Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5393
Fax: (416) 345-6833
Joanne.Richardson@HydroOne.com

Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

October 18, 2019

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

Dear Ms. Walli:

EB-2018-0270 and EB-2018-0242: Hydro One Networks Inc. MAAD s.86 Asset Purchase Applications for Orillia Power Distribution Corporation and Peterborough Distribution Inc. – Undertaking Responses and Transcript Corrections

Please find attached Hydro One Network Inc., Orillia Power Distribution Corporation and Peterborough Distribution Inc.'s Undertaking Responses from the Technical Conference in the above-referenced hearing held October 3-4, 2019. Also include are a list of Transcript Corrections from the same Technical Conference.

An electronic copy of this has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

UNDERTAKING - JT1.1

Reference:

Undertaking:

To provide a list of all capital expenditures that were deferred in 2017 and 2018 because of the pending sale.

Response:

During preparation of the 2017 and 2018 capital plans, Orillia Power was subject to a pending sale to Hydro One. However, the MAAD transaction was subject to regulatory approval from the Ontario Energy Board and the timing of that approval was unknown at the time that each year's capital plan was developed. The Board of Directors and senior staff of Orillia Power considered which capital investments, if any, could be deferred in light of the pending sale. This consideration had to be balanced against the need to continue to invest in company assets, to ensure ongoing safety and reliability.

In both 2017 and 2018, Orillia Power deferred the purchase and implementation of updated Customer Information System software (billing system). Orillia Power utilizes the Northstar / Harris billing system and is the last Ontario utility still utilizing a legacy system. This system is overdue for an upgrade to more current software. The cost of the upgrade is estimated at $115,000. This upgrade has been deferred twice, based on the fact that Orillia Power customers would be migrated to Hydro One's billing system, should the pending sale be finalized, thus the Northstar/Harris billing system would not be required after integration.

In both 2017 and 2018, Orillia Power deferred the purchase and implementation of updated SCADA software. The cost of the upgrade is estimated at $100,000. This project was twice deferred, based on the fact that Orillia Power customers would be migrated to Hydro One's SCADA system, should the pending sale be finalized.

For the 2018 capital plan, purchase of a 65-foot double bucket truck was planned to replace an older unit that was at end of life. With the expectation of imminent regulatory approval of the MAAD application, it was felt that this investment could be deferred as Hydro One has similar fleet vehicles available, so the item was removed from the 2018 capital plan. By mid-2018, with no timeline known for ultimate regulatory approval, and decreasing reliability of the existing truck, the decision was made to proceed with the order. Given that the vehicle could ultimately become part of Hydro One's fleet, Orillia

Power staff conferred with Hydro One fleet staff to ensure that vehicle specifications were aligned.

UNDERTAKING - JT1.2

Reference:

Undertaking:
To provide the T2 S1S for 2017 and 2018 for OPDC.

Response:
Please see attached OPDC T2 Schedule 1's for 2017 and 2018.

Canada Revenue Agency | Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2017-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,215,676	A
Add:				
Provision for income taxes – current	101	59,000		
Provision for income taxes – deferred	102	239,000		
Amortization of tangible assets	104	1,187,017		
Charitable donations and gifts from Schedule 2	112	12,500		
Non-deductible meals and entertainment expenses	121	8,250		
Other reserves on lines 270 and 275 from Schedule 13	125	691,777		
Reserves from financial statements – balance at the end of the year	126	1,028,618		
Subtotal of additions		3,226,162 ▶	3,226,162	

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Deferred debit CGAAP adjustment - liability increased for de	694,000
	Total of column 2	694,000

Total of column 2 ▶	296	694,000		
Subtotal of other additions	199	694,000 ▶	694,000	
Total additions	500	3,920,162 ▶	3,920,162	B
Amount A **plus** amount B			5,135,838	C
Deduct:				
Gain on disposal of assets per financial statements	401	92,985		
Capital cost allowance from Schedule 8	403	3,119,665		
Other reserves on line 280 from Schedule 13	413	927,473		
Reserves from financial statements – balance at the beginning of the year	414	693,922		
Subtotal of deductions		4,834,045 ▶	4,834,045	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Actual Repayments C GAAP Liability	4,000
	Total of column 2	4,000

Total of column 2 ▶	396	4,000		
Subtotal of other deductions	499	4,000 ▶	4,000	
Total deductions	510	4,838,045 ▶	4,838,045	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			297,793	E

Enter amount E on line 300 of the T2 return.

Canada Revenue Agency | Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2018-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,178,041	A
Add:				
Provision for income taxes – current	101	169,000		
Provision for income taxes – deferred	102	-140,000		
Amortization of tangible assets	104	1,222,768		
Loss on disposal of assets	111	59,399		
Charitable donations and gifts from Schedule 2	112	12,200		
Non-deductible meals and entertainment expenses	121	10,000		
Other reserves on lines 270 and 275 from Schedule 13	125	927,473		
Reserves from financial statements – balance at the end of the year	126	2,056,618		
Subtotal of additions		4,317,458 ▶	4,317,458	

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Deferred debit CGAAP adjustment - liability increased for de	693,000
	Total of column 2	693,000

Total of column 2 ▶	296	693,000		
Subtotal of other additions	199	693,000 ▶	693,000	
Total additions	500	5,010,458 ▶	5,010,458	B
Amount A **plus** amount B			6,188,499	C
Deduct:				
Capital cost allowance from Schedule 8	403	3,089,640		
Other reserves on line 280 from Schedule 13	413	1,828,473		
Reserves from financial statements – balance at the beginning of the year	414	1,028,618		
Subtotal of deductions		5,946,731 ▶	5,946,731	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
	Total of column 2	

Total of column 2 ▶	396			
Subtotal of other deductions	499	0 ▶	0	
Total deductions	510	5,946,731 ▶	5,946,731	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			241,768	E

Enter amount E on line 300 of the T2 return.

UNDERTAKING - JT1.3

Reference:

Undertaking:

To provide an answer as to, is there a future tax shelter and is it similar to the tax shelter that arises on the fair market value bump in a share sale.

Response:

Hydro One interprets the reference to "tax shelter" in the undertaking above to mean the tax deduction that arises on the acquisition. Provided below is a comparison of the tax deductions between PDI (asset sale) and OPDC (share sale resulting in exit in PILS regime).

In an asset sale (i.e. the case of PDI), the purchaser's (i.e. Hydro One's) tax base of the acquired assets is based on the purchase price paid. If the purchase price is higher than the tax basis, there would be an increase in the capital cost allowance up to the purchase price to be claimed in the future, resulting in a tax deduction.

In a typical share sale, the purchase price is paid to acquire the shares and thus, there is no bump to the underlying assets for tax purposes. However, there can be a bump in a share sale of a local distribution company such as OPDC because it resulted in the company exiting the PILS regime and entered the federal tax regime. Upon exiting PILS regime, the company is deemed to have disposed of its assets at fair market value (FMV) and to have re-acquired them at FMV. If the FMV is higher than the tax basis there would be an increase in the capital cost allowance up to the FMV to be claimed in the future, resulting in a tax deduction similar to an asset sale. However, under a share sale there is a difference in timing as an asset sale occurs on closing date, where a company is considered to have left the PILS regime when the share purchase agreement is signed (which is prior to closing date).

Under either scenario, the tax deduction resulting from the FMV bump is financed by the shareholder through the purchase price premium (which is not included in rates). Therefore, any tax deduction associated with the FMV bump should remain with the shareholder and be excluded from the regulatory tax calculation consistent with the principles in the 2006 EDR Handbook[1], which states:

[1] 2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK (May 11, 2005)

> *"Subject to the above, where a distributor's Cumulative Eligible Capital Amounts includes purchased goodwill or other intangible assets that are non-recoverable or disallowed for regulatory purposes, such amounts will also be excluded from the 2006 regulatory tax calculation. <u>The OEB regulatory tax calculation will not take into account any increase in capital cost allowance when distribution assets are purchased above book value</u>."*

UNDERTAKING - JT1.4

Reference:

Undertaking:

To provide the status of the regional operation centre.

Response:

A conditional agreement of purchase and sale of lands for the planned regional operations centre has been entered into between The City of Orillia and Hydro One.

Only conceptual planning has been undertaken to date to define the siting of and the suitability of the lands being offered by the City of Orillia for the planned regional operations centre. Detailed design and development will only occur after successful completion of the sale.

UNDERTAKING - JT1.5

<u>Reference:</u>

<u>Undertaking:</u>

To provide a 1575 or 1576 calculation; if refused, to provide a reason.

<u>Response:</u>

Hydro One has completed the calculations of the Year 10 rate base value for both OPDC and PDI, if each utility kept their own depreciation rate and the capital additions were as provided in Table 1 of Exhibit A, Tab 2, Schedule 1, "Hydro One Forecast". For capital additions made in Years 1- 10, Hydro One maintained its own depreciation rate as these new assets will be purchased and/or constructed by Hydro One and then operated and maintained under Hydro One's ownership throughout the life of the asset.

The calculation, in the form of the 1575 calculation is provided in Attachment 1 for OPDC and Attachment 2 for PDI. The results are summarized below:

$000	**2029**			
	OPDC		**PDI**	
	HONI's Depreciation Rates	**OPDC's Depreciation Rates**	**HONI's Depreciation Rates**	**PDI's Depreciation Rates**
Net PPE	48,369	46,367	93,409	97,146
Avg. PPE	47,575	45,673	92,458	96,013
Working Capital	3,640	3,640	8,727	8,727
Rate Base	51,215	49,313	101,185	104,740
Difference	$1,902		($3,555)	

The above analysis shows that OPDC's rate base would have been lower in 2029 (year 10 of the deferred rebasing period) by $1.9M if OPDC's depreciation rates were used on the purchased assets; whereas PDI's rate base would have been $3.6M higher in 2029 if PDI's depreciation rates were used.

Hydro One reaffirms that the change in depreciation rates is not a function of a change in accounting policies (e.g. it is not related to the change from MIFRS to USGAAP). The depreciation rates used for forecasting purposes (Years 1 to 11 of the analysis) are blended averages and are impacted by each utilities' individual region-specific asset mix and for each utility are reflective of the maintenance and operating policies of the utility owning the assets (i.e. on a stand-alone basis each LDC will have slightly different asset weightings depending on the territory-specific needs of that LDC). Hydro One's depreciation rates are determined through an independent study by Dr. White at Fosters Associates, and underpin the depreciation rates by USofA as approved by the OEB. Once Hydro One integrates the assets of both OPDC and PDI into its distribution system, Hydro One's assessment is that the overall remaining useful life of the acquired LDC's assets is approximately equal to the remaining useful life of Hydro One's assets and therefore the use of Hydro One's depreciation rates will be reflective of the assets useful lives under its stewardship.

Appendix 2-EB

OPDC

	Closing Year Rate base	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030 Rebasing Year
Reporting Basis	**MIFRS**											
		$	$	$	$	$	$	$	$	$	$	
PP&E Values under HONI Depreciation Methodo												
Forecast Opening net PP&E		33,502	35,812	37,031	38,248	39,465	40,680	42,034	43,613	45,196	46,781	
Net Additions		3,375	2,368	2,436	2,507	2,579	2,796	2,790	2,857	2,926	2,997	
Net Depreciation (amounts should be negative)		(1,065)	(1,149)	(1,218)	(1,290)	(1,364)	(1,442)	(1,211)	(1,274)	(1,340)	(1,408)	
Closing net PP&E (1)	33,502	35,812	37,031	38,248	39,465	40,680	42,034	43,613	45,196	46,781	48,369	
PP&E Values under OPDC Depreciation Method												
Forecast Opening net PP&E		33,502	35,611	36,630	37,648	38,664	39,679	40,833	42,211	43,594	44,979	
Net Additions		3,375	2,368	2,436	2,507	2,579	2,796	2,790	2,857	2,926	2,997	
Net Depreciation (amounts should be negative)		(1,266)	(1,349)	(1,419)	(1,490)	(1,564)	(1,642)	(1,412)	(1,474)	(1,541)	(1,609)	
Closing net PP&E (2)	33,502	35,611	36,630	37,648	38,664	39,679	40,833	42,211	43,594	44,979	46,367	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP		200	400	601	801	1,001	1,201	1,401	1,601	1,802	2,002	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	2,002
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-
Amount included in Deferral and Variance Account Rate Rider Calculation	2,002

WACC	
# of years of rate rider disposition period	

Forecast HONI Dep'n By Category - as of Date of Acquisition

	DEPRECIATION		
	HONI	OPDC	Variance
Land	0.00%	0.00%	0.00%
Buildings	1.82%	4.40%	-2.58%
Distribution Pla	2.30%	2.90%	-0.60%
Other Assets	17.21%	16.10%	1.11%
Fleet[note 1]	-	13.00%	-

RATIO OF CAPITAL DOLLARS SPENT		
HONI	OPDC	Variance
1.21%	0.00%	1.21%
0.00%	0.00%	0.00%
94.60%	92.10%	2.50%
4.19%	2.60%	1.59%
-	5.30%	-

Note 1

HONI assumed for forecasting that any fleet acquired by HONI in the transaction is included in the blended category "Other Assets" Hydro One did not separate Fleet separately in the acquisition

Appendix 2-EB

PDI

Reporting Basis	Closing Year Rate base	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030 Rebasing Year
	MIFRS											
		$	$	$	$	$	$	$	$	$	$	
PP&E Values under HONI Depreciation Methodol												
Forecast Opening net PP&E		67,784	70,975	75,440	77,669	79,500	82,043	85,782	87,695	89,603	91,508	
Net Additions		6,007	7,452	5,379	5,115	5,744	7,103	5,437	5,573	5,713	5,856	
Net Depreciation (amounts should be negative)		(2,816)	(2,987)	(3,150)	(3,284)	(3,201)	(3,364)	(3,524)	(3,664)	(3,808)	(3,955)	
Closing net PP&E (1)	67,784	70,975	75,440	77,669	79,500	82,043	85,782	87,695	89,603	91,508	93,409	
PP&E Values under PDI Depreciation Methodolog												
Forecast Opening net PP&E		67,784	71,361	76,212	78,827	81,043	83,952	88,057	90,335	92,609	94,880	
Net Additions		6,007	7,452	5,379	5,115	5,744	7,103	5,437	5,573	5,713	5,856	
Net Depreciation (amounts should be negative)		(2,430)	(2,601)	(2,764)	(2,898)	(2,835)	(2,999)	(3,158)	(3,298)	(3,442)	(3,589)	
Closing net PP&E (2)	67,784	71,361	76,212	78,827	81,043	83,952	88,057	90,335	92,609	94,880	97,146	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP		-386	-772	-1,158	-1,543	-1,909	-2,275	-2,640	-3,006	-3,372	-3,737	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	3,737
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2		-
Amount included in Deferral and Variance Account Rate Rider Calculation	-	3,737

WACC	
# of years of rate rider disposition period	

Forecast HONI Dep'n By Category - as of Date of Acquisition

	DEPRECIATION			RATIO OF CAPITAL DOLLARS SPENT		
	HONI	**PDI**	**Variance**	**HONI**	**PDI**	**Variance**
Land	**0.00%**	**0.00%**	**0.00%**	**1.21%**	**0.00%**	**1.21%**
Buildings	**1.82%**	**1.96%**	**-0.14%**	**0.00%**	**0.90%**	**-0.90%**
Distribution Pla	**2.30%**	**2.39%**	**-0.09%**	**94.60%**	**92.30%**	**2.30%**
Other Assets	**8.73%**	**6.24%**	**2.49%**	**4.19%**	**6.80%**	**-2.61%**
Fleet	**25.00%**	**22.73%**	**2.27%**	**0.00%**	**0.00%**	**0.00%**

UNDERTAKING - JT1.6

Reference:

Undertaking:

To provide the calculations used to revise the components of the revenue requirements from 2017 to 2030.

Response:

Please see attached excel spreadsheet.

UNDERTAKING - JT1.7

Reference:
[I/2/23 Attachment 1]

Undertaking:
To provide supplemental information on the capital forecast.

Response:
A summary of PDI's capital spend was previously included in Exhibit I, Tab 2, Schedule 23 Attachment 1.

PDI's capital forecast included in the Status Quo (Exhibit A, Tab 2, Schedule 1) is based upon historic averages, with the exception of Station Costs. Attached to this undertaking is the PDI Station Assessment report that was completed in 2018. The report details the current status of PDI's distribution station assets, as well as plans for future capital spending. This report was used to forecast PDI's Station capital expenditures.

2018 PDI Station Assessment

Executive Summary

Peterborough Distribution Inc. (PDI) owns six (6) breaker stations and sixteen (16) distribution substations. PDI has not constructed or added to a 4.16 kV substation since 1979. The substations range in age from three to 70 years and have an average age of 49 years. Sixty-four percent (64%) of our stations are beyond the Kinetrics typical useful life (TUL) and twenty-seven (27%) are beyond the maximum TUL of 60 years.

PDI's asset management plan has been focused on eliminating the 4.16 kV distribution system by converting existing load to the 27.6 kV system. This program would eventually eliminate the need to replace these stations and their associated ongoing operating and maintenance costs

Recent analysis has demonstrated that our 4.16 kV to 27.6 kV conversion has not progressed at a fast enough rate to offset the need to make major investments at our 4.16 kV substations. Our stations are well maintained and repaired as needed, however, they are continuing to age. Only four substations have been decommissioned during the past 15 years. Most stations will be well beyond their typical useful life before the area surrounding them can be converted to 27.6 kV.

PDI is planning to continue with its ongoing conversion program to target four stations for decommissioning during the next ten years. Two more stations will be planned to be decommissioned over the following ten-year period. The remaining eight 4.16 kV stations (MS 1, 2, 5, 7, 8, 10, 12, 29, and 54) are expected to remain in the distribution system and will require ongoing investments to extend the life of these stations.

