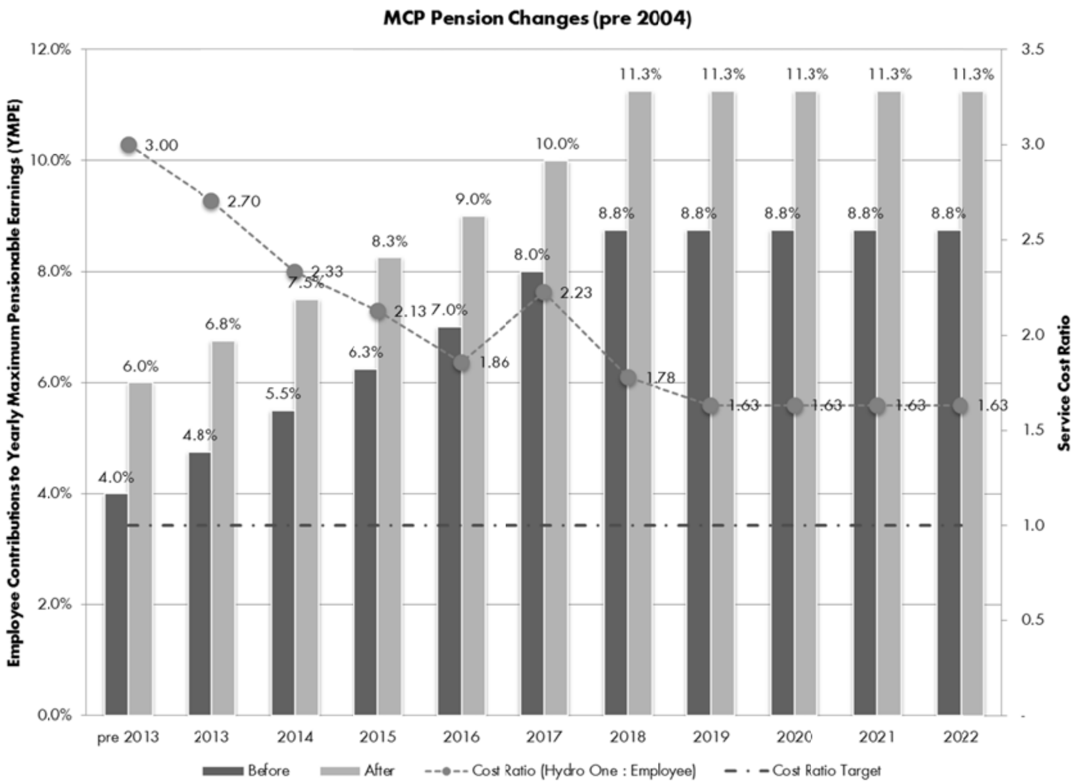
The updated pension valuation as of December 31, 2018 filed under J2.31 Attachment 1, resulted in reduced employer contributions of $12 million for 2020 test year and similar amounts for 2021 and 2022 test years. In addition, the updated pension valuation shows significant improvement in the service cost ratio for all groups, as depicted in the following charts.

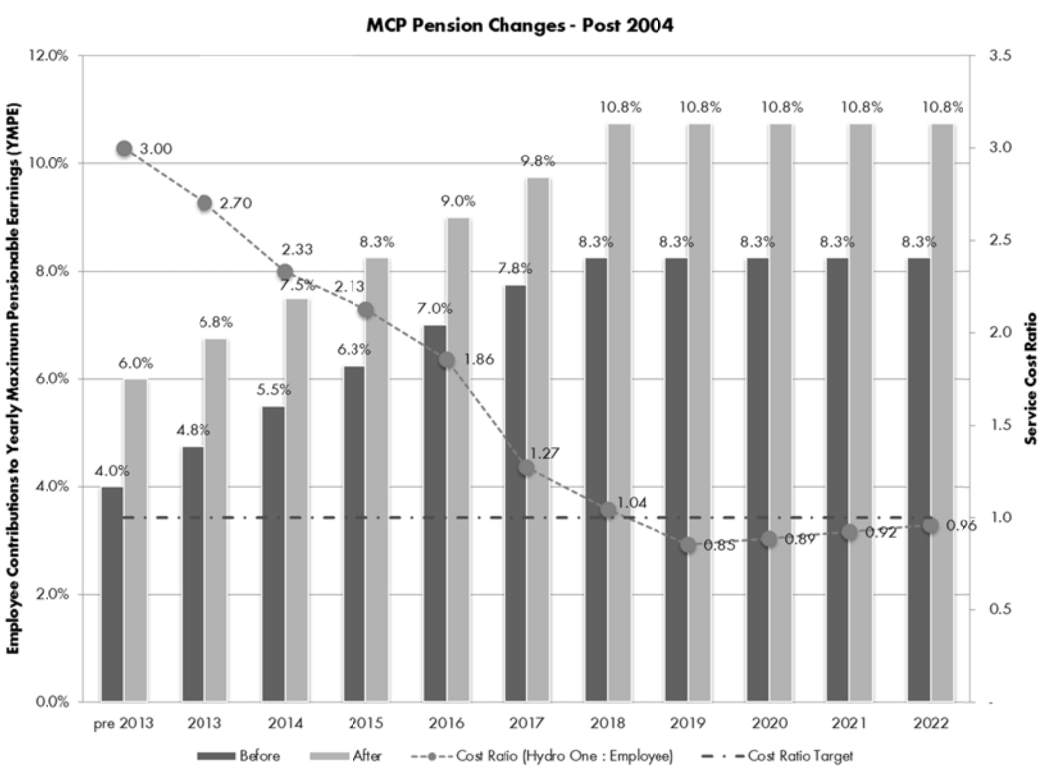
The improvements in the service costs ratios across all employee groups are a result of Hydro One's continued focus since 2013 on increasing employee pension contributions and changing the pension benefits for all groups.


PWU Pension Changes
Employee Contributions to Yearly Maximum Pensionable Earnings (YMPE)
Service Cost Ratio
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
4.5%
6.5%
5.5%
7.5%
6.3%
8.3%
7.3%
9.3%
8.3%
10.3%
8.8%
11.3%
4.00
3.17
2.70
2.13
1.78
1.56
1.50
1.27
1.27
1.33
pre 2013
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Before
After
Cost Ratio (Hydro One : Employee)
Cost Ratio Target


Society Pension Changes - Legacy Pension Plan
Employee Contributions to Yearly Maximum Pensionable Earnings (YMPE)
Service Cost Ratio
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
pre 2013
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
4.0%
6.0%
5.3%
7.3%
6.3%
8.3%
7.0%
9.0%
7.5%
9.5%
8.3%
10.3%
8.8%
11.3%
4.26
3.17
2.70
2.33
2.13
1.94
1.66
1.63
1.70
1.63
1.63
Before
After
Cost Ratio (Hydro One : Employee)
Cost Ratio Target


Society Pension Changes - Post November 2005 Members
Employee Contributions to Yearly Maximum Pensionable Earnings (YMPE)
Service Cost Ratio
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
3.0
2.5
2.0
1.5
1.0
0.5
pre 2013
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
4.0%
6.0%
4.8%
6.8%
5.8%
7.8%
6.5%
8.5%
7.0%
9.0%
7.8%
9.8%
8.3%
10.8%
2.57
2.13
1.70
1.44
1.33
1.13
1.00
0.92
0.92
0.96
1.00
Before
After
Cost Ratio (Hydro One : Employee)
Cost Ratio Target


MCP Pension Changes (pre 2004)
Employee Contributions to Yearly Maximum Pensionable Earnings (YMPE)
Service Cost Ratio
pre 2013
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Before
After
Cost Ratio (Hydro One : Employee)
Cost Ratio Target


MCP Pension Changes - Post 2004
Employee Contributions to Yearly Maximum Pensionable Earnings (YMPE)
Service Cost Ratio
pre 2013
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Before
After
Cost Ratio (Hydro One : Employee)
Cost Ratio Target

UNDERTAKING J4.11

Reference:

JT-2.31, JT-2.32
Oral Hearing Volume 4, Page 166, Line 5 – Page 167, Line 10

Undertaking:

To expand and consolidate the response to JT2.31 to include data for the Society, for MCP, and for PWU.

Response:

The following table summarizes the difference between a 1:1 service cost ratio and the current service cost ratio (as per the updated valuation as of December 31, 2018) for the period of 2020 – 2022 for all defined benefit pension plans by representation.

Hydro One has made significant strides to increase employee contribution levels since 2013. As a result, the company is saving over $22 million annually by increasing employee contribution levels from 20% to over 40% from 2013 to 2019 of total pension contributions, demonstrating meaningful movement toward 50/50 cost sharing. These significant gains in reducing pension costs are set out in Exhibit F, Tab 4, Schedule 1 pages 38 – 39 and the annual savings are provided on page 40.

Difference between 1:1 and Current Service Cost Ratio			
	2020	**2021**	**2022**
PWU	$4.70M	$ 5.05M	$ 5.00M
Society	$1.30M	$1.20M	$1.20M
Management	$0.55M	$0.55M	$0.55M
Total	$6.55M	$6.80M	$6.75M

It should be noted that Hydro One has closed the Management Defined Benefit pension plan for employees hired after September 1, 2015 in favour of a Defined Contribution pension plan. As a result, the Management line does not account for the saving associated with a Defined Contribution pension plan, which would offset the above.

Witness: Sabrin Lila

UNDERTAKING J4.12

Reference:

F-2-2, I-10-VECC-40
Oral Hearing Volume 4, Page 167, Line 11 – Page 172, Line 15

Undertaking:

With reference to Exhibit F, Tab 2, Schedule 2, page 5, to provide the costs per FTE for the Human Resources department.

Response:

Hydro One's OM&A in the test year is $374.1 million which is significantly lower than the historical actuals or OEB approved amounts between 2015 and 2018. Human Resources ("HR") is one function within OM&A.

Table 1 below summarizes the HR spend per Hydro One Networks FTE. Increasing HR spend per FTE is as a result of the following, as discussed in detail in Exhibit I, Tab 10, Schedule 40:

- a shift from transactional work to more strategic work by HR;
- a shift of internal FTEs into the HR function; and
- additional HR FTEs to strengthen change management, analytics, internal HR consulting and Talent Management programming as outlined.

The increase in HR spend per FTE is driven by internal transfers of employees into the HR function and the increasing accountabilities for the HR function over time. The metric below is not meaningful without this context.

Table 1

	2015	2016	2017	2018	2019	2020
$ HR spend per FTE	$ 1,684	$ 1,865	$ 2,197	$ 2,551	$ 2,593	$ 2,657

Witness: Sabrin Lila

UNDERTAKING J5.1

Reference:
JT-2.19
Oral Hearing Volume 5, Page 67, Line 27 – Page 69, Line 17

Undertaking:
To provide the fleet utilization rate for 2017 to 2019

Response:
The fleet utilization rates for 2017, 2018 and forecasted for 2019 are:

Year	Utilization % Rate
2017	71%
2018	77%
2019 Forecast	78%

As evident from the table above, the increase in the fleet utilization rates are due to telematics and fleet right-sizing initiatives.

UNDERTAKING J5.2

Reference:

JT-2.22

Oral Hearing Volume 5, Page 74, Line 20 – Page 77, Line 3

Undertaking:

On a best effort basis, to recast the table provided in JT-2.22 to exclude overtime and a forecast for 2019. Additionally on a best effort basis to include targets for billable hours ratio for the test period, based on wrench study productivity improvements.

Response:

The table below provides an updated billable ratio previously presented in response to JT-2.22 excluding overtime from the calculation:

(%)	2015	2016	2017	2018	2019 Forecast
Billable Hours Ratio	83	83	82	82	82
Non-Billable Hours Ratio	17	17	18	18	18
Total Hours	**100**	**100**	**100**	**100**	**100**

Target billable hours ratio for the test period based on wrench study productivity improvements is not available.

Witness: Robert Berardi, Joel Jodoin

UNDERTAKING J5.3

Reference:
JT-2.22, J-5.2, C-9-2, Table 1
Oral Hearing Volume 5, Page 77, Line 4 – Page 80, Line 12

Undertaking:
When providing the billable ratio undertaking, to advise what's included and what's not included in terms of percentages.

Response:
The Billable Hours Ratio is the percentage of total hours that are charged to the work program or other recoverable work. The ratio quantifies how much of an employee’s time is spent on direct work. It is used for analysis and in the development of the standard rates.

Billable Hours Ratio = Billable Hours / Total Hours (Billable Hours + Non-Billable Hours)

Billable Hours: represents the view of the timesheet hours that were charged directly to work program or other recoverable work (capital, OMA, and external)

Non Billable Hours: represents the hours that do not directly impact the work program.

The <u>Non Billable Hours</u> are represented in the following categories from Table 1 of the Costing of Work: Labour Rate Exhibit (C-09-02):

- Contractual time away from work (Sickness, Accidents, Vacation, Holidays, banked time)
- Time not directly benefiting a specific Project or Program (Safety Training, Meetings, etc.)

The Billable Hours Ratio is used in the development of the standard rates outlined in the Costing of Work: Labour Rate Exhibit (C-09-02).

Total payroll and expense costs, along with an assignment of support activity costs, divided by the forecast billable hours (derived using historical Billable Hour Ratio), derive the standard labour rate.

Witness: Robert Berardi, Joel Jodoin

UNDERTAKING J5.4

Reference:
F-4-1, Table 2
Oral Hearing Volume 5, Page 87, Line 15 – Page 88, Line 27

Undertaking:
To provide a reference for forecast FTEs for 2017-2018

Response:
Hydro One did not forecast FTEs in the last Transmission proceeding (EB-2016-0160). FTEs were first introduced in C1, Tab 2, Schedule 1 as part of the Distribution proceeding (EB-2017-0049).

2018 FTE forecast was provided in the current Transmission Application in Exhibit F, Tab 4, Schedule 1 submitted on March 21, 2019. The 2018 FTE forecast was updated to reflect actuals on June 19, 2019

Undertaking JT 2.08 in the current application reconciles the Distribution filing FTEs in (EB-2017-0049) with the Transmission application FTEs (EB-2019-0082).

UNDERTAKING J5.5

Reference:
I-07-SEC-026
Oral Hearing Volume 5, Page 127, Line 12 – Page 129, Line 24

Undertaking:
To provide the allocation used for the payroll table.

Response:
The allocation percentages have been included in the updated compensation table in response to undertaking J4.09 Attachment 1.

By way of background, in EB-2016-0160 Decision and Order dated September 27, 2017 at pages 56 and 57, the OEB directed Hydro One to improve its compensation tables in Hydro One's then-ongoing distribution proceeding (EB-2017-0049, which was originally filed in March 31, 2017) by including in the tables, among other things: "(g) An exhibit that shows how the allocation factors used to allocate the total compensation amounts between transmission and distribution are derived.…" ("Item (g)").

As directed, Hydro One addressed Item (g) in EB-2017-0049 for distribution rates for 2018-2022. Please see Exhibit C1, Tab 2, Schedule 1, Attachment 6 from that proceeding which is the final form of compensation table arrived at over a number of iterations that were responsive to requests made by OEB Staff and intervenors, and which addressed and discussed Item (g) in detail. The other items (a)-(f) from the EB-2016-0160 Decision and Order are further discussed under J5.6.

Below is a summary of allocation factors and assumptions used to allocate the total compensation amounts between Hydro One's transmission and distribution businesses, along with the evidentiary references where this has been described in this and past proceedings:

- **Total Compensation Calculation:** Total compensation for 2014-2018 is all compensation for all employees employed during the calendar year. Total compensation for 2019-2022 is derived by using total planned FTE multiplied by estimated average salary by representation, with standard escalation assumptions.

- **Allocation Methodology for Regular and Temporary Employees:** Where employees work on both transmission and distribution work activities, their time is allocated using the Black & Veatch methodology. More specifically, to estimate total labour spending in 2020 to 2022, the Black & Veatch 'Review of Overhead Capitalization Rates' methodology, as outlined in Exhibit C, Tab 8, Schedule 2, Attachment 1, was applied. The Black and Veatch study uses the Labour Content Method which identifies the estimated percentage of labour spending within transmission and distribution, as between OM&A and capital spending. This allocation method was utilized to estimate the overall compensation allocation between Distribution and Transmission for all regular and temporary employees, but not for casual trades employees.

- **Allocation Methodology for Casual Trades Employees:** For casual trades employees, management expertise was utilized[1] to refine the allocation of planned yearly headcount and the compensation allocation to the transmission and distribution businesses.

- **FTEs:** FTEs were derived using the following assumptions:
  - a budgeted regular position is one FTE;
  - for non-regular positions, unless budgeted for less than one year, a non-regular position is 1 FTE;
  - for casual (Hiring Hall and Casual Construction), an FTE is determined by "person months"/12; and
  - for 2014-2018, FTE's have been calculated by calculating the average number of employees by representation (# of employees per month/12).

The following table has been embedded in the updated compensation table in J4.9. It summarises the allocation percentages used in the compensation table in this application:

Allocation of Regular and Temporary Staff (Labour Content Method)	**2020**	**2021**	**2022**
Tx Allocation	48%	50%	48%
Dx Allocation	52%	50%	52%
Tx Capital Allocation	74%	76%	76%
Tx OM&A Allocation	26%	24%	24%
Dx Capital Allocation	56%	58%	61%
Dx OM&A Allocation	44%	42%	39%

[1] Compensation costs are allocated by percentage used by the line of business

Allocation of Casual Staff (Management Expertise)	**2020**	**2021**	**2022**
Tx Allocation	42%	44%	45%
Dx Allocation	58%	56%	55%
Tx Capital Allocation (per above)	74%	76%	76%
Tx OM&A Allocation (per above)	26%	24%	24%
Dx Capital Allocation (per above)	56%	58%	61%
Dx OM&A Allocation (per above)	44%	42%	39%

UNDERTAKING J5.6

Reference:
EB-2016-0160
Oral Hearing Volume 5, Page 129, Line 25 – Page 131, Line 10

Undertaking:
Indicate how the compensation table as presented in the current evidence (I-07-SEC-58), addresses the concerns from the Tx 17/18 Decision (EB-2016-0160)

Response:
By way of background, in EB-2016-0160 Decision and Order dated September 27, 2017 at pages 56 and 57, the OEB directed Hydro One to improve its compensation tables[1] in Hydro One's then-ongoing distribution proceeding (EB-2017-0049, which was originally filed in March 31, 2017) by including in the tables seven items labeled (a) through (g). Item (g) is addressed in response to undertaking J-5.05.

As directed, Hydro One addressed items (a) through (f) in EB-2017-0049. Please see Exhibit C1, Tab 2, Schedule 1, Attachment 6 from that proceeding which is the final form of compensation table arrived at over a number of iterations that were responsive to requests made by OEB Staff and intervenors, and which addressed and discussed items (a) through (f) in detail.

On December 12, 2017 Hydro One submitted Attachment 7 and Attachment 8 where it reconciled and explained any differences between the compensation originally presented in EB-2016-0160 under J10.2 and the revised methodology under Attachment 6 in EB-2017-0049.

The summary below provides further information about the evaluation of the compensation table.

Hydro One's Historical Approach
In each of Hydro One's rate applications leading up to the Distribution Application (EB-2017-0049), Hydro One presented total compensation costs at a point in time, specifically, December 31st of each year, for both its transmission and distribution

[1] Previously, response to undertaking J-10.2 filed in EB-2016-0160 was the most up to date compensation table available.

businesses, combined. Hydro One presented combined compensation data for its transmission and distribution businesses for a few reasons: (a) its payroll data systems are limited, and (b) Hydro One believed that the combined data provided continuity between filings and showed trending over multiple applications.

To clarify, evidence in past applications only captured the total compensation for employees on payroll on December 31st, but not all of Hydro One's employees are on payroll at that time. This is particularly true for Hydro One's temporary and casual employees.

Under the historical approach, "total compensation" only included base pay, overtime, short-term incentives, and other allowances for PWU and Society and Management employees. It did not include other compensation items, such as pension and OPEBs.

Exhibit J10.2 in Tx Case (EB-2016-0160)

In the transmission application (EB-2016-0160), in response to requests from parties to that proceeding, Hydro One filed its response to undertaking J-10.2 which showed, on a best efforts basis, its total compensation data with the following changes:

- an expanded definition of total compensation, which included long-term incentives, employee stock options, payroll burdens, and pension and OPEBs; and
- total compensation data for only its transmission business, applying the "labour content" method from the Black & Veatch study "Review of Overhead Capitalization Rates" (filed as Exhibit B1-3-10-1 in the Tx Case) to the combined transmission/distribution compensation data.

It is important to note that undertaking response J10.2 still reflected compensation costs for only those employees on payroll on December 31st.

Attachment 6 in Hydro One's Distribution Application (EB-2017-0049)

Hydro One improved its compensation evidence filed in the Distribution Application on March 31, 2017. Specifically, Appendix B of Exhibit C, Tab 2, Schedule 1:

- uses the expansive definition of "total compensation", consistent with Exhibit J10.2 in the Tx Case;
- reflects total compensation costs for full years, rather than a point in time, which is inconsistent with Exhibit J10.2 in the Tx Case;
- refines the allocation of casual employee compensation based on management's expertise regarding the relative contribution of casual employees to the transmission and distribution work programs;

- isolates total compensation costs for its distribution business only; and
- reflects the Distribution Business Plan (vintage December 2016).

In the transmission application (EB-2016-0160), the OEB ordered Hydro One to file additional evidence on compensation in the Distribution application (EB-2017-0049). In response, Hydro One filed Attachment 6 which shows total compensation for its transmission and distribution businesses, using its improved approach.

Differences between J10.2 and Attachment 6

The following table summarizes the main differences between J10.2 and Attachment 6.

	Exhibit C1-4-1-1 (TX Case EB-2016-0160)	**Exhibit J10.2 (Tx Case EB-2016-0160)**	**Attachment 6 (EB-2017-0049)**
Compensation Data	Based on compensation for employees on payroll December 31st	Based on compensation for employees on payroll December 31st	Based on compensation of all employees employed in the year
Compensation Elements	Base salary, Overtime, Incentive (STI) and other allowances	Base pay, burdens, other allowances, STIP, LTIP, ESOP, Share Grants	Base pay, burdens, other allowances, STIP, LTIP, ESOP, Share Grants
Headcount/ FTE's	Based on year-end headcount	Based on year-end headcount	Total & year-end count provided but FTE's used to calculate compensation costs
Compensation Costing	Average unit cost X headcount X escalation based on negotiated wage escalation/budget non represented wage escalation	Average unit cost X headcount X escalation based on negotiated wage escalation/budget non represented wage escalation	FTE X average unit cost X escalation based on negotiated wage escalation/budget non represented wage escalation
Allocation methodology	No allocation	Black and Veatch	Black and Veatch for regular employees. Casual employees compensation costs allocated by % used by line of business

Current Transmission Application and Compliance with EB-2016-0160 Decision

The compensation template from the Distribution application (EB-2017-0049) Attachment 6 was used to produce the data filed under the current Transmission Application (EB-2019-0082).

The following table summarizes how Hydro One has complied with the Transmission decision in EB-2016-0160.

OEB Decision	Hydro One Response
a) Tables comparable to the year-end payroll tables in the Transmission Payroll Tables for each the years 2014 to 2018 containing total compensation information that reconciles with the combined totals of the amounts for each of the years 2014-2018 allocated to transmission shown in Undertaking J10.2 and the amounts shown for distribution in the Distribution Payroll Tables	a) The current payroll table contains total compensation in each year data rather than year-end compensation only as found in J10.2. Since the current compensation table shows all compensation paid in each year, it is not possible to reconcile with the payroll tables that show only year-end compensation. The full reconciliation was previously presented in the Distribution Application as Attachment 7 and Attachment 8 filed on December 12, 2017 (EB-2017-0049).
b) Within these total compensation tables, for each of the line item amounts and for each year, the total number of employees in a manner that reconciles with the total number of employees information presented in Transmission Payroll Tables	b) For each employee category, Hydro One has provided total number of employees and FTEs for historical years and FTEs for forecast years.
c) Beside the “Total Number of Employees” information described in item (ii), the total company full time equivalent (FTE) information for each of the years 2014-2018 in a format similar to that shown in EB-2017-0049 Exhibit C1/Tab2/Schedule 1, Table1	c) See b).

d) In the total compensation tables, the allocation of total compensation between capital and OM&A for each of the years 2014-2018 in a manner comparable to that shown for transmission only in Undertaking J10.2	d) The current payroll table includes the allocation of compensation to OM&A and Capital
e) As part of the total compensation table, the Pension and OPEB amounts for distribution for each of the years 2014-2018 in a table similar to the table to that effect contained in Undertaking J10.2	e) The current payroll table includes the pension and OPEB amounts
f) A revision of the format used in Undertaking J10.2 to reflect the format of the total compensation tables described in items a) to e)	f) Hydro One revised the format used in J10.2 to reflect total compensation and to incorporate the directions provided in the OEB decision.
g) An exhibit that shows how the allocation factors used to allocate the total compensation amounts between transmission and distribution are derived.	g) The compensation table utilizes the compensation labour splits that are used in the Black and Veatch allocation methodology. The specific allocations can be found in response to undertaking J5.05.

In summary, Hydro One filed complete compensation data in Attachment 6 in EB-2017 -0049. Specifically, this compensation table contains:

- Total yearly compensation for both the Distribution and Transmission businesses and consolidated for Hydro One Networks.
- Expanded compensation elements (e.g. STIP, LTIP, ESOP and Share Grants)
- Year-end headcount, total headcount and FTEs

By filing compensation data in the current application (EB-2019-0082) in the same format as in Attachment 6 in EB-2017-0049, this allows for a complete overview of compensation at the Transmission, Distribution and consolidated level and trending over the baseline compensation data.

UNDERTAKING J5.8

Reference:

Transcript Volume 5, Page 163, line 9 to Page 167, line 19

Undertaking:

To describe how Hydro One would communicate how successful it was in executing the capital plan, at a Board of Directors level of detail.

Response:

The following metrics would communicate the company's success in executing its capital plan, at a "Board of Directors level" of detail:

1. Capital Expenditures and In-Service Additions Reporting, comparing the previous year-end actuals against the OEB-approved budget, along with associated variance explanations, at:
    a. The envelope level; and
    b. Using the OEB category levels of *System Access, System Service, System Renewal,* and *General Plant*
2. Project and Program Level Reporting: Status report for all projects and programs requiring Board of Directors approval (i.e. total gross budget over $50 million) including schedule and costs, relative to Business Case Approval levels
3. Costs and schedule variances for projects, relative to Business Case Approval levels, broken down by project value ($3-$10 million; $10-$30 million; $30-$50 million; over $50 million)

These metrics are illustrated in the attached sample PowerPoint as an example of how this information could be presented at a "Board of Directors level" of detail.

Project level performance reporting is tracked relative to the estimates included in the Business Case Approval, as shown at the 'star' in Figure 1 below. At this point, the scope, schedule, and cost of a project are well-defined and a baseline is created and reported against.

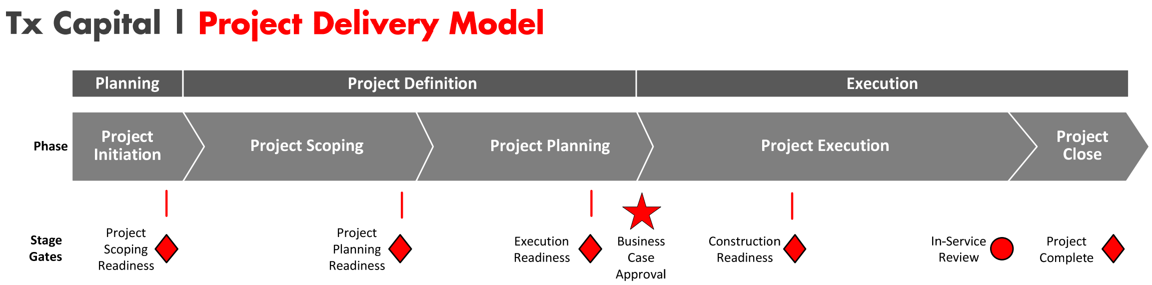


Figure 1 - Transmission Capital Project Delivery Model

In addition, Exhibit C, Tab 2, Schedule 1, Attachment 1, *Capital Program Performance Report – 2017 and 2018* (the "Capital Variance Report"),[1] describes Hydro One's performance relative to plan by identifying and explaining material scope, cost or schedule variances for projects and programs with total budgeted costs greater than $3 million which were completed in 2017 and 2018. The results indicate good performance at the portfolio level and the individual project and program levels and reflect Hydro One's ongoing efforts to continually update and enhance its Transmission Capital Project Delivery Models.

