K201

Hydro One/OPDC/PDI MAADs

EB-2018-0270/EB-2018-0242

OEB Staff Compendium

	Utility	A 2019 base monthly distribution charge residential	B 2019 base monthly distribution charge GS<50	C 2019 base monthly distribution charge GS>50	D 2019 revenue requirement	E Year 11 base monthly distribution charge residential (without consolidation)	F Year 11 base monthly distribution charge GS<50 (without consolidation)	G Year 11 base monthly distribution charge GS>50 (without consolidation)	H Year 11 revenue requirement (without consolidation)	I CAGR base monthly distribution charge residential*	J CAGR revenue requirement*
1	Orillia[1]	$ 30.94	$ 79.10	$ 721.15	$ 8,859,135	$ 50.25	$ 127.00	$ 1,316.50	$ 14,448,364	4.5%	4.5%
2	Peterborough[2]	$ 23.37	$ 50.96	$ 925.31	$ 17,168,906	$ 37.67	$ 82.14	$ 1,508.51	$ 26,324,000	4.4%	4.0%
3	HONI[3]	$ 34.26	$ 81.60	$ 2,559.27	$ 1,497,859,890	$ 44.87	$ 108.84	$ 3,440.78	$ 1,909,692,763	2.5%	2.2%

Sources:
[1] OEB 11, OEB 12
[2] SEC 43, SEC 44
[3] SEC 43, SEC 44
* OEB Staff calculations

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Source: https://www.oeb.ca/_html/performance/rates_chart.php?class=Res

ONTARIO ENERGY BOARD

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Electricity Rate Comparison

The OEB is committed to increasing energy literacy and providing consumers with reliable information. The following information shows you how electricity prices compare across Ontario. The data is from the OEB's rate database.

This chart compares the total bill amount (before HST of 13%) for Residential* customers in Ontario. It is calculated by the OEB based on the amount of electricity that the typical residential customer in Ontario uses each month: 750 kilowatt hours.

You may use more or less electricity each month at your home. Use your bill and our online bill calculator to see how your bill compares. We also have a page to help you better understand your electricity bill.

In Ontario, rates differ between urban and rural areas primarily because of the delivery cost for electricity. The commodity price of electricity is the same for all residential and small business customers who buy their power directly from their utility, rather than under contract with an electricity retailer.

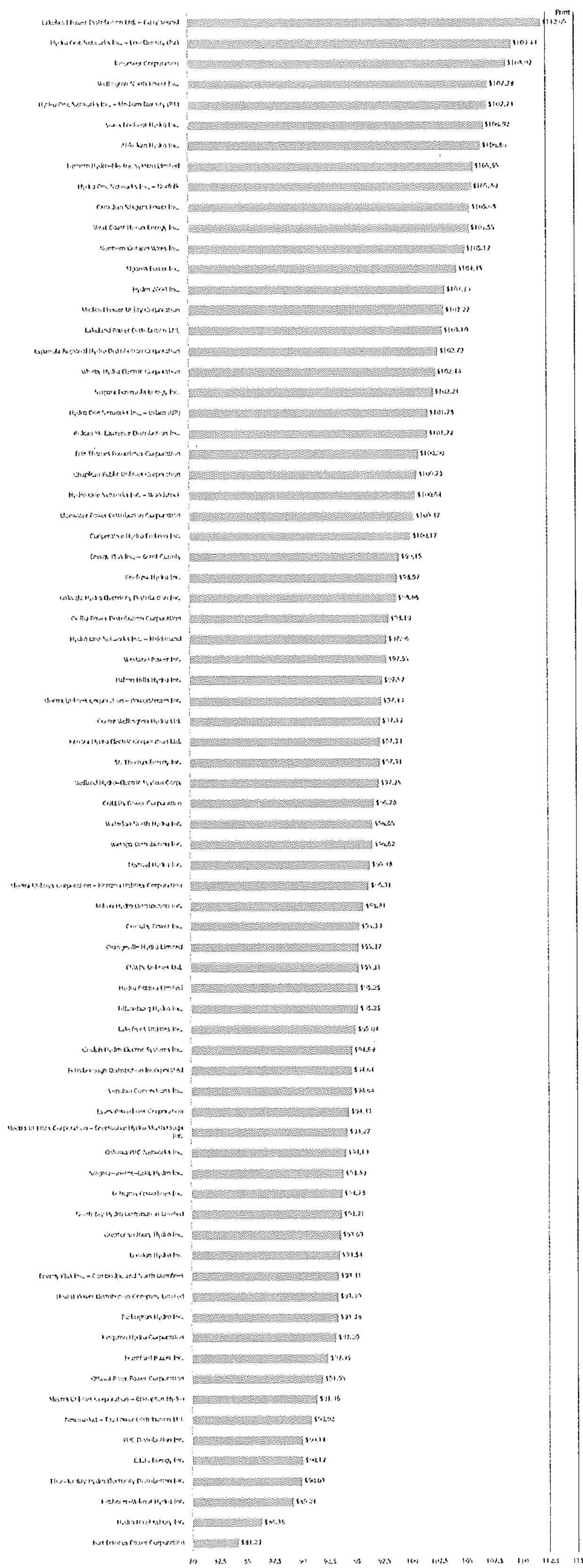
Compare: Estimated Total Bills for Ontario Utilities | Estimated Total Bills in Canada/U.S.A.