PDI is planning to increase capital spending $1.5 to 2.2 million per year in order to rectify the aging station assets detailed in this report.

Introduction

PDI owns six (6) breaker stations and sixteen (16) distribution substations situated throughout Peterborough with one located in Lakefield. These stations are a mixture of indoor and outdoor stations. Most distribution substations convert the incoming 44 kV sub-transmission voltage to a local distribution voltage of 4.16 kV.

Breaker Stations are system control points on the 44 kV sub-transmission system. These stations provide the ability to redistribute load between 44 kV feeders to facilitate maintenance, construction activities, and outage restoration. There is significantly less equipment in a breaker station and they can be bypassed during an unplanned outage.

Breaker stations are also used to make parallel between Hydro One owned Dobbin and Otonabee transformer stations (T.S.) during some 4.16 kV switching operations. Our experience has shown that phase imbalance can occur when using a load interrupting air-break switch to make and break parallel between the two stations due to the loop impedance in the transmission system. This phase imbalance has resulted in several unplanned feeder breaker operations when using air-break switches, therefore, these breaker stations have remained a vital component of our system.

Figure 1: Pictures of MS #3 (left) and MS #19 (right)

2018 PDI Station Assessment

System Loading

The loading of the 4.16 kV distribution system has dropped off since its peak demand period in the 1980s. Most substation were overloaded during that period and were difficult to take out of service for maintenance. The decreased loading is due to several factors: the 4.16 kV to 27.6 kV conversion program, conservation and demand management (CDM) programs, and a shift from electric to gas heating.

Today, the 4.16 kV substations are lightly loaded. Only one station has a peak load above 75% of its capacity. The total 4.16 kV system loading dropped 15% from 2014 to 2017. Substations can be easily removed for maintenance outside of peak loading periods and can be supplied by other substations if a failure occurs.

PDI's 4.16 kV distribution system has sufficient redundancy that loads can be transferred to other stations so that a station can normally be easily be taken out of service. PDI has several spare old station transformers available for emergency replacement. It is possible to have two stations out of service at one time outside of the peak loading periods, however, this increases the reliability risk and is not normally planned.

Figure 2: Station Loading

Distribution Station	Transformer Rating kVA	2014 Peak kW	2017 Peak kW	Feeders
MS #1, Aylmer Street	3 x 3000	7200	6048	6
MS #2, Romaine Street	5000	2880	3648	2
MS #3, Clifton Street	5000	4512	3648	3
MS #5, Upper High Street	5000	4320	3840	3
MS #7, Bellevue Street	7500	4502	3648	4
MS #8, Simcoe Street	2 x 3000	4500	4800	4
MS #9, Ashburnham Drive	5000	1680	800	2
MS #10, Erskine Avenue	2 x 3000	4902	4646	5
MS #12, Langton Street	2 x 3000	3080	1944	5
MS #18, Lansdowne Street	2 x 3000	3840	3520	6
MS #19, Wallis Drive	5000	3040	3360	3
MS #26, Francis Stewart Road	5000	4046	3029	3
MS #29, McDonnell Street	7500 + 5000	8768	5984	6
MS #35, Sherbrooke Street	5000	4080	2000	3
MS #54 Lakefield	2 x 5000	6574		4
MS #65 Hilliard Street	20000	N/A	14570	2

27.6 kV Distribution System

The 27.6 kV distribution system was introduced in Peterborough in 1987. This system was seen at the time as the most efficient voltage system overall for high-density urban areas in the future. The 27.6 kV system was less restrictive than the 4.16 kV system in supplying medium sized loads (500 to 3000 kW) and provided a less costly alternative to 44 kV for medium sized loads. The 27.6 kV voltage level could carry more load capacity on the same size lines and would not experience the voltage drop that is prevalent on the 4.16 kV system. The 44 kV system was retained to supply larger sized commercial and industrial loads (>3000 kW).

Peterborough has been expanding the 27.6 kV distribution system for thirty years with the objective of eliminating some of the 4.16 kV system and reducing the number of 44 to 4.16 kV substations and 4.16 kV distribution feeders. This conversion was also planned to improve the efficiency of delivery of electricity.

There is a larger number of customers on each 27.6 kV feeder when compared to 4.16 kV feeders. This has increased the customer impact of any unplanned feeder outages. The addition of two new feeders in 2015 and the introduction of a feeder automation system has helped to improve the 27.6 kV system reliability. Additional 27.6 kV feeders in 2023 should create further improvements.

Asset Management Plan

In 2012, PDI's long-term asset management plan was focused on eliminating the 4.16 kV distribution system by converting existing load to the 27.6 kV system. This program's goal was to eliminate the need to replace these stations and their associated ongoing operating and maintenance costs.

Station decommissioning was normally accomplished by converting the outside edges of the system first and collapsing the system towards the middle. This method reduces the need to maintain long inter-ties between the remaining substations in order to maintain reliability and provide opportunities to take substations out of service for maintenance and repair. Unfortunately, the substations on the outside edge of the system are typically newer than the older stations located in the core. The equipment from the newer stations has been kept as system spares and is available to be redeployed in the older stations.

PDI has not constructed or added to a 4.16 kV substation since 1979. PDI decommissioned its first substation at MS #24 (Crawford Drive) in the early 2000's. Further decommissioning occurred at MS #6 (High Street) in 2009, MS #36 (Neal Drive) in 2012, and MS #21 in 2017. PDI has kept most substation properties after decommissioning to determine if there may be a future use.

Most substations have had upgrades over the decades to some of the equipment. The age in Figure 3 below reflects the largest and oldest element, which is typically the power transformer and switchgear.

Figure 3: Substation Ages

Distribution Stations – 2018	Year of Installation	Age (Yrs)
MS #1, Aylmer Street	1956	62
MS #2, Romaine Street	1948	70
MS #3, Clifton Street	1950	68
BS #4, Auburn Street (breaker station)	1968	50
MS #5, Upper High Street	1951	67
MS #7, Bellevue Street	1955	63
MS #8, Simcoe Street	1956	63
MS #9, Ashburnham Drive	1971	47
MS #10, Erskine Avenue	1958	60
BS #11, Lansdowne Street W. (breaker station)	1960	58
MS #12, Langton Street	1965	53
BS #13, Jackson Park (breaker station)	1960	58
BS #14, Erskine Avenue (breaker station)	1996	22
MS #18, Lansdowne Street W.	1978	40
MS #19, Wallis Drive	1976	42
BS #21A, Water Street N. (breaker station)	1971	47
MS #26, Francis Stewart Road	1972	36
MS #29, McDonnell Street	1973	45
BS #34, High Street N. (breaker station)	1976	42
MS #35, Sherbrooke Street W.	1977	41
MS #54 Lakefield	1968	50
MS #65, Hilliard St	2015	3
Average Station Age		49

PDI's past practice on the typical life expectancy of a substation was 60 years. This is at the upper end of the utilities surveyed for the Kinetrics Asset Depreciation Study, which ranged from 30 to 60 years. Our experience has shown that the older station equipment has an excellent reliability record to date. The substations range in age from three to 70 years and have an average age of 49 years. Sixty-four percent (64%) of our stations are beyond the Kinetrics typical useful life and twenty-seven (27%) are beyond the maximum TUL of 60 years.

PDI built a larger scale 44 - 27.6 kV substation (MS #65) on Hilliard Street to augment and enhance the supply points to the 27.6 kV distribution system and to make better use of the capacity of the existing 44 kV transformer station supply points. This station has geographically diversified our 27.6 kV distribution supply points. The 27.6 kV system is also more efficient and adaptable to connect larger load customers and distributed generation.

New distribution substation installation costs average around $2 Million per station in total based on our last substation installation in 2015. New station transformers average around $300K, feeder breaker replacements averaging $50K per cell, and new 44 kV breakers average around $80K (not including other associated costs). Grounding and fence rehabilitations average $150K depending on the configuration and size.

PDI has a regular maintenance and inspection program for distribution and breaker stations. Upgrades to smaller components like insulators, SCADA, and batteries are included in its ongoing capital renewal program. These replacements are assessed at the time of the regular maintenance schedule or if poor condition is identified in a monthly inspection.

PDI's 2012 Asset Management Plan did not include any plans to make wholesale replacements at the 4.16 kV substations. The asset management philosophy was that as the 27.6 kV system grid was expanded and the ongoing voltage conversion program continued, many substations would become redundant. Substations were maintained and upgraded as necessary until the time for decommissioning was determined. Eventually, parts salvaged from those stations identified as redundant and decommissioned would be used as spares and upgrades for those stations that remain in service.

Recent analysis has demonstrated that our 4.16 kV to 27.6 kV conversion has not progressed at a fast enough rate to offset the need to make major investments at our 4.16 kV substations. These stations are well maintained and repaired as needed, however, they are continuing to age. Only four substations have been decommissioned during the past 15 years. Most stations will be well beyond their typical useful life before the area surrounding them can be converted to 27.6 kV.

Our conversion program has been steadily advancing during this period but it is limited to a scope that can be reasonably managed each year based on our normal spending and staffing levels. Conversion projects in underground areas are particularly complex and require extra planning and coordination with other utilities and our customers. The areas outside the core have been a focus for our conversion program in order to support the higher subdivision growth.

Decommissioning

PDI is planning to continue with its ongoing conversion program to target station decommissioning. These projects will eliminate incremental losses of substation transformation losses and will allow for redistribution of maintenance resources to other system needs and elimination of contract work associated with the substation. This work will also remove an environmental risk due to a potential transformer oil spill or fire. This conversion program should allow for decommissioning of the following stations over the next ten period.

Figure 4: 10-year Decommissioning Forecast

No	Station	Type	Description
1	MS #35, Sherbrooke St	New	Convert station from 4.16 kV to 27.6 kV
2	MS #19, Wallis Dr	Decommission	Convert distribution to 27.6 kV
3	MS #3, Clifton St	Decommission	Convert distribution to 27.6 kV
4	MS #9, Ashburnham Dr	Decommission	Convert distribution to 27.6 kV

The decommissioning of MS #3 and MS #9 are linked together. MS #9 is very lightly loaded but forms a back up for MS #3. It cannot be decommissioned until MS #3 is out of service. The upcoming Ashborough Village subdivision development that is across from the Lift Lock will drive some load conversion from MS #3. The feeders from both substations are in close proximity to 27.6 kV feeders to minimize the conversion costs.

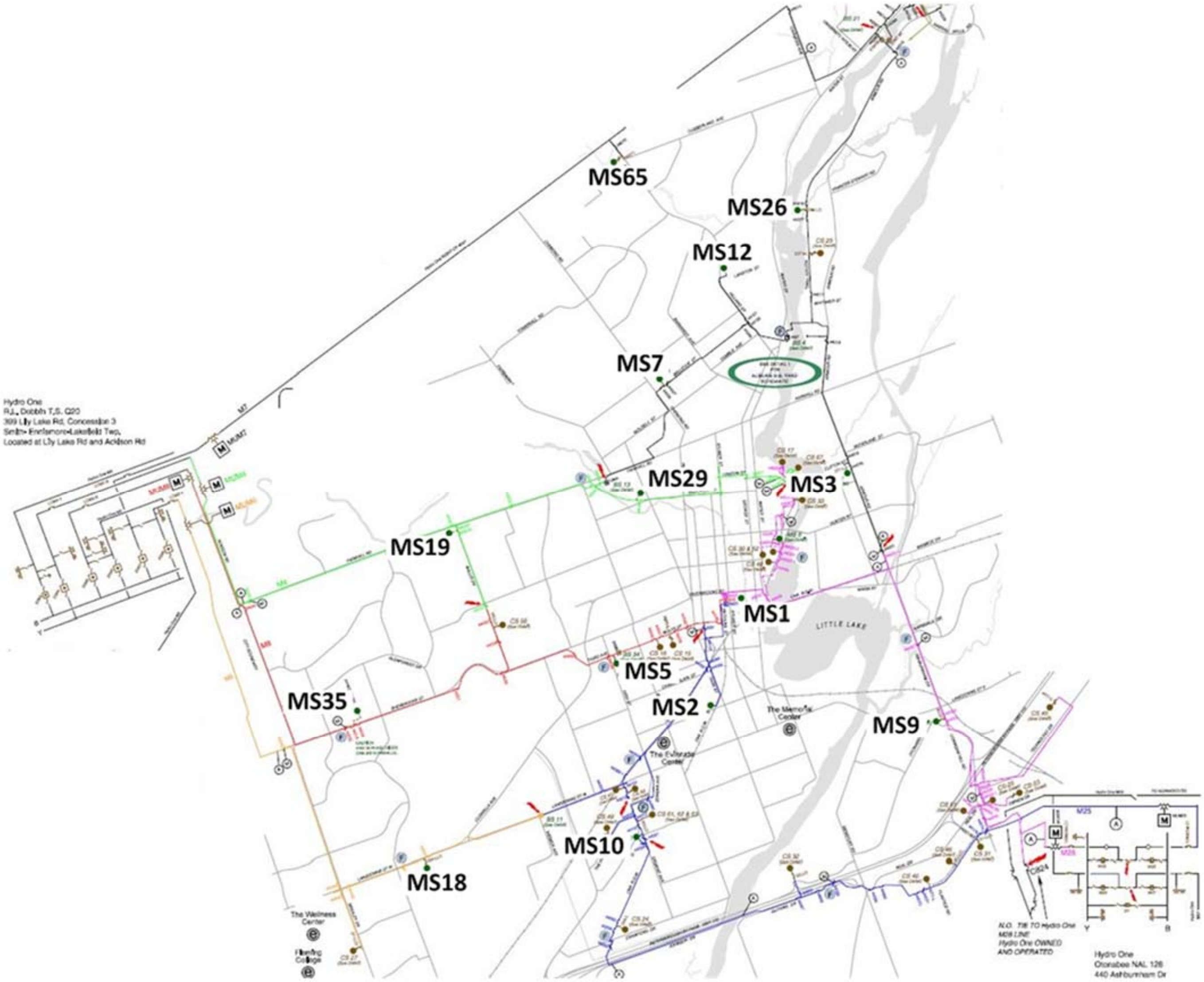
MS #26 at Frances Stewart Road and MS #18 on Lansdowne Street will be planned to be decommissioned in the longer-term forecast (more than 10 years). The loads from MS #26 along Armour Road will be converted over the next ten years.

Once MS #3 and MS #9 are decommissioned, the remaining loads from this station will be transferred over to MS #12. MS #12 has several backyard feeders, which could be challenging to covert thus making MS #26 as an easier target for conversion.

MS #18 will be a likely target after MS #19 and 35 are decommissioned. Several commercial loads will need to be converted in order facilitate decommissioning of this station.

The remaining eight 4.16 kV stations (MS 1, 2, 5, 7, 8, 10, 12, 29, and 54) are expected to remain in the distribution system and will require ongoing investments to extend the life of these stations. These stations are located in the core of our distribution system as shown in Figure 5.

Figure 5: Station Map



These station investments will be focused on major asset replacements such as transformers and switchgear. The first ten years will be focused on replacement of oil filled switchgear and transformers as well as protection improvements. The following ten years will be focused on 4.16 kV switchgear replacements.

Some saving can realized in the reduction of loading at these stations. Some stations with multiple transformers such as MS #1 could be reduced to only one transformer in the future. Wholesale replacement of stations from the ground up would very challenging at most of these existing sites.

2018 PDI Station Assessment

Figure 6: 20 Year Station Forecast

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
MS	1	Alymer	E	R										R							R		
	2	Romaine											R						R				
	3	Clifton									D												
	5	High										R										R	
	7	Bellevue								R										R			
	8	Simcoe							R														R
	9	Ashburnham											D										
	10	Erskine									R										R		
	12	Langton						R															
	18	Lansdowne					R										D						
	19	Wallis							D														
	26	Frances Stewart													D								
	29	McDonnell				R												R					
	35	Sherbrooke				D																	
	54	Lakefield			R										R								
	65	Hilliard																					
	New	27.6 kV at MS #35 Site			E		N																
	New	27.6 kV at MS #6 Site																	N				

Note that it is difficult to forecast the growth of this area over the next 20 years. It is likely that this plan will change if increased development occurs in these areas of the City. The sequence of work on these stations may vary as the asset condition assessment evolves.

New 27.6 kV Supply

MS #35 is located in the western portion of Peterborough in a good location to support new development in that area. Converting this station would help to increase the reliability of the 27.6 kV system by:

- Adding more geographic diversity to this system: MS #35 is fed 44 kV from Dobbin TS at Lily Lake Road. PDI has four 27.6 kV feeders from Otonabee TS in the south end. If a major event occurred at Otonabee TS, PDI has limited 27.6 kV supply points from Dobbin TS.
- Reducing the number of customers per feeder: Most 27.6 kV feeders are very lengthy and heavily loaded (average of 7000 customers) which tends to magnify any faults on these feeders.
- Adding more load capacity for continued conversion projects.

PDI's first 27.6 kV station (MS #65) was built on Hilliard Street for a total project cost of $2.1 million. It is expected that some savings will be realized by converting an existing station to 27.6 kV. MS #35 on Sherbrooke is an ideal site due to the large property size and types of neighbouring properties. When a three-year underground rehabilitation program is completed in the Kawartha Heights subdivision in 2022, this station will no longer be needed to supply 4.16 kV feeders.

Oil Sampling Program

The consequences of power transformer failure include long duration customer interruptions. Catastrophic failure of transformers may also result in collateral damage to other transformers, damage to other station equipment, and if staff are present, potential injury to personnel. Since transformers are filled with mineral oil, there is environmental risk of oil spills contaminating ground and water systems if the tank fails. Even if transformer failures do not occur, should a unit's health decrease significantly, it would need to be off-loaded to reduce further stress. This in turn increases the stress placed on other units, and decreases capacity to be used to deal with a contingency, which affects system reliability.