---

[1] This exhibit fulfills the OEB direction from the EB-2016-0160 proceeding

Filed: 2019-11-18
EB-2019-0082
Exhibit J-5.8
Attachment 1
Page 1 of 5

Sample Report

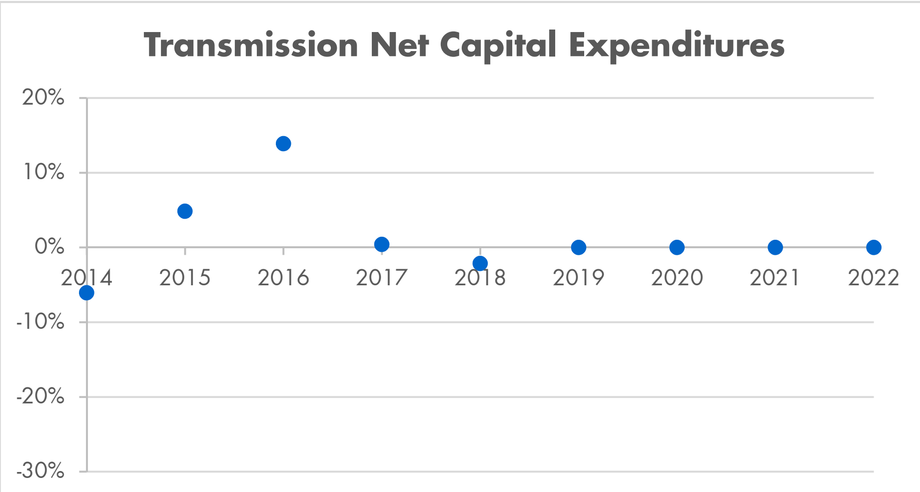
For Illustrative Purposes only

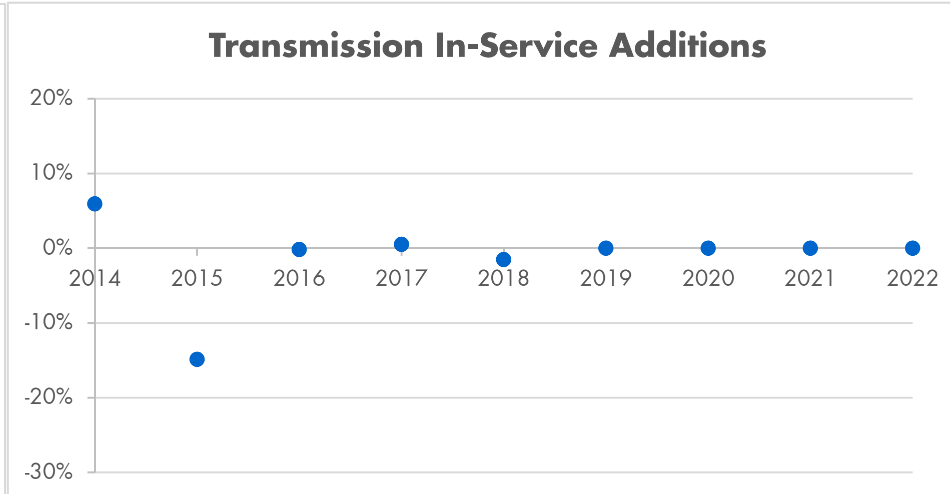
hydro One

Transmission Capital Portfolio **Data provided for Illustrative Purposes only**

Historical Performance against Capital Expenditure and In-Service Additions Targets (1)

Recent delivery of the transmission capital portfolio against target has improved significantly versus prior years for both net capital expenditures (2) and in-service additions (ISA)





Net CAPEX $M	2014	2015	2016	2017	2018	2019	2020	2021	2022
OEB Approved	899	899	866	950	1000	1038	1192	1318	1370
Actuals	845	943	987	954	967				
% Variance	**-6.1%**	**4.8%**	**13.9%**	**0.4%**	**-3.3%**				

ISA $M	2014	2015	2016	2017	2018	2019	2020	2021	2022
OEB Approved	863	821	912	868	1178	951	1037	1298	1293
Actuals	914	699	910	872	1160				
% Variance	**5.9%**	**-14.9%**	**-0.2%**	**0.5%**	**-1.5%**				

- Historically, Hydro One had difficulty in delivering the complete transmission capital portfolio on target due to delays in some planned projects initiating, and project-level variances with a bias towards over-estimation
- Portfolio performance over recent years has improved significantly, in large part due to an improved project definition process and tools that were initiated in 2016. We are now seeing increased predictability both in terms of capital expenditure and in-service additions at both the portfolio and project levels.

(1) Data set includes all of Hydro One Networks functional areas, power system and other

Transmission Capital Portfolio **Data provided for Illustrative Purposes only**

Capital Expenditures and In-Service Addition Performance Relative to Regulatory Categories

	e.g. 2018 Net Capital Expenditures			
	OEB Approved ($M)	Actual ($M)	Variance (%)	Variance Explanation
System Access	24.3	33.7	38.6%	TBD
System Renewal	780.4	776.2	-0.5%	TBD
System Service	75.6	73.9	-2.2%	TBD
General Plant	119.7	83.6	-30.2%	TBD
Total	**1,000.0**	**967.3**	**-3.3%**	

	e.g. 2018 In-Service Additions			
	OEB Approved ($M)	Actual ($M)	Variance (%)	Variance Explanation
System Access	68.2	12.1	-82.3%	TBD
System Renewal	761.4	852.3	11.9%	TBD
System Service	244.8	218.0	-10.9%	TBD
General Plant	104.0	77.9	-25.1%	TBD
Total	**1,178.4**	**1,160.4**	**-1.5%**	

Projects and Programs Performance

Status of Projects and Programs against Business Case Approval / Budget

- On Track
- At Risk
- Pending Variance Approval

Data provided for Illustrative Purposes only

Project Description	Status	Completion Date	Costs[2]	Forecasted Cost Variance	Comment
<u>Example</u> **Beach TS Station Rebuild** *Located within the industrial core in the City of Hamilton serving the bulk electricity system as well as load delivery to LDC (Alectra)* **Scope** Project includes replacement or upgrade of multiple end-of-life assets in the 230kV and 115kV switchyards including transformers, breakers and switches and associated protection and control facilities.	On Track (green)	Original: Q4 2019 Current: Q4 2019 Forecast: Q4 2019 Released: Q4 2013	Original: $77.7M Current: $77.7M Forecast: $74.3M To-Date: $74.0M	Original:-$3.4M (-4%) Current:-$3.4M (-4%)	**Status:** Site drainage, physical security perimeter, control building alterations and lighting replacements in progress. T3/T4 transformer equipment & foundations removals in progress.

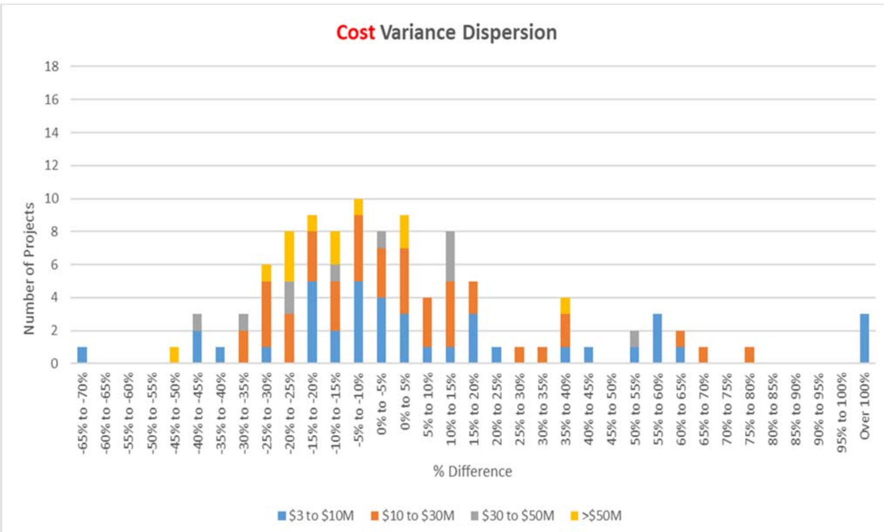
Program Description	Status	Units	Costs	Variance	Comment
<u>Example</u> **Transmission Lines Insulator Replacement Program** **Scope** Replacement of prematurely deficient Transmission lines insulators that would otherwise not survive the life of the circuit **Unit of Measure:** Number of Structures	At Risk (yellow)	Budget: 3700 Actual 3700	Budget: $61.4M Actual: $65.7M	Cost: $4.3M (7.0%) Units: 0 (0%)	**Status:** Significant number of structures with challenging terrain

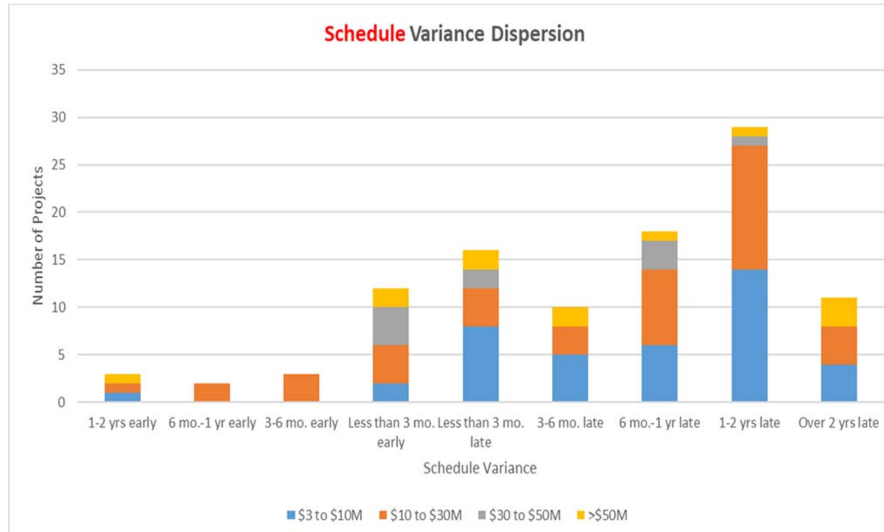
(1) Data set would inlcude all projects and programs with a Total Gross Budget >$50M. **(2)** Original – Refers to the original Business Case Approval at the beginning of the Project Execution phase; Current – refers to the most recent approval, i.e. if a variance has been approved for the project.

Tx & Stations Historical Project Performance

Cost and Schedule Variance Dispersion (1) **Data provided for Illustrative Purposes only**

- Analysis showing cost and schedule performance for completed projects relative to Business Case approved cost budgets and schedule.
- The data set in the graphs below is for projects completed from 2014 to 2018 and is included in Undertaking J.3.07.





	Projects Completed (3 year average)	Projects Completed (2020)	Change
Overall Cost Variance Dispersion (std. dev. [%])	N/A	N/A	N/A
Overall Schedule Variance Dispersion (std. dev. [Days])	N/A	N/A	N/A

(1) Data set includes Tx power system projects greater than $3M only

UNDERTAKING J5.9

Reference:

K-5.5

Oral Hearing Volume 5, Page 167, Line 20 – Page 170, Line 21

Undertaking:

To review the orange highlighted parts of K5.5 to confirm staff calculations, to provide agreed-upon compensation data; with respect to row 227, to explain the increases in transmission compensation per FTE.

Response:

Hydro One has reviewed the additional calculations in Exhibit K5.5 highlighted in orange and can confirm that they are mathematically correct, however, they do not take into account increasing FTEs levels to support the growing work program. Hydro One has completed an FTE based analysis in J6.1 including detailed explanations.

With respect to row 227 (year over year increase in Total Transmission Cost per FTEs), these small increases during the test period are largely due to base escalations which subsequently result in increases in the various components that make up the labour burdens, labour burden changes, and allocation differences year over year between Transmission and Distribution.

Witness: Joel Jodoin, Sabrin Lila

UNDERTAKING J6.1

Reference:

K6.1

Oral Hearing Volume 6, Page 16, Line 7 – Page 18, Line 13

Undertaking:

To review and confirm the numbers in the grey-shaded portions of Exhibit K6.1; to explain the significant increase in labour burdens at row 206, and how that compares to the increase in FTEs and compensation, whether the increases are in tandem or, for example, if you have a 30 percent increase in FTEs and compensation but a 79 percent increase in burdens, to explain the difference.

Response:

Analysis Performed by OEB Staff

Hydro One has reviewed the additional calculations performed by OEB Staff in exhibit K6.1 (including the October 30, 2019 correction by OEB staff to row 238) highlighted in grey and can confirm that they are mathematically correct; however, they do not take into account increasing FTE levels to support the growing Transmission work program. Moreover, the manner in which OEB Staff derived Burden costs (excluding Pension and OPEB) is misleading, as discussed below.

Hydro One completed an FTE-based analysis in J6.1 Attachment 1 (reproduced version of K6.1) in Columns V to AB and provided additional commentary based on a compound annual growth rate (CAGR) per FTE which is the more appropriate way to review compensation costs over the application term.

CAGR Calculation

CAGR is a more accurate representation of the annual growth rate compared to OEB Staff's calculation which does not take into account the compounding impact of inflation. More importantly, Hydro One has normalized the calculation for FTE levels to better represent the actual cost increases which are largely explained by compensation escalation assumptions.

Total Labour Burdens

The "Burden" amounts included in compensation table at lines 6, 17, 36, 46, 60, 70, 87, and 99 are calculated by applying an assumed burden percentage to base pay. The assumed burden is based on Hydro One's estimate of its FTE requirements to execute the Transmission System Plan included in this Application.

The Pension and OPEB burden amounts included at lines 147, 148, 151, 152 are derived differently, as follows:

- 2014 to 2018 are based on actuals; and
- 2019 to 2022 are based on an actuarial valuation dated effective December 31, 2017 which is based on historical FTE numbers and does not consider the same assumptions for future FTE growth as the "Burden" amounts at lines 6, 17, 36, 46, 60, 70, 87, and 99.

OEB Staff has taken the Burdens from lines 6, 17, 36, 46, 60, 70, 87, and 99 and subtracted the pension and OPEB burden amounts included at lines 147, 148, 151, 152, with the resulting analysis at lines 206 and 215. Because these values are based on different assumptions at different points in time, the resulting number that OEB Staff derived for "Other Burdens" is not accurate.

The burden rate that Hydro One assumed for the purpose of calculating the burden dollars excluding Pension and OPEB is provided below:

	2018	**2019**	**2020**	**2021**	**2022**
Burden Rate (excluding Pension and OPEB)	6.1%	6.2%	6.3%	6.3%	6.4%

The burden rate assumed for "Other Burdens" excluding Pension and OPEB is relatively flat year over year from 2018 to 2022. As such, once total burdens excluding Pension and OPEB is normalized for FTE levels, the CAGR per FTE should be relatively flat.

In order to help with any calculations that OEB Staff would like to perform, Hydro One has provided in the table below a comparative Burden for Transmission and Distribution which excludes Pension and OPEB costs consistent with the methodology used to derive the total burden dollars in lines 6, 17, 36, 46, 60, 70, 87, and 99.

Burden Excluding Pension & OPEB ($)	**2018**	**2019**	**2020**	**2021**	**2022**
Transmission	24,527,313	25,723,508	28,134,664	29,303,622	29,276,017
Distribution	25,519,167	29,676,565	28,807,264	29,363,127	30,890,937

UNDERTAKING J6.2

Reference:

F-5-1 Table 3
Oral Hearing Volume 6, Page 32, Line 24 – Page 33, Line 10
Oral Hearing Volume 6, Page 48, Line 3 – Page 49, Line 7

Undertaking:

To provide the OPEB amounts for 2021 and 2022 similar to 2020 in table 3, Exhibit F-5-1.

Response:

This undertaking was satisfied during the oral hearing as the requested OPEB values for Transmission are provided in Exhibit I, Tab 1, Schedule OEB-221 under part (g) of the response. Further discussion in regards to Distribution values is provided under J6.4.

Witness: Samir Chhelavda

UNDERTAKING J6.3

Reference:

JT2.24

Oral Hearing Volume 6, Page 46, Line 24 – Page 47, Line 19

Undertaking:

To provide an example of a monthly productivity report.

Response:

Attached is the Productivity Report for December 2018 (dated January 2019), which was prepared on a consolidated basis and includes productivity initiatives for both Transmission and Distribution.

Please note that the Productivity Report contains limited redactions which are subject to confidentiality request set out in a separate letter from Hydro One's counsel.

Witness: Robert Berardi, Joel Jodoin

Productivity Review

January 31st, 2019

hydro One

Meeting Chair: Rob Berardi, VP – Shared Services

December 2018 Summary

Purpose of this meeting	• Provide visibility on major Operations initiatives, and to enable cross-functional collaboration across LoB's • **Our goal today** is to review our 2018 September results and discuss any concerns for 2019 planning.
Summary of progress	▪ **YTD Actuals increased from Nov to Dec from $123.8M to $127.3M mainly due to::** ▪ Fleet 12.6M ▪ Provincial Lines $3.7M ▪ Supply Chain $2.4M ▪ Planning $2.0M
Savings to date	• **As of December Year end actuals, we are $19.7M ahead of Year end budget of $107.6M. Achieving <u>$127.3M (Tier 1)</u> in productivity savings, and $145.2M (Tier 1 + Tier 2).**

Agenda

• Meeting Follow-Ups and Action Items	All	5 min
• Overview of Operations Productivity	Rob Berardi	40 min
• Roundtable of current initiatives - Productivity	All VPs	30 min
• Appendix (Supporting Materials)	All VPs	10 min

November Major Initiatives: Follow-Up

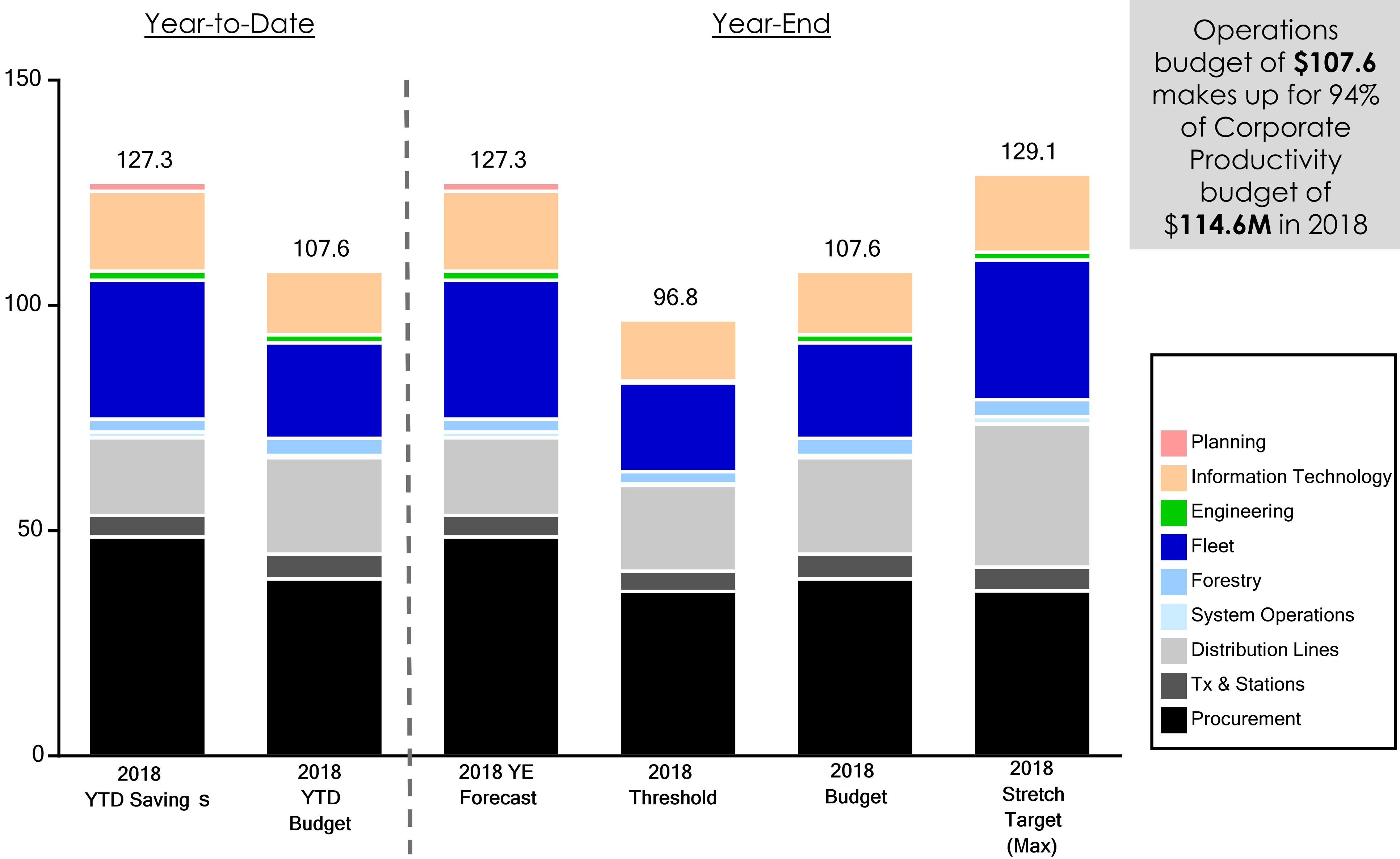
#	Item	Sponsor	Status	Expected Completion Date By

None

Agenda

• Meeting Follow-Ups and Action Items	All	5 min
• Overview of Operations Productivity	Rob Berardi	40 min
• Roundtable of current initiatives - Productivity	All VPs	30 min
• Appendix (Supporting Materials)	All VPs	10 min

2018 Productivity Savings Summary (Tier 1)



Operations budget of **$107.6** makes up for 94% of Corporate Productivity budget of $**114.6M** in 2018

Note: All numbers updated for inclusion of ISD. Max has been adjusted using a proration of the all non-Ops amounts.

hydro One

Hydro One Total Productivity Savings – December 2018

OPERATIONS			
Line of Business	**YTD Actual**	**YE Forecast**	**YE Budget**
Fleet	$ 30.9	$ 30.9	$ 21.2
Supply Chain	$ 48.6	$ 48.6	$ 39.4
Dx Lines	$ 17.2	$ 17.2	$ 21.4
Forestry	$ 2.8	$ 2.8	$ 3.8
Engineering	$ 2.0	$ 2.0	$ 1.8
Planning	$ 2.0	$ 0.0	$ 0.0
Tx & Stations	$ 4.8	$ 4.8	$ 5.5
System Operations	$ 1.3	$ 1.3	$ 0.5
Information Technology	$ 17.7	$ 17.7	$ 14.1
Total Operations	**$ 127.3**	**$ 127.3**	**$ 107.6**
HYDRO ONE			
Customer Service	$ 5.5	$ 5.5	$ 3.3
Finance	$ 0.1	$ 0.1	$ 0.6
People & Culture	$ 2.7	$ 2.7	$ 3.1
Total Corporate	**$ 8.2**	**$ 8.2**	**$ 7.0**
TOTAL	**$ 135.5**	**$ 135.5**	**$ 114.6**

Detailed Breakdown of Tier 2 – December 2018

Month over Month Shift in Tier 2

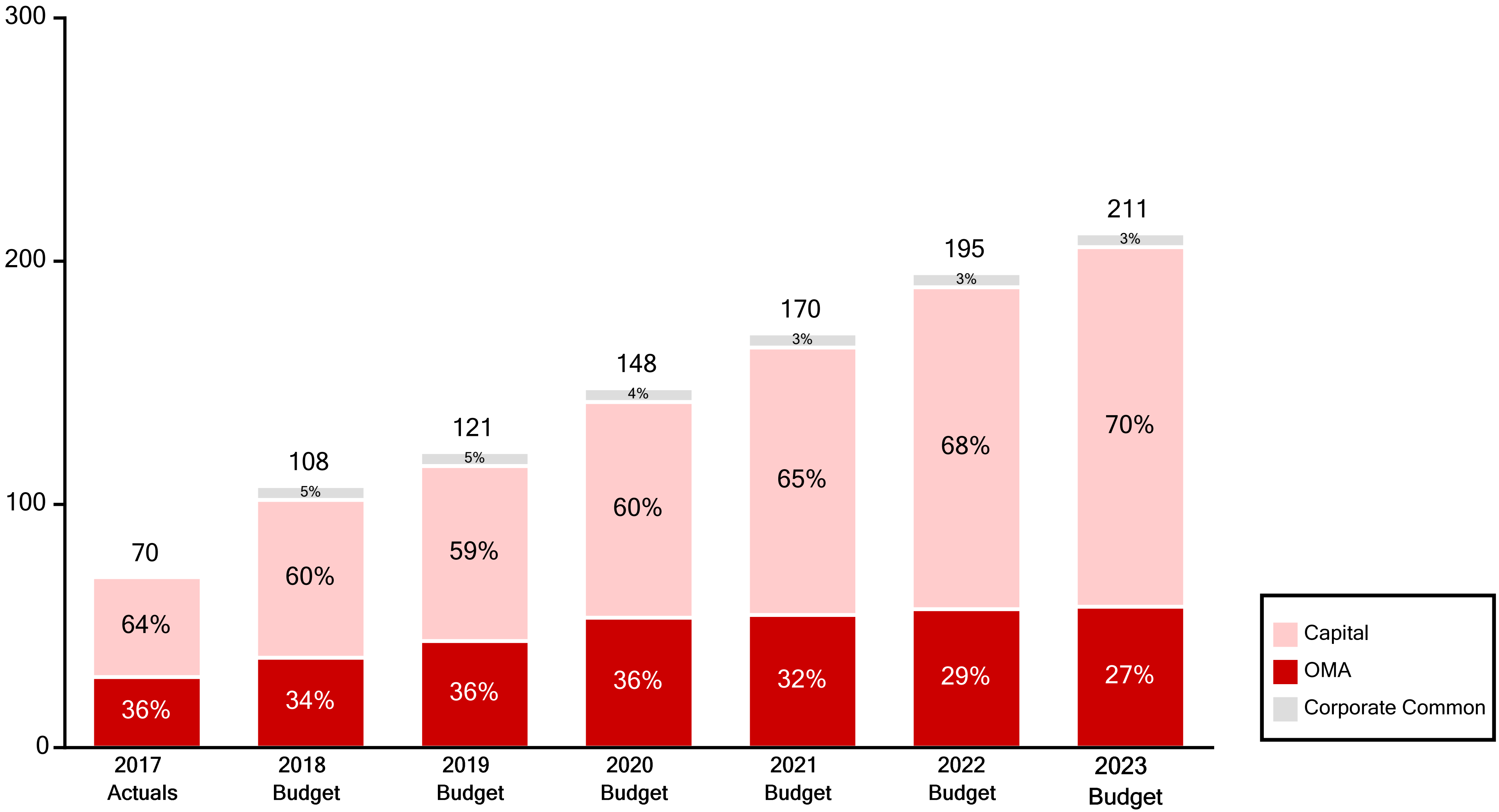
Line of Business	Tier 2 YE Forecast @ Dec	Tier 2 YE Forecast @ Nov
Fleet	$ 0.0	$ 0.0
Supply Chain	$ 12.5	$ 11.0
Dx Lines	$ 0.0	$ 0.0
Forestry	$ 0.0	$ 0.3
Engineering	$ 0.1	$ 0.4
Planning	$ 0.0	$ 0.0
Tx and Station Services	$ 3.9	$ 3.2
System Operations	$ 1.0	$ 1.0
Information Solutions	$ 0.3	$ 0.0
TOTAL	**$ 16.0**	**$ 16.0**

Tier 2 Details – December 2018

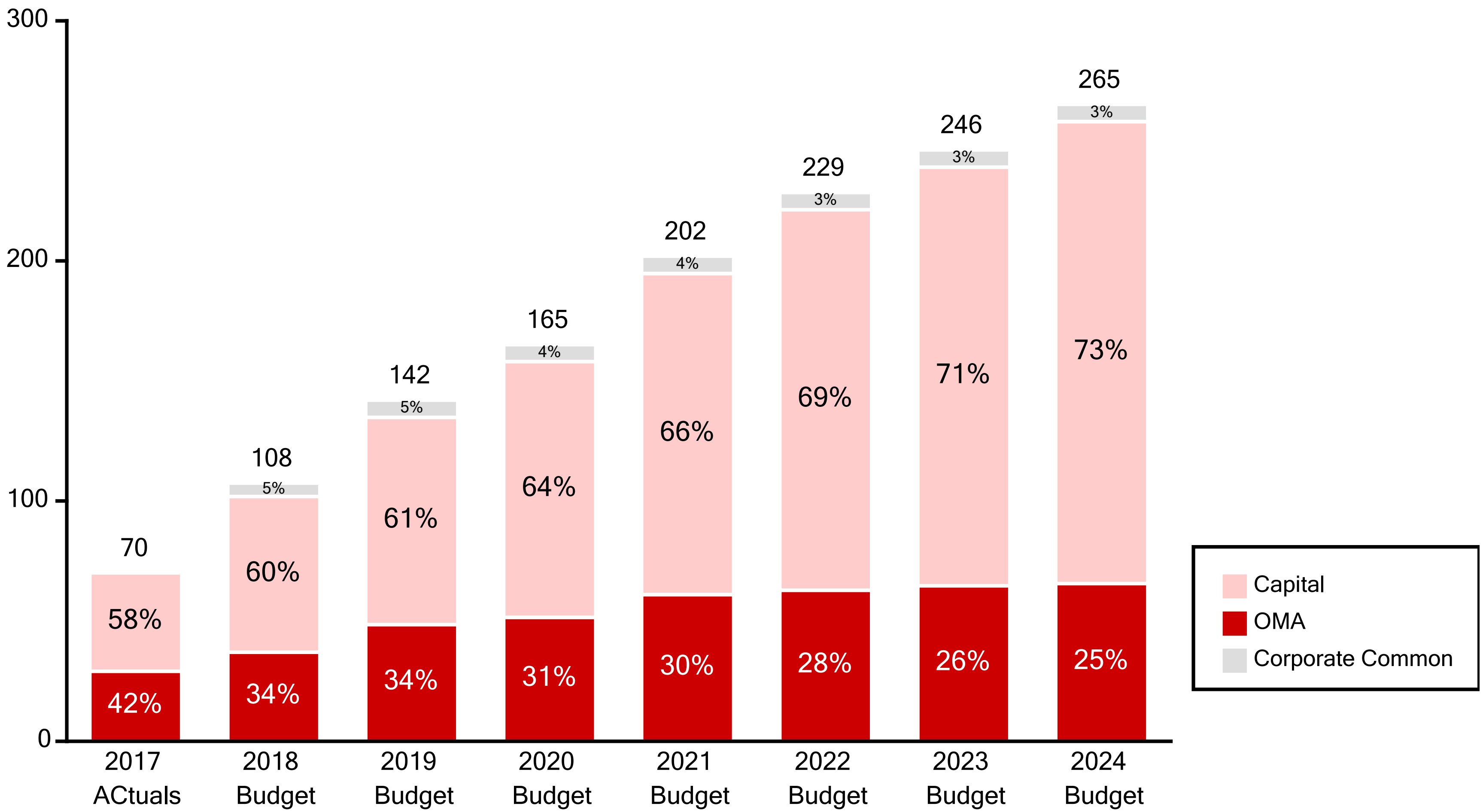
Supply Chain ($12.5)
- Telecom & ISD

Tx and Stn ($3.9)
- OT Reduction
- TWHQ

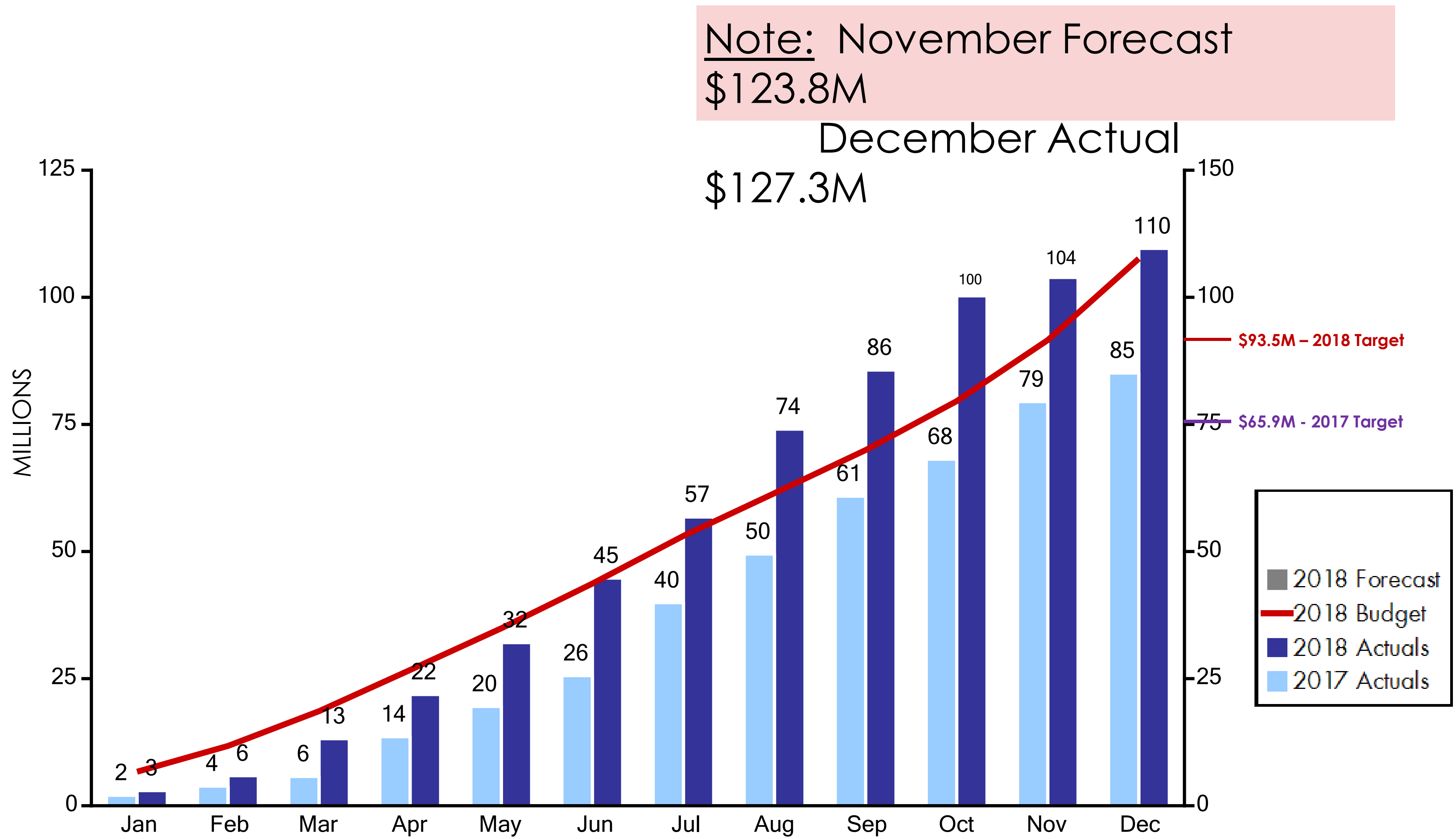
2018-2023 Operations Productivity OMA/CAPEX Breakdown