Select Rate Class: Residential | Small Business (GS<50 kW)

Select Rate Year: 2017 | 2016

CHART VIEW MAP VIEW

2017 Estimated Total Monthly Bill Amount ($) per Month (before tax) for Residential Rate Class in Ontario as of November 1



* NOTES:

1. Residential rate class applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation.
2. The total bill amount ($) data is in Canadian dollars, while the total cents per kWh data is in Canadian cents (¢). Please note 1¢ is equal to $0.01.

3. The data in this chart is based on 750 kWh, which is the typical monthly consumption for residential consumers in Ontario. Individual usage may vary
4. The cents per kWh figures have been calculated by dividing the total bill amount ($) by 750 kWh.
5. The data in this chart is based on commodity prices in effect on November 1, 2017 for a consumer paying Regulated Price Plan (RPP) time-of-use (TOU) prices which are set by the OEB. Click here for more information on electricity prices. Click here for a technical report describing how the OEB sets the RPP prices.
6. The data in this chart assumes a typical consumption pattern of 65% Off-Peak, 17% Mid-Peak and 18% On-Peak for each TOU period, which represents the average across all consumers on TOU pricing in Ontario.
7. The calculated figures include the *Ontario Fair Hydro Plan Act, 2017* adjustments.
8. The calculated figures include line-loss adjustments to account for electricity lost during its transmission and delivery between the generators and consumers. There are other factors that affect your total bill that may account for differences between this estimate and the bill you regularly receive from your utility. Always refer to your utility bill for actual usage and totals.
9. HST (13%) has been excluded in this chart and therefore the figures presented in this chart are before tax.
10. The data is not designed to estimate bills for consumers on equal billing/budget billing plans.
11. Attawapiskat Power, Fort Albany Power and Kashechewan Power, as well as Dubreuil Lumber, Cornwall Electric, Hydro One Remote Communities Inc. and Hydro One Networks Inc.'s Seasonal rate class have not been included here.
12. These figures do not include any potential Ontario Electricity Support Program (OESP) credits. Click here to learn more about the OESP credit.
13. Utilities apply to the OEB for annual distribution rate changes. Click here for more information on electricity distribution rate applications and decisions.
14. Click here to learn more about various components of your monthly electricity bill.