The end of life for station transformers is a result of the failure of the pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation.

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. Overloads cause above-normal temperatures, which can cause accelerated transformer aging. Our station transformers have been lightly loaded during the last 20 years, which had helped to extend their service life.

Annual oil samples have been taken for our oil-filled substation assets since 2011. PDI only has vacuum and SF6 switchgear assets at MS #65. The oil-filled station transformers and switchgear are tested for dielectric breakdown, dissolved gas, colour, and moisture. Assets that have been flagged for follow up are tested more frequently. Equipment that are identified for immediate action are either repaired or replaced. Equipment has not been replaced if it has had higher than normal readings but the reading has not changed during the six-year testing period. Nine substation assets have been identified for follow up testing in the 2017 test report.

Figure 7: Station Assets with Oil Testing Concerns

No	Station	Description	Serial no.	Age (2018)	Decommission
1	MS #1	Transformer A	280994	62	No
2		Transformer B	280993	62	No
3		Transformer C	280991	62	No
4	BS #11	Oil circuit breaker	52859	58	No
5	MS #12	Transformer 1	218482	53	No
6		Transformer 2	278499	53	No
7	MS #18	Transformer 2			Yes
8	MS #19	Transformer 1	288740	43	Yes
9	MS #29	Transformer 2	288157	44	No

One circuit breaker at BS #11 will be replaced with vacuum switchgear in 2018 due to the poor test results. The test results for the other eight transformers have remained steady during the last seven years of testing, however, these transformers are well beyond their typical useful life and will need to be replaced or decommissioned during the ten-year forecast. Since MS #18 is not planned to be decommissioned within the ten-year forecast but in the longer term, it may be possible to utilize a refurbished spare transformer for that station.

Other station assets that have been currently identified as needing renewal that are not captured in the oil test results are MS #3 at Clifton Street and MS #54 in Lakefield. The 4.16 kV switchgear at Clifton is of an older generation. Replacement parts are becoming harder to find and it is showing signs of aging. This station is planned to be decommissioned based on 27.6 kV conversion work in the surrounding area.

The 44 kV feed to our MS #54 substation in the Village of Lakefield is fed from Hydro One's M27 feeder. When there are any issues on this line, the power to Lakefield is lost without any back up until the faulted section of line is repaired. There is also no back up to this substation on the low voltage 4.16 kV level. This is reflected in the longer outage duration times for several outages in Lakefield. There is no economical solution for Hydro 1 to add a second 44 kV supply to Lakefield. Hydro One has completed several recent projects to improve the reliability of this radial feeder; however, back-up options are still limited. PDI has identified that this substation is in need of a rehabilitation in order to extend its useful operating life. The overhead 4.16 kV switching structure and fusing is in particular need of improvement. The addition of a reclosing function to these feeders could greatly improve reliability in this area and reduce operating costs in Lakefield.

Figure 8: MS #54 in Lakefield

Reliability Metrics

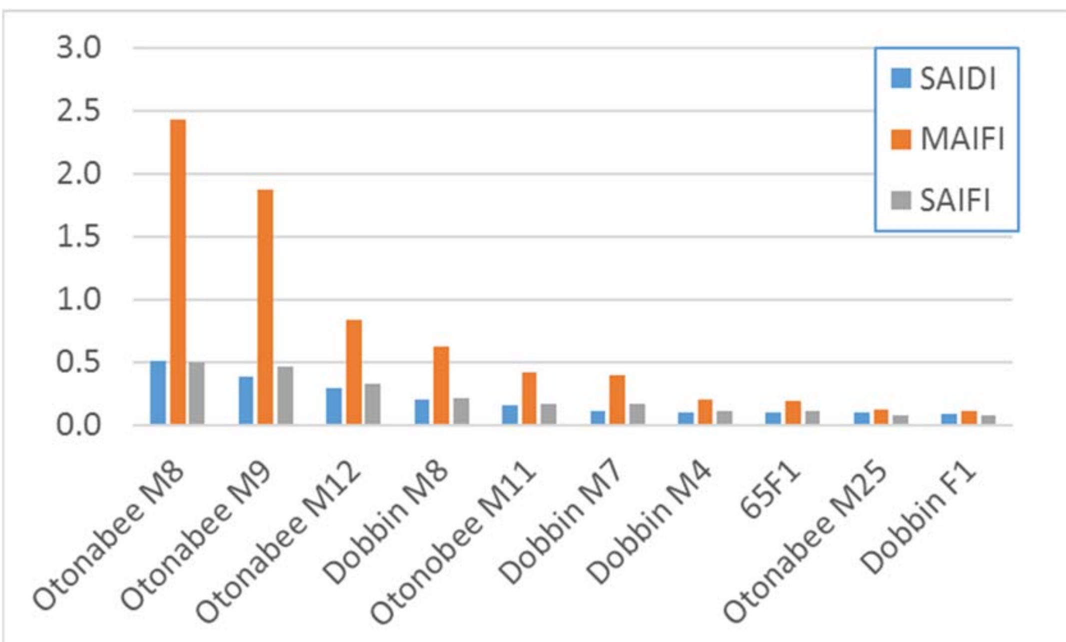
Our top five worst performing feeders are on the 27.6 kV system during the five-year period from 2013 to 2017. This is due to the high number of customers per feeder when compared to the 4.16 kV system. The top ten worst performing feeders do not include any 4.16 kV feeders. Most reliability improvements have been focused on the 27.6 kV system during the last five years.

The 8F1 feeder had the 13th worst 4.16 kV feeder average outage duration out of 79 total feeders. The 19F1 feeder had the 14th worst 4.16 kV feeder average outage frequency out of 79 total feeders. The majority of outages on these feeders were scheduled for downtown vault maintenance (8F1) or tree trimming (19F1).

We have had three failures at our 4.16 kV stations in 2018 (MS #7, MS #18, and MS #29). The interruptions at MS #18 and MS #29 were caused by buss duct failures. The outage at MS #7 was due to a 4.16 kV feeder cable splice failure. Fortunately, none of these failures resulted in any major damage and the number of customers affected was small.

It is likely that as these stations continue to age, that the failure rate will increase if equipment replacements do not take place.

Figure 9: Worst Performing Feeders 2013 to 2017



Conclusion

PDI will need an increase in capital spending in order to rectify the aging station assets detailed in this report. Figure 10 represents a forecast of the increased spending on stations from 2020 to 2029. An annual increase of between $1.5-$2.2 million per year is forecasted.

Figure 10: 10-Year Station Forecast

				2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MS	1	Alymer		E	R									
	2	Romaine												R
	3	Clifton										D		
	5	High											R	
	7	Bellevue									R			
	8	Simcoe								R				
	9	Ashburnham												D
	10	Erskine										R		
	12	Langton							R					
	18	Lansdowne						R						
	19	Wallis								D				
	26	Frances Stewart												
	29	McDonnell					R							
	35	Sherbrooke					D							
	54	Lakefield				R								
	65	Hilliard												
	New	27.6 kV at MS #35 Site				E		N						
Increased Station Spend ($MM)														
		Decommissioning	D	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.1
		Engineering	E	0.3	0.3	0.3	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		New build	N	0.0			0.8	1.2						
		Refurbishment	R	0.0	1.8	1.7	1.4	0.2	1.4	1.4	1.5	1.5	1.5	1.6
			Total	0.3	2.1	2.0	2.2	1.5	1.5	1.6	1.6	1.7	1.6	1.8

UNDERTAKING - JT1.8

Reference:

Undertaking:
To provide more granularity for the capital plan, similar to attachment at SEC 23.

Response:
Please find on Attachment 1 and 2, more granularity for the Hydro One capital plan for the Peterborough and Orillia service territories, respectively. Hydro One has provided more granularity for the capital plan in key categories of spend. A best effort attempt was made to utilize the categories found in PDI's and OPDC's capital plan which is provided in EB-2018-0242 Exhibit I, Tab 2, Schedule 23, Attachment 1 and EB-2018-0270 Exhibit I, Tab 1, Schedule 19, Attachment 4 respectively. Where spend could not be placed into one of the existing categories, we utilized the categories aligning with the functions detailed in EB-2018-0242 Exhibit I, Tab 1, Schedule 17 part a) and EB-2018-0270 Exhibit I, Tab 1, Schedule 19 for Peterborough and Orillia respectively.

Hydro One cautions against simple total dollar comparison between status quo and Hydro One's capital spending forecast in any specific category due to differences in investment and system planning approaches. For example, Hydro One has various options to address station risk for the PDI service territory such as load transfers, voltage conversion, station refurbishment, and full station replacement. Hydro One also has the ability to mitigate risk of failures with methods unavailable to PDI such as a more than adequate level of spare transformers and a fleet of Mobile Unit Substations.

Hydro One's capital envelope for PDI sufficiently addresses station needs as required. For example, the Hydro One station capital expenditure envelope over the 10 year period is sufficient to complete 6 station rebuilds/major refurbishments as well as 10 transformer replacements that could address 7 or more additional stations. Additionally, funding is also sufficient for station decommissioning as deemed appropriate. Hydro One has identified a number of specific stations to be addressed and anticipates additional station needs will arise in the forecast period. The specific plans for each station will be developed post integration.

Attachment 1

Hydro One Forecast (Peterborough)

($'s in thousands)

		2020 Year 1	2021 Year 2	2022 Year 3	2023 Year 4	2024 Year 5	2025 Year 6	2026 Year 7	2027 Year 8	2028 Year 9	2029 Year 10
Land	*Note 1*										
Buildings	*Note 2*										
Distribution Stations		986	3,696	1,617	1,259	1,791	3,124	1,358	1,393	1,429	1,465
Poles and Fixtures	*Note 3*										
Overhead Conductor	*Note 4*										
Underground Conduit	*Note 4*										
Underground Conductor	*Note 4*										
Transformers	*Note 4*										
Services	*Note 5*										
Meters		344	641	570	585	600	544	558	572	587	602
Measurement and Test Equipment		0	0	0	0	0	0	0	0	0	0
System Supervisory Equipment	*Note 6*										
Computer Equipment		0	0	0	0	0	0	0	0	0	0
Transportation Equipment	*Note 1*										
Wood Pole Replacements		204	503	516	529	543	557	571	586	601	616
Line Refurbishment		312	768	788	808	829	850	872	894	917	940
System Reinforcement		156	384	393	403	412	422	432	442	453	464
Customer Connections & Upgrades / Distributed Generation		486	1,195	1,224	1,253	1,283	1,314	1,345	1,378	1,411	1,444
Demand Work		107	264	271	278	285	293	300	308	316	324
Stand Alone LDC (7 mths)	*Note 7*	3,411									
Contributed Capital	*Note 8*										
Net Capital Expenditures		**6,007**	**7,452**	**5,379**	**5,115**	**5,744**	**7,103**	**5,437**	**5,573**	**5,713**	**5,856**

Note 1 Costs embedded in other categories as applicable
Note 2 Costs embedded in "Distribution Stations" and "System Reinforcement" categories
Note 3 Costs embedded in "Wood Pole Replacements", "Line Refurbishment", "System Reinforcement", "Customer Connections & Upgrades / Distributed Generation", "Demand Work"
Note 4 Costs embedded in "Line Refurbishment", "System Reinforcement", "Customer Connections & Upgrades / Distributed Generation", "Demand Work"
Note 5 Costs embedded in "Customer Connections & Upgrades / Distributed Generation" and "Demand Work"
Note 6 Costs embedded in "Customer Connections & Upgrades / Distributed Generation", "Distribution Stations", "System Reinforcement"
Note 7 Represents the 7 month period prior to operational integration with Hydro One
Note 8 Contributed capital accounted for in other categories as applicable

Attachment 2

Hydro One Forecast (Orillia)

($'s in thousands)

		2020 Year 1	2021 Year 2	2022 Year 3	2023 Year 4	2024 Year 5	2025 Year 6	2026 Year 7	2027 Year 8	2028 Year 9	2029 Year 10
Service Centre		0	0	0	0	0	0	0	0	0	0
Substations		215	531	546	562	579	596	614	632	650	669
Poles & Wires	*Note 1*										
Meters		422	187	193	198	204	210	217	223	230	236
Heavy Vehicles	*Note 2*										
Light Vehicles	*Note 2*										
Other Capital Assets	*Note 2*										
Wood Pole Replacements		68	168	173	178	183	188	194	200	206	212
Line Refurbishment		27	68	70	72	74	76	78	81	83	86
System Reinforcement		233	576	593	610	627	710	690	704	717	732
Customer Connections & Upgrades / Distributed Generation		290	716	737	758	779	879	856	873	891	909
Demand Work		49	122	125	129	133	136	141	145	149	153
Stand Alone LDC (7 mths)	*Note 3*	2,070									
Contributed Capital	*Note 4*										
Net Capital Expenditures		**3,375**	**2,368**	**2,436**	**2,507**	**2,579**	**2,796**	**2,790**	**2,857**	**2,926**	**2,997**

Note 1 Costs embedded in "Wood Pole Replacements", "Line Refurbishment", "System Reinforcement", "Customer Connections & Upgrades / Distributed Generation", "Demand Work"
Note 2 Costs embedded in other categories as applicable
Note 3 Represents the 7 month period prior to operational integration with Hydro One
Note 4 Contributed capital accounted for in other categories as applicable

UNDERTAKING - JT1.9

Reference:

Undertaking:
To provide the calculations for capital spend for OPDC and for PDI.

Response:
When deriving the Hydro One forecast for an LDC territory Hydro One's investment plan is used as a starting point for establishing an expenditure plan to ensure the prudent management of its distribution system. From there the plan is scaled to the LDC's demographics and further adjusted to account for specifics related to the LDC (e.g., asset condition, age, characteristics, etc. as compared to Hydro One's system). This is illustrated in Figure 1 below.

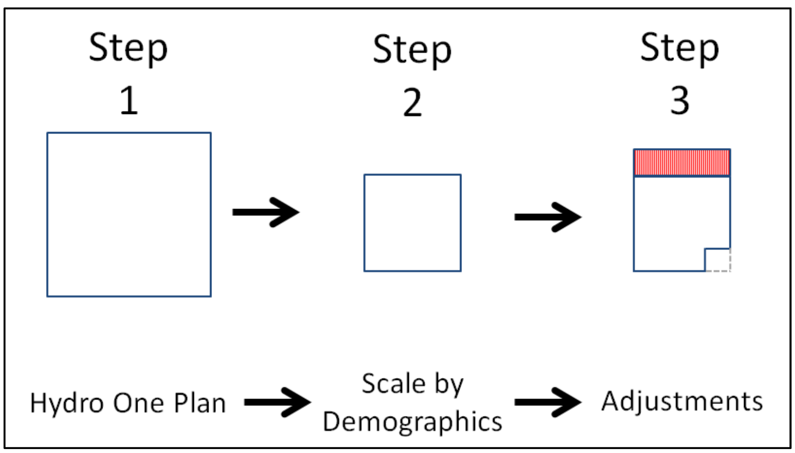


Figure 1

Hydro One's plan utilizes an Asset Risk Assessment (ARA) process. The Hydro One ARA process encompasses the assessment of a multitude of applicable asset categories. In both the OPDC and PDI integration cases, Hydro One examined the functions outlined below:

- Vegetation Management
- Lines Maintenance and Refurbishment
- Demand Work
- Wood Pole Replacement
- Stations

- Environment
- Other Sustainment
- Customer Connections / Upgrades
- System Reinforcement
- Distributed Generation
- Other Development.

As part of the due diligence process supporting the transactions, Hydro One conducted field assessments, visual inspections and evaluations in Peterborough and Orillia to collect asset information on existing PDI and OPDC assets. This information feeds directly into the capital expenditure forecasts (as explained above) and itemized in the attachments to JT1.8.

There are three main steps in the calculation of the Hydro One forecasts.

1. Hydro One's investment plan is used as a starting point representing a prudent plan needed to manage a distribution system.

2. Key system demographics are used to scale the Hydro One investment plan dollars to account for the size of the acquired LDC, effectively scaling Hydro One system costs down to the size of the LDC. These key system demographics are listed below:

   - Number of Customers
   - Total Circuit Length (km)
   - Overhead Circuit Length (km)
   - Underground Circuit Length (km)
   - Right of Way Length (km)
   - Number of Stations.

3. The scaled system costs are further adjusted to account for specifics related to the LDC being acquired (e.g., asset condition, asset age, unique system characteristics, etc.). As noted above, the information used to make such adjustments is obtained through Hydro One's due diligence via site visits, filed assessments, etc.). Some specific examples that were taken into account in deriving Hydro One's forecasts for the Peterborough and Orillia service areas include:

   - Station condition

- Urban vs rural service territory
- Pole density per km of line
- Proportion of overhead vs underground circuits
- PCB compliance status
- Local vegetation density.

The end result is a forecast that represents the Hydro One funding needed to prudently manage the acquired OPDC and PDI service territories once integrated into Hydro One Networks. A more specific capital plan will be prepared by Hydro One post-closing of any PDI and OPDC transaction.

The foregoing provides the basis for the assessment of the LDC's assets and the methodology, including scaling variables, that was used to establish the more granular forecasts set out in Undertaking JT1.8. Consistent with the OEB's typical review of capital forecasts, the provision of the mathematical calculations underpinning the forecasts are not relevant to the Board's consideration of the issues in this proceeding.

UNDERTAKING - JT2.1

Reference:

Undertaking:
To provide an explanation of the nature of the difference between the board's model and Hydro One's cost allocation model, and the impact applied to this process; if in evidence, to provide the reference.

Response:
As clarified on page 12 of the transcript, the undertaking was to clarify the impact on the results from the cost allocation model due to differences in the Peak Load Carrying Capacity ("PLCC") assumptions within the model.