2019-2024 Operations Productivity OMA/CAPEX Breakdown



2017 Actuals vs. 2018 Actuals @ Dec. 31, 2018



Note: ISD Productivity not included in chart = 109.6M. With ISD included 127.3M

hydro One

Summary of productivity savings to date

Legend
- Meets or Exceeds Budget
- Below Budget
- Below Threshold

Line of Business	Specific Initiative	YTD Tier 1 Savings	YTD Budget	YE Tier 1 Forecast As of Nov	YE Tier 1&2 Actual Dec.	YE Budget	YE Status	Summary
Information Technology	All	$17.7M	$14.1M	$17.6M	$18.0M	$14.1M		
Engineering	All	$2.0M	$1.8M	$1.7M	$2.1M	$1.8M		• Savings identified through the EDM Project and DOM Maintenance
Planning	All	$2.0M	$0.0M	$0.0M	$0.0M	$0.0M		• Moved DOM Maintenance initiative into Engineering Savings as of February 2018
System Operations	All	$1.3M	$0.5M	$1.3M	$2.3M	$0.5M		• Initiative includes outage cancellation reductions, load transfer studies & Dx After Hours
TX & Stations	All	$4.8M	$5.5M	$4.8M	$8.7M	$5.5M		• Savings on 10 initiatives continuing to drive productivity.
Distribution	Move to Mobile	$5.8M	$13.0M	$5.0M	$5.8M	$13.0M		• Savings derived from M2M clerical and field initiative.
	Cable Locates	$11.4M	$8.4M	$11.2M	$11.4M	$8.4M		• Savings from the continued outsourcing of demands to locate HONI cables to a low cost service provider and avoiding locates when possible
	Forestry	$2.8M	$3.8M	$3.2M	$2.8M	$3.8M		• Savings below budget include: inclement weather and switching & grounding
Shared Services	Fleet	$30.9M	$21.2M	$31.2M	$30.9M	$21.2M		• Includes Fuel and MFA savings. Fleet initiative being implemented with vehicles right-sizing.
	Supply Chain	$48.6M	$39.4M	$47.7M	$61.1M	$39.4M		• Significant value locked-in through renegotiated contracts, to be realized over coming months
Total Cost Savings		**$127.3M**	**$107.6M**	**$123.8M**	**$145.2M**	**$107.6M**		

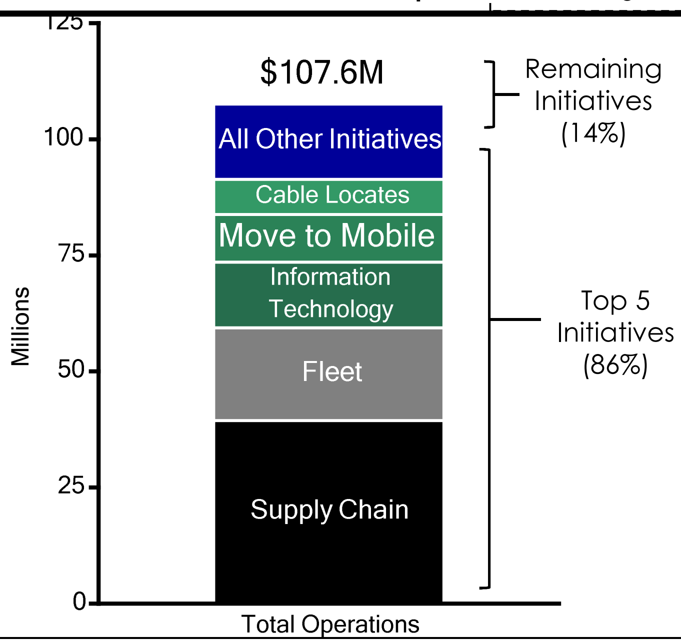
Note 1: YE Budget includes Cable Locates $7.6M and Fault Indicators at $0.8M. Note 2: YTD Budget includes Cable Locates and Fault Indicators

Top Initiatives

TOP 5 INITIATIVES MAKE UP FOR ~86% OF YE BUDGET

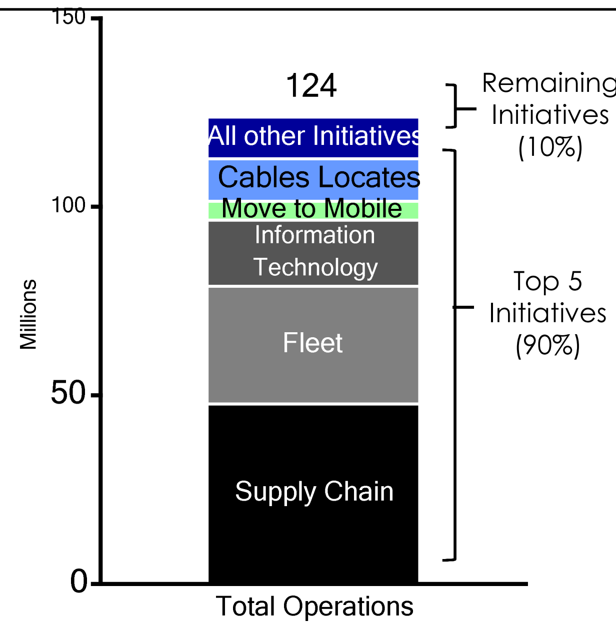
Initiative	YE Budget	% of Total Operations
Supply Chain	39.4	37%
Fleet Capital Reduction	21.2	19%
Information Technology	14.1	13%
Move to Mobile (Field)	10.3	10%
Cable Locates	7.6	7%
Total	**$92.6M**	**86%**

***Total budget of $107.6M*



TOP 5 INITIATIVES MAKE UP FOR ~90% OF YE ACTUAL

Initiative	YE Actual	% of Total Operations
Supply Chain	48.6	38%
Fleet Capital Reduction	30.9	24%
Information Technology	17.7	14%
Cable Locates	11.4	9%
Move to Mobile (Field)	5.8	5%
Total	**$114.4M**	**90%**



hydro One

Agenda

• Meeting Follow-Ups and Action Items	All	5 min
• Overview of Operations Productivity	Rob Berardi	40 min
• Roundtable of current initiatives - Productivity	All VPs	30 min
• Appendix (Supporting Materials)	All VPs	20 min

hydro One

Supply Chain | December 2018

Rob Berardi / Susan Wylie

On Track

At Risk

Definite Impact

- Procurement activities that have a quantifiable impact on HONI work program
- Budgeted procurement savings that were allocated to LOB's 2018 investment drivers and cost centers are included below, as well as ongoing Supply Chain initiatives that continue to realize value for Hydro One

		YTD 2018		YE 2018					
Portfolio Group	**Status**	**Actual**	**Budget**	**Actual (Tier 1)**	**Actual (Tier 2)**	**Tier 1 & Tier 2**	**Budget**	**YE Comment**	**Actions to Tier 2 to Tier 1**
Transmission & Stations		28.1	24.0	28.1	0.3	28.4	24.0	• [redacted]	
Telecom and ISD		4.9	4.9	4.9	10.4	15.3	4.9	• [redacted]	
Distribution		5.0	4.5	5.0	1.5	6.4	4.5	• YE actuals exceeded YE budget • [redacted]	
Corporate Functions		0.5	0.5	0.5	0.3	0.9	0.5	• [redacted]	
Non-Sourcing		10.1	5.5	10.1		10.1	5.5	• [redacted] • Higher than expected savings due to increased management of volume rebates and new tracking tool • Volume rebate backlog has now been collected, collection rate for remainder of year expected to slow	
Total Savings		**48.6**	**39.4**	**48.6**	**12.5**	**61.1**	**39.4**		

Fleet Services | December 2018

Rob Berardi

On Track
At Risk
Definite Impact

- The Telematics initiative has been implemented with ~4300 behavior modification devices and ~300 location-only devices at year-end 2017 with a goal to improve safety, reduce carbon footprint, as well as continuing to optimize the fleet complement.

		YTD 2018		YE 2018				
Portfolio Group	**Status**	**Actual ($M)**	**Budget ($M)**	**Forecast (Tier 1 - $M)**	**Forecast (Tier 2 - $M)**	**Budget ($M)**	**Comment**	**Actions to Move Tier 2 to Tier 1**
Telematics Fuel Savings		(0.23)	1.2	(0.23)	0.00	1.20	Definite Impact – Deterioration in expected fuel consumption efficiency for LOB Telematics equipped on-road assets. Non-Productive idle is trending higher compared to 2016. Negative Productivity reported in conjunction with approved methodology.	• None
Fleet Capital Reduction (MFA)		29.82	19.98	29.82	0.00	19.98	On track	• None
Right-Sizing Gains on Disposition		1.27	N/A	1.27	0.00	N/A	On track – Net New Productivity for 2018, no budget was set.	• None
Total Savings		**30.86**	**21.18**	**30.86**	**0.00**	**21.18**		

Key Developments / Achievements

- Savings will be realized through:
  - An improvement in driver behavior (e.g. reduction in speeding incidents, sharp acceleration, harsh braking and non-productive idling)
  - The fleet right-sizing exercise in collaboration with the lines of business. Assets with low utilization have been removed from service and further fleet optimization will continue through 2018. These initiatives will reduce our capital investment requirement going forward.
  - The net gains from the sale of Surplused right-sized transport and work equipment (TWE) via Investment Recovery.
- Complete all required documentation to send surplus assets to auction.
- Continue to work with LOBs to ensure accurate and thorough identification of all assets for continued right-sizing as required.

Key Decisions upcoming

- Assess the quantities and type of equipment within the Hydro One equipment pool to ensure optimal levels are maintained going forward.

Risks Being Managed

- Potential lag between decision and savings realized given vehicle resale / disposal process.
- [illegible]cation with LOB's in regards to the deterioration in expected fuel consumption efficiency.

Distribution Overview | December 2018

Brad Bowness/Scott Vicary, Dave Price & Kelly Kingsley

On Track
At Risk
Definite Impact

		YTD 2018		YE 2018						
Sub-initiative	**Status**	**Actual**	**Budget**	**Forecast (Tier 1)**	**Forecast (Tier 2)**	**Tier 1 + Tier 2 Forecast**	**Budget**	**Comment**	**Actions to move $ to Tier 1**	**Initiative Status**
Cable Locate Outsourcing		11.20	7.60	11.20	0.00	11.20	7.60	• Outsource portion of Dx cable locates to lower cost provider	• No action required all Tier 1	*On track*
Tx Brush Control		0.85	0.99	0.85	0.00	0.85	0.99	• Brush control unit costs compared against 2015 baseline. Difference in unit costs multiplied by the 2018 units will be used to derive savings.	• No action required	*At risk*
Inclement Weather		0.96	1.60	0.96	0.00	0.96	1.60	• Change management of shifts for temporary staff to increase flexibility during inclement weather	• No action required	*At risk*
Switching & Grounding		0.00	0.71	0.00	0.00	0.00	0.71	• Restore power faster by training Forestry crew(s) to open switches and apply grounds in place of Lines crews	• No action required	*At risk*
OCP Trouble Call Reduction		1.03	0.50	1.03	0.00	1.03	0.50	• Completion of the defect correction program will drive down the number of Trouble calls.	• No action required	*On track*
Move to Mobile Field Force		3.94	10.30	3.94	0.00	3.94	10.30	• Sustainment team is continuing support and will address defects through minor enhancements. • Year end forecast reflects 2017 year end actuals.	• No action required	*At risk*
Move to Mobile Back Office		1.86	2.70	1.86	0.00	1.86	2.70	• Methodology approved with Finance for monthly reporting and tracking. • Year end forecast reflects back office savings as identified in the 2018 business plan	• No action required	*At risk*
Total Category Value Savings		**19.84**	**24.4**	**19.84**	**0.00**	**19.84**	**24.4**			

Transmission & Stations Overview

Sponsor: Andrew Spencer

- On Track
- At Risk
- Definite Impact

		YTD 2018		YE 2018						
Sub-initiative	**Status**	**Actual**	**Budget**	**Forecast (Tier 1)**	**Forecast (Tier 2)**	**Tier 1 + 2 Forecast**	**Budget**	**Savings Tracking Method**	**Actions to move $ to Tier 1**	**Initiative Status**
OT Reductions	On Track	2.5	1.0	1.0	1.5	**2.5**	1.0	• % old OT hrs on base reg. hrs.* new reg. hrs. – new OT hrs * lbr rate.	Another review of stats and logic for 2019	*Clear plan in place*
Recondition Oil	On Track	0.6	0.6	0.6	0.0	**0.6**	0.6	• Liters of oil used * difference in cost/L ($1.5)		*Clear plan in place*
TWHQ Stations	On Track	2.0	0.5	0.5	1.5	**2.0**	0.5	• # Person days on TWHQ * (saved travel time * lbr rate + distance to TWHQ * fuel cost (0.12) – travel allowance (55) – motel/meals)[1]	• Another review of stats and logic for 2019	*Clear plan in place*
Straddle Hoist Usage	On Track	0.5	0.4	0.4	0.1	**0.5**	0.4	• # hrs * external hrly cost ($800) – # hrs * internal hrly cost ($25)		*Clear plan in place*
Wrench Time Studies	At Risk	0.5	1.0	0.5	0.0	**0.5**	1.0	• Actual cost of work (old) – actual cost of work (new) • Budget spend/accomplishments met	• Review of Capital savings required to confirm forecast.	*Plan in place,*
Outsourcing G&S BGIS	On Track	0.7	0.3	0.4	0.3	**0.7**	0.3	• Old cost – new cost		*On track*
OMA Stretch	At Risk	1.3	1.0	1.0	0.3	**1.3**	1.0	• Actual cost of work (old) – actual cost of work (new) • Budget spend/accomplishments met	Review completed confirmed Tier 1	*Plan in place,*
Remote Impact Recorders	On Track	0.1	0.1	0.1	0.0	**0.1**	0.1	• # Hrs * lbr rate ($130) + # hrs * TWE ($12.5) + meals/hotel/flight/car savings	• No Action	*Clear plan in place*
In-House Retorques	On Track	0.2	0.1	0.2	0.0	**0.2**	0.1	• # In-house vehicles * hrs saved/vehicle (0.875)* lbr rate ($140/hr) + external garage cost/vehicle ($10))	• No Action	*Clear plan in place*
Scheduling Tool	On Track	0.3	0.5	0.3	0.0	**0.4**	0.5	• Implementation of Scheduling Tool leading to efficiencies and reduced h	• Savings review for correctives 2019	*Clear plan in place*
Total Category										

Note: 1. All values used are Zone averages, based on 2016 information

Source: Major Initiatives Governance Submissions

System Operations Overview

Sponsor: Martin Huang *(Including New Initiatives)*

On Track
At Risk
Definite Impact

		YTD 2018		YE 2018							
Initiative	**Status**	**Actual**	**Budget**	**Forecast (Tier 1)**	**Forecast (Tier 2)**	**Total Tier 1 + 2 forecast**	**Budget**	**Initiative Description**	**Actions to move $ to Tier 1**	**Savings Tracking Method**	**Initiative Status**
Outage Cancellation Reduction	●	0.53	0.53	0.53	1.03	1.56	0.53	Reduce outage cancellations; save unused equip. costs, improve outage execution group efficiency		# reduced cancelled outages * avg. cancelled outage cost	*On Track*
Load Transfer Studies	●	0.38	0	0.38	0	0.38	0	Reduce the per unit cost to do a Load Transfer Study using the Distribution Management System (DMS)		# of studies done using DMS tool as compared to using CYME	*On Track*
Dx Cleared After Hours Locates	●	0.36	0	0.36	0	0.36	0	Reduction in After Hours Locates dispatched. Reduce unnecessary truck roles, reduce cost, (labor, equipment)		# Total number of after hours locates cleared multiplied by avg truck roll cost	*On Track*
Approved initiatives total:		**1.26**	**0.53**	**1.26**	**1.03**	**2.30**	**0.53**				
Total Savings		**1.26**	**0.53**	**1.26**	**1.03**	**2.30**	**0.53**				

Methodology approved
Methodology not yet approved

hydroOne

Source: Major Initiatives Governance Submissions

UNDERTAKING J6.4

Reference:

F-5-1 Table 3
Oral Hearing Volume 6, Page 48, Line 3 – Page 50, Line 3
Oral Hearing Volume 6, Page 108, Line 21 – Page 109, Line 20

Undertaking:

To provide OPEB figures for distribution similar to the numbers for transmission and any other information required to make a determination for Transmission and Distribution in regards to capitalization of OPEB costs.

Response:

As set out in the Application at Exhibit H, Tab 1, Schedule 2, sections 3.16 and 3.16.2, Hydro One is seeking OEB approval to continue capitalizing the non-service component of Other Post-Employment Benefit costs ("OPEBs") for both its Transmission and its Distribution businesses.

The continued capitalization of the non-service component of OPEBs enables Hydro One to accurately depict the true costs of its capital assets because, under this approach, all relevant labour costs incurred in developing and building capital assets would be allocated to the corresponding assets and be recovered over the useful lives of those assets. If Hydro One's request for continued capitalization is denied, and its alternative proposal of continuing the OPEB Cost Deferral Account and applying a 20-year rolling balance disposition method (as discussed below) is also denied, then the non-service component of OPEBs would instead need to be collected as part of OM&A, which would give rise to revenue requirement increases of $21 million for Transmission in 2020 and $15 million for Distribution in 2020. Similar amounts would impact OM&A for both Transmission and Distribution in future years.

Table 1, below, summarizes the non-service component of OPEBs for Hydro One's Transmission and Distribution businesses. The amounts shown are the amounts for which Hydro One seeks OEB approval to continue capitalizing. The OPEB amounts shown for the Transmission business are derived from Exhibit I, Tab 1, Schedule OEB-221 for 2019 to 2022. The 2018 amount shown for the Transmission business is currently captured under the OPEB Cost Deferral Account and presented in Exhibit H, Tab 1, Schedule 1 Table 2. The OPEB amounts shown for the Distribution business align with the amounts provided by Hydro One in the Distribution Draft Rate Order in EB-2017-0049. These amounts were excluded from the calculation of the Distribution revenue requirement and are currently being tracked in the OPEB Cost Deferral Account.

Table 1 – Non-Service Component of OPEB ($ Millions)

	2018	2019	2020	2021	2022
Distribution	13	15	15	15	16
Transmission	22	19	21	23	23

Background

Hydro One uses the accrual method of accounting for OPEB costs. The OPEB costs included in Transmission rates are presented in Exhibit F, Tab 5, Schedule 1, Table 3 for 2020 Test Year and 2021 and 2022 amounts were provided as part of a response to OEB Staff IR 221. Since 2018, the capital component of OPEBs has been impacted by a change in USGAAP. In particular, and as described further in Exhibit H, Tab 1, Schedule 2, Sections 3.16 and 3.16.2, this change has precluded Hydro One from capitalizing the non-service component of its OPEB costs unless approved to do so by the OEB.[1] The non-service component of OPEB costs refers to all costs other than current service costs.

In response to the change in USGAAP, in EB-2017-0338, Hydro One obtained approval from the OEB to establish the OPEB Cost Deferral Account, effective from January 1, 2018 until the effective date of Hydro One's next transmission revenue requirement application.[2] In the account, Hydro One records the OPEB costs previously capitalized in respect of the Transmission business but no longer allowed to be capitalized as a result of the change to USGAAP, which was issued through Accounting Standards Update (ASU) 2017-07. The OEB, in establishing the OPEB Cost Deferral Account, stated that the panel in Hydro One's next transmission rate application (the current proceeding) could consider whether Hydro One should continue to capitalize OPEBs. The OPEB Cost

[1] Only the service cost component of the net periodic pension cost and net periodic post-retirement benefit cost is eligible for capitalization. Hydro One accounts for pension costs on a cash basis for rate-setting purposes. The cash basis calculates the normal cost using a discount rate which is based on the long term expected return of the plan assets. The normal cost for pensions at this time is solely comprised of current service costs, therefore this amendment to the accounting standards (ASU 2017-07) does not impact capitalization of pension costs. OPEB costs are accounted for on an accrual basis, and therefore are impacted by the amendment.

[2] EB-2017-0338, Decision and Order, Hydro One Networks Inc., Application for an Accounting Order approving the establishment of a deferral account (May 10, 2018).

Deferral Account for the Transmission business was approved for continuance in EB-2018-0130 until the effective date of the revenue requirement in the current application.

In addition, in its decision on Hydro One's most recent Distribution rates application (EB-2017-0049), the OEB approved the establishment of an OPEB Costs Deferral Account for the Distribution business, effective from January 1, 2018. The panel in that proceeding instructed Hydro One to file the necessary evidence regarding the Distribution business's OPEB Costs Deferral Account in the next Transmission rate proceeding, to permit the matter to be determined for both Hydro One's Transmission and Distribution businesses.

Rationale for Continued Capitalization

As noted at the outset of this response, the continued capitalization of the non-service component of OPEBs enables Hydro One to accurately depict the true costs of its capital assets because, under this approach, all relevant labour costs incurred in developing and building capital assets would be allocated to the corresponding assets and be recovered over the useful lives of those assets. If not capitalized, the non-service component of OPEBs would need to be treated as OM&A, instead of as capital, despite the fact that these costs were previously treated as capital. In addition to being inconsistent with the prior treatment of these costs, accounting for these costs as OM&A would give rise to intergenerational inequities by making current transmission and distribution ratepayers pay for assets that future generations of ratepayers will benefit from, and enabling those future generations to benefit from those assets without bearing the costs of those assets.[3]

Hydro One's request for the continued capitalization of the non-service component of OPEB costs is in line with guidance that the Federal Energy Regulatory Commission (FERC) provided in its letter, dated December 28, 2017, which allows FERC-regulated entities, which are subject to USGAAP and the changes in ASU 2017-07, to continue to capitalize both the service and non-service cost components of pensions and OPEBs. A copy of the FERC letter is provided in Attachment 1 of this undertaking response.

Continued capitalization would also prevent material rate impacts to both Transmission and Distribution customers by not increasing OM&A costs as further discussed below.

[3] Oral Hearing Transcript, Volume 6, page 30, lines 9-21.

Another benefit of permitting Hydro One to continue capitalizing the non-service component of its OPEB costs, in respect of its Transmission and Distribution businesses, is that continued capitalization would limit the additional regulatory overhead costs associated with the ongoing tracking and disposition of the balances of the current OPEB Cost Deferral Account.

Potential Outcomes

If the OEB approves Hydro One's request for continued capitalization of the non-service cost component of OPEBs, Hydro One proposes, in respect of the Transmission business, to add the accumulated amounts in the approved OPEB Cost Deferral Account to the Transmission rate base as a single high level adjustment when setting the 2020 revenue requirement. In respect of the Distribution business, as the 2018, 2019, and 2020 Distribution revenue requirement amounts do not include the revenue requirement impact associated with the OPEB component of non-service costs, an adjustment would have to be made to calculate the new revenue requirement during an annual update for 2021 Distribution rates so as to include the OPEB costs captured in the OPEB Cost Deferral Account. Through such adjustment, Hydro One would expect to be able to recover the revenue requirement associated with amounts for 2018, 2019 and 2020, which it did not collect when deriving its 2018, 2019 and 2020 revenue requirement. Moreover, capital expenditures for 2021 and 2022 would have to be adjusted to include the OPEB costs which were previously excluded.[4]

If the OEB denies Hydro One's request for continued capitalization of the non-service cost component of OPEBs, and also denies Hydro One's alternative proposal (described below), this would result in significant rate impacts for Transmission and Distribution ratepayers because Hydro One would need to recover these costs through OM&A each year. As described in Hydro One's response to OEB Staff IR 221, Transmission OM&A for 2020 would increase by approximately $21 million, which would result in a 1.4% increase in the 2020 rates revenue requirement relative to 2019 OEB approved levels. Moreover, as indicated in Table 1, above, Distribution OM&A for 2021 would increase

[4] During the Draft Rate Order process implementing the Distribution Decision (EB-2017-0049), Hydro One reduced the capital expenditures by $13.5 million for 2018, $14.6 million in 2019, $14.8 million in 2020, $14.6 million in 2021 and $16.4 million in 2022. The exact calculation was provided in Table 1 – Proposed Capital Spending Summary ($ millions) in the DRO Reply Submission4 under the OPEB and OPEB Adjustment lines.

by $15 million. Moreover, any amounts accumulated in the OPEB cost deferral account[5] would have to be disposed of which would result in further rate increases.

Alternative Proposal

If the OEB does not approve Hydro One's request for continued capitalization of the non-service cost component of OPEB for each of the Transmission and Distribution businesses, Hydro One requests as an alternative that it be permitted to continue using the OPEB Cost Deferral Account for each of the Transmission and Distribution businesses and that it be permitted to dispose of the balances of each such account on a twenty-year rolling balance (as opposed to periodic clearance of the accounts in future rate applications). Twenty years is consistent with the US GAAP guidance that allowed recovery of OPEB related amounts not exceed a period of twenty years. Moreover, the twenty-year rolling balance disposition method would be beneficial to ratepayers as it would minimize the impact on rates.[6] As part of the alternative proposal, Hydro One proposes that interest improvement be recorded on the opening monthly balance of the principal amount. While continued capitalization would provide the most effective means of aligning costs with asset lives, and is Hydro One's preferred approach, the alternative proposal would at least provide better alignment with asset lives as compared to recovery of these costs through OM&A.

[5] For Transmission and Distribution 2018 and 2019 costs are currently accumulated in the OPEB Cost Deferral Account. Pending OEB decision timing, 2020 costs could be captured in the OPEB Cost Deferral Account.
[6] See H-1-2, Attachment 10 in the Transmission Application for disposition example.

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AI18-1-000
December 28, 2017

TO ALL JURISDICTIONAL PUBLIC UTILITIES AND LICENSEES, NATURAL GAS COMPANIES, OIL PIPELINE COMPANIES AND CENTRALIZED SERVICE COMPANIES

Subject: Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions

The Financial Accounting Standards Board (FASB) has issued Accounting Standards Update (ASU) No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.* ASU No. 2017-07 amends FASB Accounting Standards Codification (ASC), Topic 715, *Compensation – Retirement Benefits*, to specify how the amount of pension costs and costs for post-retirement benefits other than pensions (PBOP) should be presented on the income statement under Generally Accepted Accounting Principles (GAAP), and what components of those costs are eligible for capitalization in assets. The Commission has received a number of inquiries from industry regarding clarification of whether and how to apply this ASU for purposes of regulatory accounting and reporting to the Commission. Accordingly, this accounting issuance is intended to provide clarity and certainty to industry on how they should apply the Commission's accounting and reporting requirements over pension and PBOP costs.

Pension and PBOP costs are made up of several components that reflect different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. Prior to this ASU, companies typically reported all of these components on an aggregate basis, without separating the various components on the financial statements. The amendments in this ASU require that an employer report the service cost component of pension and PBOP costs with other compensation costs arising from services rendered by employees during the period. Additionally, based on this ASU, these costs generally fall under a subtotal of income from operations for GAAP financial reporting. The other components of pension and PBOP costs are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The amendments in this ASU also allow only the service cost component to be eligible for capitalization when all of the other normal criteria for capitalization under GAAP are met.

Based on the Commission's Uniform System of Accounts, Commission jurisdictional public utilities and licensees, natural gas companies, and centralized service companies recognize pension and PBOP costs in Account 926, Employee Pensions and Benefits,[1] while oil pipeline companies recognize pension and PBOP costs in Account 550, Employee Benefits,[2] if the pension and PBOP costs are not eligible for capitalization. The Commission's longstanding policy is to view these expenses as part of a single line item on the income statement in the Form No. 1, Form No. 1-F, Form No. 2, Form No. 2-A, Form No. 3-Q, Form No. 6, and Form No. 60 (collectively as FERC Forms), and that pension and PBOP costs in their entirety are attributable to the calculation of Net Utility Operating Income on the FERC Forms. The pension and PBOP expenses are recorded to the respective jurisdictional account without separation of the various components making up the pension and PBOP costs.