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	A	B	C	D	E	F	G	H	J	K	L	
1	*Source: Adapted from EB-2018-0242, Attachment 19, page 1 of 1*						*OEB Staff Calculations*					1
2	**Utility (2018 Approvals)**	**Application**	**Base Revenue Requirement, 2018 Approval ($)**	**Base Revenue Requirement, Last Approval ($)**	**Change ($)**	**Change (%)**	**Average Annual Change (%)**	**Compound Annual Growth Rate (%)**	*2018 Approval Year*	*Last Approval Year*	*# of years*	2
3	Centre Wellington	EB-2017-0032	3,665,637	3,023,099	642,538	21.3%	4.3%	3.93%	*2018*	*2013*	*5*	3
4	Cooperative Hydro Embrun Inc.	EB-2017-0035	1,067,336	858,144	209,192	24.4%	6.1%	5.61%	*2018*	*2014*	*4*	4
5	Essex	EB-2017-0039	12,351,144	11,208,453	1,142,691	10.2%	1.3%	1.22%	*2018*	*2010*	*8*	5
6	Hydro Hawkesbury	EB-2017-0048	1,744,140	1,590,565	153,575	9.7%	2.4%	2.33%	*2018*	*2014*	*4*	6
7	Westario	EB-2017-0084	10,669,547	9,631,581	1,037,966	10.8%	2.2%	2.07%	*2018*	*2013*	*5*	7
8					**Average:**	**15.3%**	**3.2%**	**3.0%**				8
9												9
10	*Source: Adapted from EB-2018-0242, Attachment 19, page 1 of 1*						*OEB Staff Calculations*					10
11	**Utility (2017 Approvals)**	**Application**	**Base Revenue Requirement, 2017 Approval ($)**	**Base Revenue Requirement, Last Approval ($)**	**Change ($)**	**Change (%)**	**Average Annual Change (%)**	**Compound Annual Growth Rate (%)**	*2017 Approval Year*	*Last Approval Year*	*# of years*	11
12	Atikokan	EB-2016-0055	1,402,256	1,232,815	169,441	13.7%	2.7%	2.61%	*2017*	*2012*	*5*	12
13	Brantyford	EB-2016-0058	17,098,955	15,826,563	1,272,392	8.0%	2.0%	1.95%	*2017*	*2013*	*4*	13
14	CNP	EB-2016-0061	18,840,476	17,562,996	1,277,480	7.3%	1.8%	1.77%	*2017*	*2013*	*4*	14
15	InnPOwer	EB-2016-0085	10,117,125	7,590,696	2,526,429	33.3%	8.3%	7.45%	*2017*	*2013*	*4*	15
16	Lakefront	EB-2016-0089	4,260,112	4,039,506	220,606	5.5%	1.1%	1.07%	*2017*	*2012*	*5*	16
17	London	EB-2016-0091	66,339,088	62,675,465	3,663,623	5.8%	1.5%	1.43%	*2017*	*2013*	*4*	17
18	Northern Ontario	EB-2016-0096	3,411,159	2,916,654	494,505	17.0%	4.2%	3.99%	*2017*	*2013*	*4*	18
19	Renfrew	EB-2016-0166	2,003,438	1,877,960	125,478	6.7%	1.0%	0.93%	*2017*	*2010*	*7*	19
20	Thunder Bay	EB-2016-0105	22,770,707	19,210,613	3,560,094	18.5%	4.6%	4.34%	*2017*	*2013*	*4*	20
21	Welland	EB-2016-0110	9,684,025	8,715,039	968,986	11.1%	2.8%	2.67%	*2017*	*2013*	*4*	21
22					**Average:**	**12.7%**	**3.0%**	**2.8%**				22
23												23
24			*Source: Adapted from EB-2018-0242, Attachment 19, page 1 of 1*				*OEB Staff Calculations*					24
25						**Change (%)**	**Average Annual Change (%)**	**Average Compound Annual Growth Rate (%)**				25
26			**Average of 2017 and 2018 Approvals:**			**13.5%**	**3.1%**	**2.9%**				26
	A	B	C	D	E	F	G	H	J	K	L	

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SEC INTERROGATORY # 43

Reference:

[I/1/1, p. 2]

Interrogatory:

Please update the table on this page to reflect the proposals in A/5/1, including the proposed allocation of Shared Costs. If this table remains valid, please explain why. In either case, please provide details of each adjustment factor applied to the Year 11 figures and the dollar impact of those adjustment factors.

Response:

An update to the table provided in Exhibit I, Tab 1, Schedule 1 is provided below.

The Year 11- With Consolidation figures provided in the Table reflect the output of the cost allocation run provided in the response to Exhibit I, Tab 1, Schedule 48, which includes details of the assumptions and allocation process for estimating the PDI acquired classes' rates.

Please refer to Exhibit I, Tab 1, Schedule 48 for details on the calculation of the Year 11 figures.