Hydro One's cost allocation model applies PLCC values that are specific to Hydro One's conductors and transformers. These values are based on a Minimum System Study originally approved by the OEB in EB-2008-0187, with further updates approved by the OEB in EB-2013-0416. Hydro One's specific PLCC values are 1,154 watts for conductors and 2,939 watts for transformers.

The PLCC values used in PDI and OPDC's cost allocation models (as filed in EB-2012-0160 and EB-2009-0273, respectively) are the default values established by the OEB in 2006. The OEB cost allocation model's default PLCC values are 400 watts for both conductors and transformers.

Exhibit Q, Tab 1, Schedule 1, page 23 of Hydro One's last distribution rate application (EB-2017-0049) included a discussion on the impact of using different PLCC values in Hydro One versus Acquired Utility cost allocation models. As noted in Exhibit Q, Tab 1, Schedule 1, use of higher PLCC values results in a shifting of allocated costs from residential to general service classes.

The table provided below shows the impact on the 2018 Hydro One cost allocation model[1] as a result of applying different PLCC values (Hydro One specific PLCC values and default OEB PLCC values.)

[1] EB-2017-0049, Draft Rate Order Exhibit 3.1 filed on April 5, 2019

	Using HONI's PLCC Values		Using OEB Default PLCC Values	
HONI Rate Class	**Allocated Costs ($M)**	**Revenue to Cost Ratio**	**Allocated Costs ($M)**	**Revenue to Cost Ratio**
UR	$ 87.1	1.08	$ 94.3	0.99
R1	$ 285.0	1.09	$ 310.4	1.00
R2	$ 530.1	0.97	$ 570.1	0.90
Seasonal	$ 100.0	1.09	$ 114.1	0.96
GSe	$ 166.3	0.99	$ 147.5	1.11
GSd	$ 156.0	0.89	$ 101.2	1.37
UGe	$ 22.5	1.01	$ 18.5	1.22
UGd	$ 31.0	0.91	$ 20.7	1.36
St Lgt	$ 11.0	0.93	$ 12.6	0.81
Sen Lgt	$ 5.7	0.97	$ 5.7	0.96
USL	$ 2.8	1.23	$ 3.0	1.15
DGen	$ 6.3	0.58	$ 6.4	0.58
ST	$ 54.8	0.96	$ 54.0	0.97
Total	**$ 1,458.5**	**1.00**	**$ 1,458.5**	**1.00**

UNDERTAKING - JT2.2

Reference:

Undertaking:

To provide the spreadsheet showing decrease in revenue requirement by 400,000 in year 11.

Response:

As per Exhibit I, Tab 1, Schedule 15 of EB-2018-0242, Hydro One previously assessed areas of USGAAP and IFRS differences, and determined that the only area that could impact revenue requirement is the potential difference in the capitalization policies of the two companies, particularly with respect to the capitalization of certain overhead costs. PDI's capitalization policy does not include an allocation of indirect costs whereas Hydro One does capitalize applicable indirect overhead costs.

Applying this policy change to the revenue requirement forecast results in PDI's revenue requirement for year 11 decreasing by $400,000, from $24.9 million to $24.5 million.

Please see the attachment to this undertaking for further detail.

Peterborough Distribution Inc.
JT2.2
[Schedule as originally provided in OEB IR #17 - and amended as noted for overhead capitalization]

	2017 Act.	2018 Fore.	2019 Fore.	2020 Fore.	2021 Fore.	2022 Fore.	2023 Fore.	2024 Fore.	2025 Fore.	2026 Fore.	2027 Fore.	2028 Fore.	2029 Fore.	2030 Fore.
Working Capital Allowance														
Controllable expenses, per 10 year forecast	9,014	9,221	9,433	9,650	9,872	10,099	10,332	10,580	10,844	11,115	11,393	11,678	11,970	12,269
GAAP Adjustment - Capitalization of indirect costs				(774)	(798)	(757)	(781)	(805)	(819)	(843)	(868)	(882)	(907)	(898)
Restated Controllable expenses	9,014	9,221	9,433	8,876	9,074	9,343	9,551	9,774	10,025	10,272	10,525	10,796	11,063	11,372
Cost of Power	90,971	92,336	93,721	95,126	96,078	97,038	98,009	98,989	99,979	100,979	101,988	103,008	104,038	106,130
Subtotal	99,985	101,557	103,154	104,003	105,152	106,381	107,560	108,763	110,004	111,250	112,513	113,804	115,102	117,501
Working Capital Allowance Factor	13%	13%	13%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**12,998**	**13,202**	**13,410**	**7,800**	**7,886**	**7,979**	**8,067**	**8,157**	**8,250**	**8,344**	**8,439**	**8,535**	**8,633**	**8,813**
Rate Base														
Net Capital Assets (Average of Current and Prior)	61,951	63,574	65,802	68,623	72,050	75,159	77,959	80,729	83,463	86,160	88,824	91,448	94,031	96,559
Allowance for Working Capital, per above	12,998	13,202	13,410	7,800	7,886	7,979	8,067	8,157	8,250	8,344	8,439	8,535	8,633	8,813
Rate Base	**74,949**	**76,776**	**79,212**	**76,423**	**79,936**	**83,138**	**86,026**	**88,886**	**91,713**	**94,504**	**97,263**	**99,983**	**102,663**	**105,372**

Calculation of Net Capital Assets (Average of Current and Prior)

	2016 Act.	2017 Act.	2018 Fore.	2019 Fore.	2020 Fore.	2021 Fore.	2022 Fore.	2023 Fore.	2024 Fore.	2025 Fore.	2026 Fore.	2027 Fore.	2028 Fore.	2029 Fore.	2030 Fore.
Property Plant and Equipment	77,097	79,359	82,891	86,358	90,330	94,235	97,590	100,892	104,141	107,335	110,472	113,552	116,573	119,532	122,430
GAAP Adjustment (cumulative above)					774	1,572	2,329	3,110	3,915	4,734	5,577	6,445	7,327	8,234	9,131
Accumulated Depreciation adjustment					(26)	(52)	(78)	(104)	(130)	(158)	(186)	(215)	(244)	(274)	(304)
Less Deferred Contributions	15,640	16,915	18,187	19,459	20,731	22,003	23,275	24,547	25,819	27,091	28,363	29,635	30,907	32,179	33,451
Net Capital Asset	61,457	62,444	64,704	66,899	70,347	73,752	76,566	79,351	82,106	84,820	87,501	90,148	92,749	95,313	97,806

ORIGINAL SEC 22

Original SEC 22 - Filed **Revenue Requirement**	2020 Fore.	2021 Fore.	2022 Fore.	2023 Fore.	2024 Fore.	2025 Fore.	2026 Fore.	2027 Fore.	2028 Fore.	2029 Fore.	2030 Fore.
Average of NBV of Assets	68,249	70,916	73,274	75,330	77,334	79,283	81,177	83,013	84,791	86,510	88,166
Working Capital	7,858	7,946	8,035	8,126	8,218	8,312	8,407	8,504	8,601	8,701	8,880
Rate Base	**76,107**	**78,862**	**81,309**	**83,456**	**85,552**	**87,595**	**89,584**	**91,517**	**93,392**	**95,211**	**97,046**
Revenue Requirement											
OM&A	9,650	9,872	10,099	10,332	10,580	10,844	11,115	11,393	11,678	11,970	12,269
Depreciation	3,971	4,184	4,386	4,592	4,804	5,021	5,244	5,472	5,706	5,947	6,193
Cost of Capital - Debt Interest	1,843	1,909	1,969	2,021	2,071	2,121	2,169	2,216	2,261	2,305	2,350
Cost of Capital - Equity Return	2,740	2,839	2,927	3,004	3,080	3,153	3,225	3,295	3,362	3,428	3,494
Tax	790	704	634	558	773	701	616	531	707	602	607
Revenue Requirement	**18,994**	**19,508**	**20,015**	**20,507**	**21,308**	**21,840**	**22,369**	**22,907**	**23,714**	**24,252**	**24,913**

REVISED SEC 22

SEC 22 - Amended for Overhead **Revenue Requirement**	2020 Fore.	2021 Fore.	2022 Fore.	2023 Fore.	2024 Fore.	2025 Fore.	2026 Fore.	2027 Fore.	2028 Fore.	2029 Fore.	2030 Fore.
Average of NBV of Assets	68,623	72,050	75,159	77,959	80,729	83,463	86,160	88,824	91,448	94,031	96,559
Working Capital	7,800	7,886	7,979	8,067	8,157	8,250	8,344	8,439	8,535	8,633	8,813
Rate Base	**76,423**	**79,936**	**83,138**	**86,026**	**88,886**	**91,713**	**94,504**	**97,263**	**99,983**	**102,663**	**105,372**
Revenue Requirement											
OM&A	8,876	9,074	9,343	9,551	9,774	10,025	10,272	10,525	10,796	11,063	11,372
Depreciation	3,997	4,211	4,411	4,618	4,831	5,048	5,272	5,501	5,735	5,977	6,223
Cost of Capital - Debt Interest	1,850	1,935	2,013	2,083	2,152	2,221	2,288	2,355	2,421	2,486	2,551
Cost of Capital - Equity Return	2,751	2,878	2,993	3,097	3,200	3,302	3,402	3,501	3,599	3,696	3,793
Tax	789	700	627	548	760	685	596	508	681	572	574
Revenue Requirement	**18,264**	**18,798**	**19,387**	**19,896**	**20,717**	**21,280**	**21,831**	**22,391**	**23,232**	**23,794**	**24,513**

UNDERTAKING - JT2.3

Reference:

Undertaking:

For Orillia to provide their 7.55 percent calculation; (b) for Hydro One to provide their 8.07 percent calculation; (c) for Peterborough to provide their calculation.

Response:

a) Please see Attachment 1 for Orillia's ROE calculation.
b) Please see Attachment 2 for Hydro One's ROE calculation.
c) Please see Attachment 3 for Peterborough's ROE calculation.

Checklist Input Appendices ROE Summary Over Earning Drivers Under Earning Drivers

Report Summary

Filing Due Year	Filing Form Name	RRR Filing No
2019	2.1.5.6	23880
Reporting Period and Company Name	**Licence Type**	**Status**
April- 2019Orillia Power Distribution Corporation, Orillia: Corporation; ED-2002	Distributor	Submitted
Report Version	**Extension Granted**	**Extension Deadline**
0		
Filing Due Date	**Reporting From**	**Reporting To**
April 30, 2019	January 1, 2018	December 31, 2018
Submitted On	**Submitter Name**	**Expiry Date**
April 26, 2019	. .	May 01, 2019

Instructions

Please check off the activities that you have reviewed and completed in the list below. The form can be submitted only after all the boxes have been checked.

Clicking Save or Apply will not automatically submit this filing. To SUBMIT this filing, scroll to the end of the page, select Yes in the Submit drop down then click the SAVE button.

Checklist

Checkbox	No.	Questions
Overview		
☑	1	Have you read the ROE filing guide for completing the RRR 2.1.5.6 ROE filing?
☑	2	Have you reviewed and confirmed the accuracy of the RRR 2.1.7 trial balance?
☑	3	Have you reviewed and confirmed all auto-populated/linked cells on the form for accuracy?
☑	4	Have you resolved (i.e. re-filing the RRR 2.1.7 trial balance or contact the IRE) any issues that you may have noted with the auto-populated/linked cells?
☑	5	Regarding the input cells, have you ensured that the signs of the numbers entered align with the RRR 2.1.7 trial balance?
Input Appendices tab		
☑	1	Have you completed and reviewed Appendix 1 if you have non-rate regulated business that is recorded in the RRR 2.1.7 trial balance?
☑	2	Have you included all other adjustment(s) in Appendix 1?
☑	3	Have you identified and included in Appendix 1 all adjustments for non-rate regulated activities?
☑	4	Have you completed and reviewed Appendix 2 if you have non-recoverable donations that are recorded in the RRR 2.1.7 trial balance?
☑	5	Have you completed and reviewed Appendix 3 regarding net interest/carrying charge from DVAs?
		Have you included in Appendix 4 all adjustments so that the interest expense in cell dc

☑	6	is related to debt only?
☑	7	Have you completed and reviewed Appendix 4 on deemed debt?
☑	8	Have you included all adjustments regarding regulated PP&E in Appendix 5?
☑	9	Have you completed and reviewed Appendix 5 regarding regulated PP&E?
☑	10	Have you completed and reviewed Appendix 6 regarding current tax for regulatory purposes?
☑	11	Have you included in Appendix 6 the tax effects of all non-regulatory items?
☑	12	Have you reviewed the RRR Filing Guide and determined the accurate tax treatment regarding the activities in regulatory accounts in Appendix 6?
ROE Summary tab		
☑	1	Have you entered the input cells for the the Unrealized (gains)/losses on interest rate swaps (cell c) and identified the USoA(s), if applicable?
☑	2	Have you entered the input cells for the Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB (cell d) and identified the USoA(s), if applicable?
Over and Under-earning driver tabs		
☑	1	Have you completed and reviewed Appendices 7 and 8 if the ROE status for the year (cell z2) shows "Over-earning"?
☑	2	Have you completed and reviewed Appendices 9 and 10 if the ROE status for the year (cell z2) shows "Under-earning"?
☑	3	Have you submitted the Q4 RRR 2.1.2 customers if you are required to complete over/under-earning driver tabs?
☑	4	Have you submitted the RRR 2.1.5.4 annual billings if you are required to complete over/under-earning driver tabs?
Submitting the form		
☑	1	Have you clicked the Save button to update all the calculations on the form?
☑	2	Have you validated the accuracy of the Achieved ROE% as calculated in cell y on the ROE Summary tab?
☑	3	Have you retained the necessary supporting documents for the ROE filing?

Submit?

* Submit Form

No

Checklist | **Input Appendices** | ROE Summary | Over Earning Drivers | Under Earning Drivers

Input Appendices 1 to 6

Instructions

The calculations from Appendices 1 to 6 will populate the ROE Summary tab to calculate the Achieved ROE %.

The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.

Please complete Appendices 1-5 first before filling in Appendix 6. Please input pre-tax figures in Appendices 1-5.

All inputs are in $.

Please refer to the guide for detailed instruction on the filing of Appendices.

Appendix 1

Non-rate regulated items and other adjustments

CDM revenues (recorded in Account 4375)	aa	-349916.00
CDM expenses (recorded in Account 4380)	ab	349916.00
CDM - Net revenues/expenses	ac=aa+ab	0.00
Renewable generation revenues (recorded in Account 4375)	ad	
Renewable generation expenses (recorded in Account 4380)	ae	
Renewable generation - Net revenues/expenses	af=ad+ae	0.00
Water services revenues (recorded in Account 4375)	ag	
Water services expenses (recorded in Account 4380)	ah	
Water services - Net revenues/expenses	ai=ag+ah	0.00
Non-rate regulated utility rental income/investment income (recorded in Account 4385)	aj	-11400.00

Please provide

Depreciation expense on non-rate regulated assets	ak	USoAs
Other adjustments:		
Please list the other revenue items that were not approved by the OEB (Please specify):		
	al	Please provide USoAs
	am	Please provide USoAs
Please list the other expense items that were not approved by the OEB (Please specify):		
Sentinel Lighting operations and maintenance expenses	an 10120.00	Please provide USoAs 5170, 5172
	ao	Please provide USoAs
	ap	Please provide USoAs
Total non-rate regulated items and other adjustments	aq=ac+af+ai+aj+ak+al+am+an+ao+ap -1280.00	

Appendix 2

Non-Recoverable Donations

		Data Source
All donations	ba 12200.00	RRR 2.1.7 - Control account USoA 6205
Recoverable donations:		
LEAP Funding	bb 9200.00	RRR 2.1.7 - Sub-account LEAP Funding USoA 6205
Calculated LEAP Funding approved in the distributor's last CoS	bb1 9187.34	CoS Decision and Order (for reference only)
Other recoverable donations approved, please specify:		
	bc	
	bd	
Non-recoverable donations	be=ba-bb-bc-bd 3000.00	

Appendix 3

Net interest/carrying charges on Deferral and Variance Accounts (DVAs)

Interest expense on DVAs (recorded in Account 6035)	ca	30776.00
Interest income on DVAs (recorded in Account 4405)	cb	-37832.00
Net interest/carrying charges from DVAs	cc=ca+cb	-7056.00

Appendix 4

Interest Adjustment for Deemed Debt

			Data Source
Interest expense as per RRR 2.1.7	da	840936.00	RRR 2.1.7 - Sum of USoA 6005-6045 inclusive
Less:			
Interest expense on DVAs (recorded in Account 6035)	db = ca	30776.00	Appendix 3 cell (ca)
Unrealized (gains)/losses on interest rate swaps if recorded in Account 6035	db1		
Other adjustments, please specify:			
	db2		
	db3		
Interest expense after adjustments	dc=da-db-db1-db2-db3	810160.00	
Regulated deemed debt, as per ROE Summary tab	dd	19664711.79	ROE Summary tab cell (v1) + (w1)
Weighted average debt rate (%)	% de	5.92	CoS Decision and Order
Deemed interest	df=dd*de	1164150.94	
Interest adjustment for deemed debt	dg=dc-df	-353990.94	

Appendix 5

Property Plant & Equipment (PP&E)

		Data Source
Prior year "Closing balance - regulated PP&E (NBV)"	ea 26560744.00	Prior year "Closing balance - regulated PP&E (NBV)" data in RRR 2.1.5.6
Adjustments if required, please explain the nature		
	eb	
Opening balance - regulated PP&E (NBV)	ec=ea+eb 26560744.00	
Total PP&E (NBV) - Closing Balance	ed 29436863.00	RRR 2.1.7 - Sum of USoA 1605-2075, 2440, and 2105-2180 inclusive
Adjustment items:		
Construction Work-in-Progress (CWIP)	ee 114789.00	RRR 2.1.7 - USoA 2055
Non-distribution assets (NBV)	ef 0.00	RRR 2.1.7 - USoA 2075 + USoA 2180
Less other adjustments, please specify:		
Unamortized closing balance of Account 1576	eg 2593390.00	
	eh	
	ei	
	ej	
	ek	
Adjusted closing balance - regulated PP&E (NBV)	el=ed-ee-ef-eg-eh-ei-ej-ek 26728684.00	