Regarding capitalization of pension and PBOP costs when the costs are incurred as part of a capital project, the Uniform System of Accounts does not specify whether capitalization of pension and PBOP costs should include or exclude the non-service cost components that make up the pension and PBOP costs. The instructions to Account 926 under the Uniform System of Accounts prescribed for public utilities and licensees, natural gas companies, and centralized service companies state that there shall be credited to this account the portion of pensions and benefits expenses which is charged to construction, and that records in support of this account shall be so kept that the amounts of pensions and benefits expenses transferred to construction or other accounts will be readily available. In practice, companies generally have capitalized both the service cost component and non-service cost components of the pension and PBOP costs in the past, as long as the capitalization of those costs were in compliance with Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, or Service Company Property Instruction No. 367.52, of the Uniform System of Accounts. The instructions for Account 550 under the Uniform System of Accounts prescribed for oil pipeline companies similarly do not discuss service or non-service components of pension and PBOP costs to be transferred to construction.

---

[1] *See* 18 C.F.R. Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; 18 C.F.R. Part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act*; and 18 C.F.R. Part 367, *Uniform System of Accounts for Centralized Service Companies Subject to the Provisions of the Public Utility Holding Company Act of 2005*.

[2] *See* 18 C.F.R. Part 352, *Uniform System of Accounts Prescribed for the Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act*.

The focus of the Commission's accounting regulations is to ensure that the Commission and other stakeholders have available to them financial information about jurisdictional entities that is useful for the development and monitoring of rates. The uniform application of the Commission's accounting regulations is essential in providing comparability and decision-useful information to the Commission and stakeholders to reach informed rate decisions and conclusions. Accordingly, the objective of this guidance is to provide clarification as to how all jurisdictional entities should account for and report pension and PBOP costs, in response to ASU No. 2017-07.

The guidance is being provided to all jurisdictional entities to ensure proper and consistent application of the Commission's accounting requirements over pension and PBOP costs in response to ASU No. 2017-07 for Commission financial reporting purposes. This guidance is for Commission accounting and reporting purposes only and is without prejudice to the ratemaking practice or treatment that should be afforded the items addressed herein.

1. ACCOUNTING FOR PENSION AND PBOP COSTS ON THE INCOME STATEMENT

Question: How should jurisdictional entities account for pension and PBOP costs on the income statement for Commission accounting and reporting purposes?

Response: Jurisdictional public utilities and licensees, natural gas companies, and centralized service companies should record pension and PBOP costs in their entirety in Account 926, while oil pipeline companies should record pension and PBOP costs in their entirety in Account 550, provided the costs are not transferred to construction.

Pension and PBOP costs are made up of several components: service cost, interest cost, actual return on plan assets, gain or loss, amortization of prior service cost or credit, and amortization of any transition asset or obligation existing at the date of initial application of ASC Subtopic 715-30. Though pension and PBOP costs are computed using the aggregate total of these various components, the Commission's longstanding policy is to consider the amount as a singular cost to the employer. This cost is calculated based on Statement of Financial Accounting Standards (SFAS) No. 106[3] and reported as an accrued expense under net income from continuing operations.

[3] SFAS No. 106 was superseded for GAAP reporting purposes by ASC Topic 715 in 2009 when FASB codified all of the former accounting statements into ASC topics, but the calculations under both SFAS No. 106 and ASC 715 to arrive at the pension and PBOP costs remained the same.

Accordingly, there is one account designated for pension and PBOP costs under each respective Uniform System of Accounts for public utilities and licensees, natural gas companies, centralized service, and oil pipeline companies. This accounting is consistent with the rate treatment of pension and PBOP costs to most jurisdictional entities with cost-of-service rates. While there are some varying rate schemes approved by the Commission and other regulatory bodies to calculate recoverable pension and PBOP costs in cost-of-service rates, the Commission has determined that a uniform requirement for how jurisdictional entities should account for and report pension and PBOP costs are most conducive to promoting comparability and decision-usefulness of the information.[4] As such, we will continue to require all jurisdictional entities to recognize pension and PBOP costs on the income statement, in its entirety without disaggregation of its various components, in the currently existing account designated for pension and PBOP costs under each respective Uniform System of Accounts.

2. CAPITALIZATION OF PENSION AND PBOP COSTS

Question: Is it appropriate for jurisdictional entities to capitalize pension and PBOP costs using the method prescribed under ASU No. 2017-07?

Response: Provided that the pension and PBOP costs are based on appropriate labor costs and have a definite relation to construction as required under Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, and Service Company Property Instruction No. 367.52, jurisdictional entities may continue to capitalize the service cost component and non-service cost components of pension and PBOP costs as it has traditionally been the widely accepted practice, or they may elect to capitalize only the service cost component of pension and PBOP costs, as prescribed by ASU No. 2017-07. Both methods are appropriate and are not precluded by the Commission's accounting requirements.

The Commission's Uniform System of Accounts prescribed for public utilities and licensees, natural gas companies, and centralized service companies do not require any specific method to determine the components of pension and PBOP costs to be included or excluded from capitalization, as long as the capitalization is based on labor costs and have a definite relation to construction. The instructions to Account 926 only requires that records in support of this account shall be so kept that the amounts of pensions and benefits expenses transferred to construction or other accounts will be readily available. Additionally, Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, and Service

[4] *See* California Independent System Operator Corporation, 126 FERC ¶ 61,263 (2009), *order on reh'g*.

Company Property Instruction No. 367.52 require overhead costs allocated to construction and capitalized to have a definite relation to the construction, either based on direct charges using employee time tracking or special studies. The Uniform System of Accounts prescribed for oil pipeline companies similarly do not discuss the service or non-service components of pension and PBOP costs to be included or excluded from capitalization.

Because there is no definitive requirement under the Uniform Systems of Accounts requiring specific identification of pension and PBOP cost components to be capitalized, outside of the requirement for the capitalization to be based on appropriate labor costs and to have a definite relation to construction, jurisdictional entities may elect to follow the capitalization required under ASU No. 2017-07. It is also acceptable to continue capitalizing all of the pension and PBOP costs, as companies have done so prior to the issuance of the ASU. Either approach will not conflict with the existing requirements under the Uniform System of Accounts, provided that the method of capitalization adheres to Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, and Service Company Property Instruction No. 367.52.

Question: How should jurisdictional entities account for deferred income taxes related to property, plant, and equipment which include capitalized pension and PBOP costs, if those amounts of pension and PBOP costs capitalized for regulatory accounting and reporting to the Commission differ from the amounts capitalized for GAAP reporting purposes?

Response: Jurisdictional entities must account for and report deferred income taxes to the Commission based on the temporary differences between the basis of assets reported to the Internal Revenue Service (IRS) and the basis of assets reported to the Commission. Similarly, the amount of deferred income tax reversals in subsequent periods must be based on the difference between the revenues and expenses used for reporting to the IRS and the revenues and expenses recognized for reporting to the Commission. Balances used in GAAP reporting should not be a factor in determining the deferred income tax balances reported to the Commission. Jurisdictional entities must be able to reconcile deferred income tax balances reported on the financial statements filed with the Commission with the respective asset and liability balances on those same set of financial statements.

3. DISCLOSURES AND FUTURE FILINGS TO THE COMMISSION

Question: What are the required disclosures or filings to the Commission related to changes made to a jurisdictional entity’s accounting practice in response to ASU No. 2017-07?

Response: Jurisdictional entities should disclose any changes in accounting practice in response to ASU No. 2017-7 in their respective FERC Forms filed to the Commission quarterly and annually, within the Notes to the Financial Statements. Disclosures should include potential rate impacts resulting from these changes, including the effects on rate base and current period expenses. Jurisdictional entities should also make similar disclosures on future rate filings, as applicable.

Question: What are the required procedures for jurisdictional entities that want to change its capitalization policy over pension and PBOP costs after the 2018 reporting period?

Response: While either approach to capitalization of pension and PBOP costs as discussed herein is acceptable, there is a risk that the approach elected by companies will change from one period to the next in order to influence rate outcomes. Accordingly, jurisdictional entities are required to be consistent in all future periods using the capitalization approach elected after effectuation of ASU No. 2017-07 or during the 2018 reporting period. They must write in to the Commission for approval if there is any change of capitalization policy for pension and PBOP costs in the future.

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2017). The Director has designated this authority to the Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2017).

Sincerely,

Bryan K. Craig
Chief Accountant and Director
Division of Audits and Accounting
Office of Enforcement

Document Content(s)

UNDERTAKING J6.5

Reference:

K6.3

Oral Hearing Volume 6, Page 72, Line 4 – Page 74, Line 25

Undertaking:

Explain the order of magnitude or provide a sense of what is the bigger driver for the transmission allocated FTEs between distribution application and transmission application.

Response:

Exhibit K6.3 summarizes the difference in Transmission allocated FTEs presented in the Distribution Application (EB-2017-0049) and the current Transmission Application as provided in Exhibit I, Schedule 7, Tab SEC-58. Hydro One notes that the two applications are underpinned by different business plans, the 2017 – 2022 Business Plan was the basis of the EB-2017-0049, while the 2019 – 2024 is the basis for the current application.

The primary drivers behind the changes between the Transmission allocated FTEs are as follows:

1. An increase in Hydro One Networks engineers transferred from Hydro One Telecom. This was not previously contemplated under the Distribution application (EB-2017-0049);
2. An increase in Health, Safety and Environment resources, particularly in light of the helicopter incident. This was not previously contemplated under the Distribution application (EB-2017-0049);
3. Additional resources to support the strategic sourcing initiative. This was not previously contemplated under the Distribution application (EB-2017-0049); and
4. Changes in the Transmission work program.

The first three points noted above are the main drives for the changes in FTE levels.

Witness: Sabrin Lila

UNDERTAKING J6.6

Reference:

J1.1

Oral Hearing Volume 6, Page 83, Line 5 – Page 84, Line 21

Undertaking:

To explain the translation of Progressive Productivity CapEx to In-Service Additions.

Response:

As discussed in Exhibit B-1-1, TSP Section 1.6 Pages 7 and 8, Hydro One has reduced capital costs by an amount identified as progressive productivity, which represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes. As this commitment is to find further efficiencies through additional productivity improvements, the reductions are envelope based. As a result, an assumption had to be completed to translate the capital expenditure envelope reductions, to how assets would be placed in-service.

The impact of the capital Progressive Productivity Placeholder was translated to In-Service Addition impacts using a proportional ratio of Sustainment Capital Expenditures to In-Service Additions based on forecasted envelope level rates over the Plan years.

UNDERTAKING J6.7

Reference:
JT-2.28
Oral Hearing Volume 6, Page 85, Line 22 – Page 87, Line 19

Undertaking:
To check whether the $5 million in Progressive Defined Productivity included at Exhibit JT-2.28 were embedded into the plan for 2019.

Response:
The $5 million Progressive Defined Productivity for 2019 which is evident from JT-2.28 reflects all the defined initiatives for 2019, and as such the dollars were allocated to the related initiatives and embedded within the capital categories in the 2019 bridge year. 2019 is also considered a budget year for the company.

The remaining years (2020-2024) utilize the Progressive Productivity Placeholder approach. Hydro One allocates committed Defined Progressive initiatives to specific drivers in the budget year (currently 2019). As initiatives are defined, they will be assessed within normal planning processes and planned at the appropriate project or program level. The format provided in undertaking JT-2.28 will always track the progress of the Progressive Initiatives in order to maintain consistency and allow for comparability across rate applications, but the detailed Plan will be built up according to where the initiatives land.

UNDERTAKING J6.8

Reference:
Oral Hearing Volume 6, Page 108, Line 21 – Page 110, Line 27

Undertaking:
To provide a list of instances, under either transmission or distribution, where HONI is relying on a regulator's decision that allows it to apply the principles of rate regulation and depart from the US GAAP standard that would not otherwise apply to a non-rate-regulated company.

Response:
Since Hydro One adopted US GAAP in 2012, the OEB has approved a number of instances allowing the company to depart from US GAAP as it applies to non-rate-regulated entities, and as permitted under US GAAP Accounting Standards Codification 980 – Regulated Operations (ASC 980).

These instances have generally arisen where there is a change in law or policy or other external conditions that would result in either (or both):

- A significant rate impact;
- Intergenerational inequity, where the costs incurred in providing service in one period are paid in a different period;

In other words, anytime the OEB has ordered a deferral or variance account to address either of the above-noted issues, there is a departure from US GAAP which is permitted under ASC 980.

Under US GAAP for non-rate-regulated entities, costs are recorded in the period in which they are incurred whereas under regulatory principles, effort is made to match costs to the period in which ratepayers benefit from the costs. The resulting accounting treatments are acceptable under US GAAP.

In this instance, a change to US GAAP standards precipitated by the Financial Accounting Standards Board's new Accounting Standards Update (ASU) No. 2017-07 "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost" (ASU 2017-07) creates both a large rate impact and an inequitable matching of costs.

ASU 2017-07 specifies how pension and OPEB costs should be presented on the income statement under US GAAP and what components of those costs are eligible for capitalization in assets. Consequently, without OEB approval to do otherwise, Hydro One must stop capitalizing the non-service cost component of its OPEBs and must recover this amount through Operations, Maintenance, and Administration expenses (OM&A) instead. This will give rise to revenue requirement increases of $21 million for Transmission and $15 million for Distribution in 2020, and similar amounts in future years.[1]

The OEB may allow Hydro One to continue capitalizing the non-service component of OPEBs and, under ASC 980, Hydro One would be permitted to do so and would remain compliant with US GAAP. This avoids both a large rate impact and an inequitable matching of costs. For the reasons set out in response to undertaking J-6.04, Hydro One submits that this produces the most equitable result for ratepayers (as it effectively retains the cost ratepayers would have otherwise seen absent the accounting change).

In fact, the Federal Energy Regulatory Commission (FERC) took this approach in its guidance dated December 28, 2017, in which it allowed the continued capitalization of both the service and non-service cost components of pensions and OPEBs. A copy of the FERC letter is provided in Attachment 1 of undertaking response J-6.04.

This response to the undertaking details: (i) the parameters of ASC 980; and (ii) prior instances where the OEB has approved a departure from US GAAP principles, as permitted for rate-regulated enterprises such as Hydro One by ASC 980.

Hydro One is asking the OEB to allow the continued capitalization of the non-current component of OPEB costs. Absent OEB approval, these costs would have to be recognized as expenses annually.

ASC 980

Hydro One has been using rate regulated accounting since 1999. Prior to the adoption of US GAAP in 2012, Hydro One used Legacy Canadian GAAP, which contained limited guidance on rate regulation. Where there was no guidance under Legacy Canadian GAAP, companies referred to and securities regulators (such as the Ontario Securities Commission) permitted reliance on US GAAP Accounting Standards Codification 980 – Regulated Operations (ASC 980) (formerly Financial Accounting Standard 71 –

[1] Refer to response to J6.4 for further details

Accounting for the Effects of Certain Types of Regulation). Thus, the transition from Legacy Canadian GAAP to US GAAP has not introduced any new basis of accounting or fundamentally changed the accounting Hydro One uses; rather, it is a continuation of historical practices as the fundamental principles under Legacy Canadian GAAP and US GAAP are the same.

Rate regulated accounting (per ASC 980) applies when all of the following criteria are met:

1. Rates are established by an independent third-party regulator or the entity's own Governing board;
2. Rates are designed to recover costs of service; and
3. Rates designed to recover costs can be charged to and collected from customers.

The purpose of ASC 980 is summarized in PricewaterhouseCooper's "Utilities and Power Companies" accounting guide (partially updated December 2018) ("PWC Guidance") as follows:

> *The purpose of ASC 980 is for financial reporting to reflect the economic effects of certain rate-regulated activities and actions taken by regulators that arise in the normal course of regulated operations. The basic premise of ASC 980 is that the actions of a regulator will impact the financial statements prepared for financial reporting purposes only if the action has an economic effect on the regulated utility and meets the requirements for recognition or deferral under the standard. A regulated utility should comply with U.S. GAAP applicable to entities in general with regard to its accounting and financial reporting. If it is also subject to ASC 980, the applicable provisions within that standard are applied as an adjustment to or in lieu of other U.S. GAAP (when specifically required by ASC 980).*[2]

Rate regulated accounting allows for the recognition of regulatory assets and liabilities. While the timing and recognition of related revenues and expenses may differ from that of non-regulated entities to which ASC 980 is not applicable. In other words, rate regulated accounting (per ASC 980) helps address instances where a change in law or

---

[2] PWC Guidance, p. 573 excerpt is provided as attachment 3 to this undertaking

policy or other external conditions result in either (or both) a rate shock or intergenerational inequity. The PWC Guidance on ASC 980 is helpful in this regard. It states:

> *One of the primary areas in which accounting by regulated utilities differs from unregulated entities is regulated utilities' ability to defer certain expenditures as regulatory assets that would otherwise be expensed under U.S. GAAP.*[3]

The ability for rate-regulated entities to recognize regulatory assets and liabilities in the form of deferral and variance accounts is inherently covered in the OEB's Accounting Procedures Handbook – the OEB expects utilities to report quarterly on the account balances. Moreover, the OEB expects utilities to bring forward any applicable regulatory accounts for disposition in their rate applications.

Examples of OEB Direction Permitting a Departure from US GAAP Principles

Attachment 1 of this Undertaking Response lists several instances from past Transmission and Distribution proceedings where the OEB approved a departure from standard US GAAP principles under ASC 980 to address large rate impact or intergenerational inequity since 2012 when Hydro One adopted US GAAP. In each of these instances, there is an associated deferral or variance account which allows the company to manage the rate impact or the intergenerational inequity. The corresponding benefit is passed on to ratepayers in the form of current and future rates.

In addition to the items noted in Attachment 1, there are other regulatory asset & liability mechanisms that Hydro One maintains, which a non-rate-regulated company would not otherwise be permitted to maintain under US GAAP. These accounts are detailed in the 2018 financial statements for Hydro One Transmission4 (Note 10) and Hydro One Distribution5 (Note 11). Such current examples include the following accounts, where Hydro One Transmission and Hydro One Distribution recognize a regulatory asset or regulatory liability based on the OEB's approval of the underlying transactions. The treatment of these accounts has been consistent since the inception of each account.

[3] PWC Guidance, p. 581 excerpt is provided as attachment 3 to this undertaking
[4] Exhibit A-6-2 Attachment 3
[5] Provided as Attachment 2 to this undertaking

1. ENVIRONMENTAL REGULATORY ASSET

Background: In 2001, Hydro One Networks revised its accounting policy for environmental costs to move from an incurred approach to one of full recognition. As part of this change, in EB-2001-0016, a request was made for an Accounting Order to establish a deferral account to record environmental costs incremental to those included in Networks' approved revenue requirement. The request recognized the net present value of estimated future cash flows expected to be required to discharge financial obligations associated with PCB management and the remediation of contaminated lands. These past service obligations are intended to be amortized over the term of the remediation program, as expenditures are incurred. The OEB approved the account.

Purpose and description of the account: Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. The expenditures are included in revenue requirement for the period in which they will be incurred. Based on the OEB's approval of expenditures for recovery in rates in prior periods, a regulatory asset is recognized because Hydro One considers it to be probable that environmental expenditures will continue to be recovered in the future through the rate-setting process.

Since 2001, Hydro One has included environmental contamination remediation costs in its OM&A requests in rate applications and reiterated the existence of the offsetting regulatory asset (See Exhibit A, Tab 12 in EB-2005-0378).

2. SHARE-BASED COMPENSATION REGULATORY ASSET

Background: In 2015, as part of the settlement with the Power Workers' Union ("PWU") and Society of United Professionals ("Society") during the collective bargaining process, eligible PWU and Society employees were awarded shares in exchange for concessions on pension costs. The share-based compensation costs are included for recovery in the year in which the grant is settled, as this is when ratepayers benefit from the work performed by PWU and Society employees.

Purpose and description of the account: Hydro One recognizes costs associated with share grant plans in a regulatory asset, and costs of the share grant plans costs will be sought for recovery in the corresponding rate period. In the absence of rate-regulated accounting, there would be an instant impact on OM&A expenses.

Share based compensation is part of the overall compensation cost of represented employees for each year in which the shares are issued to the eligible employees. These costs were included and discussed in Hydro One's capital and OM&A evidence in its most recent distribution and transmission rate applications (EB-2016-0160 and EB–2017-0049) and Hydro One manages its compensation, including share based compensation, within OEB approved envelopes. As a result, Hydro One recognizes a regulatory asset under ASC 980 to defer the expense (that would otherwise be recognized under ASC 718, Compensation – Stock Compensation) to the period in which it will be incurred and approved for recovery as part of Hydro One's capital and OM&A envelopes.

This approach maintains generational equity in that the pension plan valuations that will be conducted from this point forward which will impact (reduce) the cash pension contributions (which are recovered in rates) commencing 2017 and better matches the ongoing reduction in company pension costs with the temporary increase in compensation costs for the eligible represented employees.

3. DEFERRED INCOME TAX REGULATORY ASSET AND LIABILITY

Background: In August 2007, the Accounting Standards Board decided to remove a temporary exemption in CICA Handbook Section 1100, retain existing references to rate regulated accounting in the CICA Handbook, require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes, and retain existing requirements to disclose the effects of rate regulation.

Purpose and description of the account: Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company can recognize regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, there would be an impact on income tax expense.

Since 2009, Hydro One has recorded a deferred tax asset due to the existence of temporary differences. Hydro One shares this deferred tax asset with ratepayers, which gives rise to the offsetting regulatory liability. The OEB has approved Hydro One's inclusion of deferred income taxes in its revenue requirement.

4. POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS REGULATORY ASSET

Purpose and description of the account: This account balance is made up of any OPEB actuarial gain/loss that would be recognized within Accumulated Other Comprehensive Income (AOCI) under the provisions of ASC 715 (Compensation – Retirement Benefits) and would be amortized to accrual-basis expense in future periods. Based on the OEB's approval of recovery of OPEB costs on an accrual-basis, Hydro One recognizes a regulatory mechanism (regulatory asset or liability) on the basis that it is probable that accrual-basis OPEB costs including the amortization of any actuarial gain/loss from AOCI would continue to be approved and included in future rates.

HYDRO ONE DISTRIBUTION

Proceeding	Proceeding Description	Request	Request Initiator	Outcome
EB-2011-0399	Distribution 2012 rates and adoption of US GAAP	Discontinue the "Impact for Changes in IFRS Account"	Hydro One, as a result of requesting to adopt US GAAP for rate setting, regulatory accounting, and regulatory reporting.	OEB approved
		Continue the "IFRS Incremental Transition Costs Account" with modified scope - to change name to "US GAAP – Incremental Transition Costs Account"	Hydro One, as a result of requesting to adopt US GAAP for rate setting, regulatory accounting, and regulatory reporting.	OEB approved
		Establish the "Impact for US GAAP Account"	Hydro One, as a result of requesting to adopt US GAAP for rate setting, regulatory accounting, and regulatory reporting.	OEB approved
EB-2012-0136	Distribution 2013 rates	Continue the "Smart Grid Deferral Account"	Hydro One	OEB approved
EB-2013-0416	Distribution 2015-2017 rates	Continue the "Tax Rate Changes Account"	Hydro One	OEB approved
		Continue the "Pension Cost Differential Account"	Hydro One	OEB approved
		Establish a new 2015 "Bill Impact Mitigation Variance Account"	Hydro One, in order to limit the bill impact of those customers that are moving to a rate class classification with higher rates as a result a rate class review. The bill impact is limited to higher of 10% or $3 for residential customers, 10% or $10 for General Service Energy Billed Customers and 10% or $100 for General Service Demand Billed Customers	OEB approved
		Establish a new "Rate Smoothing Deferral Account"	Hydro One, due to large increase in revenue requirement in 2015.	OEB disapproved - revenue requirement and rates approved in this Application were in place for 3 years as opposed to 5
		Discontinuance of the following accounts: 1) Smart Meter – Minimum Functionality 2) Smart Meter – Exceeding Minimum Functionality 3) Distribution Generation – Other Costs – HONI - Variance Account 4) Distribution Generation - Express Feeders – HONI - Variance Account 5) Distribution System Code (DSC) Exemption Deferral Account 6) Deferred Revenue Project Costs Variance Account (2009) 7) Generator Joint Use Revenue Variance Account 8) Special Purpose Charge Variance Account 9) Microfit Connection Charge Variance Account 10) OEB Cost Differential Account 11) Smart Grid Variance Account	Hydro One requested discontinuation of the accounts. Notes below: 1 and 2) Accounts were first directed to be set up by the Minister of Energy and the smart meters initiatives ended by the end of 2014. 3 and 4) Accounts were first directed to be set up by the OEB. Increasing renewable generation was one of the key objectives of the Green Energy and Green Economy Act, 2009 ("GEGEA"). The Hydro One Distribution Green Energy Plan (the "Plan") in EB-2009-0096 presented the Company's response to the GEGEA in alignment with Hydro One's corporate strategy. 10) Account was first directed to be set-up by the OEB on February 6, 2016 and utilities were instructed to discontinue the account when their rates rebased during their next Application. 11) Account was first directed to be set up by the OEB in EB-2009-0096.	OEB approved
EB-2015-0040	Report of the OEB - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs	The OEB provides for the establishment of the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account on a generic basis in this Report.	OEB Directive	In EB-2019-0082, Hydro One requests that the OEB approve a modified approach to calculate the reference amount
EB-2017-0049	Distribution 2018-2022 rates	Establish an "Earnings Share Mechanism Account"	Hydro One	OEB approved
		Establish an "OPEB Cost Deferral Account"	Hydro One	OEB approved
		Establish a "Lost Revenue Adjustment Mechanism Variance Account"	Hydro One	OEB disapproved
		Establish a "Capital In-Service Additions Variance Account"	Hydro One	OEB approved
		Establish a "Bill Impact Mitigation Variance Account – Acquired Utilities"	Hydro One	OEB disapproved
		Establish a "Integrated System Operating Center (ISOC) Asymmetric Variance Account"	OEB Directive	
		Discontinuance of the following accounts: 1) Rural or Remote Electricity Rate Protection (RRRP) Variance Account 2) Bill Impact Mitigation Variance Account (2015) 3) Revenue Offset Difference Account – Pole Attachment Charge 4) Revenue Difference Account – Pole Attachment Charge	Hydro One	OEB approved
OEB Accounting Direction - July 25, 2019		Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance. Establishment of a separate sub-account of Account 1592 - PILs and Tax Variances – CCA Changes specifically for the purposes of tracking the impact of changes in CCA rules.	OEB Directive	

In the most recently OEB approved Distribution Rates Application (EB-2017-0049), Hydro One requested continuance of the following regulatory accounts: Retail Settlement Variance Accounts (RSVAs), Retail Cost Variance Accounts (RCVAs), Pension Cost Differential Account, Tax Rate Changes Account, OEB Cost Differential Account, Smart Meter Entity (SME) Charge Variance Account, and Long Term Load Transfer Rate Impact Mitigation Deferral Account. The OEB approved the continuance of these accounts.

HYDRO ONE TRANSMISSION

Proceeding	Proceeding Description	Request	Request Initiator	Outcome
EB-2011-0268	Transmission 2012 rates and adoption of US GAAP	Discontinue the "Impact for Changes in IFRS Account (2012 only)", the "IFRS – Gains and Losses Account (2012 only)", and the "IFRS Capitalization Policy Variance Account (2012 only)".	Hydro One, as a result of requesting to adopt US GAAP for rate setting, regulatory accounting, and regulatory reporting.	OEB approved
		Continue the "IFRS Incremental Transition Costs Account" with modified scope - to change name to "US GAAP – Incremental Transition Costs Account"	Hydro One, as a result of requesting to adopt US GAAP for rate setting, regulatory accounting, and regulatory reporting.	OEB approved
		Establish the "Impact for US GAAP Account (2012 only)"	Hydro One, as a result of requesting to adopt US GAAP for rate setting, regulatory accounting, and regulatory reporting.	OEB approved
EB-2012-0031	Transmission 2013 and 2014 rates	Establishment of the "External Revenue - Partnership Transmission Projects Account"	Hydro One requested the approval to establish the account	OEB approved
		Establishment of the "Long-term Transmission Future Corridor Acquisition and Development Account"	Hydro One requested the approval to establish the account	OEB approved
		Establishment of the "Other External Revenues Variance Account"	As part of the settlement agreement Hydro one agreed to establish a new symmetrical variance account to track differences in Other External Revenue (as this was the only input into External Revenue which was not previously tracked in the other 3 symmetrical variance accounts)	OEB approved
		Discontinuance of the following accounts: 1) Deferred Export Service Credit Revenue Account 2) Long Term Project Development Costs Account 3) Impact for US GAAP Account 4) US GAAP – Incremental Transition Costs Account	Hydro One	OEB approved
		Establishment of the "Conservation and Demand Management (CDM) Variance Account"	Hydro One, resulting from concerns from certain intervenors about the accuracy and reliability of the CDM and Demand Response forecasts prepared by the OPA (now the IESO).	OEB approved
EB-2012-0180	Request to establish the East West Tie Deferral Account (EWTDA)	Establishment of the "EWTDA"	Hydro One requested this account because The Minister of Energy sent a letter to the Board (March 29, 2011) suggesting that the designation process, outlined in the new Board policy "Framework for Transmission Project Development Plans (EB-2010-0059)" be used to select a transmission company for the EWT Line.	OEB approved
EB-2013-0421	Leave to construct a new transmission line and facilities in the Windsor-Essex Region, Ontario.	Establishment of the "Supply to Essex County Transmission Reinforcement Deferral Account"	Hydro One	OEB approved
EB-2014-0140	Transmission 2015-2016 rates	Establishment of a net cumulative asymmetrical variance account for 2014, 2015, and 2016 to track the impact on revenue requirement of any in-service capital additions shortfall compared to Board approved amounts, for disposition in a future rates application.	Hydro One requested this account because Intervenors expressed concern, regarding Hydro One's historic ISA levels compared to Board-approved ISA levels. To address this concern, parties agreed to create a net cumulative asymmetrical variance account for 2014, 2015, and 2016 to track the impact on revenue requirement of any ISA shortfall compared to Board approved amounts, for disposition in a future rates application.	OEB approved
EB-2014-0311	Request for an Accounting Order to Establish a Deferral Account for Preliminary Development work relating to the North West Bulk Transmission Line Project (NWBTL).	Establishment of the "North West Bulk Transmission Line Deferral Account"	Hydro One requested this account because the NWBTL Project was identified as a priority project in the 2013 Long-Term Energy Plan (LTEP) and in December 2013, Hydro One received a directive from the Ministry of Energy (see Attachment A) to begin the development phase of the project and subsequent to that letter, the OEB included this request as a condition to Hydro One Transmission's license in January 2014 (EB-2013-0437).	OEB approved
EB-2015-0040	Report of the OEB - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs	The OEB provides for the establishment of the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account on a generic basis in this Report.	OEB Directive	In EB-2019-0082, Hydro One requests that the OEB approve a modified approach to calculate the reference amount
EB-2016-0160	Transmission 2017-2018 rates	In EB-2015-0040, the OEB provides for the establishment of the Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account on a generic basis in this Report.	OEB Directive	Hydro One requests that the OEB approve a modified approach to calculate the reference amount - OEB decision is pending
		Establishment of the "Foregone Transmission Revenue Account"	OEB Directive	
		Closure of the "LDC CDM and DR Variance Account"	Hydro One	OEB disapproved
		Establish an "Incentive Payments Deferral Account"	Energy Probe	OEB disapproved
EB-2018-0269	2018 Transmission Revenue Requirement and Charge Determinants, Reconsideration of Future Tax Savings	The OEB determined in EB-2016-0160 that a portion of the future tax savings resulting from the Government of Ontario's decision to sell its ownership interest in Hydro One Limited by way of an IPO and subsequent sale of shares should be applied to reduce Hydro One's revenue requirement for 2017 and 2018.	Hydro One did not make this request - it was imposed to Hydro One by the OEB.	The OEB found that the Original Decision which resulted in the allocation of the future tax savings (62% to shareholder and 38% to ratepayers) was within the realm of reasonable outcomes. Therefore, this gave rise to the deferred income tax regulatory liability.