PDI	Today - 2019		Year10 - With Consolidation[1]		Year10 - Without Consolidation[2]		Year11 - With Consolidation[3]		Year11 - Without Consolidation[2]	
	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]
Residential (750kWh)	$23.37	$107.18	$25.85	$109.78	$36.58	$121.04	$27.16	$111.16	$37.67	$122.19
GS < 50kW (2,000kWh)	$50.96	$270.23	$56.06	$275.58	$79.74	$300.45	$61.55	$281.35	$82.14	$302.97
GS 50 to 4,999 kW (250kW)	$925.31	$28,315.37	$1,068.03	$28,476.64	$1,468.19	$28,928.82	$1,027.66	$28,431.02	$1,508.51	$28,974.38

[1] Indicative distribution rates for year 10 (with consolidation) have been calculated by applying -1% to PDI's exsting rates then holding them constant for 2020-2024 and then applying IRM increase of 1.55% for 2025-2029.

[2] Indicative distribution rates for year 10 and year 11 (without consolidation) have been calculated using the percentage increase in rates revenue requirement compared to 2019 (refer to Exhibit I, Tab 2, Schedule 44).

[3] Indicative distribution rates for year 11 (with consolidation) per Exhibit I, Tab 1,Schedule 49, Attachement 2.

[4] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period.

Hydro One	Today - 2019		Year10 - With Consolidation[1]		Year10 - Without Consolidation[1]		Year11 - With Consolidation[2]		Year11 - Without Consolidation[1]	
	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]
Residential (UR 750kWh)	$34.26	$121.77	$43.72	$131.71	$43.72	$131.71	$41.44	$129.32	$44.87	$132.92
GS < 50kW (UGe 2,000kWh)	$81.60	$306.91	$105.88	$332.41	$105.88	$332.41	$102.26	$328.61	$108.84	$335.52
GS > 50 kW (UGd 250kW)	$2,559.27	$30,087.07	$3,347.54	$30,977.82	$3,347.54	$30,977.82	$3,238.09	$30,854.14	$3,440.78	$31,083.18

[1] Indicative distribution rates for year 10 (with and without consolidation) and year 11 (without consolidation) have been calculated using the compound annual growth rate between 2018 and 2022 and then applying it to 2022 rates.

[2] Indicative distribution rates for year 11 (with consolidation) per Exhibit I, Tab 1,Schedule 49, Attachement 2.

[3] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period.

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Statistics by Customer Class For the Year Ended December 31	Hydro One Networks Inc.	Orillia Power Distribution Corporation	Peterborough Distribution Incorporated	Total Industry
Residential Customers				
Number of Customers	1,212,458	12,522	33,351	4,712,742
Metered kWh	12,870,557,424	110,356,004	292,820,369	41,318,383,306
Distribution Revenue ($)	998,129,775	4,582,195	8,968,858	2,245,266,465
Metered kWh per Customer	10,615	8,813	8,780	8,767
Distribution Revenue per Customer ($)	823	366	269	476
	26%	0%	1%	100%
General Service <50kW Customers	211.79	0.97	1.90	
Number of Customers	111,595	1,404	3,426	440,574
Metered kWh	3,101,461,887	44,691,235	118,092,168	13,542,967,467
Distribution Revenue ($)	182,875,063	1,533,535	2,334,580	502,911,877
Metered kWh per Customer	27,792	31,831	34,469	30,739
Distribution Revenue per Customer ($)	1,639	1,092	681	1,141
General Service >50kW, Large User (>5000kW) and Sub Transmission				
Number of GS >50kW Customers	8,967	165	360	54,969
Number of Large Users	-	-	2	119
Number of Sub Transmission Customers	581	-	-	581
Metered kWh	8,860,436,731	164,401,360	375,136,038	65,275,749,273
Distribution Revenue ($)	221,310,521	2,093,836	2,900,219	934,175,237
Metered kWh per Customer	927,989	996,372	1,036,287	1,172,569
Distribution Revenue per Customer ($)	23,179	12,690	8,012	16,781
Unmetered Scattered Load Connections				
Number of Connections	5,606	151	391	44,239
Metered kWh	29,977,189	759,957	2,110,358	188,916,152
Distribution Revenue ($)	3,133,650	26,836	69,930	11,555,135
Metered kWh per Connection	5,347	5,033	5,397	4,270
Distribution Revenue per Customer ($)	559	178	179	261

Source: Extract from OEB Yearbook of Electricity Distributors, 2018 (Published on August 19, 2019), Tab: "Stats by Class"