Appendix 6

Current Tax for Regulatory Purposes

	Tax Provision/(Recovery)
Current Tax Provision/(Recovery) as per the Audited Financial Statments (AFS)	fa 169000.00
Reassessment of taxes	

from prior years included in current tax provision as per AFS (add Tax Payable/ (Recovery))	fa1	
Loss carry forward from prior years included in current tax provision as per AFS	fa2	
Actual Tax rate (%)	% xy 26.50	
Current Tax Adjustment required to reconcile to RRR 2.1.7 trial balance		fb
Current Tax Provision/ (Recovery) as per RRR 2.1.7 USoA 6110		fc 169000.00
Check balance - Does fa+fb=fc?		fa+fb = fc? CORRECT
	(Income)/Expense	
Adjustment items		
Non-rate regulated items (Appendix 1)	gd=aq -1280.00	fd=gd*xy -339.20
Non-recoverable donations (Appendix 2)	ge=be 3000.00	fe=ge*xy 795.00
Activity in Regulatory Accounts included in taxable income on Schedule 1, if applicable	gf -819456.00	ff=gf*xy -217155.84
Net carrying charges on DVAs (Appendix 3)	gg=cc -7056.00	fg=gg*xy -1869.84
Add back Actual interest expense (Appendix 4)	gh=dc 810160.00	fh=gh*xy 214692.40
Deduct Deemed Interest Expense (Appendix 4)	gi=-df -1164150.94	fi=gi*xy -308500.00
CCA on Non-rate regulated assets	gj	fj=gj*xy 0.00
CEC adjustment on Goodwill from acquisitions or other intangible assets that were not approved in the distributor's last CoS	gk	fk=gk*xy 0.00
CCA adjustment on PP&E from acquisitions that were not approved in the distributor's last CoS	gl	fl=gl*xy 0.00
Other adjustments (Please specify)		
	gm	fm=gm*xy 0.00

	gn	fn=gn*xy
		0.00
	go	fo=go*xy
		0.00
	gp=gd+ge+gf+gg+gh+gi+gj+gk+gl+gm+gn+go	fp=fd+fe+ff+fg+fh+fi+fj+fk+fl+fm+fn+fo
Total Adjustment Items	-1178782.94	-312377.48
Current Tax Provision/ (Recovery) for the purposes of calculating Regulated ROE		fq=fc+fp -143377.48

Checklist | Input Appendices | **ROE Summary** | Over Earning Drivers | Under Earning Drivers

Instructions

A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.

The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).

The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.

Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.

Click here for tips and examples (from RRR Filing Guide).

Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form.

Please review each input for accuracy and contact Industry Relations Enquiry if you have any questions.

CoS Decision and Order Info

		Data Source
The CoS Decision and Order EB number for the ROE	xx EB-2009-0273	CoS Decision and Order (last CoS establishing the current reporting year's base rates)
Accounting standard used in CoS Decision and Order	yy Canadian GAAP	CoS Decision and Order

Regulated Net Income

		Data Source
Regulated net income (loss), as per RRR 2.1.7	a 1176936.00	RRR 2.1.7 - USoA 3046 * (-1)
Adjustment items:		
Non-rate regulated items and other adjustments (Appendix 1)	b -1280.00	Appendix 1 cell (aq)
Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)	c	Please provide USoAs
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB	d	Please provide USoAs
Non-recoverable donations (Appendix 2)	e 3000.00	Appendix 2 cell (be)
Net interest/carrying charges from	f	Appendix 3 cell

DVAs (Appendix 3)	-7056.00	(cc)
Interest adjustment for deemed debt (Appendix 4)	g -353990.94	Appendix 4 cell (dg)
Adjusted regulated net income before tax adjustments	h=a+b+c+d+e+f+g 817609.06	
Add back:		
Future/deferred taxes expense	i -140000.00	RRR 2.1.7 - USoA 6115
Current income tax expense (Does not include future income tax)	j 169000.00	RRR 2.1.7 - USoA 6110
Deduct:		
Current income tax expense for regulated ROE purposes (Appendix 6)	k -143377.48	Appendix 6 cell (fq)
Adjusted regulated net income	l=h+i+j-k 989986.54	

Deemed Equity

Rate base:		**Data Source**
Cost of power	m 35822451.00	RRR 2.1.7 - Sum of USoA 4705-4751 inclusive
Operating expenses before any applicable adjustments	n1 5053040.00	RRR 2.1.7 - Sum of USoA 4505-4640, 4805-5695, 6105, 6205, 6210, and 6225, then subtract ROE Summary cell (d) and subtract ROE Summary cell (e)
Other Adjustments:		
Sentinel Lighting operations and mainten	n2 10120.00	Please provide USoAs 5170, 5172
Adjusted operating expenses	n=n1-n2 5042920.00	
Total Cost of Power and Operating Expenses	o=m+n 40865371.00	
Working capital allowance % as approved in the last CoS Decision and Order	% p 15.00	CoS Decision and Order
Total working capital allowance ($)	q=o*p 6129805.65	
PP&E		

Opening balance - regulated PP&E (NBV) (Appendix 5)		r 26560744.00	Appendix 5 cell (ec)
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)		s 26728684.00	Appendix 5 cell (el)
Average regulated PP&E		t=(r+s)/2 26644714.00	
Total rate base		u=q+t 32774519.65	
Regulated deemed short-term debt % and $	% v 4.00	v1=v*u 1310980.79	Cell (v) from CoS Decision and Order
Regulated deemed long-term debt % and $	% w 56.00	w1=w*u 18353731.00	Cell (w) from CoS Decision and Order
Regulated deemed equity % and $	% x 40.00	x1=x*u 13109807.86	Cell (x) from CoS Decision and order

Regulated Rate of Return on Deemed Equity (ROE)

			Data Source
Achieved ROE %		% y=l/x1 7.55	
Deemed ROE % from the distributor's last CoS Decision and Order		% z 9.85	CoS Decision and Order
Difference - maximum deadband 3%		% z1=y-z -2.30	
ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)		z2 Within	If the distributor is in an over-earning position as indicated in cell (z2), please complete Appendices 7 & 8. If the distributor is in an under-earning position as indicated in cell (z2), please complete Appendices 9 & 10.

Ontario Energy Board

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2.1.5.6 Regulated Return on Equity (ROE)

October 08, 2019

Search

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Case Documents
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Submit RRR E2.1.4.2.10 I
Past RRR E2.1.4.2.10 Ma
Submit E2.1.18 Loss of L
Past E2.1.18 Loss of Larg
RRR Data Revision Requ
My Company's RRR Revi
SOP: View Work-In-Prog
SOP Application
Submit Weekly Winter Re
Past Weekly Winter Reco
Submit USMP
Past USMP
Submit Quarterly Arrears
Past Quarterly Arrears a
Submit an Application

Checklist | Input Appendices | ROE Summary | Over Earning Drivers | Under Earning Drivers

Report Summary

Filing Due Year: 2019	Filing Form Name: 2.1.5.6	RRR Filing No: 23625
Reporting Period and Company Name: April- 2019Hydro One Networks Inc., Toronto: Corporation ED-2003-0043 Issued;	Licence Type: Distributor	Status: Revised
Report Version: 1	Extension Granted:	Extension Deadline:
Filing Due Date: April 30, 2019	Reporting From: January 1, 2018	Reporting To: December 31, 2018
Submitted On: April 30, 2019	Submitter Name: Keith Tran	Expiry Date: May 01, 2019

Instructions

Please check off the activities that you have reviewed and completed in the list below. The form can be submitted only after all the boxes have been checked.

Clicking Save or Apply will not automatically submit this filing. To SUBMIT this filing, scroll to the end of the page, select Yes in the Submit drop down then click the SAVE button.

Checklist

Checkbox	No.	Questions
Overview		
☑	1	Have you read the ROE filing guide for completing the RRR 2.1.5.6 ROE filing?
☑	2	Have you reviewed and confirmed the accuracy of the RRR 2.1.7 trial balance?
☑	3	Have you reviewed and confirmed all auto-populated/linked cells on the form for accuracy?
☑	4	Have you resolved (i.e. re-filing the RRR 2.1.7 trial balance or contact the IRE) any issues that you may have noted with the auto-populated/linked cells?
☑	5	Regarding the input cells, have you ensured that the signs of the numbers entered align with the RRR 2.1.7 trial balance?
Input Appendices tab		

SAVE | SAVE & EXIT | PRINT ALL | Cancel

Ontario Energy Board

October 09, 2019

2.1.5.6 Regulated Return on Equity (ROE)

☑	1	Have you completed and reviewed Appendix 1 if you have non-rate regulated business that is recorded in the RRR 2.1.7 trial balance?
☑	2	Have you included all other adjustment(s) in Appendix 1?
☑	3	Have you identified and included in Appendix 1 all adjustments for non-rate regulated activities?
☑	4	Have you completed and reviewed Appendix 2 if you have non-recoverable donations that are recorded in the RRR 2.1.7 trial balance?
☑	5	Have you completed and reviewed Appendix 3 regarding net interest/carrying charge from DVAs?
☑	6	Have you included in Appendix 4 all adjustments so that the interest expense in cell dc is related to debt only?
☑	7	Have you completed and reviewed Appendix 4 on deemed debt?
☑	8	Have you included all adjustments regarding regulated PP&E in Appendix 5?
☑	9	Have you completed and reviewed Appendix 5 regarding regulated PP&E?
☑	10	Have you completed and reviewed Appendix 6 regarding current tax for regulatory purposes?
☑	11	Have you included in Appendix 6 the tax effects of all non-regulatory items?
☑	12	Have you reviewed the RRR Filing Guide and determined the accurate tax treatment regarding the activities in regulatory accounts in Appendix 6?
ROE Summary tab		
☑	1	Have you entered the input cells for the the Unrealized (gains)/losses on interest rate swaps (cell c) and identified the USoA(s), if applicable?
☑	2	Have you entered the input cells for the Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB (cell d) and identified the USoA(s), if applicable?
Over and Under-earning driver tabs		
☑	1	Have you completed and reviewed Appendices 7 and 8 if the ROE status for the year (cell z2) shows "Over-earning"?
☑	2	Have you completed and reviewed Appendices 9 and 10 if the ROE status for the year (cell z2) shows "Under-earning"?
☑	3	Have you submitted the Q4 RRR 2.1.2 customers if you are required to complete over/under-earning driver tabs?
☑	4	Have you submitted the RRR 2.1.5.4 annual billings if you are required to complete over/under-earning driver tabs?
Submitting the form		
☑	1	Have you clicked the Save button to update all the calculations on the form?
☑	2	Have you validated the accuracy of the Achieved ROE% as calculated in cell y on the ROE Summary tab?
☑	3	Have you retained the necessary supporting documents for the ROE filing?

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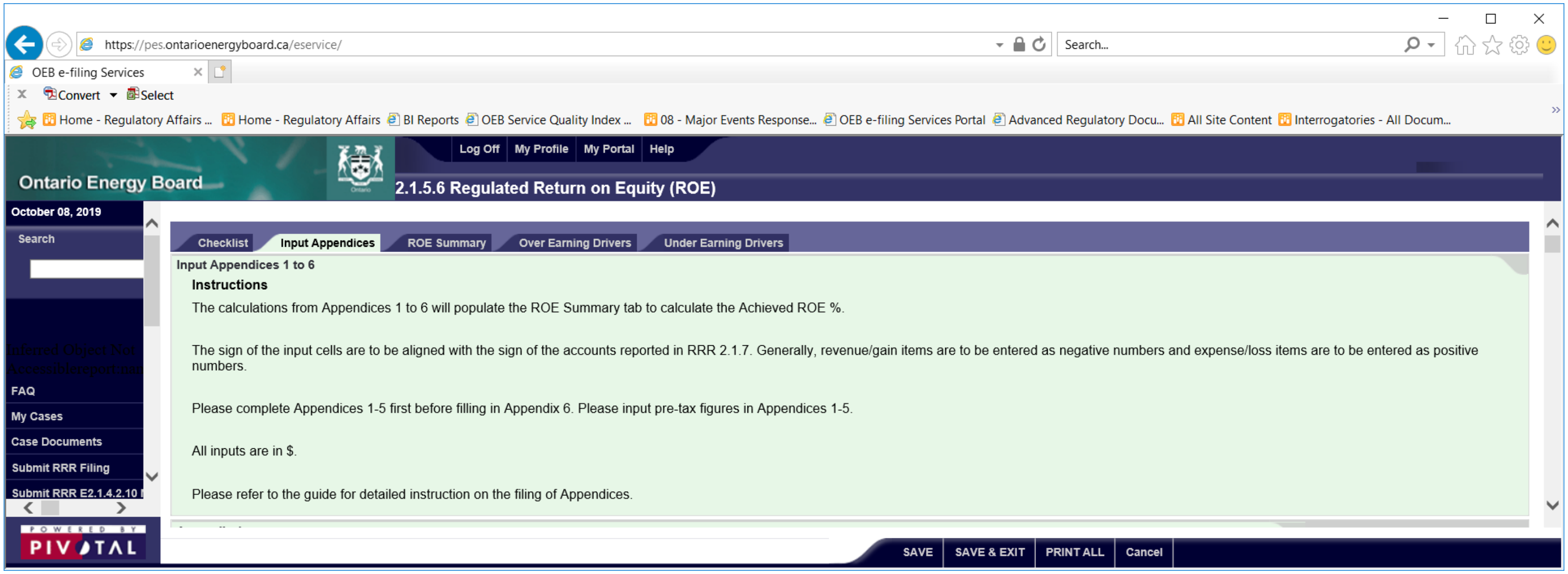
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Submit RRR E2.1.4.2.10
Checklist
Input Appendices
ROE Summary
Over Earning Drivers
Under Earning Drivers
Input Appendices 1 to 6
Instructions
The calculations from Appendices 1 to 6 will populate the ROE Summary tab to calculate the Achieved ROE %.
The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.
Please complete Appendices 1-5 first before filling in Appendix 6. Please input pre-tax figures in Appendices 1-5.
All inputs are in $.
Please refer to the guide for detailed instruction on the filing of Appendices.
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Appendix 1

Non-rate regulated items and other adjustments

CDM revenues (recorded in Account 4375)	aa	-4138519.32	
CDM expenses (recorded in Account 4380)	ab	0.00	
CDM - Net revenues/expenses	ac=aa+ab	-4138519.32	
Renewable generation revenues (recorded in Account 4375)	ad	0.00	
Renewable generation expenses (recorded in Account 4380)	ae	0.00	
Renewable generation - Net revenues/expenses	af=ad+ae	0.00	
Water services revenues (recorded in Account 4375)	ag	0.00	
Water services expenses (recorded in Account 4380)	ah	0.00	
Water services - Net revenues/expenses	ai=ag+ah	0.00	
Non-rate regulated utility rental income/investment income (recorded in Account 4385)	aj	0.00	
Depreciation expense on non-rate regulated assets	ak		Please provide USoAs

Other adjustments:

Please list the other revenue items that were not approved by the OEB (Please specify):

	al		Please provide USoAs

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	am	Please provide USoAs
Please list the other expense items that were not approved by the OEB (Please specify):		
	an	Please provide USoAs
	ao	Please provide USoAs
	ap	Please provide USoAs
Total non-rate regulated items and other adjustments	aq=ac+af+ai+aj+ak+al+am+an+ao+ap -4138519.32	

Appendix 2

Non-Recoverable Donations

		Data Source
All donations	ba 2604209.43	RRR 2.1.7 - Control account USoA 6205
Recoverable donations:		
LEAP Funding	bb 1805124.00	RRR 2.1.7 - Sub-account LEAP Funding USoA 6205
Calculated LEAP Funding approved in the distributor's last CoS	bb1 1650360.00	CoS Decision and Order (for reference only)
Other recoverable donations approved, please specify:		
	bc	
	bd	
Non-recoverable donations	be=ba-bb-bc-bd 799085.43	

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Appendix 3

Net interest/carrying charges on Deferral and Variance Accounts (DVAs)

Interest expense on DVAs (recorded in Account 6035)	ca: 1860728.98	
Interest income on DVAs (recorded in Account 4405)	cb:	
Net interest/carrying charges from DVAs	cc=ca+cb: 1860728.98	

Appendix 4

Interest Adjustment for Deemed Debt

		Data Source
Interest expense as per RRR 2.1.7	da: 173300295.05	RRR 2.1.7 - Sum of USoA 6005-6045 inclusive
Less:		
Interest expense on DVAs (recorded in Account 6035)	db = ca: 1860728.98	Appendix 3 cell (ca)
Unrealized (gains)/losses on interest rate swaps if recorded in Account 6035	db1:	
Other adjustments, please specify:		
	db2:	
	db3:	
Interest expense after adjustments	dc=da-db-db1-db2-db3: 171439566.07	
Regulated deemed debt, as per ROE Summary tab	dd: 4682618006.97	ROE Summary tab cell (v1) + (w1)

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Weighted average debt rate (%)	% de	4.25	CoS Decision and Order
Deemed interest	df=dd*de	199011265.30	
Interest adjustment for deemed debt	dg=dc-df	-27571699.23	

Appendix 5

Property Plant & Equipment (PP&E)