EB-2018-0130	Transmission 2019 rates	Establish a "Revenue Cap Index Parameters Differential Account"	Hydro One	OEB disapproved
		Discontinuance of the "OEB Cost Assessment Variance Account"	Account was first directed to be set-up by the OEB on February 6, 2016 and utilities were instructed to discontinue the account when their rates rebased during their next Application.	OEB approved
OEB Accounting Direction - July 25, 2019		Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance. Establishment of a separate sub-account of Account 1592 - PILs and Tax Variances – CCA Changes specifically for the purposes of tracking the impact of changes in CCA rules.	OEB Directive	
EB-2019-0151	Application for an accounting order approving the establishment of a tracking deferral account	Approval of the Waasigan Transmission Tracking Deferral Account (WTTDA)	Hydro One requested this account because The Minister of Energy issued an Order in Council No. 1701/2013 and Directive to the OEB for Hydro One to commence development work on the North West Bulk Transmission Line (since renamed to Waasigan Transmission Line Project (the Project)) in 2013, and on October 24, 2018, the IESO confirmed the need for the Project. The project has now reached the stage where costs will be capitalized and recorded in CWIP.	OEB approved

In the most recently OEB approved Transmission Rates Application (EB-2018-0130), Hydro One requested continuance of the following regulatory accounts: Excess Export Service Revenue, External Secondary Land Use Revenue, External Station Maintenance, E&CS and Other External Revenue, Tax Rate Changes, Rights Payments, Pension Cost Differential, Long-Term Transmission Future Corridor Acquisition and Development, LDC CDM Variance Account, External Revenue – Partnership Transmission Projects Account, In-Service Capital Additions Variance Account, NWBTL Account, SECTR Account, and EWT Deferral Account. The OEB approved the continuance of these accounts.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2018

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the carve-out financial statements of the Distribution Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve out balance sheet as at December 31, 2018
- the carve out statement of operations and comprehensive income for the year then ended
- the carve out statement of cash flows for the year then ended
- and notes to the carve out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "carve-out financial statements").

In our opinion, the accompanying carve-out financial statements as at and for the year ended December 31, 2018 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these carve-out financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Carve-Out Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Preparation

We draw attention to Note 2 to the carve-out financial statements which describes the basis of preparation used in these carve-out financial statements.

The purpose of the carve-out financial statements is to meet Hydro One Networks Inc.'s obligation to the Ontario Energy Board. As a result, these carve-out financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Carve-Out Financial Statements

Management is responsible for the preparation of the carve-out financial statements in accordance with the financial reporting framework described in Note 2 in the carve-out financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Carve-Out Financial Statements

Our objectives are to obtain reasonable assurance about whether the carve-out financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the carve-out financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the carve-out financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the carve-out financial statements, including the disclosures, and whether the carve-out financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 25, 2019

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2018 and 2017

Year ended December 31 *(millions of Canadian dollars)*	2018	2017
Revenues		
Energy sales	4,078	4,005
Rural rate protection *(Note 22)*	239	247
Other	52	63
	4,369	4,315
Costs		
Purchased power *(Note 22)*	2,900	2,875
Operation, maintenance and administration *(Note 22)*	568	567
Depreciation, amortization and asset removal costs *(Note 4)*	396	388
	3,864	3,830
Income before financing charges and income taxes	**505**	**485**
Financing charges *(Notes 5, 22)*	174	165
Income before income taxes	**331**	**320**
Income taxes *(Note 6)*	50	55
Net income	**281**	**265**
Other comprehensive income	—	—
Comprehensive income	**281**	**265**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
At December 31, 2018 and 2017

December 31 *(millions of Canadian dollars)*	2018	2017
Assets		
Current assets:		
Accounts receivable *(Note 7)*	578	588
Due from related parties *(Note 22)*	125	119
Other current assets *(Note 8)*	34	38
	737	745
Property, plant and equipment *(Note 9)*	7,511	7,324
Other long-term assets:		
Regulatory assets *(Note 11)*	204	638
Intangible assets *(Note 10)*	309	289
Goodwill	168	168
Other assets	—	1
	681	1,096
Total assets	**8,929**	**9,165**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 22)*	392	213
Long-term debt payable within one year *(Notes 14, 15, 22)*	291	337
Accounts payable and other current liabilities *(Note 12)*	720	679
Due to related parties *(Note 22)*	84	153
	1,487	1,382
Long-term liabilities:		
Long-term debt *(Notes 14, 15, 22)*	3,620	3,498
Deferred income tax liabilities *(Note 6)*	33	499
Regulatory liabilities *(Note 11)*	217	84
Other long-term liabilities *(Note 13)*	856	934
	4,726	5,015
Total liabilities	**6,213**	**6,397**
Contingencies and Commitments (Notes 24, 25)		
Subsequent Events (Note 26)		
Excess of assets over liabilities *(Notes 16, 20)*	2,716	2,768
Total liabilities and excess of assets over liabilities	**8,929**	**9,165**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

William Sheffield
Chair, Audit Committee

Russel Robertson
Director

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	281	265
Environmental expenditures	(15)	(15)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	345	337
Regulatory assets and liabilities	53	172
Deferred income taxes	(15)	(44)
Other	6	5
Changes in non-cash balances related to operations *(Note 23)*	(27)	173
Net cash from operating activities	**628**	**893**
Financing activities		
Long-term debt issued	412	—
Long-term debt repaid	(337)	(195)
Payments to finance dividends and return on stated capital	(333)	(263)
Change in inter-company demand facility	177	138
Other	(2)	—
Net cash used in financing activities	**(83)**	**(320)**
Investing activities		
Capital expenditures *(Note 23)*		
Property, plant and equipment	(483)	(522)
Intangible assets	(75)	(56)
Other	13	(4)
Net cash used in investing activities	**(545)**	**(582)**
Net change in cash and cash equivalents	—	(9)
Cash and cash equivalents, beginning of year	—	9
Cash and cash equivalents, end of year	**—**	**—**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly-owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

Rate Setting

OEB March 7, 2019 Decisions

Subsequent to year end, on March 7, 2019, the OEB issued a decision on its reconsideration of its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements dated September 28, 2017 (Original Decision) with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange.

The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under United States (US) Generally Accepted Accounting Principles (GAAP). As a result, the financial impact of this OEB decision has been reflected in these financial statements, as more fully discussed in Note 11 - Regulatory Assets and Liabilities.

Distribution

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. The revenue requirements of $1,459 million for 2018, $1,498 million for 2019, $1,532 million for 2020, $1,578 million for 2021, and $1,624 million for 2022 were based on the OEB decision received on March 7, 2019. See Note 26(C) - Subsequent Events - OEB Regulatory Decisions.

On November 17, 2017, Hydro One filed with the OEB a request for 2018 interim rates based on 2017 OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim 2018 rates based on 2017 OEB-approved rates with no adjustments.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with US GAAP, with the exception that business combinations of entities under common control have been accounted for as of the date of the transfer, such that (1) the Financial Statements were not prepared as though the transfer of entities under common control had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted.

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated Financial Statements of Hydro One for the year ended December 31, 2018 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Distribution Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. These Financial Statements include deferred taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 25, 2019, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 26 - Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations, asset impairments, contingencies, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Distribution Business' regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission Business continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Distribution Business judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a Type I subsequent event.

Revenue Recognition

The Company adopted Accounting Standard Codification (ASC) 606 - *Revenue from Contracts with Customers* on January 1, 2018 using the retrospective method, without the election of any practical expedients. There was no material impact to the Company's revenue recognition policy as a result of adopting ASC 606, and no adjustments were made to prior period reported financial statements amounts.

Nature of Revenues

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes. Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' best estimate of losses on billed accounts receivable balances. The Distribution Business estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Distribution Business records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Distribution Business' intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent review resulted in changes to rates effective January 1, 2015 for Hydro One Networks' distribution business. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate	
	Service Life	Range	Average
Property, plant and equipment:			
Distribution	47 years	1% - 7%	2%
Communication	8 years	1% - 15%	12%
Administration and service	20 years	1% - 20%	5%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on assessment performed as at September 30, 2018, the Company has concluded that goodwill was not impaired at December 31, 2018.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Distribution Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2018 and 2017, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI and net income are presented in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 15 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation at December 31, 2018 or 2017.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the Consolidated Statements of Operations and Comprehensive Income.

<u>Defined Benefit Pension</u>

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

<u>Post-retirement and Post-employment Benefits</u>

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One’s incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the “corridor” approach. The amount calculated above the “corridor” is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the “corridor” approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with the Directors’ and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Distribution Business' Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Distribution Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Distribution Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Distribution Business records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm’s length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company’s credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company’s distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company’s easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Distribution Business expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Distribution Business' asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact
ASC 606	May 2014 – November 2017	ASC 606 *Revenue from Contracts with Customers* replaced ASC 605 *Revenue Recognition*. ASC 606 provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.	January 1, 2018	On January 1, 2018, the Company adopted ASC 606 using the retrospective method, without the election of any practical expedients. Upon adoption, there was no material impact to the Company's revenue recognition policy and no adjustments were made to prior period reported financial statements amounts. The Company has included the disclosure requirements of ASC 606 for annual and interim periods in the year of adoption.
ASU 2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company’s employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	The Company applied for a regulatory asset to maintain the capitalization of post-employment benefit related costs and as such, there is no material impact upon adoption. See Note 2 - Significant Accounting Policies and Note 11 - Regulatory Assets and Liabilities.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
2016-02 2018-01 2018-10 2018-11 2018-20 2019-01	February 2016 – March 2019	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under ASC 842 land easements that exist or expired before the entity's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. ASU 2018-10 amends narrow aspects of ASC 842. ASU 2018-11 provides entities with an additional and option transition method in adopting ASC 842. ASU 2018-11 also permits lessors to elect an optional practical expedient to not separate non-lease components from the associated lease component by underlying asset classes. ASU 2018-20 provides relief to lessors that have lease contracts that either require lessees to pay lessor costs directly to a third party or require lessees to reimburse lessors for costs paid by lessors directly to third parties. ASU 2019-01 provides clarification on three issues: determining the fair value of the underlying assets by lessors that are not manufacturers or dealers, presentation of statement of cash flows for sales-type and direct financing leases and interim transition disclosures relating to Topic 250, Accounting Changes and Error Corrections.	January 1, 2019	The Distribution Business reviewed its existing leases and other contracts that are within the scope of ASC 842. Apart from the existing leases, no other contracts contained lease arrangements. Upon adoption in the first quarter of 2019, the Distribution Business will utilize the modified retrospective transition approach using the effective date of January 1, 2019 as its date of initial application. As a result, comparatives will not be updated. The Distribution Business will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to the Distribution Business' financial statements will be the recognition of approximately $12 million of Right-of-Use (ROU) assets and corresponding lease obligations on the Balance Sheet. The ROU assets and lease obligations represent the present value of the Distribution Business' remaining minimum lease payments for leases with terms greater than 12 months. Discount rates used in calculating the ROU assets and lease obligations correspond to Hydro One's incremental borrowing rate.
2018-07	June 2018	Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees.	January 1, 2019	No impact upon adoption
2018-13	August 2018	Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	Under assessment
2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	Under assessment
2018-15	August 2018	The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The accounting for the service element of a hosting arrangement is not affected by the amendment.	January 1, 2020	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2018	2017
Depreciation of property, plant and equipment	278	278
Amortization of intangible assets	52	44
Amortization of regulatory assets	15	15
Depreciation and amortization	345	337
Asset removal costs	51	51
	396	388

hydro One

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2018	2017
Interest on long-term debt *(Note 22)*	168	170
Interest on inter-company demand facility *(Note 22)*	4	2
Other	10	4
Less: Interest capitalized on construction and development in progress	(8)	(11)
	174	165

6. INCOME TAXES

As a rate regulated utility business, the Distribution Business's effective tax rate excludes temporary differences that are recoverable in future rates charged to customers. Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2018	2017
Income before income taxes	331	320
Income taxes at statutory rate of 26.5% (2017 - 26.5%)	88	85
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(20)	(15)
Overheads capitalized for accounting but deducted for tax purposes	(7)	(7)
Pension contributions in excess of pension expense	(5)	(6)
Environmental expenditures	(4)	(4)
Interest capitalized for accounting but deducted for tax purposes	(2)	(3)
Other	(1)	4
Net temporary differences	(39)	(31)
Net permanent differences	1	1
Total income taxes	50	55
Effective income tax rate	15.1%	17.2%

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2018	2017
Current income taxes	65	99
Deferred income taxes (recovery)	(15)	(44)
Total income taxes	50	55

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2018 and 2017, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2018	2017
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(362)	(808)
Goodwill	(10)	(10)
Post-retirement and post-employment benefits expense in excess of cash payments	291	311
Regulatory amounts that are not recognized for tax purposes	32	(17)
Environmental expenditures	22	30
Non-capital losses	1	1
Other	(7)	(6)
Net deferred income tax liabilities	(33)	(499)

The net deferred income tax liabilities are presented on the Balance Sheets as long-term liabilities.

7. ACCOUNTS RECEIVABLE

December 31 *(millions of dollars)*	2018	2017
Accounts receivable – billed	262	276
Accounts receivable – unbilled	336	341
Accounts receivable, gross	598	617
Allowance for doubtful accounts	(20)	(29)
Accounts receivable, net	578	588

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2018 and 2017:

Year ended December 31 *(millions of dollars)*	2018	2017
Allowance for doubtful accounts – beginning	(29)	(35)
Write-offs	26	25
Additions to allowance for doubtful accounts	(17)	(19)
Allowance for doubtful accounts – ending	(20)	(29)

8. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2018	2017
Regulatory assets *(Note 11)*	18	22
Prepaid expenses and other assets	11	12
Materials and supplies	5	4
	34	38

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2018 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	10,518	3,538	74	7,054
Communication	144	112	—	32
Administration and service	975	583	25	417
Easements	12	4	—	8
	11,649	4,237	99	7,511

[1] Includes future use assets totalling $50 million.

December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	10,155	3,488	147	6,814
Communication	145	99	2	48
Administration and service	991	561	25	455
Easements	11	4	—	7
	11,302	4,152	174	7,324

[1] Includes future use assets totalling $57 million.

Financing charges capitalized on property, plant and equipment under construction were $5 million in 2018 (2017 - $9 million).

10. INTANGIBLE ASSETS

December 31, 2018 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	492	247	30	275
Other	52	18	—	34
	544	265	30	309

December 31, 2017 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	428	201	23	250
Other	49	12	2	39
	477	213	25	289

Financing charges capitalized to intangible assets under development were $1 million in 2018 (2017 - $2 million). The estimated annual amortization expense for intangible assets is as follows: 2019 - $51 million; 2020 - $42 million; 2021 - $41 million; 2022 - $40 million; and 2023 - $31 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2018	2017
Regulatory assets:		
Deferred income tax regulatory asset	96	513
Environmental	61	83
Stock-based compensation	21	20
Post-retirement and post-employment benefits non-service cost	16	—
Distribution system code exemption	10	10
Post-retirement and post-employment benefits	—	20
Other	18	14
Total regulatory assets	222	660
Less: current portion	(18)	(22)
	204	638
Regulatory liabilities:		
Post-retirement and post-employment benefits	73	—
Green Energy expenditure variance	52	60
Retail settlement variance account	39	—
Pension cost differential	38	13
Deferred income tax regulatory liability	33	—
2015-2017 rate rider	6	6
PST savings deferral	4	4
Other	13	12
Total regulatory liabilities	258	95
Less: current portion	(41)	(11)
	217	84

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Distribution Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Distribution Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2018 income tax expense would have been lower by approximately $331 million (2017 - higher by $38 million).

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the Electricity Act (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One Limited shareholders and that a portion should be shared with ratepayers. On

November 9, 2017, the OEB issued a decision and order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of a portion of Hydro One Networks' transmission deferred income tax regulatory asset. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, it would also result in an additional impairment of a portion of Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Decision relating to the deferred tax asset to an OEB panel for reconsideration.

Subsequent to year end, on March 7, 2019, the OEB issued its reconsideration decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019 the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates.

As a result of these decisions, the Distribution Business has recognized a reduction in Hydro One Networks' distribution deferred income tax regulatory asset of $473 million, an increase in deferred income tax regulatory liability of $33 million, and a decrease in deferred tax liability of $506 million. Notwithstanding the recognition of the effects of the decision in the 2018 financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's deferred tax benefit decision.

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process In 2018, the environmental regulatory asset decreased by $10 million (2017 - $1 million) to reflect related changes in the Company's PCB and LAR environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been lower by $10 million (2017 - $1 million). In addition, 2018 amortization expense would have been lower by $15 million (2017 - $15 million), and 2018 financing charges would have been higher by $3 million (2017 - $4 million).

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One Networks applied to the OEB for a regulatory asset to record the components other than service costs relating to its post-retirement and post-employment benefits that would have previously been capitalized to property, plant and equipment and intangible assets prior to adoption of ASU 2017-07. In March 2019, the OEB approved the regulatory asset for Hydro One Networks' Distribution Business. Hydro One Networks has recorded the components other than service costs relating to its post-retirement and post-employment benefits that would have been capitalized to property, plant and equipment and intangible assets, in the Post-Retirement and Post-Employment Benefits Non-Service Cost Regulatory Asset.

Stock-based Compensation

The Distribution Business recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been higher by $1 million (2017 - $4 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Post-Retirement and Post-Employment Benefits

The Distribution Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory liability, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2018 OCI would have been higher by $93 million (2017 - $116 million).

Pension Cost Differential

A pension cost differential account was established for Hydro One Networks' Distribution Businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The Distribution Business balance as at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application. In the absence of rate-regulated accounting, 2018 revenue would have been higher by $25 million (2017 - $21 million).

Distribution System Code (DSC) Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the DSC, with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Networks distribution applications. In 2015, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2018 or 2017. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

Retail Settlement Variance Account (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The balance as at December 31, 2014, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015-2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administration expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2015 and recorded in a deferral account, as directed by the OEB. In March 2015, the OEB approved the disposition of the PST Savings Deferral account at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider.

12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2018	2017
Accrued liabilities	588	562
Accounts payable	53	66
Accrued interest *(Note 22)*	38	40
Regulatory liabilities *(Note 11)*	41	11
	720	679

13. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2018	2017
Post-retirement and post-employment benefit liability *(Note 17)*	781	838
Environmental liabilities *(Note 18)*	48	66
Long-term inter-company payable *(Note 22)*	17	18
Long-term accounts payable and other liabilities	5	8
Asset retirement obligations *(Note 19)*	5	4
	856	934

14. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Distribution Business outstanding at December 31, 2018 and 2017:

December 31 *(millions of dollars)*	2018	2017
Long-term debt	3,921	3,846
Add: Net unamortized debt premiums	7	8
Add: Unrealized mark-to-market gain[1]	(2)	(4)
Less: Deferred debt issuance costs	(15)	(15)
Less: Long-term debt payable within one year	(291)	(337)
Long-term debt	3,620	3,498

[1] The unrealized mark-to-market net gain relates to $30 million of notes due in 2020 and $200 million notes due in 2019. The unrealized mark-to-market net gain is offset by a $2 million (2017 - $4 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

In 2018, Hydro One issued $1,400 million (2017 - $nil) of long-term debt under its MTN Program, all of which was mirrored down to Hydro One Networks, and $412 million was allocated to the Company's Distribution Business.

In 2018, Hydro One repaid $750 million (2017 - $600 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $750 million (2017 - $600 million) to Hydro One, of which $337 million (2017 - $195 million) was allocated to the Company's Distribution Business.

Principal and Interest Payments

Principal repayments, interest payments, and related weighted-average interest rates are summarized by year in the following table:

Years	Long-term Debt Principal Repayments *(millions of dollars)*	Interest Payments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
2019	291	167	2.0
2020	150	160	3.9
2021	250	154	2.1
2022	261	148	3.2
2023	—	143	—
	952	772	2.7
2024-2028	376	684	3.1
2029 and thereafter	2,593	1,691	5.1
	3,921	3,147	4.3

15. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2018 and 2017, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Distribution Business' long-term debt at December 31, 2018 and 2017 are as follows:

December 31 *(millions of dollars)*	2018 Carrying Value	2018 Fair Value	2017 Carrying Value	2017 Fair Value
$200 million notes due 2019	198	198	197	197
$30 million notes due 2020	30	30	29	29
Other notes and debentures	3,683	4,028	3,609	4,159
Long-term debt, including current portion	3,911	4,256	3,835	4,385

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

At December 31, 2018, the Distribution Business' share of the Company's derivative instruments included $230 million (2017 - $230 million) interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was approximately 6% (2017 - 6%) of its total long-term debt. At December 31, 2018, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

- a $200 million fixed-to-floating interest-rate swap agreement to convert $200 million notes maturing on November 18, 2019 into three-month variable rate debt; and
- a $30 million fixed-to-floating interest-rate swap agreement to convert $30 million of the $350 million notes maturing on April 30, 2020 into three-month variable rate debt.

At December 31, 2018 and 2017, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2018 and 2017 is as follows:

December 31, 2018 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	392	392	392	—	—
Long-term debt, including current portion	3,911	4,256	—	4,256	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	—	2	—
	4,305	4,650	392	4,258	—

December 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	213	213	213	—	—
Long-term debt, including current portion	3,835	4,385	—	4,385	—
Derivative instruments					
Fair value hedges – interest-rate swaps	4	4	—	4	—
	4,052	4,602	213	4,389	—

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2018 or 2017.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Distribution Business' net income for the years ended December 31, 2018 and 2017.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Distribution Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2018 and 2017 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2018 and 2017, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business' revenue is earned from a broad base of customers. As a result, the Distribution Business did not earn a material amount of revenue from any single customer. At December 31, 2018 and 2017, there was no material accounts receivable balance due from any single customer.

At December 31, 2018, the Company's provision for bad debts was $20 million (2017 - $29 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2018, approximately 5% (2017 - 5%) of the Distribution Business' net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on the Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2018 and 2017, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2018, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund normal operating requirements.

16. CAPITAL MANAGEMENT

The Distribution Business' objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. At December 31, 2018 and 2017, the Distribution Business' capital structure was as follows:

December 31 *(millions of dollars)*	2018	2017
Long-term debt payable within one year	291	337
Inter-company demand facility	392	213
	683	550
Long-term debt	3,620	3,498
Excess of assets over liabilities	2,716	2,768
Total capital	7,019	6,816

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2018 and 2017:

Year ended December 31 *(millions of dollars)*	2018	2017
Excess of assets over liabilities - beginning	2,768	2,766
Net income	281	265
Payments to Hydro One to finance dividends and return of stated capital	(333)	(263)
Excess of assets over liabilities - ending	2,716	2,768

17. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. The Distribution Business contributions to the DC Plan for the year ended December 31, 2018 were less than $1 million (2017 - less than $1 million).

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. Annual Pension Plan contributions for 2018 were $75 million (2017 - $87 million). Estimated annual Pension Plan contributions for the years 2019, 2020, 2021, 2022, 2023 and 2024 are approximately $78 million, $77 million, $78 million, $79 million, $81 million and $83 million, respectively. The most recent actuarial valuation was performed effective December 31, 2017, and the next actuarial valuation will be performed no later than effective December 31, 2020. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

At December 31, 2018, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,752 million (2017 - $8,258 million). The fair value of pension plan assets available for these benefits was $7,205 million (2017 - $7,277 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2018, the Distribution Business charged $33 million (2017 - $35 million) of post-retirement and post-employment benefit costs to operation, and capitalized $31 million (2017 - $35 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2018 were $27 million (2017 - $24 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $93 million (2017 - $116 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets as follows:

December 31 *(millions of dollars)*	2018	2017
Accrued liabilities	27	26
Post-retirement and post-employment benefit liability	781	838
Net unfunded status	808	864

18. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2018 and 2017:

Year ended December 31, 2018 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	61	22	83
Interest accretion	2	1	3
Expenditures	(10)	(5)	(15)
Revaluation adjustment	(8)	(2)	(10)
Environmental liabilities - ending	45	16	61
Less: current portion	(9)	(4)	(13)
	36	12	48

Year ended December 31, 2017 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	66	29	95
Interest accretion	3	1	4
Expenditures	(10)	(5)	(15)
Revaluation adjustment	2	(3)	(1)
Environmental liabilities - ending	61	22	83
Less: current portion	(12)	(5)	(17)
	49	17	66

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

December 31, 2018 *(millions of dollars)*	PCB	LAR	Total
Undiscounted environmental liabilities	49	16	65
Less: discounting environmental liabilities to present value	(4)	—	(4)
Discounted environmental liabilities	45	16	61

December 31, 2017 *(millions of dollars)*	PCB	LAR	Total
Undiscounted environmental liabilities	64	23	87
Less: discounting environmental liabilities to present value	(3)	(1)	(4)
Discounted environmental liabilities	61	22	83

At December 31, 2018, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2019	14
2020	16
2021	13
2022	11
2023	10
Thereafter	1
	65

The Distribution Business records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution Business' environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCB

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $49 million (2017 - $64 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2018 to decrease the PCB environmental liability by $8 million (2017 - increase by $2 million).

LAR

The Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program is $16 million (2017 - $22 million). These expenditures are expected to be incurred over the period from 2018 to 2023. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2018 to decrease the LAR environmental liability by $2 million (2017 - $3 million).

19. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 4.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution Business' asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, the Company recorded a revaluation adjustment in 2018 to increase the asset retirement liability for the Distribution Business by $1 million (2017 - $nil).

At December 31, 2018, Hydro One Networks had recorded asset retirement obligations of $5 million (2017 - $4 million) related to its Distribution Business, primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

20. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2018 and 2017, Hydro One Networks had 207,557,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2018, Hydro One Networks declared common share dividends in the amount of $1 million (2017 - $2 million) and made a return of stated capital of $545 million (2017 – $509 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends and return of stated capital was $333 million (2017 - $263 million).

21. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (formerly the Society of Energy Professionals) (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an inter-company agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 2,152,519 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 743,877 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Distribution Business was $59 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2018, 248,109 common shares were issued under the Share Grant Plans (2017 - 186,489) to eligible employees of Hydro One Networks and allocated to the Distribution Business. Total stock-based compensation recognized by the Distribution Business during 2018 was $6 million (2017 - $8 million) and was recorded as a regulatory asset.

A summary of the Distribution Business' share grant activity under the Share Grant Plans during years ended December 31, 2018 and 2017 is presented below:

Year ended December 31, 2018	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,599,170	$20.50
Vested and issued[1]	(248,109)	—
Forfeited	(55,187)	$20.50
Share grants outstanding - ending	2,295,874	$20.50

[1] In 2018,Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2017	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	2,853,079	$20.50
Vested and issued[1]	(186,489)	
Forfeited	(67,420)	$20.50
Share grants outstanding - ending	2,599,170	$20.50

[1] In 2017, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU Share Grant Plan. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2018 and 2017, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2018	2017
DSUs outstanding - beginning	74,268	53,481
Granted	19,457	20,787
Settled	(52,618)	—
DSUs outstanding - ending	41,107	74,268

For the year ended December 31, 2018, an expense of $nil (2017 - $nil) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2018, a liability of $nil (2017 - $1 million) related to Directors' DSUs has been recorded at the December 31, 2018 closing price of Hydro One Limited common shares of $20.25. This liability is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

DSUs related to the Company's former Board of Directors were settled at the June 29, 2018 (last business day in June 2018) closing price of Hydro One Limited common shares of $20.04, with an amount of approximately $1 million paid in 2018.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2018 and 2017, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2018	2017
DSUs outstanding - beginning	25,162	—
Granted	8,740	25,601
Paid	—	(439)
DSUs outstanding - ending	33,902	25,162

For the year ended December 31, 2018, an expense recognized in earnings by the Distribution Business with respect to the Management DSU Plan was $nil (2017 - $1 million). At December 31, 2018, a liability related to outstanding DSUs recorded at the closing price of Hydro One Limited common shares of $20.25 and included in long-term accounts payable and other liabilities on the Balance Sheets was $nil (2017 - $1 million).

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2018, Company contributions made under the ESOP for the Distribution Business were $1 million (2017 - $1 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2018 and 2017, LTIP awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2018	2017	2018	2017
Units outstanding – beginning	168,490	74,063	151,490	83,394
Granted	128,364	118,467	97,207	96,697
Vested and issued[1]	(56)	(276)	(45,139)	(7,054)
Forfeited	(13,656)	(23,764)	(13,184)	(21,547)
Settled	(51,010)	—	(34,159)	—
Units outstanding – ending	232,132	168,490	156,215	151,490

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks Transmission Business employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

The grant date total fair value of the awards granted in 2018 was $5 million (2017 - $5 million). The compensation expense related to the PSU and RSU awards recognized by the Distribution Business during 2018 was $4 million (2017 - $2 million). The expense recognized in 2018 included less than $1 million related to previously awarded PSUs and RSUs to Hydro One's former President and CEO for which costs had not previously been recognized. These awards were settled in 2018 through a one-time cash settlement arrangement.