			Data Source
Prior year "Closing balance - regulated PP&E (NBV)"	ea	7417078036.10	Prior year "Closing balance - regulated PP&E (NBV)" data in RRR 2.1.5.6
Adjustments if required, please explain the nature	eb		
Opening balance - regulated PP&E (NBV)	ec=ea+eb	7417078036.10	
Total PP&E (NBV) - Closing Balance	ed	7987288683.76	RRR 2.1.7 - Sum of USoA 1605-2075, 2440, and 2105-2180 inclusive
Adjustment items:			
Construction Work-in-Progress (CWIP)	ee	129018494.50	RRR 2.1.7 - USoA 2055
Non-distribution assets (NBV)	ef	0.00	RRR 2.1.7 - USoA 2075 + USoA 2180
Less other adjustments, please specify:			
Electric Plant Acquisition Adjustment (Goodwill)	eg	167315774.73	
Add back: Material and supplies inventory	eh	4623503.57	

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	ei
	ej
	ek
Adjusted closing balance - regulated PP&E (NBV)	el=ed-ee-ef-eg-eh-ei-ej-ek 7686330910.96

Appendix 6

Current Tax for Regulatory Purposes

		Tax Provision/(Recovery)
Current Tax Provision/(Recovery) as per the Audited Financial Statments (AFS)		fa 65823096.56
Reassessment of taxes from prior years included in current tax provision as per AFS (add Tax Payable/(Recovery))	fa1 298504.00	
Loss carry forward from prior years included in current tax provision as per AFS	fa2	
Actual Tax rate (%)	% xy 26.50	
Current Tax Adjustment required to reconcile to RRR 2.1.7 trial balance		fb 0.27
Current Tax Provision/(Recovery) as per RRR 2.1.7 USoA 6110		fc 65823096.56
Check balance - Does fa+fb=fc?		fa+fb = fc? CORRECT

	(Income)/Expense	
Adjustment items		
Non-rate regulated items (Appendix 1)	gd=aq -4138519.32	fd=gd*xy -1096707.62
	ge=be	fe=ge*xy

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2.1.5.6 Regulated Return on Equity (ROE)

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Non-recoverable donations (Appendix 2)	ge=be	799085.43	fe=ge*xy	211757.64
Activity in Regulatory Accounts included in taxable income on Schedule 1, if applicable	gf	-52307329.29	ff=gf*xy	-13861442.26
Net carrying charges on DVAs (Appendix 3)	gg=cc	1860728.98	fg=gg*xy	493093.18
Add back Actual interest expense (Appendix 4)	gh=dc	171439566.07	fh=gh*xy	45431485.01
Deduct Deemed Interest Expense (Appendix 4)	gi=-df	-199011265.30	fi=gi*xy	-52737985.30
CCA on Non-rate regulated assets	gj	1811900.63	fj=gj*xy	480153.67
CEC adjustment on Goodwill from acquisitions or other intangible assets that were not approved in the distributor's last CoS	gk	1188836.60	fk=gk*xy	315041.70
CCA adjustment on PP&E from acquisitions that were not approved in the distributor's last CoS	gl		fl=gl*xy	0.00
Other adjustments (Please specify)				
Loss carry-forward+Contingent Liability+Debt Repay. Penalties+Reverse Net Carrying Charge on DVA (as not deducted for tax)	gm	12024920.05	fm=gm*xy	3186603.81
Capitalized Interest Deducted for tax	gn	7590090.37	fn=gn*xy	2011373.95
Tax Credits+Other Provision	go	3024229.55	fo=go*xy	801420.83
Total Adjustment Items	gp=gd+ge+gf+gg+gh+gi+gj+gk+gl+gm+gn+go	-55717756.23	fp=fd+fe+ff+fg+fh+fi+fj+fk+fl+fm+fn+fo	-14765205.39
Current Tax Provision/(Recovery) for the purposes of calculating Regulated ROE			fq=fc+fp	51057891.17

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2.1.5.6 Regulated Return on Equity (ROE)

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Submit Other Documents

Checklist | Input Appendices | ROE Summary | Over Earning Drivers | Under Earning Drivers

Instructions

A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.

The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).

The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.
Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.

Click here for tips and examples (from RRR Filing Guide).

Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form.
Please review each input for accuracy and contact Industry Relations Enquiry if you have any questions.

CoS Decision and Order Info

			Data Source
The CoS Decision and Order EB number for the ROE	xx	EB-2013-0416	CoS Decision and Order (last CoS establishing the current reporting year's base rates)
Accounting standard used in CoS Decision and Order	yy	US GAAP	CoS Decision and Order

Regulated Net Income

			Data Source
Regulated net income (loss), as per RRR 2.1.7	a	281624233.97	RRR 2.1.7 - USoA 3046 * (-1)
Adjustment items:			
Non-rate regulated items and other adjustments (Appendix 1)	b	-4138519.32	Appendix 1 cell (aq)
Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)	c		Please provide USoAs
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB	d		Please provide USoAs
Non-recoverable donations (Appendix 2)	e	799085.43	Appendix 2 cell (be)
Net interest/carrying charges from DVAs (Appendix 3)	f	1860728.98	Appendix 3 cell (cc)
Interest adjustment for deemed debt (Appendix 4)	g	-27571699.23	Appendix 4 cell (dg)
Adjusted regulated net income before tax adjustments	h=a+b+c+d+e+f+g	252573829.83	
Add back:			
Future/deferred taxes expense	i	-15386338.56	RRR 2.1.7 - USoA 6115

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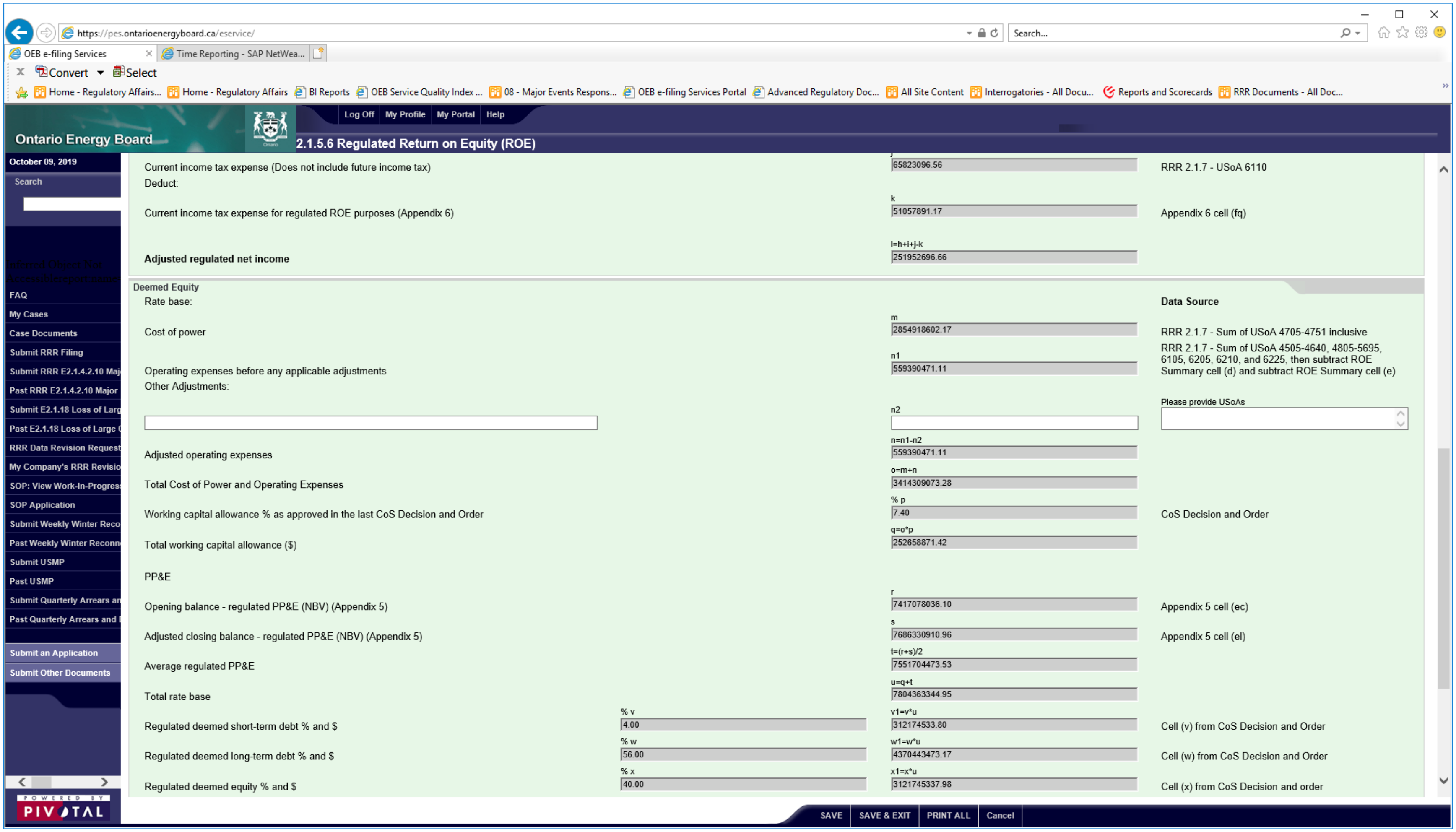

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2.1.5.6 Regulated Return on Equity (ROE)

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Current income tax expense (Does not include future income tax)		j: 65823096.56	RRR 2.1.7 - USoA 6110
Deduct:			
Current income tax expense for regulated ROE purposes (Appendix 6)		k: 51057891.17	Appendix 6 cell (fq)
Adjusted regulated net income		l=h+i+j-k: 251952696.66	

Deemed Equity

			Data Source
Rate base:			
Cost of power		m: 2854918602.17	RRR 2.1.7 - Sum of USoA 4705-4751 inclusive
Operating expenses before any applicable adjustments		n1: 559390471.11	RRR 2.1.7 - Sum of USoA 4505-4640, 4805-5695, 6105, 6205, 6210, and 6225, then subtract ROE Summary cell (d) and subtract ROE Summary cell (e)
Other Adjustments:		n2:	Please provide USoAs
Adjusted operating expenses		n=n1-n2: 559390471.11	
Total Cost of Power and Operating Expenses		o=m+n: 3414309073.28	
Working capital allowance % as approved in the last CoS Decision and Order		% p: 7.40	CoS Decision and Order
Total working capital allowance ($)		q=o*p: 252658871.42	
PP&E			
Opening balance - regulated PP&E (NBV) (Appendix 5)		r: 7417078036.10	Appendix 5 cell (ec)
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)		s: 7686330910.96	Appendix 5 cell (el)
Average regulated PP&E		t=(r+s)/2: 7551704473.53	
Total rate base		u=q+t: 7804363344.95	
Regulated deemed short-term debt % and $	% v: 4.00	v1=v*u: 312174533.80	Cell (v) from CoS Decision and Order
Regulated deemed long-term debt % and $	% w: 56.00	w1=w*u: 4370443473.17	Cell (w) from CoS Decision and Order
Regulated deemed equity % and $	% x: 40.00	x1=x*u: 3121745337.98	Cell (x) from CoS Decision and order

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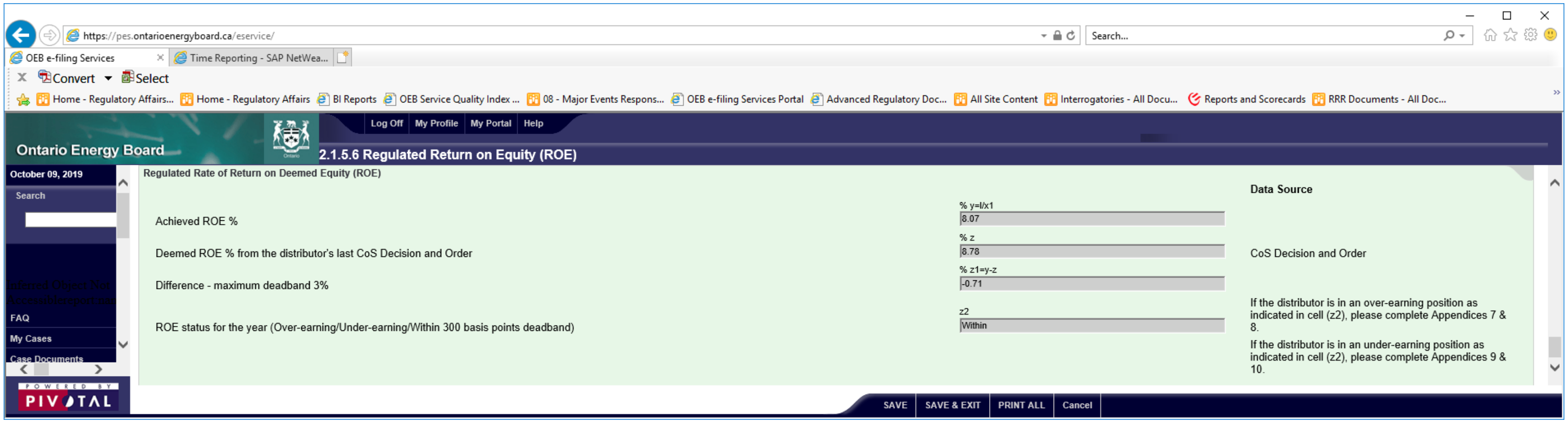

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2.1.5.6 Regulated Return on Equity (ROE)

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Regulated Rate of Return on Deemed Equity (ROE)

		Data Source
Achieved ROE %	% y=l/x1 8.07	
Deemed ROE % from the distributor's last CoS Decision and Order	% z 8.78	CoS Decision and Order
Difference - maximum deadband 3%	% z1=y-z -0.71	
ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)	z2 Within	If the distributor is in an over-earning position as indicated in cell (z2), please complete Appendices 7 & 8. If the distributor is in an under-earning position as indicated in cell (z2), please complete Appendices 9 & 10.

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Report Summary

Printed at October 07, 2019 8:49:28AM

Filed: 2019-10-18
EB-2018-0270/0242
Exhibit JT2.3
Attachment 3
Page 1 of 5

Filing Due Year 2019	**Filing Form Name** 2.1.5.6	**RRR Filing No** 23,925	**Reporting Period and Company Name** Peterborough Distributior	
Licence Type Distributor	**Status** Submitted	**Report Version** 0	**Extension Granted**	**Extension Deadline**
Filing Due Date April 30, 2019	**Reporting From** January 1, 2018	**Reporting To** December 31, 2018		
Submitted On April 29, 2019	**Submitter Name** Navneet Malik	**Expiry Date** May 01, 2019		

Checklist

Checkbox Overview	No. Questions
Y	1. Have you read the ROE filing guide for completing the RRR 2.1.5.6 ROE filing?
Y	2. Have you reviewed and confirmed the accuracy of the RRR 2.1.7 trial balance?
Y	3. Have you reviewed and confirmed all auto-populated/linked cells on the form for accuracy?
Y	4. Have you resolved (i.e. re-filing the RRR 2.1.7 trial balance or contact the IRE) any issues that you may have noted with the auto-populated/linked cells?
Y	5 Regarding the input cells, have you ensured that the signs of the numbers entered align with the RRR 2.1.7 trial balance?

Input Appendices tab

Y	1. Have you completed and reviewed Appendix 1 if you have non-rate regulated business that is recorded in the RRR 2.1.7 trial balance?
Y	2. Have you included all other adjustment(s) in Appendix 1?
Y	3. Have you identified and included in Appendix 1 all adjustments for non-rate regulated activities?
Y	4. Have you completed and reviewed Appendix 2 if you have non-recoverable donations that are recorded in the RRR 2.1.7 trial balance?
Y	5. Have you completed and reviewed Appendix 3 regarding net interest/carrying charge from DVAs?
Y	6. Have you included in Appendix 4 all adjustments so that the interest expense in cell dc is related to debt only?
Y	7. Have you completed and reviewed Appendix 4 on deemed debt?
Y	8. Have you included all adjustments regarding regulated PP&E in Appendix 5?
Y	9. Have you completed and reviewed Appendix 5 regarding regulated PP&E?
Y	10. Have you completed and reviewed Appendix 6 regarding current tax for regulatory purposes?
Y	11. Have you included in Appendix 6 the tax effects of all non-regulatory items?
Y	12. Have you reviewed the RRR Filing Guide and determined the accurate tax treatment regarding the activities in regulatory accounts in Appendix 6?

ROE Summary tab

Y	1. Have you entered the input cells for the the Unrealized (gains)/losses on interest rate swaps (cell c) and identified the USoA(s), if applicable?
Y	2. Have you entered the input cells for the Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB (cell d) and identified the USoA(s), if applicable?

Over and Under-earning driver tabs

N	1. Have you entered the input cells for the the Unrealized (gains)/losses on interest rate swaps (cell c) and identified the USoA(s), if applicable?
N	2. Have you completed and reviewed Appendices 9 and 10 if the ROE status for the year (cell z2) shows "Under-earning"?
N	3. Have you submitted the Q4 RRR 2.1.2 customers if you are required to complete over/under-earning driver tabs?
N	4. Have you submitted the RRR 2.1.5.4 annual billings if you are required to complete over/under-earning driver tabs?

Submitting the form

N	1. Have you clicked the Save button to update all the calculations on the form?
N	2 Have you validated the accuracy of the Achieved ROE% as calculated in cell y on the ROE Summary tab?
N	3. Have you retained the necessary supporting documents for the ROE filing?

Input Appendices (1 to 6)

Appendix 1
Non-rate regulated items and other adjustments

CDM revenues (recorded in Account 4375)	- aa	-235,106.75	
CDM expenses (recorded in Account 4380)	- ab		
CDM - Net revenues/expenses	- ac=aa+ab	-235,106.75	
Renewable generation revenues (recorded in Account 4375)	- ad		
Renewable generation expenses (recorded in Account 4380)	- ae		
Renewable generation - Net revenues/expenses	- af=ad+ae	0.00	
Water services revenues (recorded in Account 4375)	- ag		
Water services expenses (recorded in Account 4380)	- ah		
Water services - Net revenues/expenses - ai=ag+ah	- ai=ag+ah	0.00	
Non-rate regulated utility rental income/investment income (recorded in Account 4385)	-aj		**Please provide USoAs**
Depreciation expense on non-rate regulated assets	- ak		

Other adjustments:
Please list the other revenue items that were not approved by the OEB (Please specify):

- al
- am

Please list the other expense items that were not approved by the OEB (Please specify):

- an
- ao
- ap

Total non-rate regulated items and other adjustments	- aq =ac+af+ai+aj+ak+al+am+an+ao+ap	**-235,106.75**

Appendix 2

Non-Recoverable Donations			**Data Source**
All donations	- ba	39,720.00	RRR 2.1.7 - Control account USoA 6205
Recoverable donations:			
LEAP Funding	- bb	17,220.00	RRR 2.1.7 - Sub-account LEAP Funding USoA 6205
Calculated LEAP Funding approved in the distributor's last CoS	- bb1	18,466.51	CoS Decision and Order (for reference only)
Other recoverable donations approved, please specify:			
	- bc		
	- bd		
Non-Recoverable Donations	- be=ba-bb-bc-bd	**22,500.00**	

Appendix 3

Net interest/carrying charges on Deferral and Variance Accounts (DVAs)

Interest expense on DVAs (recorded in Account 6035)	- ca	90,692.89
Interest income on DVAs (recorded in Account 4405)	- cb	-120,841.66
Net interest/carrying charges from DVAs	- cc=ca+cb	**-30,148.77**

Appendix 4

Interest Adjustment for Deemed Debt			**Data Source**
Interest expense as per RRR 2.1.7	- da	1,770,817.08	RRR 2.1.7 - Sum of USoA 6005-6045 inclusive
Less:			
Interest expense on DVAs (recorded in Account 6035)	- db = ca	90,692.89	Appendix 3 cell (ca)
Unrealized (gains)/losses on interest rate swaps if recorded in Account 6035	- db1		
Other adjustments, please specify:			
	- db2		
	- db3		
Interest expense after adjustments	- dc=da-db-db1-db2-db3	**1,680,124.19**	
Regulated deemed debt, as per ROE Summary tab	- dd	44,617,003.52	ROE Summary tab cell (v1) + (w1)
Weighted average debt rate (%)	- %de	3.97	
Deemed interest	- df=dd*de	1,771,295.04	CoS Decision and Order
Interest adjustment for deemed debt	- dg=dc-df	**-91,170.85**	

Appendix 5

Property Plant & Equipment (PP&E)			Data Source
Prior year "Closing balance - regulated PP&E (NBV)"	- ea	60,737,086.24	Prior year "Closing balance - regulated PP&E (NBV)" data in RRR 2.1.5.6
Adjustments if required, please explain the nature	- eb		
Opening balance - regulated PP&E (NBV)	- ec=ea+eb	60,737,086.24	
Total PP&E (NBV) - Closing Balance	- ed	63,966,874.35	RRR 2.1.7 - Sum of USoA 1605-2075, 2440 , and 2105-2180 inclusive
Construction Work-in-Progress (CWIP)	- ee	1,642,213.39	RRR 2.1.7 - USoA 2055
Non-distribution assets (NBV)	- ef	0.00	RRR 2.1.7 - USoA 2075 + USoA 2180
Less other adjustments, please specify:			
	- eg		
	- eh		
	- ei		
	- ej		
	- ek		
Adjusted closing balance - regulated PP&E (NBV)	- el=ed-ee-ef-eg-eh-ei-ej-ek	62,324,660.96	

Appendix 6

Current Tax for Regulatory Purposes				Tax Provision/ (Recovery)
Current Tax Provision/(Recovery) as per the Audited Financial Statments (AFS)			- fa	464,045.00
Reassessment of taxes from prior years included in current tax provision as per AFS (add Tax Payable/(Recovery))	- fa1			
Loss carry forward from prior years included in current tax provision as per AFS	- fa2			
Actual Tax rate (%)	- %xy	26.50		
Current Tax Adjustment required to reconcile to RRR 2.1.7 trial balance			- fb	
Current Tax Provision/(Recovery) as per RRR 2.1.7 USoA 6110			- fc	464,045.00
Check balance - Does fa+fb=fc?			- fa+fb = fc?	CORRECT
Adjustment items	**(Income)/Expense**			
Non-rate regulated items (Appendix 1)	- gd=aq	-235,106.75	- fd=gd*xy	-62,303.29
Non-recoverable donations (Appendix 2)	- ge=be	22,500.00	- fe=ge*xy	5,962.50
Activity in Regulatory Accounts included in taxable income on Schedule 1, if applicable	- gf		- ff=gf*xy	0.00
Net carrying charges on DVAs (Appendix 3)	- gg=cc	-30,148.77	- fg=gg*xy	-7,989.42
Add back Actual interest expense (Appendix 4)	- gh=dc	1,680,124.19	- fh=gh*xy	445,232.91
Deduct Deemed Interest Expense (Appendix 4)	- gi=-df	-1,771,295.04	- fi=gi*xy	-469,393.19
CCA on Non-rate regulated assets	- gj		- fj=gj*xy	0.00
CEC adjustment on Goodwill from acquisitions or other intangible assets that were not approved in the distributor's last CoS	- gk		- fk=gk*xy	0.00
CCA adjustment on PP&E from acquisitions that were not approved in the distributor's last CoS	- gl		- fl=gl*xy	0.00
Other adjustments (Please specify)				
	- gm		- fm=gm*xy	0.00
	- gn		- fn=gn*xy	0.00
	- go		- fo=go*xy	0.00
Total Adjustment Items	gp=gd+ge+gf+gg+gh+gi+gj+gk+gl+gm+gn+go	-333,926.37	fp=fd+fe+ff+fg+fh+fi+fj+fk+fl+fm+fn+fo	-88,490.49
Current Tax Provision/(Recovery) for the purposes of calculating Regulated ROE	- fq=fc+fp			375,554.51

ROE Summary

Instructions

A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.

The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).

The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.
Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.
Click here for tips and examples (from RRR Filing Guide)

Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form.
Please review each input for accuracy and contact Industry Relations Enquiry if you have any questions

CoS Decision and Order Info			**Data Source**
The CoS Decision and Order EB number for the ROE	- xx	EB-2012-0160	CoS Decision and Order (last CoS establishing the current reporting year's base rates)
Accounting standard used in CoS Decision and Order	- yy	Canadian GAAP	CoS Decision and Order

Regulated Net Income			**Data Source**
Regulated net income (loss), as per RRR 2.1.7	- a	2,119,949.04	RRR 2.1.7 - USoA 3046 * (-1)
Non-rate regulated items and other adjustments (Appendix 1)	- b	-235,106.75	Appendix 1 cell (aq) Please provide USoAs
Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)	- c		
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB	- d		
Non-recoverable donations (Appendix 2)	- e	22,500.00	Appendix 2 cell (be)
Net interest/carrying charges from DVAs (Appendix 3)	- f	-30,148.77	Appendix 3 cell (cc)
Interest adjustment for deemed debt (Appendix 4)	- g	-91,170.85	Appendix 4 cell (dg)
Adjusted regulated net income before tax adjustments			
Add back:	- h=a+b+c+d+e+f+g	1,786,022.67	
Future/deferred taxes expense	- i	300,000.00	RRR 2.1.7 - USoA 6115
Current income tax expense (Does not include future income tax)	- j	464,045.00	RRR 2.1.7 - USoA 6110
Deduct:			
Current income tax expense for regulated ROE purposes (Appendix 6)	- k	375,554.51	Appendix 6 cell (fq)
Adjusted regulated net income	- l=h+i+j-k	2,174,513.16	

Deemed Equity			**Data Source**
Rate base:	- m	89,627,322.85	RRR 2.1.7 - Sum of USoA 4705-4751 inclusive
Cost of power	- n1	9,071,130.56	RRR 2.1.7 - Sum of USoA 4505-4640, 4805-5695, 6105, 6205, 6210, and 6225, then subtract ROE Summary cell (d) and subtract ROE Summary cell (e)
Operating expenses before any applicable adjustments			
Other Adjustments:			
	- n2		
Adjusted operating expenses	- n=n1-n2	9,071,130.56	
Total Cost of Power and Operating Expenses	- o=m+n	98,698,453.41	
Working capital allowance % as approved in the last CoS Decision and Order	- % p	13.00	CoS Decision and Order
Total working capital allowance ($)	- q=o*p	12,830,798.94	
PP&E			
Opening balance - regulated PP&E (NBV) (Appendix 5)	- r	60,737,086.24	Appendix 5 cell (ec)
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)	- s	62,324,660.96	Appendix 5 cell (el)
Average regulated PP&E	- t=(r+s)/2	61,530,873.60	
Total rate base	- u=q+t	74,361,672.54	
Regulated deemed short-term debt % and $	- % v 4.00	- v1=v*u 2,974,466.90	Cell (v) from CoS Decision and Order
Regulated deemed long-term debt % and $	- % w 56.00	- w1=w*u 41,642,536.62	Cell (w) from CoS Decision and Order
Regulated deemed equity % and $	- % x 40.00	- x1=x*u 29,744,669.02	Cell (x) from CoS Decision and order

Regulated Rate of Return on Deemed Equity (ROE)			**Data Source**
Achieved ROE %	- % y=l/x1	7.31	
Deemed ROE % from the distributor's last CoS Decision and Order	- % z	8.98	CoS Decision and Order
Difference - maximum deadband 3%	- % z1=y-z	-1.67	
ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)	- z2		If the distributor is in an over-earning position as indicated in cell (z2), please complete Appendices 7 & 8. If the distributor is in an under-earning position as indicated in cell (z2), please complete Appendices 9 & 10.

UNDERTAKING - JT2.4

Reference:

Undertaking:
To confirm the 2018 value for the 6-30.

Response:
The average annual rate increase in 2018, as approved in Hydro One's distribution rate application (EB-2017-0049), is 4.6%.

UNDERTAKING - JT2.5

Reference:

Undertaking:
To advise as to whether any of these current specific service charges set out from Hydro One's perspective changed as a result of the approval or whether this is still valid in terms of the numbers.

Response:
Attachment 1 to this response provides a revised list of all specific service charges currently in effect for Peterborough Distribution Inc. and Hydro One Networks Inc.

Non-payment of account	Current PDI Charge (per EB-2018-0067)	Current Hydro One Charge (per EB-2017-0049)
Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)[1]	1.50%	1.50%
Late payment - per annum	Discontinued[1]	Discontinued[1]
Notification charge (notice of overdue account)	$15.00	Discontinued
Collection of account charge - no disconnect (site visit required to collect account) - during regular hours (8 am to 7 pm)	Discontinued[1]	Discontinued[1]
Collection of account charge - no disconnect (site visit required to collect account) - after regular hours	Discontinued[1]	Discontinued[1]
Reconnect at meter - during regular hours (8 am to 7 pm)[1]	$65.00	$65.00
Reconnect at meter - after regular hours[1]	$185.00	$185.00
Reconnect at pole - during regular hours (8 am to 4 pm)[1]	$185.00	$185.00
Reconnect at pole - after regular hours[1]	$415.00	$415.00

Administration	Charge	Charge
Account set-up charge / change of occupancy charge (plus credit agency costs if applicable)	$30.00	$38.00
Statement of account (required when applying to waive deposit at new utility)	$15.00	Discontinued
Pulling post-dated cheques	$15.00	n/a
Duplicate invoices for previous billing	$15.00	Discontinued
Request for other billing information	$15.00	Discontinued
Easement letter	$15.00	Letter Request - $88.29 Web Request - $25.00
Income tax letter (statement of account for income tax purposes)	$15.00	Discontinued
Account history	$15.00	Discontinued
Credit reference / credit check (plus credit agency costs) (in lieu of deposit)	$15.00	Discontinued
Returned cheque charge (plus bank charges)	$15.00	$7.00
Legal letter charge (required by lawyer during property sale)	$15.00	Discontinued
Arrears certificate (letter of reference, credit history)	$15.00	n/a
Special meter reads (unscheduled or reversed move-in or out)	$30.00	$90.00
Install/remove load control device - during regular hours (8 am to 7 pm)	Discontinued[1]	Discontinued[1]
Install/remove load control device - after regular hours	Discontinued[1]	Discontinued[1]
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$30.00	$30.00
Service call (customer-owned equipment) - during regular hours (8 am to 4:30 pm)	$30.00	$210.00*
Service call (customer-owned equipment) - after regular hours	$165.00	$775.00*
Temporary service install and/or remove - overhead - no transformer	$500.00	Actual Costs
Temporary service install and/or remove - overhead - with transformer	$1,000.00	Actual Costs
Temporary service install and/or remove - underground - no transformer	$300.00	Actual Costs
Specific charge for access to the power poles ($ per pole per year)	$43.63	Telecom $43.63
Hydro One Only	**Charge**	**Charge**
Vacant Premise - Move in with Reconnect of Electrical Service at Meter		Discontinued
Vacant Premise - Move in with Reconnect of Electrical Service at Pole		Discontinued
Reconnect Completed after Regular Hours (Customer/Contract Driven) - at Meter		$245.00
Reconnect Completed after Regular Hours (Customer/Contract) Driven) - at Pole		$475.00
Additional Service Layout Fee - Basic/Complex (more than one hour)		$569.51
Pipeline Crossings		$2,396.75
Water Crossings		$3,570.65
Railway Crossings		$4,760.48 + Railway feedthrough costs
Overhead Line Staking Per Meter		$4.24
Underground Line Staking Per Meter		$3.05
Subcable Line Staking Per Meter		$2.66
Central Metering - New Service <45 kW		$100.00
Conversion to Central Metering <45 kW		$1,533.47
Conversion to Central Metering >=45 kW		$1,453.47
Connection Impact Assessments - Net Metering		$3,192.85
Connection Impact Assessments - Embedded LDC Generators		$2,873.57
Connection Impact Assessments - Small Projects <= 500 kW		$3,266.07
Connection Impact Assessments - Small Projects <= 500 kW, Simplified		$1,971.27
Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects		$8,641.91
Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects		$5,727.89
Specific Charge for Access to Power Poles - Municipal Streetlights		$2.04
Sentinel Light Rental Charge		$10.00
Sentinel Light Pole Rental Charge		$7.00
Specific Charge for LDCs Access to the Power Poles ($/pole/year)		
LDC Rate for 10' of power space		$86.56
LDC Rate for 15' of power space		$103.88
LDC Rate for 20' of power space		$115.42
LDC Rate for 25' of power space		$123.66
LDC Rate for 30' of power space		$129.85
LDC Rate for 35' of power space		$134.66
LDC Rate for 40' of power space		$138.50
LDC Rate for 45' of power space		$141.65
LDC Rate for 50' of power space		$144.27
LDC Rate for 55' of power space		$146.49
LDC Rate for 60' of power space		$148.40
Specific Charge for Generator Access to the Power Poles ($/pole/year)		
Generator Rate for 10' of power space		$86.56
Generator Rate for 15' of power space		$103.88
Generator Rate for 20' of power space		$115.42
Generator Rate for 25' of power space		$123.66
Generator Rate for 30' of power space		$129.85
Generator Rate for 35' of power space		$134.66
Generator Rate for 40' of power space		$138.50
Generator Rate for 45' of power space		$141.65
Generator Rate for 50' of power space		$144.27
Generator Rate for 55' of power space		$146.49
Generator Rate for 60' of power space		$148.40

* Base charge only. Additional work on equipment will be based on actual costs.

[1] Per new Customer Service Rules issued by the OEB on March 14, 2019 (EB-2017-0183).

UNDERTAKING - JT2.6

Reference:

Undertaking:

To make best efforts to produce a table for PDI similar to sec number 6.

Response:

PDI has made best efforts to complete a comparison of miscellaneous service charges between PDI and Hydro One, as provided in Attachment 1, which compares revenue collected at current rates for each utility on historical volumes (2016-2018). This information has been gathered from the systems/departments that track these items separately. Items that indicate a zero have no activity or are not systematically tracked. What has become evident through this process is that PDI has fees listed for services that it no longer charges for (e.g. pulling a postdated cheque).

As shown in response to Exhibit I, Tab 2, Schedule 50, the bulk of service charge revenues are generated from pole rental and late payment fees, for which PDI and Hydro One have the exact same specific charges.