At December 31, 2018, $4 million (2017 - $3 million) payable relating to PSU and RSU awards was included in due to related parties on the Balance Sheets.

Stock Options

Hydro One Limited is authorized to grant stock options under its LTIP to certain eligible employees. During 2018, Hydro One Limited granted 1,450,880 stock options (2017 - nil). The stock options granted are exercisable for a period not to exceed seven years from the date of grant and vest evenly over a three-year period on each anniversary of the date of grant.

The fair value based method is used to measure compensation expense related to stock options and the expense is recognized over the vesting period on a straight-line basis. The fair value of the stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model.

Stock options granted and the weighted-average assumptions used in the valuation model for options granted during 2018 are as follows:

Exercise price[1]	$ 20.70
Grant date fair value per option	$ 1.66
Valuation assumptions:	
Expected dividend yield[2]	3.78%
Expected volatility[3]	15.01%
Risk-free interest rate[4]	2.00%
Expected option term[5]	4.5 years

[1] Hydro One Limited common share price on the date of the grant.
[2] Based on dividend and Hydro One Limited common share price on the date of the grant.
[3] Based on average daily volatility of Hydro One Limited's peer entities for a 4.5-year term.
[4] Based on bond yield for an equivalent Canadian government bond.
[5] Determined using the option term and the vesting period.

During 2018 and 2017, the activity of stock options granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

Year ended December 31 *(number of stock options)*	2018	2017
Stock options outstanding - beginning	—	—
Granted[1]	391,118	—
Cancelled[2]	(54,604)	—
Stock options outstanding - ending[1]	336,514	—

[1] All stock options granted and outstanding at December 31, 2018 are non-vested.
[2] During 2018, stock options previously awarded to the Company's former President and CEO were cancelled. The Hydro One Networks unrecognized compensation expense related to the cancelled stock options was not significant.

The compensation expense related to stock options recognized by the Company during 2018 was not significant.

22. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2018. The IESO, Ontario Power Generation Inc. (OPG), OEFC, and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province.

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2018	2017
IESO	Power purchased	1,636	1,583
	Amounts related to electricity rebates	475	357
	Distribution revenues related to rural rate protection	239	247
	Funding received related to Conservation and Demand Management programs	62	59
OPG	Power purchased	10	9
	Revenues related to supply of electricity	6	5
OEFC	Power purchased from power contracts administered by the OEFC	2	2
OEB	OEB fees	4	5
Hydro One Limited and its subsidiaries	Revenues for services provided	2	1
	Services received - costs expensed	12	16
	Interest expense on long-term debt	168	170
	Interest expense on inter-company demand facility	4	2
	Payments to finance dividends and return of stated capital	333	263
	Stock-based compensation costs	10	10

The amounts due to and from related parties at December 31, 2018 and 2017 are as follows:

December 31 *(millions of dollars)*	2018	2017
Inter-company demand facility	(392)	(213)
Due from related parties	125	119
Due to related parties	(84)	(153)
Accrued interest	(38)	(40)
Long-term inter-company payable	(17)	(18)
Long-term debt, including current portion	(3,911)	(3,835)

23. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2018	2017
Accounts receivable	10	198
Due from related parties	(6)	(86)
Materials and supplies	(1)	—
Other assets	2	4
Accounts payable	(10)	10
Accrued liabilities	29	32
Due to related parties	(68)	(25)
Accrued interest	(2)	(2)
Long-term accounts payable and other liabilities	(1)	(6)
Post-retirement and post-employment benefit liability	20	48
	(27)	173

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the Statements of Cash Flows for the years ended December 31, 2018 and 2017. The reconciling items include change in accruals and capitalized depreciation.

Year ended December 31, 2018 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(497)	(76)	(573)
Reconciling items	14	1	15
Cash outflow for capital expenditures	(483)	(75)	(558)

Year ended December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(537)	(48)	(585)
Reconciling items	15	(8)	7
Cash outflow for capital expenditures	(522)	(56)	(578)

Supplementary Information

Year ended December 31 *(millions of dollars)*	2018	2017
Net interest paid	170	172
Income taxes paid	70	16

24. CONTINGENCIES

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Hydro One and certain of its subsidiaries, including Hydro One Networks, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The action was commenced in the Superior Court of Ontario on September 9, 2015. The plaintiff's motion for certification was dismissed by the court in November 2017. The plaintiff appealed the court's decision to the Divisional Court. The appeal was heard in October 2018; the Divisional Court dismissed the appeal in December 2018; and in January 2019, the plaintiff applied for leave to appeal to the Ontario Court of Appeal. The plaintiff's application for leave to appeal was denied by the Ontario Court of Appeal in March 2019, which means that the lawsuit has effectively ended.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

25. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

26. SUBSEQUENT EVENTS

(A) Payments to Finance Dividends and Return of Stated Capital

On February 20, 2019, Hydro One Networks declared common share dividends of $1 million, and a return of stated capital of $138 million was approved. The amount allocated to the Distribution Business to finance these payments was $93 million.

(B) Stock-based Compensation

Subsequent to December 31, 2018, Hydro One Limited issued from treasury 20,949 and 207,737 common shares to eligible Distribution Business employees in accordance with provisions of the LTIP and Share Grant Plans, respectively.

(C) OEB Regulatory Decisions

Deferred Income Tax Regulatory Asset

Subsequent to year end, on March 7, 2019, the OEB issued a decision on its reconsideration of its Original Decision with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime. The OEB's Original Decision concluded that these benefits should not accrue entirely to Hydro One shareholders and that a portion should be shared with ratepayers. The OEB has concluded that the Original Decision was reasonable and should be upheld. The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under US GAAP. As a result, the financial impact of this OEB decision has been reflected in these financial statements, as more fully discussed in Note 11 - Regulatory Assets and Liabilities.

Hydro One Networks' 2018-2022 Distribution Rates

Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. This aspect of the decision has been reflected in the adjustments discussed in Note 11 - Regulatory Assets and Liabilities. The other impacts from the OEB decision for Hydro One Networks' 2018-2022 distribution rates will be reflected prospectively in 2019.

(D) Long-term Debt

On April 5, 2019, Hydro One issued the following long-term debt under its MTN Program:

- $700 million notes with a maturity date of April 5, 2024 and a coupon rate of 2.54%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 2.79%, of which $287 million was allocated to the Distribution Business;
- $550 million notes with a maturity date of April 5, 2029 and a coupon rate of 3.02%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 3.27%, of which $225 million was allocated to the Distribution Business; and
- $250 million notes with a maturity date of April 5, 2050 and a coupon rate of 3.64%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 3.89%, of which 103 million was allocated to the Distribution Business.

On March 21, 2019, Hydro One repaid $228 million of maturing long-term debt notes under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $228 million to Hydro One, of which $91 million was allocated to the Distribution Business.

Chapter 17: Regulated operations

17.1 Chapter overview

Industry-specific accounting guidance for regulated operations is predominantly codified as ASC 980. Regulated utilities that meet certain criteria under ASC 980 are required to apply its guidance.

The purpose of ASC 980 is for financial reporting to reflect the economic effects of certain rate-regulated activities and actions taken by regulators that arise in the normal course of regulated operations. The basic premise of ASC 980 is that the actions of a regulator will impact the financial statements prepared for financial reporting purposes only if the action has an economic effect on the regulated utility and meets the requirements for recognition or deferral under the standard. A regulated utility should comply with U.S. GAAP applicable to entities in general with regard to its accounting and financial reporting. If it is also subject to ASC 980, the applicable provisions within that standard are applied as an adjustment to or in lieu of other U.S. GAAP (when specifically required by ASC 980).

ASC 980 provides guidance for (1) determining whether a reporting entity has regulated operations subject to rate-regulated accounting and (2) accounting for certain assets, liabilities, and transactions arising from regulated operations. This chapter addresses these requirements and the discontinuation of application and reapplication of ASC 980. See UP 18, UP 19, and UP 20 for further information on utility plant, income tax, and business combination issues, respectively, specific to regulated utilities.

17.2 Scope of ASC 980

As outlined in ASC 980-10-15-2, a reporting entity is required to apply ASC 980 if it meets three specified criteria.

- Rates are established by an independent third-party regulator or the entity's own governing board (UP 17.2.1)
- Rates are designed to recover costs of service (UP 17.2.2)
- Rates designed to recover costs can be charged to and collected from customers (UP 17.2.3)

A reporting entity should assess and document whether it continues to meet each of the criteria, setting forth the significant factors considered, at least annually or any time rate structures change or regulatory developments occur. The unit of account for the application of ASC 980 can be a transaction, a group of transactions, a separable operation of the reporting entity or the reporting entity in its entirety. The unit of account is based on the level at which the criteria in ASC 980-10-15-2 are met. The documentation should address the rationale for the determination of the unit of account if there are specific or different factors impacting various parts of the business (e.g., service territories, customer classes, or functional activity such as generation).

The determination of whether a reporting entity's rate structure continues to meet the criteria of ASC 980 should consider the totality of the evidence and all relevant facts.

criteria for application of ASC 980. However, analyzing whether a specific asset or group of costs are subject to regulation and recovery may be complex. Determining whether the asset or group of costs is clearly specified in a rate order or other evidence that would support regulatory accounting, including the means and timing of cost recovery, is key to this analysis.

For example, assuming all of the criteria in ASC 980 are met, a pipeline expansion for which capital and operating expenses will be recovered through rates imposed by a regulator may qualify for regulatory accounting if the related capital and operating costs are segregated such that it is clear which costs are being recovered through a cost-of-service mechanism. Similarly, if a reporting entity does not qualify for application of ASC 980 to its entire business but has cost-of-service regulation for one aspect of its costs (e.g., fuel costs), it may qualify for rate-regulated accounting for those costs, assuming the other criteria of ASC 980 are met.

The application of ASC 980 to a group of costs is highly judgmental and may not be appropriate in many circumstances.

17.3 Regulatory assets

One of the primary areas in which accounting by regulated utilities differs from unregulated entities is regulated utilities' ability to defer certain expenditures as regulatory assets that would otherwise be expensed under U.S. GAAP. Specific criteria exist for the recognition and measurement of regulatory assets as summarized in Figure 17-3.

Figure 17-3

Key areas of accounting consideration for regulatory assets

Area	Considerations
Initial recognition and measurement (UP 17.3.1)	□ Incurred costs may be capitalized as a regulatory asset if the amounts are probable of recovery through rates. □ Regulatory assets are initially measured as the amount of the incurred cost. □ If a cost does not meet the criteria for deferral as a regulatory asset at the date incurred, it should be expensed; a regulatory asset may subsequently be recorded if and when the criteria for recognition are met.
Subsequent measurement (UP 17.3.2)	□ Regulatory assets are typically amortized over future periods consistent with the period of recovery through rates. □ If all or part of an incurred cost recorded as a regulatory asset is no longer probable of being recovered, the amount that will not be recovered should be written off to earnings. □ If a regulator subsequently allows recovery of costs that were previously disallowed, a new asset is recorded; classification of the new asset depends on how the asset would have been classified had it been previously allowed.

UNDERTAKING J7.1

Reference:
K-1.1, p. 3
Transcript Volume 7, October 31, 2019, page 44, line 10 to page 46, line 5

Undertaking:
To update the timeline in K1.1 to include regional or other engagement with Indigenous communities conducted by Hydro One prior to the date the Application was filed, on March 21, 2019.

Response:
As noted in evidence, Indigenous communities in Ontario are not directly connected to the transmission system, however, a number of Indigenous communities are directly connected to Hydro One's distribution system.

Slide 3 of Hydro One's opening presentation for the Oral Hearing has been updated to include First Nations and Métis customer engagement sessions and activities on a number of topics including both transmission and distribution-related issues.

Markers	Date	Description
A	February 9-10, 2017	Provincial Engagement Sessions with First Nation communities Hydro One serves
B	March 29, 2017	Session for OEB Staff and Intervenors (including Anwaatin) from EB-2016-0160 to seek input on customer engagement process
C	May 13, 2017	Provincial Engagement Session with the 29 Community Metis Councils represented by the Metis Nation of Ontario.
D	July 2, 2017	Customer engagement survey concluded. Hydro One asked LDCs that serve First Nations and Métis communities what they felt Hydro One could do to better serve the specific needs of these communities.
E	February 21, 2018	Provincial Engagement Session with First Nation communities Hydro One serves
F	June 2018 to June 2019	**Ongoing Engagement with Indigenous communities:** **11-Jun-18**: 3 Phase Power Workshop with Wabigoon Lake Ojibway Nation, Seine River, Mitaanjigaming and Nigigoonsiminikaaning **16-Jun-18**: Reliability Meeting with Wikwemikong

		19-Jun-18: 3 Phase Power Meeting with Wahgoshig **01-Aug-19**: Manitoulin Regional First Nations Engagement Session **27-Sep-18**: Battery Energy Storage System (BESS) Site Visit and Meeting at Aroland First Nation **26-Oct-18**: Reliability Meeting with Mattagami **20-Nov-18**: 3 Phase Power Meeting with Shawanaga **04-Dec-18**: 3 Phase Power Follow up Meeting with Wahgoshig **21-Jan-19**: Reliability Meeting with Six Nations Elected Council **06-Mar-19**: BESS Meeting with Aroland in Toronto **28-Mar-19**: 3 Phase Power and Forestry Meeting with Brunswick House **29-Mar-19**: Reliability Meeting with Mississaugas of Scugog **19-Jun-19**: Conference Call with Animbiigoo Zaagi'igan Anishinaabekto to connect a community in the Beardmore Area (Geraldton Area).

Witness: Derek Chum

UNDERTAKING J7.2

Reference:

A-7- 2, Attachment 3, page 7

Undertaking:

To clarify reliability data given in presentations to First Nations, northern system reliability versus first nations transmission reliability.

Response:

As there are no First Nations directly connected to the transmission system, the data included in the referenced table, reproduced below, is based on the delivery points serving First Nations communities.

Transmission Connections Performance: By Geographic Region (First Nations Only)

Transmission System - Northern Sub-System (2016 YE Performance)

Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes/ Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
[1]First Nations	44	216.4 (68.4)	4.48

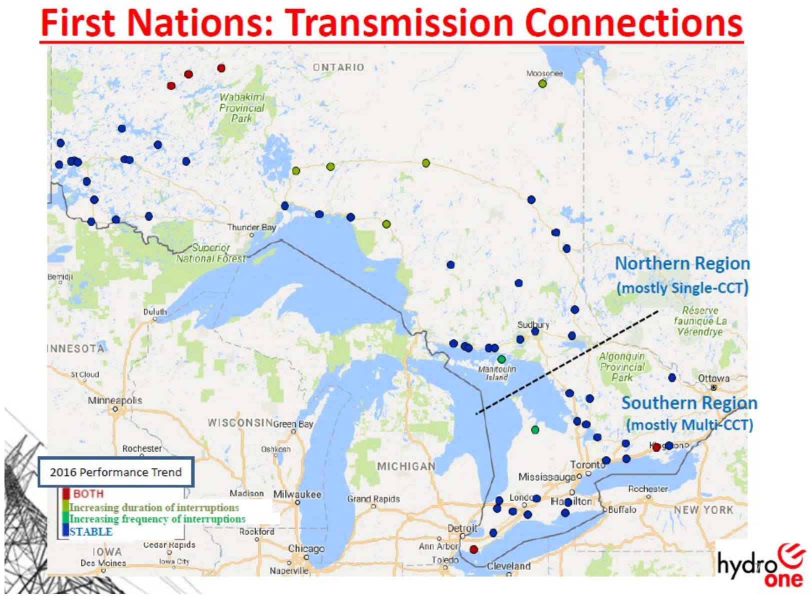
Transmission System - Southern Sub-System (2016 YE Performance)

Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes /Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
First Nations	25	25.1	1.20

[1] Two lines account for 58% of total interruption minutes for entire year

Source: Hydro One and First Nations Engagement Session Presentation, February 9 & 10, 2017; filed Exhibit K7.2 Anwaatin Compendium for Panel 3, page 65.

Of the 69 delivery points serving First Nations communities, 44 are located in the Northern sub-system and 25 are located in the Southern sub-system, divided based on the separation shown below:



Source: First Nations – Reliability Performance Overview Presentation, February 21, 2018; filed Exhibit A, Tab 7, Schedule 2, Attachment 3, page 7.

The “Duration of Interruptions (interruption minutes/Tx Connection)” is the average interruption duration per delivery point per year for the 44 delivery points in the Northern region and the 25 delivery points in Southern region. The calculation is similar to T-SAIDI.

The “Frequency of Interruptions (# of interruptions/Tx Connection)” is the interruption frequency per delivery point per year for the 44 delivery points in the Northern region and the 25 delivery points in the Southern region. The calculation is similar to T-SAIFI.

UNDERTAKING J7.3

Reference:

Undertaking:
To file the 2017 Customer Satisfaction Survey.

Response:
Provided as Attachment 1 of this undertaking response is the *2017 Large Tx Customer Satisfaction Summary of Findings*.

Customer Experience

Large TX Customer Satisfaction Summary of Findings

November 28, 2017

Technical Vocabulary Glossary

Throughout the survey, Northstar has presented data graphically, using arrows to represent statistical differences in data, and has crafted recommendations and key insights using technical research terminology. Below is a glossary of terminology and symbols used throughout the report.

- T2B / T4B – The top two box score (on a 5 point scale), or top four box score (on a 10 point scale) is compared throughout the report as a means of streamlining analysis.

- Arrows have been used to distinguish results which are statistically or directionally significant.
  - Findings which are statistically higher or lower (calculated at a 90% confidence level) between years.
  - Findings which are statistically higher or lower (calculated at an 80% confidence level) between years.

- Circles have been used to distinguish results which are statistically or directionally significant between customer groups.
  - Findings which are statistically higher (calculated at a 90% confidence level) between customer groups.
  - Findings which are statistically lower (calculated at a 80% confidence level) between customer groups.

Survey Overview: Tx CSAT

- **Survey Objectives** – To measure key drivers of satisfaction among LTX customers and monitor Hydro One's performance in key service areas.
- **Survey Type** – Measures customers' opinion of the company as a whole (whether they have interacted with Hydro One recently or not). It seeks to uncover perceptions of how well the company is meeting customer expectations and delivering on critical success factors.
- **In-field Dates** – The 2017 Large TX research project was carried out by Northstar and our field partner – Decision Point Research. In 2017, only one wave was conducted for LTX, as opposed to two waves in previous years. Additionally, the survey was condensed this wave – only including questions 2, 10, 18, 19B, 24, 24B, 25, 26, 38 and 39. Field dates for the Large TX study changed in 2017. This wave included Hydro One sending the initial email invitation to all 183 Large TX customers on September 11, 2017. Telephone interviews started on September 18th. E-mail reminders were sent by Hydro One on September 28, with field closing on October 20.
- **Method of Communication** –All interviewing was conducted via telephone followed by computer-assisted telephone interviewing if customer prefers/is not reached.
- **Response Rate** – Of the 183 names provided, 3 had been disconnected / removed, resulting in a sample size of 180. 111 customers answered at least one foundational scorecard question, resulting in a survey response rate of 62% (vs. 64% in 2016).
- **Surveyed Segment** – the below table outlines the surveyed customer types & survey sample size. Please note that two non-responders were undefined in the sample.

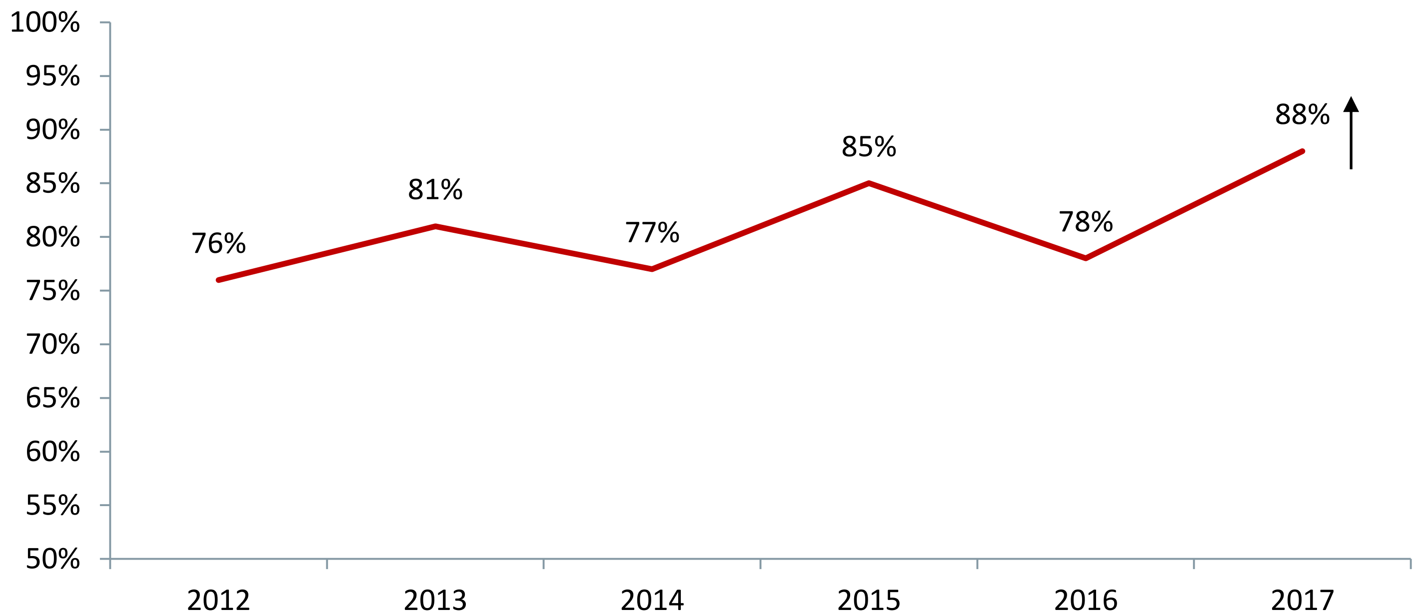
Segment Size	End Users	LDCs	Generators
Total Population Size*	59	66	58
Surveyed (N Value)	29	47	35

*Note: Total Population Size represent the total number of records provided in the sample.

Overall Satisfaction – Survey Results (All Tx)

The survey question reads:

"Overall, how satisfied are you with Hydro One? Would you say you are…?"



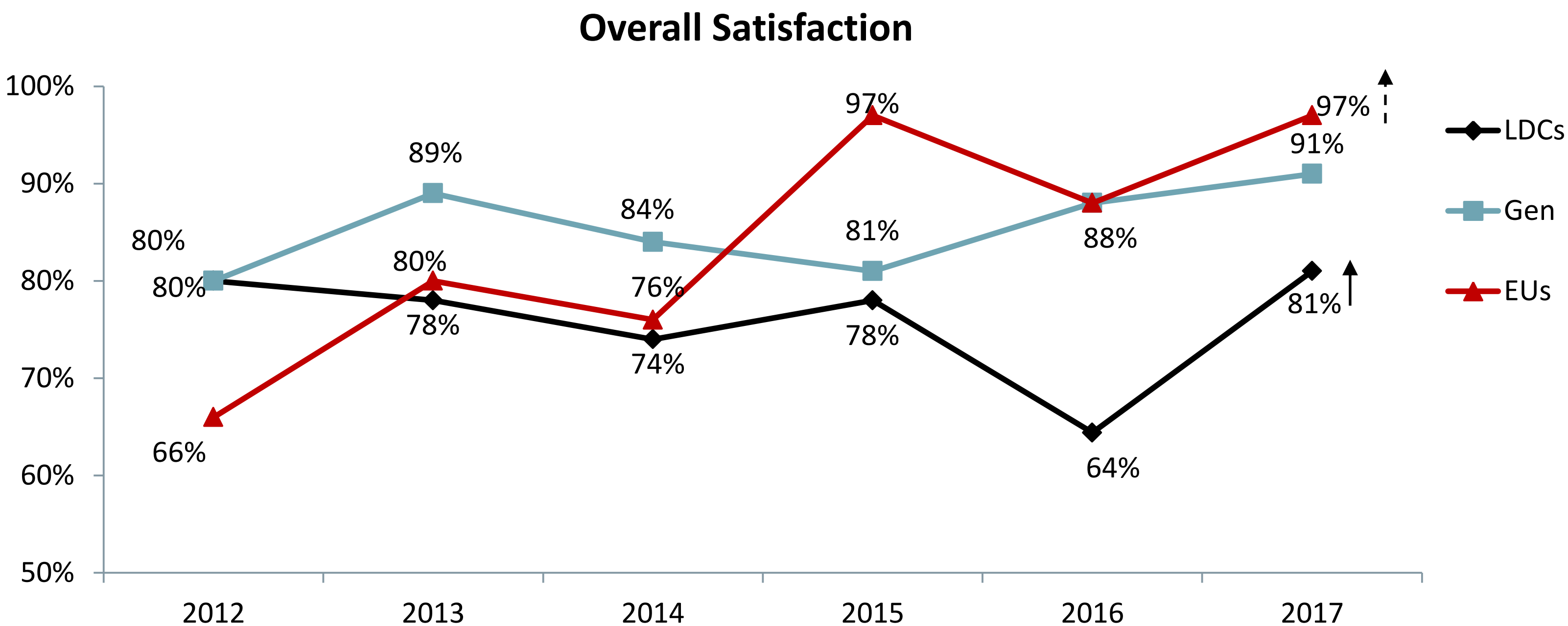
Key Insights

- *Overall satisfaction with Hydro One has increased 10 points over the previous year, with levels at the highest since tracking began in 2012.*

Overall Satisfaction – Survey Results (By Segment)

The survey question reads:

"Overall, how satisfied are you with Hydro One? Would you say you are…?"



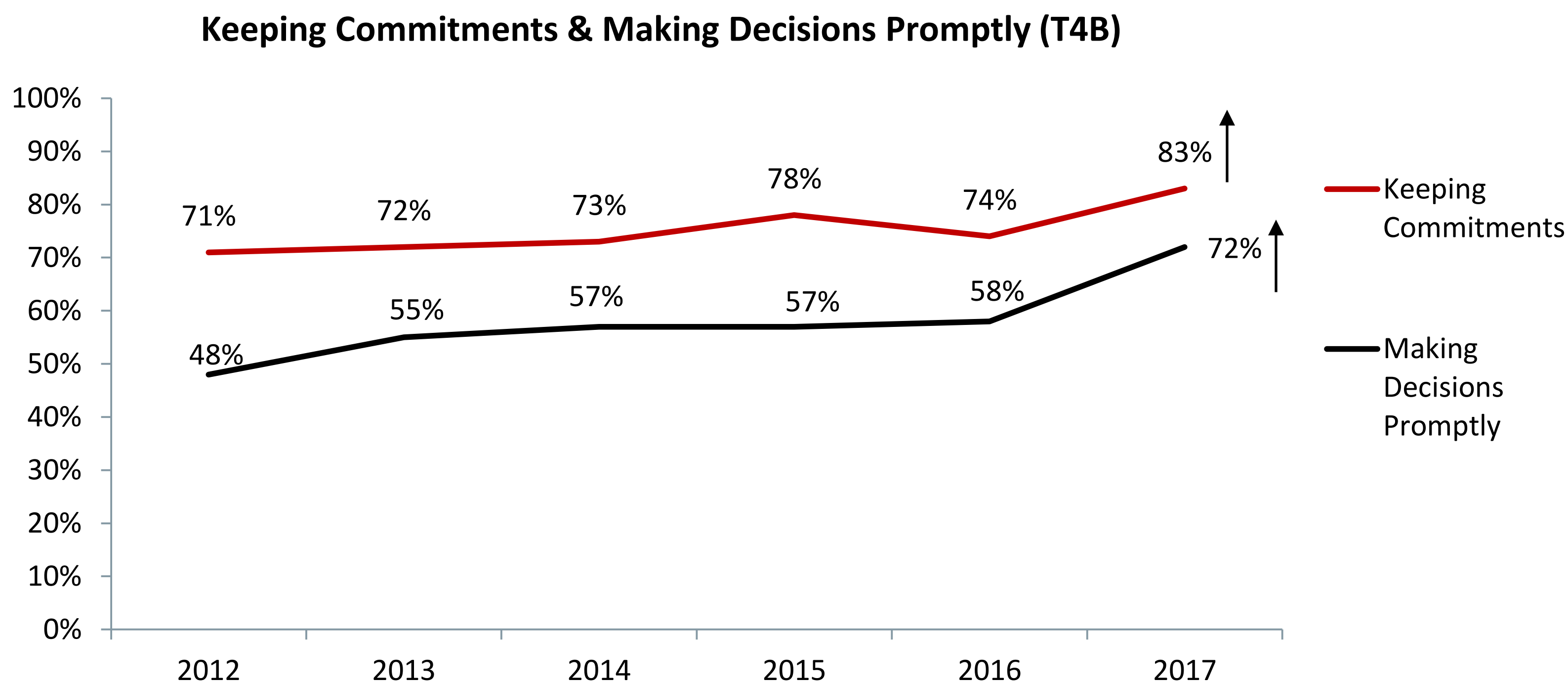
Key Insights

- *The increase in overall satisfaction score can be largely attributed to LDC customers, who show a significant (+17, 81%) increase in satisfaction, reversing the 14 point decline in satisfaction in 2016.*
- *End User customers show a directional increase of 9 points.*
- *Satisfaction for all three customer groups is at its highest since tracking started.*

Scorecard Metrics – Survey Results (All Tx)

The survey questions read:

"How would you rate Hydro One on the following specific attributes… Keeping Commitments and Making Decisions Promptly?"



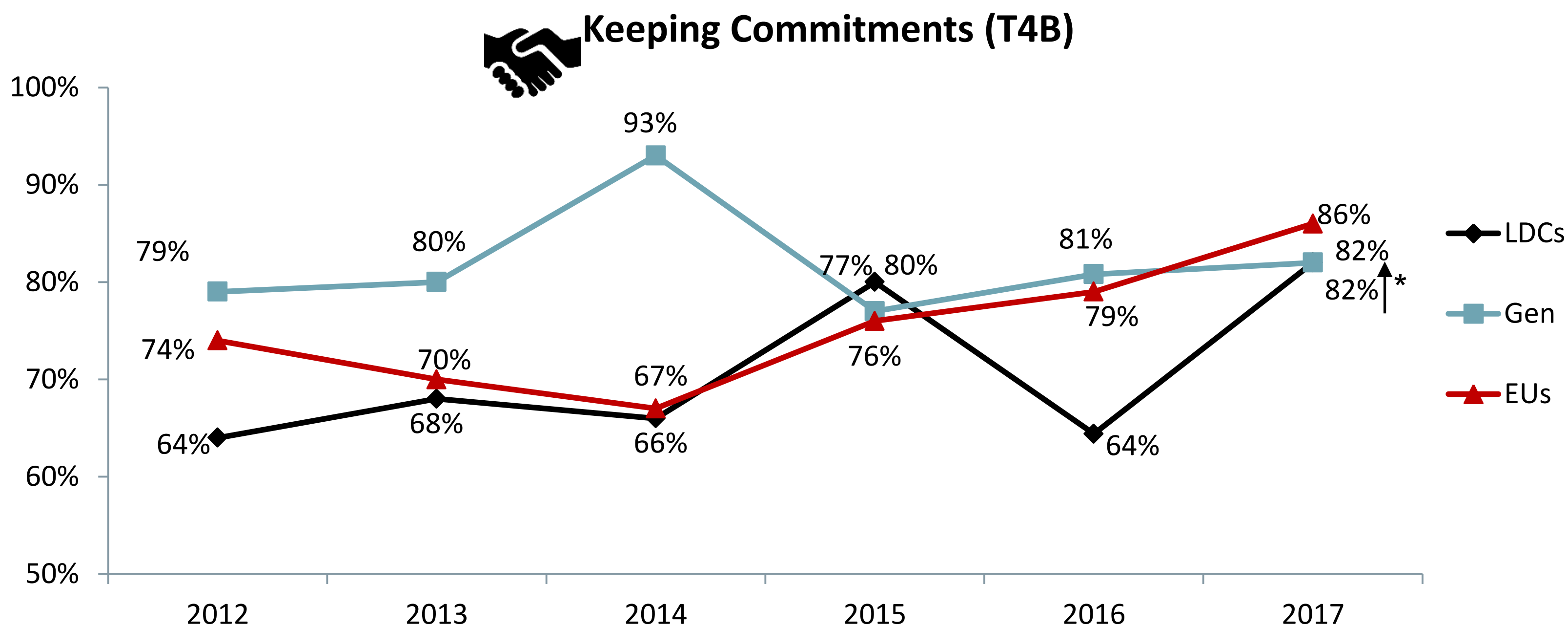
Key Insights

- *Hydro One's performance on both these foundational attributes is now at its highest since tracking began.*
- *Hydro One's ability to make decisions promptly shows a significant 14 point increase over the last year, and its ability to keep commitments shows a significant 9 point increase over the same period.*

Keeping Commitments – Survey Results (By Segment)

The survey question reads:

"How would you rate Hydro One on the following specific attributes… Keeping Commitments?"



Key Insights

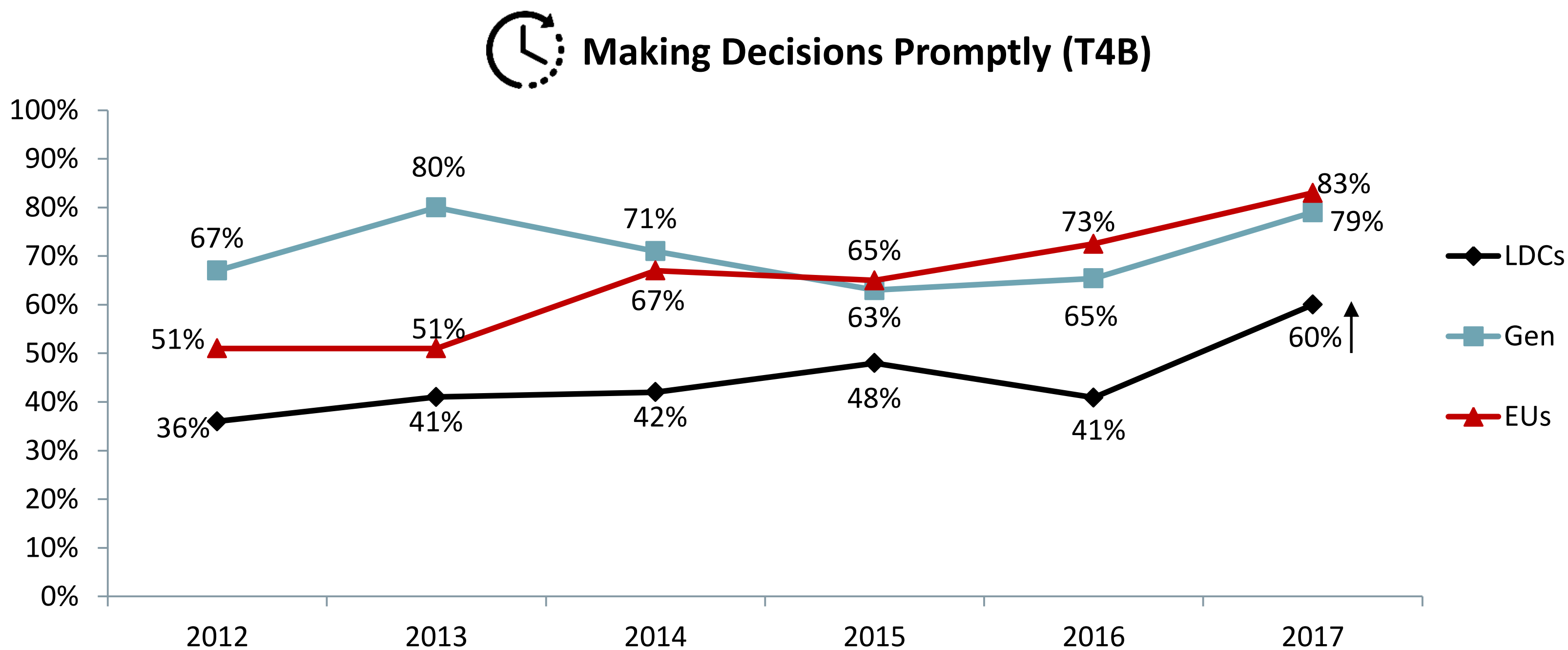
- *Generator customers have historically shown the highest level of satisfaction regarding Hydro One's focus on keeping commitments.*
- *LDCs show a significant 18 point increase in satisfaction regarding Hydro One's focus on keeping commitments, reaching the highest point seen since tracking began.*
- *End Users continue their upward movement, with satisfaction at its highest since tracking began.*

*** Note:** *the arrow in the graph only refers to a significant increase in Keeping Commitments for LDCs.*

Making Decisions Promptly – Survey Results (By Segment)

The survey question reads:

"How would you rate Hydro One on the following specific attributes… Making Decisions Promptly?"



Key Insights

- *LDC customers provided significantly higher ratings for Hydro One's ability to make decisions promptly.*
- *Both End Users and Generators show an increase in satisfaction with Hydro One's ability to make decisions promptly over the last year.*

Survey Findings

Key Findings	Impacted Segment

- **The overall Large TX customer score is 86%, with overall satisfaction at 88%. Both these are at their highest since tracking began, underscoring Hydro One's initiative to improve relations with all three subgroups.**
  - The increase in overall satisfaction can be largely attributed to LDCs (+17, 81%) and End User customers (+9, 97%). Both show a reversal of the previous year's negative shift, with satisfaction ratings climbing back to their highest points since tracking began.
  - Generator customers continue to show consistent satisfaction with Hydro One, with satisfaction ratings rising steadily over the past few waves.
- **Both scorecard metrics show significant improvement over the previous year.**
  - LDC customer ratings of Hydro One are at their highest over time, with a significant increase in satisfaction with HON Keeping Commitments (82%) and Making Decisions Promptly (60%). The latter metric marks one of the largest score improvements this wave.
  - Consistent with 2016, Generators continue to identify product and planning issues (outage planning, infrastructure upgrades) as key areas for HON to address in order to increase satisfaction.
- **Large TX customers are satisfied with their most recent contact experience with their Account Executive.**
  - Generators rate increasing satisfaction with their Account Executive (+12, 97%) while LDCs and End Users show dwindling levels of satisfaction.
  - The Ability to Access HON has decreased this wave. End Users and LDCs provide perfect scores for Easy to Reach [HON] during Unplanned Outages with any questions or concerns.

LDC
End Users
Generators

UNDERTAKING J7.4

Reference:
Exhibit K-7.04

Undertaking:
To check if long-term reliability impact is available and if so to provide it.

Response:
The average percentage of key assets (conductors, breakers and transformers) beyond expected service life (ESL) in 2016 was approximately 19%.[1] Please see the Customer Engagement report filed in Exhibit B-1-1 TSP Section 1.3, Attachment 1.

Since Hydro One’s last application, assets have aged and more assets have exceeded their ESL than before. ESL is used to indicate potential replacement quantities in the longer-term. Importantly, replacement decisions are determined by asset condition and other criteria such as historical performance, utilization, and technological obsolesce, and not asset age relative to ESL.

[1] EB-2016-0160 Exhibit B1-2-2 Attachment 2 p 14: [conductors (20%) + transformers (28%) + breakers (9%)]/3

UNDERTAKING J7.5

Reference:
Transcript Volume 7, Page 107, line 13 to Page 108, line 7.

Undertaking:
To add to the appendix data the position on the Scenario scale that the verbatim responses are associated with.

Response:
Below is a list of respondents by customer-type who provided a verbatim response, the point on the Scenario scale they selected, and their verbatim responses. None of the verbatim responses were summarized.

Customer Type	Slider Placement	Verbatim
Generator	15	Best choice overall from reliability and long term cost perspective
LDC	13	•Ideally, the rate increase would be inflation plus some nominal percentage. However, if 3.3% results in a material decrease in service capability, this new information suggests that the next highest level of investment is appropriate, thereby putting this somewhere in between Scenarios C and D.
LDC	12	•The system already has a health percentage of aged equipment and with the increasing reliance on the transmission system to achieve the government's environmental goals, reliability will only become more important.
LDC	11	•It combines all four scenarios into one with moderate rate increase, high reliability and moderature future increases.
LDC	11	•decrease on reliability risk while levelling future rate increases.
LDC	11	•This scenario keeps the transmission system at about the same health level as it is today and while the transmission rate increase is moderate, the overall bill impact is small and likely tolerable by most customers.
End User	11	•maintaining the current level of investments will provide the planning and necessary funds for equipment is replace/upgrade as required to ensure reliability of power supply
End User	11	•To maintain a consistent cost(although increased) with a higher reliability.
End User	11	•The current level of reliability is acceptable therefore maintaining the status quo would seem appropriate.

Witness: Greg Lyle

Customer Type	Slider Placement	Verbatim
End User	11	•Reduces risk, reduces the number of assets beyond expected life, cost increase is high, moving to Scenario D does not reduce the risks that much more based to cost. Selecting Scenario A or B will put our distribution system at to high a risk.
End User	11	Do not want to see any service supply or reliability deteriorate from the current state
Generator	11	•It meets many of the things and it's a subtantial capital investment, but it has a lot of things moving in the right way. Decrease in reliability risk, improvement in long-term reliability. Fairly level future rate increase.
Generator	11	•increased reliability, levelled rates
Generator	11	•The current situation is in part the result of a deliberate reduction in re-investment in the mid 1990's to mid 2000's which has resulted in equipment beyond service life. If reliability levels are to be maintained or improved, then a balanced and consistent approach is required.
Generator	11	•there is a lot of old components that need replacing already. reducing spent $'s will not enhance current performance
LDC	10	•This rate should still enable you to decrease the risk without a significant short term rate increase.
LDC	10	•The costs are a major input into these evaluations. A TS decommisioning was quoted at over $10M, transfer trip for a DG a few years ago was $180k is now being quoted at $400k, rebuilding a TS is being quoted at $38M. The choice is really C with an A rate increase.
End User	10	•Maintains the average percentage of key assets beyond expected service life constant.
End User	10	•Internal savings and efficiencies must be considered (salaries) to minimize rate increases. Increases in the 2 to 3% range combined with internal savings should net to Scenario C. This should be the goal.
LDC	9	•best balance of costs vs benefits
LDC	9	•Significant investments have been made over the last five years to allow for DG resources to be connected. My expectation is that the rate of investment can now be curtailed back some.
End User	9	•Chose the middle, trying to find a happy medium, so that we try to fix the mess we are in efficiently and cost affective as possible. However the rate increases is to high but we can't keep delaying either creating a bigger problem for future etc

Customer Type	Slider Placement	Verbatim
End User	9	•Reliability needs to improve but rate increases need to be balanced as it effects our operating costs
End User	9	•Preference would be investment close to scenario C but at lower transmission rate increase. i.e. Hydro One should look into improving its own efficiencies or finding ways to obtain the required funds to achieve scenario D or at minimum Scenario C's goals without significant increases to the transmission rates.
Generator	9	•We want a decrease in reliability risk and not too much increase in rates;
Generator	9	•I do not agree with Hydro One's premise that there should be increases in Hydro rates amongst all the options. Like any other business; Hydro One needs to improve how it runs its business; how it seeks innovative answers; how it can deliver the same or better service for less money. I fundamentally disagree with all the options above; Hydro One has to stop acting in a way that it think it is entitled to more money or else the lights go out; Hydro One needs to start thinking like all other businesses; get lean; lower costs; meet customer expectations. The people and businesses of Ontario shouldn't have to keep paying for Hydro One's excesses. Rates should be kept constant; and the service should improve for that cost moving forward.
LDC	9	•Under your maintain current level you are showing a reduction in average percentage of key assets beyond normal life expectancy. how is this maintain? In addition, you are suggesting that to maintain current levels of expenditures you need a 5.1 % annual increase in rates. Why is it not at or below inflation? These various senerios don't seem to make sense when looking at the rates or risks shown
End User	8	•Transmission costs are already too high. More needs to be done to ensure the investment $$ are being spent wisely.
End User	7	•Hydro One is unfortunately operating in one of the highest rate markets in North America. Normally higher increases could be tolerated, however with the current state of the electricity market reasonable rate increase are expected, even if it comes at the cost of degraded reliability. This is ultimately due to current and previous provincial governments however Hydro One is forced to take this under consideration.

Customer Type	Slider Placement	Verbatim
End User	7	•we're on unreliable lines so we'd like some investment in those lines under any scenario. some is more than what we've seen in recent years. with upward pressure on rates, we'd be hard pressed to call for much more reinvestment than B. I'm wondering about the capital estimates and whether or not there is any room for efficiencies within?
Generator	7	•Balance the annual rate increase based on risk.
LDC	6	•I recognize HONI has very difficult choices to make. However, it is very difficult to support a transmission rate increase that is greater than 1.5 times CPI
Generator	6	•You should manage your business to be at or below the annual Canadian index price increase and still be reliable. Actual rates are already very high. We pay anywhere between $120-150/MW which is too high.
LDC	5	Keep increases at inflation.
LDC	3	•Low rates a priority and managed risks - information is imperfect and so the best investment is to get better data/information while you have the time to drive better investment outcomes while living within a cost affordability index. Are you getting the right bang for your investment today? That data was not made available - can you assume you will get more for the money you are investing?
End User	3	•I am prepared to take on more risk as we get the cost envelop sorted out and I am not willing to accept that rates would only change from .11% to .46% between scenario's when costs to the public have been going up by double digits per year for many years. IN addition I am not prepared to accept that managing the rate of investment now will necessarily result in significantly higher future rates. The whole system has to take responsibility for the costs the public is struggling with NOW !
Generator	3	•Scenario A seems the most favourable at this time; companies are very cost focus and margins are currently very tight.
LDC	2	•1) Hydro One is inefficient and needs to sort out their internal processes and find greater efficiency.2) There is nothing in this plan for innovation. Why would they invest in Tx infrastructure without a plan to manage the two-way flow of electricity that distributed generation will bring in 10-15 years. The last thing anyone wants is billions of $ in distressed transmission assets.
Generator	1	•Clever OEB type presentation Ontario in very fragile economic condition Just focus on cutting cost There is not as you imply direct correlation between cost reduction and reliability

Customer Type	Slider Placement	Verbatim
LDC	None	•No choice made. Analysis simplistic. Need to look for alternative savings (OM&A) to offset cost of increased asset investments.
End User	None	•Good balance
End User	None	•It would appear that the infrastructure has not been maintained at the correct pace. A reduction now would jeopardize future reliability.
Generator	None	•The reality is we have taken the cheap route and now the system needs to be upgraded and repaired. Best to pay and be done with it.

UNDERTAKING J7.6

Reference:

Exhibit B, Tab 1, Schedule 1, TSP Section 1.3, Attachment 1, p.28 of 144

Undertaking:

[Reserved for question relating to safety, in the event Panel 1 has something to add]

Response:

The Customer Engagement Survey asked customers to a) rank which outcomes were important to them[1] and then b) prioritize these important outcomes to help Hydro One's planners set priorities when preparing its business plan.[2]

Across all segments (LDC, End user, Generator) most customers (79 out of 103) rated safety to be extremely important. When asked to prioritize these important outcomes to help Hydro One's planners prepare its business plan, half of the surveyed customers (54 out of 103) rated safety as the top priority.

Importantly, deteriorated equipment has the potential to fail unexpectedly causing unplanned outages and safety risks. Surveyed customers on an overall basis ranked reliability and safety as the top two priorities and noted "that outages are not only a safety hazard, but also a financial concern affecting their business/production."[3]

Customers' prioritization of safety informs the identification and consideration of alternative investment strategies such as a proactive versus reactive replacement. Adopting a reactive replacement approach involves waiting for deteriorating components to fail, and subsequently replacing those components on a reactive basis, which can present a risk to both public and employee safety. Understanding that customers prioritize safety reinforces the importance of proactive system renewal to minimize exposure to safety hazards.

Hydro One was not seeking customer feedback on whether its design practices should incorporate safety standards. Hydro One designs and builds according to industry standards for safety and incorporates safety practices in its day-to-day operations such as engineering controls, administrative controls, and personal protective equipment.

[1] Exhibit B-1-1 TSP Section 1.3 Attachment 1 pg 18.
[2] Exhibit B-1-1 TSP Section 1.3 Attachment 1 pg 28.
[3] Exhibit B-1-1 TSP Section 1.3 Attachment 1 pg 6.

Witness: Bruno Jesus

UNDERTAKING J7.7

Reference:
EB-2014-0140, Settlement Agreement, Section II, p. 24 of 27

Undertaking:
To confirm whether or not the statement in the settlement proposal is factually accurate, in that Hydro One did in fact propose $1.70 per megawatt-hour at that time.

Response:
Hydro One's Application, Evidence and Settlement Agreement in EB-2014-0140 was filed with the OEB on September 16, 2014 and was posted to the OEB website/webdrawer as a pdf document on September 22, 2014.

Exhibit H1, Tab 5, Schedule 1 starting at page 535 of the pdf document provided Hydro One's proposals with respect to Export Transmission Service (ETS). As stated on page 535 of the pdf document, Hydro One proposed to adopt the recommendation of the Elenchus report filed with the Application, Evidence and Settlement Agreement (which was for a $1.70 rate). As stated on page 538 of the pdf document, Hydro One's ETS revenues used for establishing the rates revenue requirement in the application were determined based on the approved tariff at the time of $2/MWh and Hydro One indicated that it would update the ETS revenue to reflect the Board's Decision on ETS as part of the Draft Rate Order process.

UNDERTAKING J7.8

Reference:
I-03-APPrO-003, Part c)

Undertaking:
To update the response to Exhibit I, Tab 3, Schedule 3, to include 1.21 per megawatt-hour.

Response:
Table below provides the updated response to Exhibit I, Tab 3, Schedule 3, to include Export Transmission Service rate of $1.21/MWh.

Response	ETS Rate ($/MWh)	Volume (MWh)	Estimated Revenues	Ontario ETS Revenue Requirement*	Revenue to Cost Ratio
	A	B	C = A X B	D	E = C/D
Interrogatory I-3-3-Part a	1.85	18,800,000	$ 34,780,000	$ 23,532,133	1.48
Interrogatory I-3-3-Part b	1.05	18,800,000	$ 19,740,000	$ 23,532,133	0.84
Interrogatory I-3-3-Part c	1.25	18,800,000	$ 23,500,000	$ 23,532,133	1.00
Interrogatory I-3-3-Part d	1.45	18,800,000	$ 27,260,000	$ 23,532,133	1.16
Undertaking J7.8	1.21	18,800,000	$ 22,748,000	$ 23,532,133	0.97

** Note: 2020 Ontario ETS Revenue Requirement provided in Interrogatory Response I-03-APPrO-001 Part (b)*

UNDERTAKING J7.9

Reference:

I-03-APPrO-004

Undertaking:

To model the rate impact on other customers of $1.21 per megawatt-hour.

Response:

Tables 1 and 2 provide the 2020 bill impacts for typical medium density (R1) Residential and General Service Energy less than 50 kW customers using an assumed Export Transmission Service (ETS) rate of $1.21/MWh.[1]

Table 3 provides the updated summary of bill impacts using an assumed ETS rate of $1.21/MWh.

Table 1: Typical Medium Density (R1) Residential Customer Bill Impacts

	400 kWh	**750 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$121.75	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$8.96	$21.50
Estimated 2019 Monthly RTSR[4]	$5.10	$9.56	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.24**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[5]	$5.56	$10.42	$25.01
2020 increase in Monthly Bill	**$0.46**	**$0.86**	**$2.06**
2020 increase as a % of total bill	*0.5%*	*0.7%*	*0.9%*

[1] Revenue Requirement as per the blue page update filed on June 19th, 2019.

A Table 2: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$198.93	$367.73	$2,562.20
RTSR included in 2017 GSe Customer's Bill (based on 2016 UTR)	$10.63	$21.26	$159.47
Estimated 2019 Monthly RTSR[4]	$11.35	$22.69	$170.21
2019 increase in Monthly Bill	**$0.29**	**$0.58**	**$4.33**
2019 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[5]	$12.37	$24.73	$185.49
2020 increase in Monthly Bill	**$1.02**	**$2.04**	**$15.28**
2020 increase as a % of total bill	*0.5%*	*0.6%*	*0.6%*

Table 3: Summary of 2020 Bill Impacts

	R1 @ 750 kWh		**GSe @ 2,000 kWh**	
	Change in Total Bill ($)	**Change in Total Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**
ETS Rate: $1.05/MWh	$0.88	0.72%	$2.08	0.56%
ETS Rate: $1.25/MWh	$0.85	0.70%	$2.03	0.55%
ETS Rate: $1.45/MWh	$0.83	0.68%	$1.97	0.53%
ETS Rate: $1.85/MWh	$0.79	0.64%	$1.86	0.51%
ETS Rate: $1.21/MWh	$0.86	0.70%	$2.04	0.55%

UNDERTAKING J8.1

Reference:
K-8.4

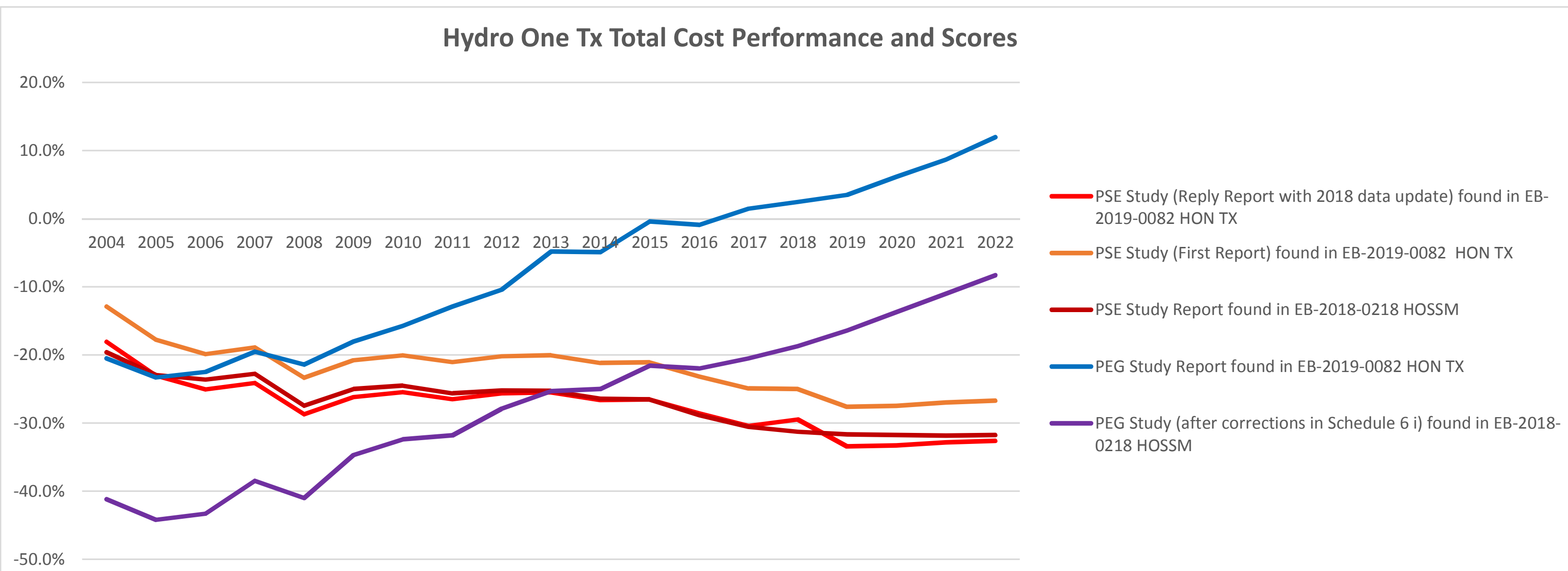
Undertaking:
To provide an updated version of Exhibit K8.4

Response:
Please see attached for an updated version of Exhibit K8.4. As indicated at the oral hearing, this updated version corrects and replaces the Exhibit K8.4 placed on the record at the oral hearing.

Witness: Steve Fenrick

J-8.1

	PSE Study (Reply Report with 2018 data update) found in EB-2019-0082 HON TX	PSE Study (First Report) found in EB-2019-0082 HON TX	PSE Study Report found in EB-2018-0218 HOSSM	PEG Study Report found in EB-2019-0082 HON TX	PEG Study (after corrections in Schedule 6 i) found in EB-2018-0218 HOSSM
2004	-18.1%	-12.9%	-19.6%	-20.5%	-41.20%
2005	-23.0%	-17.8%	-23.0%	-23.3%	-44.2%
2006	-25.1%	-19.9%	-23.6%	-22.5%	-43.3%
2007	-24.1%	-18.9%	-22.8%	-19.5%	-38.5%
2008	-28.7%	-23.4%	-27.4%	-21.4%	-41.0%
2009	-26.2%	-20.8%	-25.0%	-18.0%	-34.7%
2010	-25.4%	-20.1%	-24.5%	-15.7%	-32.4%
2011	-26.5%	-21.0%	-25.7%	-12.9%	-31.8%
2012	-25.6%	-20.2%	-25.2%	-10.4%	-27.9%
2013	-25.5%	-20.0%	-25.3%	-4.8%	-25.3%
2014	-26.6%	-21.2%	-26.4%	-4.9%	-25.0%
2015	-26.6%	-21.1%	-26.5%	-0.4%	-21.6%
2016	-28.6%	-23.2%	-28.9%	-0.9%	-22.0%
2017	-30.4%	-24.9%	-30.6%	1.5%	-20.5%
2018	-29.5%	-25.0%	-31.3%	2.5%	-18.7%
2019	-33.4%	-27.6%	-31.7%	3.5%	-16.4%
2020	-33.3%	-27.5%	-31.8%	6.2%	-13.7%
2021	-32.8%	-27.0%	-31.8%	8.7%	-11.0%
2022	-32.6%	-26.7%	-31.8%	12.0%	-8.3%



UNDERTAKING J8.2

Reference:
JT-2.34-Q9

Undertaking:
To confirm MSP revenue increase as described in JT2.34, Q 9(a).

Response:
The actual 2018 MSP revenue provided in response to undertaking JT2.34, question 9, part a, inadvertently included exit fees along with the meter service fees. The correct amount for actual 2018 MSP revenue is $0.4M.

UNDERTAKING J8.3

Reference:
I-10-VECC-024

Undertaking:
With reference to VECC compendium, Tab 11, page 5, to provide a link to the IESO's province-wide verified CDM results, or to file the document

Response:
A copy of the report referenced as item 5 in the response to Exhibit I, Tab 10, Schedule 24 part d) is attached in Excel format.

Hydro One notes that this report does not include historical (2006-2014) EE program and C&S savings. As such, it does not provide consistent historical results up to 2018 required for preparing forecasting models, and does not provide consistent bridge and test year data required for load forecast purposes.

UNDERTAKING J8.4

Reference:
JT2.34, question 17

Undertaking:
To update undertaking no. JT2.34, question 17 to the end of October

Response:
The table below provides the updated response to technical conference undertaking JT2.34, question 17, covering the period of January to September for 2017, 2018 and 2019. October 2019 ETS export volume is not yet available.

	Actual Export Volume (MWh)		
	2017	**2018**	**2019**
January-September	14,488,262	14,009,258	15,138,054

Witness: Clement Li

UNDERTAKING J8.5

Reference:

J-1.1

Oral Hearing Volume 8, Page 124, Line 13 – Page 128, Line 2

Undertaking:

To provide an updated version of J1.1.

Response:

As a result of the 2020 Cost of Capital Parameters and the updated inflation factor for incentive rate setting for rate changes effective in 2020, issued by the OEB on October 31, 2019, Hydro One has updated the impacted tables from J1.1 to reflect the lower revenue requirement. For the 2020 test year, revenue requirement was further reduced by $39.7 million. Moreover, Hydro One is providing the calculation in Table 3 below to support the inflation factor consistent with evidence in Exhibit A, Tab 4, Schedule 1.