Non-Payment of Account	PDI Charge	2016	2017	2018	Proposed Hydro One Charge Including Updates in EB-2017-0049 Oral Hearing		2016	2017	2018
			Count					Count	
Late payment Interest	1.5% per month 19.56 per				1.5% per month 19.56 per annum				
Notification Charge (noticeof Overdue account)	$15.00	28,988	20,168	23,162	$0.00	Not Applied	28988	20168	23162
Collection of Account Charge (Collection Visit No disconnect)	$30.00	213	161	276	$100.00	Discontinued	213	161	276
Collection of Account, (No disconnect), after hours	$165.00	-	-	-	$0.00	Discontinued	0	0	0
Disconnect/Reconnect at Meter during Regular Hours	$65.00	3,261	1,681	1,744	$65.00		3261	1681	1744
Disconnect/Reconnectat meter- after regular hours	$185.00	12	8	-	$185.00		12	8	0
Disconnect/reconnect at pole during regular hours	$185.00	-	-	-	$185.00		0	0	0
Disconnection/reconnection at pole - after regular hours	$415.00	-	-	-	$415.00		0	0	0
Total		**$655,395.00**	**$418,095.00**	**$469,070.00**		**Total**	**$235,485.00**	**$126,845.00**	**$140,960.00**
Account setup Charge/ Change of occupancy (plus credit check)	$30.00	5,900	5,433	5,500	$38.00		5900	5433	5500
Statement of Account required to waive deposit	$15.00	7	10	5	$0.00	Not Applied	7	10	5
Pulling Post dated Cheques	$15.00	-	-	-	$0.00	n/a	0	0	0
Duplicate invoices for previous billing	$15.00	-	-	-	$0.00	Not Applied	0	0	0
Request for other billing information	$15.00	-	-	-	$0.00		0	0	0
Easement Letter	$15.00	8	3	16	$88.29		8	3	16
Easement Letter Web Request	$15.00	-	-	-	$25.00		0	0	0
Income tax letter (statement of account for tax purposes	$15.00	-	-	-	$0.00	Not Applied	0	0	0
Account History	$15.00	-	-	-	$0.00	Not Applied	0	0	0
Credit Reference/ Credit check (with agency cost)	$19.50	303	340	226	$0.00	Not Applied	303	340	226
Returned Cheque Charge (plus bank charges)	$15.00	148	131	114	$7.00		148	131	114
Charge to Certify Cheque	$15.00	-	-	-	$0.00	n/a	0	0	0
Legal letter charge (required by lawyer for property sale)	$15.00	-	-	-	$0.00	Not Applied	0	0	0
Arrears Certificate (letters of reference, credit history)	$15.00	64	30	25	$0.00	n/a	64	30	25
Special Meter Reads (unscheduled or reversed move in)	$30.00	4	3	8	$90.00		4	3	8
Install/remove load control device during regular hours	$65.00	-	-	-	$65.00		0	0	0
Install/remove load limter after hours	$185.00	-	-	-	$185.00		0	0	0
Meter dispute charge including MC charges if found correct)	$30.00	7	8	-	$30.00	plus MC charges	7	8	0
Service Call Customer Owned Equipment (regular hours)	$30.00	-	-	-	$210.00		0	0	0
Service Call Customer Owned Equipment (after Regular hours)	$165.00	-	-	-	$775.00		0	0	0
Temporary Service install and/or remove Overhead, no transformer	$500.00	3	5	12	$0.00	Actual Cost	3	5	12
Temporary Service install and/or remove Overhead, with transformer	$1,000.00	1	-	-	$0.00	Actual Cost	1	0	0
Temporary Service install and/or remove Underground, no transformer	$300.00	4	3	2	$0.00	Actual Cost	4	3	2
Temporary Service install and/or remove Underground, with transformer	$22.35	-	-	-	$0.00	Actual Cost	0	0	0
Total		**$190,344**	**$175,960**	**$178,647**		**Total**	**$226,512**	**$208,146**	**$211,931**

UNDERTAKING - JT2.7

Reference:

Undertaking:

To confirm the reasons given for the differences between the OM&A numbers recorded for Hydro One in the financial statements versus what was reported in the response to VECC 9.

Response:

The OM&A number in Hydro One Distribution's 2017 Financial Statements ($567M) includes costs for all Hydro One Distribution, which includes the acquired utilities of Norfolk Power, Haldimand Hydro and Woodstock Hydro.

In response to EB-2018-0242, Exhibit I, Tab 4, Schedule 9, which allocates OM&A costs ($559M) to Hydro One's existing rate classes, the OM&A associated with the acquired utilities was excluded.

UNDERTAKING - JT2.8

Reference:

EB-2018-0242 Exhibit I, Tab 4, Schedule 9 (VECC 9)
EB-2018-0242 Exhibit I, Tab 4, Schedule 10 (VECC 10)
EB-2018-0242 Exhibit I, Tab 4, Schedule 12 (VECC 12)

Undertaking:

To update the numbers in the EB-2017-0049 draft rate order and cost allocation; to provide an updated to Hydro One responses VECC 9, 10, 12 based on the 2018 draft rate order and underlying cost allocation.

Response:

Hydro One is providing updates to the following EB-2018-0242 responses to reflect the results from Hydro One's 2018 cost allocation model as filed in its draft rate order in proceeding EB-2017-0049[1] ("2018 DRO"):

1. VECC 9 part b
2. VECC 10 part e
3. VECC 10 part f
4. VECC 12 part a
5. VECC 12 part b

[1] EB-2017-0049 Draft Rate Order, Exhibit 3.1, filed on April 5 2019.

1. VECC 9 part b). The table below provides the requested information.

	Forecast (as filed in 2018 DRO)
OM&A	$544,408,355
Total Number of Customers	1,303,822
UR	227,025
R1	447,465
R2	328,479
Seasonal	147,679
GSe	87,902
GSd	5,239
UGe	18,000
UGd	1,735
St Lgt*	21,581
Sen Lgt*	11,301
USL	5,490
Dgen	1,119
ST	807

Number of connections used for cost allocation purposes.

2. VECC 10 part e): Hydro One's average 2018 OM&A cost per customer is $176/customer for its UR rate class.

3. VECC 10 part f): Hydro One's average 2018 OM&A cost per customer for the UGe, UGd, and ST rate classes are shown in the table below:

Rate Class	**OMA per Customer**
UGe	$ 447
UGd	$ 5,028
ST	$ 23,904

4. VECC 12 part a): Hydro One's average depreciation per customer for UR, UGe, UGd and ST customer classes (based on the 2018 DRO) are provided below.

	Hydro One			
	UR	**UGe**	**UGd**	**ST**
Depreciation/Customer	$96	$351	$5,699	$18,737

5. VECC 12 part b): Hydro One's average NBV per customer for UR, UGe, UGd and ST customer classes (based on the 2018 DRO) are provided below.

	Hydro One			
	UR	**UGe**	**UGd**	**ST**
NBV/Customer	$1,552	$6,139	$98,771	$341,662

UNDERTAKING - JT2.9

Reference:

Undertaking:

To provide the Kinectrics numbers by USofA, and then the Hydro One, Dr. White's by USofA.

Response:

The Kinectrics "Asset Depreciation Study for the Ontario Energy Board" dated July 8, 2010, summary of componentized assets useful life is provided in Attachment 1.

The Hydro One 2013 Depreciation Rate Review study, completed by Fosters Associates (Dr. White) is provided in Attachment 2.

The two studies are difficult to compare in a line by line basis.

- The Kinectrics study does not include a USofA grouping, and refers to very specific assets (e.g. it distinguished between wood, concrete and steel poles). The Hydro One study uses USofA accounts to determine depreciation rates (e.g. there is only one USofA account which includes all pole types).
- The Hydro One study applies a methodology for a group of assets whereas the Kinectrics study is intended for individual assets.
- The presentation in the Hydro One study denotes depreciation as a percentage, whereas the Kinectrics study denotes it as a useful life.

F SUMMARY OF RESULTS

Table F - 1 summarizes useful lives, and factors impacting those lives as developed by this report.

Table F - 1 Summary of Componentized Assets, Service Life and Factors

PARENT*	#	ASSET DETAILS: Category | Component | Type			USEFUL LIFE: MIN UL	TUL	MAX UL	FACTORS **: MC	EL	EN	OP	MP	NPF
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	4	OH Line Switch			30	45	55	L	L	L	L	M	L
	5	OH Line Switch Motor			15	25	25	L	NI	L	L	M	L
	6	OH Line Switch RTU			15	20	20	NI	NI	L	L	L	M
	7	OH Integral Switches			35	45	60	L	M	M	M	L	H
	8	OH Conductors			50	60	75	M	L	M	NI	NI	L
	9	OH Transformers & Voltage Regulators			30	40	60	L	M	M	NI	NI	M
	10	OH Shunt Capacitor Banks			25	30	40	-	-	-	-	-	-
	11	Reclosers			25	40	55	L	L	L	M	L	M
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55	NI	L	M	L	NI	L
	14	Station Grounding Transformer			30	40	40	-	-	-	-	-	-
	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M
			Battery bank		10	15	15						
			Charger		20	20	30						
	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65	M	M	M	M	M	M
	18	Station Switch			30	50	60	M	L	M	M	M	L

*** OH = Overhead Lines System TS & MS = Transformer and Municipal Stations**
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

PARENT*	#	ASSET DETAILS: Category | Component | Type		USEFUL LIFE: MIN UL	TUL	MAX UL	FACTORS **: MC	EL	EN	OP	MP	NPF
	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H
TS & MS	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H
	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L
	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L
	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	M	M	M	L	L	L
	27	Primary Non-TR XLPE Cables In Duct		20	25	30	M	M	M	L	L	M
	28	Primary TR XLPE Cables Direct Buried		25	30	35	M	M	M	L	L	L
	29	Primary TR XLPE Cables In Duct		35	40	55	M	M	M	L	L	L
	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H
	31	Secondary Cables Direct Buried		25	35	40	M	M	M	L	NI	NI
	32	Secondary Cables In Duct		35	40	60	M	M	M	L	NI	NI
UG	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI
			Protector	20	35	40						
	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L
	35	Submersible/Vault Transformers		25	35	45	L	M	M	NI	L	L
	36	UG Foundations		35	55	70	M	NI	M	L	L	M
	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L
			Roof	20	30	45						
	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI
	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L
	40	Ducts		30	50	85	H	NI	M	NI	NI	L
	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L
	42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI
S	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

HYDRO ONE NETWORKS INC. (BU 220) Statement A

Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
1610 Computer Software	2.16		9.36%	← 10 Year Amortization →			1.14%
Total Intangible Plant			9.36%	7.28		91.68%	1.14%
GENERATION PLANT							
1620 Buildings and Fixtures	19.18			8.21		89.97%	1.22%
1665 Fuel Holders, Producers and Accessories	28.79		1.36%	15.79		64.13%	2.27%
1675 Generators	16.69		1.18%	1.00		116.03%	-16.03%
1680 Accessory Electric Equpment	14.35			15.50		71.56%	1.83%
Total Generation Plant			1.16%	8.77		104.51%	-11.69%
DISTRIBUTION PLANT							
1805D Land - Depreciable			1.33%	6.92		101.23%	-0.18%
1806 Land Rights	60.09		1.22%	75.16		29.02%	0.94%
1808 Buildings and Fixtures	38.45		1.73%	33.17		39.61%	1.82%
1815 Transformer Station Equipment > 50 kV	30.02		1.98%	26.88		39.96%	2.23%
1820 Distribution Station Equipment < 50 kV	28.83		1.97%	17.79		51.88%	2.70%
1830 Poles, Towers and Fixtures	36.17		1.83%	40.14		31.89%	1.70%
1835 Overhead Conductors and Devices	27.08		2.14%	39.47		33.48%	1.69%
1840 Underground Conduit	29.49		1.97%	27.61		52.73%	1.71%
1845 Underground Conductors and Devices	10.79		3.53%	17.04		51.78%	2.83%
1850 Line Transformers	34.86		2.06%	29.42		32.17%	2.31%
1860 Meters	2.81		20.00%	17.68		13.55%	4.89%
1860S Meters (Sustainment)			6.67%	14.50		3.89%	6.63%
1555 Smart Meters			6.67%	11.77		25.16%	6.36%
1565 Smart Meters - Pilot			6.67%	9.01		41.64%	6.48%
Total Distribution Plant			2.44%	28.24		35.39%	2.27%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	28.59		2.08%	34.00		37.55%	1.84%
1910 Leasehold Improvements	4.28		7.94%	7.51		58.73%	5.50%
1922 Computer Hardware - Major	2.43		6.49%	2.79		110.65%	-3.82%
1955 Communication Equipment	4.04		9.01%	1.21		112.09%	-9.99%
1980 System Supervisory Equipment	9.57		8.01%	4.95		26.05%	14.94%
1985 Sentinel Lighting Rental Units	21.05		3.01%	18.81		44.69%	2.94%
Total Depreciable			5.27%	8.44		42.50%	5.73%
Amortizable							
1925 Computer Software - Major	2.16		9.36%	← 6 Year Amortization →			13.43%
Total Amortizable			9.36%	3.34		54.43%	13.43%
Total General Plant			6.53%	5.91		46.17%	8.10%
TOTAL DISTRIBUTION OPERATIONS			2.67%	24.16		36.35%	2.51%

UNDERTAKING - JT2.10

Reference:

Undertaking:

To clarify assumptions and annual escalation in customer care costs.

Response:

Hydro One's customer service area is going through and is anticipated to continue to go through significant transformation/evolution over the 10-year planning period which forms this application. Many of these transformations relate to a customer shift to greater reliance and use of digital service channels which typically can be delivered at a lower cost than traditional channels. An example of such a shift is customers switching from receiving a paper bill every month in their mail box to receiving an electronic bill in their e-mail box. Through this simple shift in customer acceptance this same service can be delivered at a fraction of the historical cost. These shifts and efficiencies are expected to occur in billing delivery, some aspects of contact handling and outage reporting, all of which were accounted for in the cost projections.

UNDERTAKING - JT2.11

Reference:

Undertaking:

With respect to VECC 7c, to provide the forecast for Hydro One residual OM&A and Peterborough's status quo OM&A broken down to the level of detail shown in table 2, such that the differences reconcile with the amounts shown in the response.

Response:

Attachment 1 provides PDI Status Quo OM&A and Hydro One Forecast OM&A presented at the level of detail shown in EB-2018-0242, Exhibit I, Tab 4, Schedule 7 (VECC 7), Part c), Table 1.

Attachment 2 provides OPDC Status Quo OM&A and Hydro One Forecast OM&A presented at the level of detail shown in EB-2018-0270, Exhibit I, Tab 1, Schedule 3 (Staff 3), Part b), Table 1.

Attachment 1
PDI Savings / Synergy Category
($ thousands)

	Status Quo Forecast		Hydro One Forecast		Projected Savings	
	Year 2	Year 10	Year 2	Year 10	Year 2	Year 10
Administration						
Mgmt / Corporate Governance	975	1,182	-	-	975	1,182
Financial / Regulatory	723	876	-	-	723	876
Other	1,232	1,494	793	72	439	1,422
	2,930	**3,552**	**793**	**72**	**2,137**	**3,480**
Back Office						
Customer Service	1,836	2,226	2,033	2,215	(197)	11
Information Technology / Other	1,380	1,673	-	-	1,380	1,673
	3,215	**3,899**	**2,033**	**2,215**	**1,182**	**1,684**
Distribution Operations	**3,727**	**4,519**	**1,641**	**1,941**	**2,086**	**2,578**
Total OM&A	**9,872**	**11,970**	**4,467**	**4,228**	**5,405**	**7,742**

Attachment 2
OPDC Savings / Synergy Category
($ thousands)

	Status Quo Forecast		Hydro One Forecast		Projected Savings	
	Year 2	Year 10	Year 2	Year 10	Year 2	Year 10
Administration						
Mgmt / Corporate Governance	795	931	-	-	795	931
Financial / Regulatory	413	484	-	-	413	484
Other	634	742	498	88	135	654
	1,842	**2,157**	**498**	**88**	**1,344**	**2,069**
Back Office						
Customer Service	1,357	1,589	782	876	575	713
Information Technology / Other	574	673	-	-	574	673
	1,931	**2,262**	**782**	**876**	**1,149**	**1,386**
Distribution Operations	**1,881**	**2,202**	**729**	**919**	**1,152**	**1,283**
Total OM&A	**5,654**	**6,621**	**2,009**	**1,883**	**3,645**	**4,738**

UNDERTAKING - JT2.12

Reference:

Undertaking:

To provide an explanation of why, if the cost of equity has only gone down by possibly $27,000, the taxes which are usually calculated as a percentage of the return go down by 348,000.

Response:

The following provides further information with respect to the calculation of the cost of equity and tax provided in Exhibit I, Tab 2, Schedule 3 or EB-2018-0270.

$000s	Hydro One	Orillia Power	Variance
Rate Base	52,906	53,678	
40% Equity	21,162	21,471	
Allowed Return on Equity	9%	9%	
Cost of Capital – Equity	$1,905	$1,932	($27)
Revenue	6,859	13,443	
OM&A	(1,921)	(6,754)	
Depreciation	(1,433)	(2,882)	
Interest	(1,373)	(1,300)	
Earnings before Taxes	2,132	2,507	
Add Back: Depreciation	1,433	2,882	
Less: CCA	(2,707)	(3,221)	
Earnings before Cash Tax	858	2,168	
Tax Rate	26.5%	26.5%	
Tax	$227	$575	($348)

Taxes are not solely a function of return on equity. The differential between the $27 thousand variance in cost of equity and the $348 thousand mainly relates to the differences in depreciation and CCA.

Corrections to the Transcripts

Day	Page	Line	Correction
1 and 2			Mr. Faltaous' name has been misspelled throughout the transcripts. The transcripts read Mr. Faltous, where the correct spelling is Mr. Faltaous
1	179	20	Says "MR.ANDRE: Right. Do you want to answer?" - Should say "MR.ANDRE: Right."
1	181	11	Says "That is what (inaudible) is going to be using. She is …" - Should say "That is what Mr.Andre is going to be using. He is …
1	195	26	Says "…sure we had at a minimum …" - Should say "…sure we would at a minimum …"
2	8	4-11	This statement should be attributed to Mr.Andre.
2	14	28	Says "… you looked at more density, you recall density factors, but we look at …" - Should say "… we looked at more than density, we call it density factors, but we look at …"
2	15	1	Says "… you looked at more density, you recall density factors, but we look at …" - Should say "… we looked at more than density, we call it density factors, but we look at …"
2	17	5 and 7	Says " … LD charges…" - but should say "… LV charges…"
2	18	4	Says …" our TSR charges …" - but should say "… our RTSR charges …"
2	19	2	Says " … or year 1, rather." - But should say "… or year 11, rather."
2	53	13	Says "… derivation of those sheets." - But should say "… derivation of those numbers."
2	72	21	Says "…ultimately improved as part of …" - but should say "…ultimately approved as part of …"
2	78	9	Says "… as part of the settlement." - But should say "… as part of the proposal."
2	103	16	Says "We did some PIL controls and we would have collected information on the assets as ell", - should day "we did some patrols and we would have collected information on assets as well"
2	142	11	Says " … it would need some of the …" - but should say "… it would mean some of the …"