Table 1: Revenue Requirement ($ Millions)
Revised from Exhibit E, Tab 1, Schedule 1 – Table 1

Components	2018[1]	2019[2]	2020 Blue Page	2020 Accelerated CCA[4]	2020 Actual Debt Issuances[5]	2020 Updated Pension Valuation[6]	2020 OPEB ISA Assumptions[7]	2020 Cost of Capital Parameters and Updated Inflation Factor	2020 Cost of Capital Update
OM&A	394.3		375.8			(1.7)			374.1
Depreciation and Amortization	468.6		474.6			(0.1)	0.0		474.5
Income Taxes	57.2		48.3	(23.6)	0.1	1.3	0.1	(8.2)	18.1
Return on Capital	703.6		775.0		(8.3)	(0.2)	0.6	(31.5)	735.6
Total Revenue Requirement	**1,623.8**	**1,644.4**	**1,673.8**	**(23.6)**	**(8.2)**	**(0.7)**	**0.7**	**(39.7)**	**1,602.3**
Deduct External Revenues and Other [3]	(54.7)	(54.5)	(52.6)						(52.6)
Rates Revenue Requirement	**1,569.1**	**1,589.9**	**1,621.2**						**1,549.7**
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	6.8						6.8
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,510.7**	**1,552.3**	**1,628.0**						**1,556.6**

Note 1: Represents OEB approved 2018 revenue requirement from Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160
Note 2: Represents OEB approved 2019 revenue requirement in EB-2018-0130
Note 3: External Revenue and Other includes External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit
Note 4: As quantified in I-1-OEB-208
Note 5: I-04-LPMA-019 reflected a lower cost of debt for 2020 of 4.45% based on 2019 actual issuances relative to 4.57% presented in the blue-page update
Note 6: Updated JT-2.31 Attachment 1 (October 17, 2019) provided the updated pension valuation as of December 31, 2018
Note 7: As quantified in I-01-OEB-206 the revenue requirement impact related to OPEB ISA assumptions
Note 8: 2020 Cost of Capital Parameter and Updated Inflation Factor. Updated inflation factor only impacts 2021 and 2022 revenue requirement.

Table 2: Summary of Revenue Requirement Components ($ Million)

Revised from Exhibit A, Tab 4, Schedule 1 – Table 2

Line		Reference	2020	2021	2022
1	Rate Base	C-1-1	12,407.0	13,130.2	13,951.7
2	Return on Debt	E1-1-1	313.8	332.9	353.7
3	Return on Equity	E1-1-1	421.9	447.5	475.5
4	Depreciation	F-6-1	474.5	503.4	528.9
5	Income Taxes	F-7-2	18.1	18.5	31.2
6	Capital Related Revenue Requirement		1,228.2	1,302.4	1,389.3
7	Less Productivity Factor (0.0%)			-	-
8	**Total Capital Related Revenue Requirement**		**1,228.2**	**1,302.4**	**1,389.3**
9	OM&A	F-1-1	374.1	380.9	387.7
10	**Total Revenue Requirement**		**1,602.3**	**1,683.2**	**1,777.1**
11	Increase in Capital Related Revenue Requirement			74.2	87.0
12	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.63%	5.17%
13	Less Capital Related Revenue Requirement in I-X			1.38%	1.39%
14	**Capital Factor**			**3.25%**	**3.77%**

1 **Table 3: Derivation of Inflation Factor**

2 **Revised from Exhibit A, Tab 4, Schedule 1 – Table 1**

	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Value - Annual Growth for the 2-factor IPI
Year	Q1	Q2	Q3	Q4	Annual	Annual % Change (A)	Weight (B)	Annual	Annual % Change (C)	Weight (D)	Annual % Change ([A*B]+[C*D])
2017	108.0	108.5	108.3	109.0	108.45			992.42			
2018	109.4	109.8	110.5	111.1	110.20	1.6%	86%	1021.40	2.9%	14%	1.8%

3

4 **Table 4: Custom Cap Index (RCI) by Component (%)**

5 **Revised from Exhibit A, Tab 4, Schedule 1 – Table 3**

Custom Revenue Cap Index by Component	2021	2022
Inflation Factor (I)	1.80	1.80
Productivity Factor (X)	0.00	0.00
Capital Factor (C)	3.25	3.77
Custom Revenue Cap Index Total	5.05	5.57

Table 5: Revenue Requirement by Year

Revised from Exhibit A, Tab 4, Schedule 1 – Table 4

Year	Formula	Revenue Requirement
2020	Cost of Service	$1,602.3 million
2021	2020 Revenue Requirement x 1.0505	$1,683.2 million
2022	2021 Revenue Requirement x 1.0557	$1,777.1 million

** Calculations assume that Inflation Factor remains at 1.8% through term*

Table 6: Average Bill Impacts on Transmission and Distribution-connected Customers Revised from Exhibit I2, Tab 5, Schedule 1 – Table 2

	2019[1]	2020		2021		2022	
		Blue Page	CoC Update	Blue Page	CoC Update	Blue Page	CoC Update
Rates Revenue Requirement ($M)	**$1,552.3**	**$1,628.0**	**$1,556.6**	**$1,719.4**	**$1,636.9**	**$1,808.4**	**$1,731.6**
% Increase in Rates RR over prior year		4.90%	0.3%	5.6%	5.2%	5.2%	5.8%
% Impact of load forecast change		3.8%	3.8%	0.6%	0.6%	0.7%	0.7%
Net Impact on Average Transmission Rates		**8.7%**	**4.1%**	**6.2%**	**5.8%**	**5.9%**	**6.5%**
Transmission as a % of Tx-connected customer's Total Bill		*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*
Estimated Average Bill impact		**0.6%**	**0.3%**	**0.5%**	**0.4%**	**0.4%**	**0.5%**
Transmission as a % of Dx-connected customer's Total Bill		*6.2%*	*6.2%*	*6.2%*	*6.2%*	*6.2%*	*6.2%*
Estimated Average Bill impact		**0.5%**	**0.3%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**

[1] 2019 rates revenue requirement as per the OEB's Decision and Order for Hydro One's 2019 Transmission Revenue Requirement application (EB-2018-0130), issued on 25th April, 2019.

Table 7: Typical Medium Density (R1) Residential Customer Bill Impacts Revised from Exhibit I2, Tab 5, Schedule 1 – Table 3

	Typical R1 Residential Customer					
	Blue Page	**CoC Update**	**Blue Page**	**CoC Update**	**Blue Page**	**CoC Update**
	400 kWh	**400 kWh**	**750 kWh**	**750 kWh**	**1,800 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$83.40	$121.75	$121.75	$236.81	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$4.78	$8.96	$8.96	$21.50	$21.50
Estimated 2019 Monthly RTSR[2]	$5.10	$5.10	$9.56	$9.56	$22.95	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.13**	**$0.24**	**$0.24**	**$0.58**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$5.52	$5.30	$10.35	$9.93	$24.83	$23.83
2020 increase in Monthly Bill	**$0.42**	**$0.20**	**$0.79**	**$0.37**	**$1.89**	**$0.89**
2020 increase as a % of total bill	*0.5%*	*0.2%*	*0.6%*	*0.3%*	*0.8%*	*0.4%*
Estimated 2021 Monthly RTSR[3]	$5.84	$5.58	$10.96	$10.47	$26.29	$25.13
2021 increase in Monthly Bill	**$0.32**	**$0.29**	**$0.61**	**$0.54**	**$1.46**	**$1.30**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.5%*	*0.4%*	*0.6%*	*0.5%*
Estimated 2022 Monthly RTSR[3]	$6.17	$5.93	$11.56	$11.12	$27.76	$26.68
2022 increase in Monthly Bill	**$0.32**	**$0.34**	**$0.61**	**$0.64**	**$1.46**	**$1.54**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.5%*	*0.5%*	*0.6%*	*0.6%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).

[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One’s 2019 rates revenue requirement as shown in Table 6 above.

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 6above, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

Table 8: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts
Revised from Exhibit I2, Tab 5, Schedule 1 – Table 4

	Typical General Service Energy-Billed (<50kW) Customer					
	Blue Page	**CoC Update**	**Blue Page**	**CoC Update**	**Blue Page**	**CoC Update**
	1,000 kWh	**1,000 kWh**	**2,000 kWh**	**2,000 kWh**	**15,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$198.93	$198.93	$367.73	$367.73	$2,562.20	$2,562.20
RTSR included in 2017 GSe Customer's Bill (based on 2016 UTR)	$10.63	$10.63	$21.26	$21.26	$159.47	$159.47
Estimated 2019 Monthly RTSR[2]	$11.35	$11.35	$22.69	$22.69	$170.21	$170.21
2019 increase in Monthly Bill	**$0.29**	**$0.29**	**$0.58**	**$0.58**	**$4.33**	**$4.32**
2019 increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$12.28	$11.79	$24.56	$23.57	$184.20	$176.78
2020 increase in Monthly Bill	**$0.93**	**$0.44**	**$1.86**	**$0.88**	**$13.99**	**$6.57**
2020 increase as a % of total bill	*0.5%*	*0.2%*	*0.5%*	*0.2%*	*0.5%*	*0.3%*
Estimated 2021 Monthly RTSR[3]	$13.00	$12.43	$26.00	$24.86	$195.04	$186.42
2021 increase in Monthly Bill	**$0.72**	**$0.64**	**$1.44**	**$1.29**	**$10.84**	**$9.64**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.4%*	*0.3%*	*0.4%*	*0.4%*
Estimated 2022 Monthly RTSR[3]	$13.73	$13.19	$27.45	$26.38	$205.88	$197.87
2022 increase in Monthly Bill	**$0.72**	**$0.76**	**$1.45**	**$1.53**	**$10.85**	**$11.45**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.4%*	*0.4%*	*0.4%*	*0.4%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).

[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One’s 2019 rates revenue requirement as shown in Table 6 above.

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 6 above, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

UNDERTAKING J8.6

Reference:

I2-6-2, Attachment 1

Undertaking:

To provide a revised version of Exhibit I2, Tab 6, Schedule 2, attachment 1 with track changes to reflect the removal of solar generators.

Response:

A revised version of Exhibit I2, Tab 6, Schedule 2, attachment 1 is provided as an attachment to this undertaking.[1]

[1] Hydro One notes that the UTRs included in the attached rate schedule are based on the revenue requirement per the Blue Page update filed on June 19, 2019.

2020 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2019-xxxx

The rate schedules contained herein shall be effective January 1, 2020

Issued: Month, Year
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such ~~generation~~ generator unit or energy storage facility are obtained after October 30, 1998; and (b) the generator unit nameplate rating is 2 MW or higher for renewable generation and 1 MW or higher for non- renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage; and (c) the Transmission Delivery Point through which the generator or energy storage facility is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments or expansions approved after October 30, 1998, to a generator or generation facility ~~unit~~ that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental generator nameplate capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for expansion of energy storage facilities. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**4.35**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.83**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.44**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit or energy storage facility for which the required government approvals are obtained after October 30, 1998 and which have installed nameplate capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage, ~~on~~ or the demand supplied by the incremental capacity associated with a refurbishment or expansion approved after October 30, 1998, to a generator ~~unit~~ or generation facility that existed on or prior to October 30, 1998. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

UNDERTAKING J8.7

Reference:
PSE Reply Report filed October 15, 2019

Undertaking:
To provide updated versions of the tables for TFP analysis in the PSE original evidence, that have not yet been updated.

Response:
Please see attached.

J-8.7

The numbers are slightly different in years prior to 2017 due to input price revisions subsequent to original research. In 2018, Duke Energy Ohio had missing data. We did not include data in 2018 for the company but kept them in the sample prior to 2018 for sample consistency with the original research. If Duke Energy Ohio is excluded entirely, the industry TFP trend is raised by 0.03% to -1.58% for the 2004 to 2018 period.

We note that in the original PSE report, the start year of the sample is reported as 2004. However, PEG reports the growth rates starting in the first "growth rate" year of 2005 rather than the first year of data included in the analysis. To avoid confusion, PSE matched PEG's approach in the Reply Report and we continue that in our response below. For example, the average annual growth rate reported below as 2005 – 2016 has a base year of 2004 but the average growth rates are in 2005 to 2016.

Table 1 Industry TFP and Hydro One TFP

Year	Industry TFP Index	Hydro One TFP Index
2004	1.000	1.000
2005	0.959	1.038
2006	0.995	1.046
2007	1.005	1.021
2008	0.999	1.063
2009	0.992	1.023
2010	0.968	1.009
2011	0.971	1.008
2012	0.954	0.982
2013	0.925	0.971
2014	0.902	0.976
2015	0.868	0.963
2016	0.838	0.969
2017	0.826	0.967
2018	0.799	0.949
2019 (projected)	NA	0.972
2020 (projected)	NA	0.957
2021 (projected)	NA	0.939
2022 (projected)	NA	0.923
Average Annual Growth Rate		
2005-2016	**-1.47%**	**-0.27%**
2005-2018	**-1.61%**	**-0.38%**
2011-2018	**-2.41%**	**-0.77%**
2017-2018	**-2.42%**	**-1.04%**
2021-2022	**NA**	**-1.77%**

Figure 1 Industry TFP and Hydro One TFP

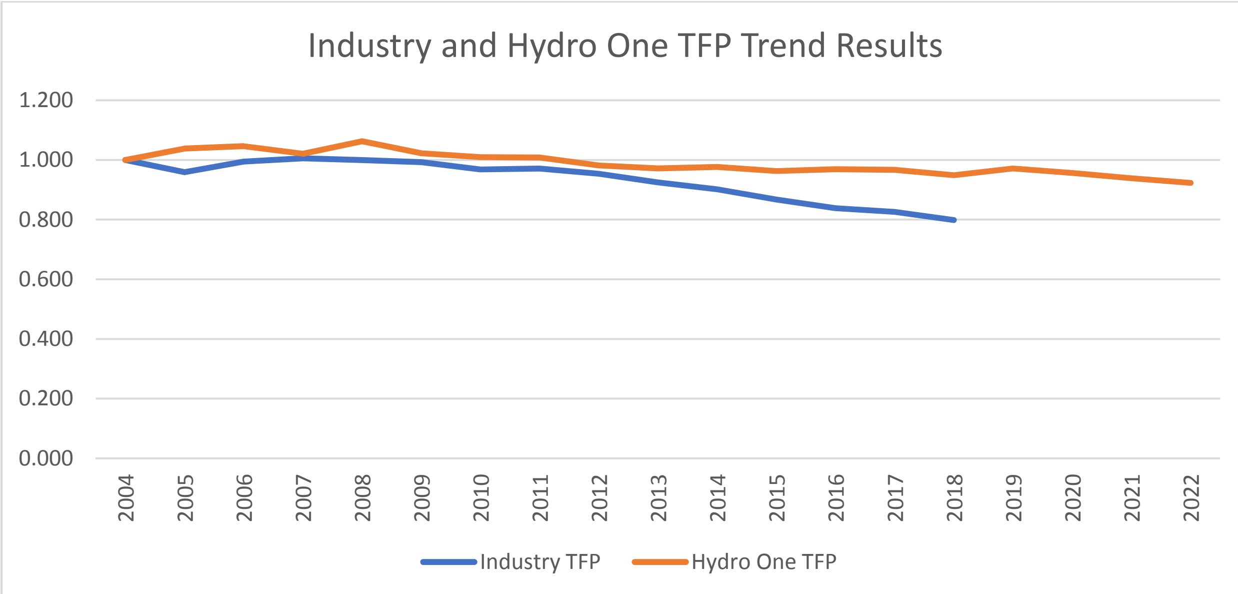


Table 2 Outputs for the U.S. Industry (Sum of Industry)

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	269,938	322,074	1.000
2005	270,606	341,545	1.039
2006	271,519	352,957	1.062
2007	273,730	360,471	1.079
2008	274,995	373,230	1.105
2009	275,529	375,386	1.110
2010	276,661	379,747	1.120
2011	278,122	381,717	1.126
2012	281,442	381,872	1.131
2013	282,314	382,283	1.133
2014	284,859	383,462	1.139
2015	286,866	385,546	1.146
2016	286,274	385,812	1.145
2017	288,818	386,352	1.150
2018	289,275	381,235	1.141
Average Annual Growth Rate			
2005-2016	**0.49%**	**1.50%**	**1.13%**
2005-2018	**0.49%**	**1.20%**	**0.94%**
2011-2018	**0.56%**	**0.05%**	**0.23%**
2017-2018	**0.52%**	**-0.60%**	**-0.19%**

Table 3 Outputs for Hydro One

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	20,603	25,414	1.000
2005	20,547	26,160	1.017
2006	20,625	27,005	1.040
2007	20,624	27,005	1.040
2008	20,661	27,005	1.040
2009	20,658	27,005	1.040
2010	20,676	27,005	1.040
2011	20,694	27,005	1.041
2012	20,891	27,005	1.044
2013	20,904	27,005	1.045
2014	20,882	27,005	1.044
2015	20,948	27,005	1.045
2016	20,949	27,005	1.045
2017 (projected)	20,689	27,005	1.041
2018 (projected)	20,965	27,005	1.046
2019 (projected)	20,967	27,005	1.046
2020 (projected)	20,967	27,005	1.046
2021 (projected)	20,970	27,005	1.046
2022 (projected)	20,974	27,005	1.046
Average Annual Growth Rate			
2005-2016	**0.14%**	**0.51%**	**0.37%**
2005-2018	**0.12%**	**0.43%**	**0.32%**
2011-2018	**0.17%**	**0.00%**	**0.06%**
2017-2018	**0.04%**	**0.00%**	**0.01%**
2021-2022	**0.02%**	**0.00%**	**0.01%**

Table 4 Input Quantities for the U.S. Transmission Industry

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	812,953	2,338,817	1.000
2005	816,873	3,010,246	1.083
2006	825,852	2,806,816	1.068
2007	837,328	2,763,533	1.073
2008	856,872	2,898,901	1.106
2009	876,273	2,843,708	1.119
2010	903,007	2,968,541	1.157
2011	923,140	2,810,525	1.159
2012	951,810	2,802,229	1.186
2013	994,699	2,792,424	1.225
2014	1,040,001	2,742,882	1.263
2015	1,081,752	2,923,110	1.321
2016	1,114,750	3,065,448	1.366
2017	1,143,383	3,060,691	1.393
2018	1,165,471	3,205,374	1.429
Average Annual Growth Rate			
2005-2016	**2.63%**	**2.25%**	**2.60%**
2005-2018	**2.57%**	**2.25%**	**2.55%**
2011-2018	**3.19%**	**0.96%**	**2.64%**
2017-2018	**2.22%**	**2.23%**	**2.23%**

Table 5 Input Quantities for Hydro One

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	137,513	259,756	1.000
2005	137,060	239,556	0.980
2006	135,904	264,144	0.994
2007	136,392	291,855	1.018
2008	135,507	247,012	0.979
2009	137,319	284,640	1.017
2010	140,541	277,211	1.031
2011	142,755	261,372	1.033
2012	148,227	259,444	1.064
2013	149,155	268,572	1.076
2014	151,727	238,857	1.070
2015	151,731	261,093	1.086
2016	153,644	236,655	1.079
2017	155,045	221,972	1.077
2018	158,220	231,148	1.102
2019 (projected)	159,699	184,471	1.076
2020 (projected)	161,608	192,113	1.093
2021 (projected)	165,161	191,928	1.114
2022 (projected)	168,352	191,735	1.133
Average Annual Growth Rate			
2005-2016	**0.92%**	**-0.78%**	**0.64%**
2005-2018	**1.00%**	**-0.83%**	**0.70%**
2011-2018	**1.48%**	**-2.27%**	**0.84%**
2017-2018	**1.47%**	**-1.18%**	**1.05%**
2021-2022	**2.04%**	**-0.10%**	**1.77%**

Table 6 Industry and Hydro One TFP Results

Year	Industry TFP Index	Industry TFP Growth Rate	Hydro One TFP Index	Hydro One TFP Growth Rate
2004	1.000		1.000	
2005	0.959	-4.2%	1.038	3.7%
2006	0.995	3.6%	1.046	0.8%
2007	1.005	1.1%	1.021	-2.5%
2008	0.999	-0.6%	1.063	4.0%
2009	0.992	-0.7%	1.023	-3.8%
2010	0.968	-2.5%	1.009	-1.3%
2011	0.971	0.3%	1.008	-0.1%
2012	0.954	-1.8%	0.982	-2.6%
2013	0.925	-3.1%	0.971	-1.1%
2014	0.902	-2.5%	0.976	0.5%
2015	0.868	-3.9%	0.963	-1.4%
2016	0.838	-3.4%	0.969	0.6%
2017	0.826	-1.5%	0.967	-0.2%
2018	0.799	-3.4%	0.949	-1.9%
2019 (projected)	NA	NA	0.972	2.4%
2020 (projected)	NA	NA	0.957	-1.6%
2021 (projected)	NA	NA	0.939	-1.9%
2022 (projected)	NA	NA	0.923	-1.7%
Average Annual Growth Rate				
2005-2016	**-1.47%**		**-0.27%**	
2005-2018	**-1.61%**		**-0.38%**	
2011-2018	**-2.41%**		**-0.77%**	
2017-2018	**-2.42%**		**-1.04%**	
2021-2022	**NA**		**-1.77%**	

UNDERTAKING J8.8

Reference:
PSE Reply Report filed October 15, 2019

Undertaking:
To provide the statistical model summaries for the total cost benchmarking in the reply report.

Response:
Please see attached.

Witness: Steve Fenrick

J-8.8

The small difference in actual costs due to input price index updates since original research. Duke Energy Ohio was excluded in 2018 due to missing data.

Table 1 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,291,742	$1,547,841	-18.1%
2005	$1,345,894	$1,694,003	-23.0%
2006	$1,440,112	$1,850,193	-25.1%
2007	$1,575,837	$2,005,453	-24.1%
2008	$1,643,735	$2,190,062	-28.7%
2009	$1,754,312	$2,279,231	-26.2%
2010	$1,794,360	$2,314,267	-25.4%
2011	$1,949,822	$2,541,204	-26.5%
2012	$2,059,992	$2,661,677	-25.6%
2013	$2,052,515	$2,648,653	-25.5%
2014	$2,091,997	$2,730,386	-26.6%
2015	$2,185,921	$2,850,894	-26.6%
2016	$2,218,630	$2,952,273	-28.6%
2017	$2,097,418	$2,842,567	-30.4%
2018	$2,282,409	$3,064,682	-29.5%
2019 (projected)	$2,300,462	$3,213,522	-33.4%
2020 (projected)	$2,387,703	$3,331,116	-33.3%
2021 (projected)	$2,486,384	$3,453,237	-32.8%
2022 (projected)	$2,583,385	$3,580,226	-32.6%
Average % Difference			
2004-2018			**-26.0%**
2016-2018			**-29.5%**
2020-2022			**-32.9%**

Figure 1 Hydro One's Cost Performance 2004-2022

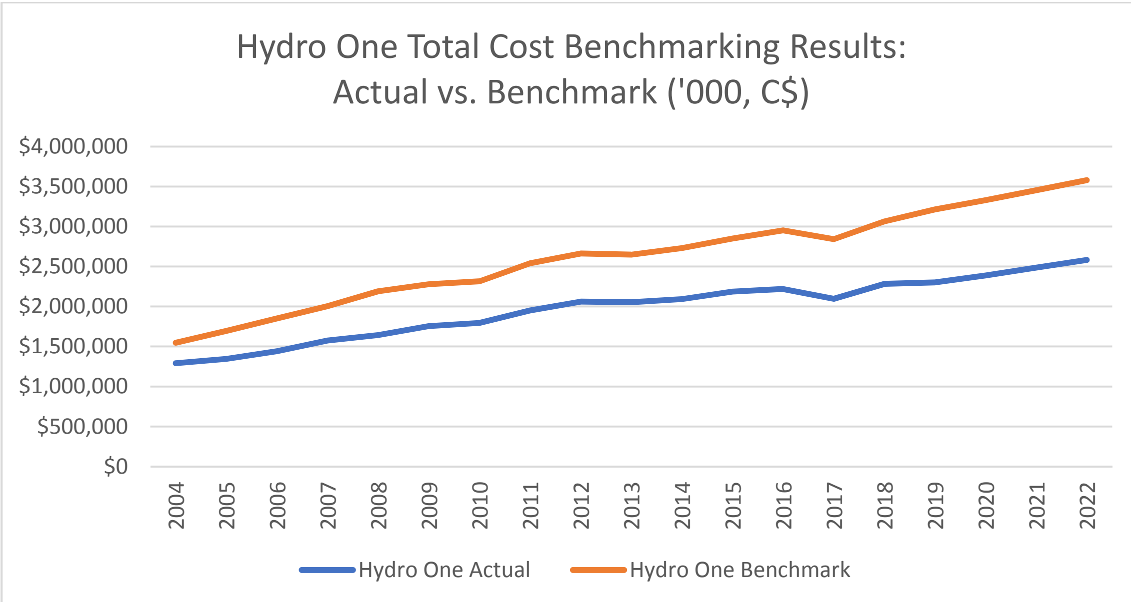


Table 2 Econometric Model Parameter Estimates

Total Cost Model Estimates

VARIABLE KEY

KM = Total transmission Kilometres of line
D = Maximum peak demand
Tx = Percent of transmission plant in total electric utility plant
Cap = Average capacity (MVa) per substation
Sub = Number of transmission substations per KM of line
Volt = Average voltage of transmission lines
CS = Construction standards of building transmission pole
UG = Percent of transmission lines underground
Trend = Time trend (current year minus 2003)

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM	0.353	20.930	CS	0.239	6.160
KM*KM	0.127	6.080			
KM*D	-0.400	-6.770	UG	0.729	3.170
D	0.615	24.250	Trend	0.014	7.370
D*D	0.364	16.430	Constant	11.671	141.630
Tx	0.533	16.010	Adjusted R-Squared	0.920	
Cap	0.160	6.920	Sample Period:		2004-2022
Sub	0.113	7.280	Number of Observations		839
Volt	0.210	12.080			

UNDERTAKING J8.09

Reference:
PSE Reply Report filed October 15, 2019

Undertaking:
To provide the working papers in confidence.

Response:
The working papers will be provided by Hydro One's counsel under separate cover.

UNDERTAKING J9.1

Reference:

A-4-1, JT-2.28

Oral Hearing Volume 9, Page 16, Line 17 – Page 21, Line 27

Undertaking:

To clarify what aspects of the Cumulative In-Service Variance Account (CISVA) the OEB is approving as part of the existing application and specifically as it relates to excluding verifiable productivity gains from the calculation.

Response:

As discussed in response to interrogatory OEB-11, verifiable productivity gains are to be excluded from the calculation of the Cumulative In-Service Variance Account (CISVA). Verifiable productivity gains refer to additional capital-related productivity gains beyond those identified and included in the current revenue requirement (both specific productivity savings and progressive productivity savings). As further discussed in OEB-11, the intent of excluding verifiable productivity gains is to incent incremental findings of productivity gains throughout the custom IR period without penalizing the utility for finding these savings. Moreover, the process associated with achieving and quantifying verifiable productivity savings places the onus on Hydro One to prove the achievements of these additional savings in future rate proceedings.

As it relates to the current application, Hydro One is seeking OEB approval for the following items:

- Establish the CISVA with key features as described under Exhibit A, Tab 4, Schedule 1, Section 2.2. The key features of the account are consistent with the previously approved variance account in the Distribution Decision (EB-2017-0049).
- Approve the capital expenditures envelope and the associated in-service additions as discussed further in Exhibit B-1-1 TSP Section 3.3 and Exhibit C, Tab 2, Schedule 1 which reflect both the base productivity savings and the progressive productivity.
- Note the level of productivity savings reflected in the TSP are tied to the specific mix of investments proposed in the application. If the OEB directs a capital reduction in its decision, this capital cut will result in corresponding reductions to Hydro One's in-service additions forecast and may result in reductions to the productivity savings currently embedded in the proposed capital plan.

The impact of the capital cuts on in-service additions and productivity savings will be evaluated and reported on as part the Draft Rate Order process and will form the baseline for CISVA entries in future years.

- At the next rebasing application, the onus will be on Hydro One to prove the achieved incremental productivity savings above the levels embedded in the approved revenue requirement.

Hydro One has requested that the CISVA track the impact on revenue requirement of any in-service additions that are on a cumulative basis 98% or lower than the OEB-approved amount for each year of the Custom IR term. Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains should be excluded from the calculation, as described in Exhibit A, Tab 4, Schedule 1 page 10.

By way of example, Hydro One's in-service additions for 2020 could be 96% of the OEB-approved levels for two different reasons:

1. The under in-service is not due to verifiable productivity and instead simply reflects a failure to in-service to forecast amounts. In this event, Hydro One will record an entry to reduce revenue and record the revenue requirement impact in the CISVA, which will be refunded to customers when Hydro One files its next rate application.
2. Hydro One over-achieves on the in-year productivity commitments embedded in this application by an amount that translates to 2% or greater than the forecast in-service additions. In this event, Hydro One will not make an entry to the account.[1]

Under both scenarios, Hydro One is committed demonstrating to the OEB at the next rebasing application the results of the productivity program and how it has impacted the associated capital spending levels and the CISVA. The CISVA entry, or lack thereof, will be undertaken by Finance and will be part of the Company's audited financial statements.

[1] In the event that Hydro One over-achieves on the in-year productivity commitments by an amount that is less than 2%, an entry will be made but only for the amount it under in-serviced after factoring the over-achievement on productivity gains.

UNDERTAKING J9.2

Reference:

A-4-1

Oral Hearing Volume 9, Page 21, Line 28 – Page 23, Line 26

Undertaking:

To confirm whether the additional verifiable productivity gains which are excluded from the Cumulative In-Service Variance Account (CISVA) calculation also excluded from the Earning Sharing Mechanism calculation.

Response:

Please refer to Undertaking J9.1 for details relating to Hydro One's verifiable productivity gains.

The regulatory net income component of the ESM calculation will be inclusive of verifiable productivity gains.

As previously mentioned in the Oral Hearing, the calculation of actual ROE will use the OEB approved mid-year rate base for that period to avoid double counting with amounts in the proposed in-service variance account.[1]

[1] Oral Hearing Volume 9, Page 22, Line 1 – Line 16

UNDERTAKING J9.3

Reference:

I2-06-02-01, 2020 Proposed Uniform Transmission Rate Schedule

Undertaking:

To confirm that the definition of renewables in the schedules is consistent with the Electricity Act.

Response:

Section 2 of the *Electricity Act*, *1998* (the "EA") currently defines "renewable energy source" as follows:

> *"renewable energy source" means an energy source that is renewed by natural processes and includes wind, water, biomass, biogas, biofuel, solar energy, geothermal energy, tidal forces and such other energy sources as may be prescribed by the regulations, but only if the energy source satisfies such criteria as may be prescribed by the regulations for that energy source; ("source d'énergie renouvelable")*

Subsection 1(1) of O. Reg. 160/99, the Definitions and Exemptions regulation to the EA provides further definitions in regards to "biofuel", "biogas" and "biomass".

The current definition of "renewable generation" in Section G of Ontario uniform transmission rate schedules is not significantly different from the above-noted EA definition. Hydro One also notes that neither definition lists energy storage as a renewable energy source.

Hydro One proposes that going forward the transmission rate schedules refer to renewable generation as defined in the Electricity Act. Hydro One will make this change, along with its proposal to add a separate reference to energy storage, in the UTR schedules to be provided as part of the Draft Rate Order following the Board's Decision in this application.