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Statistics by Customer Class For the year ended December 31, 2013	Hydro One Networks Inc.	Orillia Power Distribution Corporation	Peterborough Distribution Incorporated
Residential Customers			
Number of Customers	1,106,925	11,702	31,905
Billed kWh	12,384,150,704	106,997,102	287,135,105
Distribution Revenue	$ 830,158,960	$ 4,127,145	$ 8,555,707
Billed kWh per Customer	11,188	9,143	9,000
Distribution Revenue per Customer	$ 750	$ 353	$ 268
General Service <50kW Customers			
Number of Customers	104,750	1,349	3,573
Billed kWh	2,705,658,268	45,899,615	117,056,288
Distribution Revenue	$ 152,847,548	$ 1,529,338	$ 2,683,101
Billed kWh per Customer	25,830	34,025	32,761
Distribution Revenue per Customer	$ 1,459	$ 1,134	$ 751
General Service >50kW, Large User (>5000kW) and Sub Transmission			
Number of GS >50kW Customers	7,893	168	365
Number of Large Users	-	-	2
Number of Sub Transmission Customers	533	-	-
Billed kWh	7,132,036,944	144,672,158	387,386,924
Distribution Revenue	$ 158,966,588	$ 1,858,316	$ 2,966,072
Billed kWh per Customer	846,432	861,144	1,055,550
Distribution Revenue per Customer	$ 18,866	$ 11,061	$ 8,082
Unmetered Scattered Load Connections			
Number of Connections	5,517	153	415
Billed kWh	43,417,113	795,024	1,760,029
Distribution Revenue	$ 3,104,310	$ 25,379	$ 172,013
Billed kWh per Connection	7,870	5,196	4,241
Distribution Revenue per Connection	$ 563	$ 166	$ 414

Source: OEB Yearbook of Electricity Distributors, 2013 (Published on August 14 2014), Tab: "Stats by Customer Class"

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SEC INTERROGATORY # 44

Reference:
[I/1/3, p. 2,3]

Interrogatory:
Please update the tables on these pages to reflect the proposals in A/5/1, including the proposed allocation of Shared Costs. If these tables remain valid, please explain why. In either case, please provide details of each adjustment factor applied to the Year 11 figures and the dollar impact of those adjustment factors.

Response:
Below is an update to the tables provided in Exhibit I, Tab 1, Schedule 3 to reflect the assumptions and output from the cost allocation and rate design completed in the response to Exhibits 1, Tab 1, Schedules 48 and 49:

PDI	Today (2019)[1,2,3]	Year 10 (2029) with consolidation[2,3,4]	Year 10 (2029) without consolidation[2,3,5]	Year 11 (2030) with consolidation[6]	Year 11 (2030) without consolidation[2,3,7]
Revenue Collected					
Residential	$9,972,113	$10,778,546	$14,864,540	$11,995,089	$15,259,604
GS < 50kW	$2,654,781	$2,882,231	$3,988,616	$3,262,266	$4,096,265
GS 50-4,999 kW	$3,551,950	$3,904,773	$5,308,166	$3,844,882	$5,449,494
Other	$990,062	$1,078,764	$1,479,201	$1,447,995	$1,518,637
Total	**$17,168,906**	**$18,644,315**	**$25,640,523**	**$20,550,232**	**$26,324,000**
Revenue Collected per Customer					
Residential	$300	$308	$424	$341	$433
GS < 50kW	$749	$741	$1,026	$831	$1,044
GS 50-4,999 kW	$9,567	$9,763	$13,272	$9,543	$13,525
Other	$107	$109	$150	$145	$153
Total	**$370**	**$379**	**$521**	**$415**	**$532**

[1] Total revenue collected from rates is derived by applying approved IRM increases between 2013 and 2019 to the approved revenue collected from rates in 2013.

[2] External revenues are held constant at 2013 approved values.

[3] Estimated values for revenues related to LV charges have been added to the total distribution revenue collected as described in Exhibit A-4-1, pg 3.

[4] Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.55% for 2025-2029.

[5] Total revenue collected (including external revenues) per Exhibit I, Tab 1, Schedule 10, part (d).

[6] Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus $1.5M in estimated revenue collected from the "combined classes").

[7] Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

Hydro One	Today (2019)[1]	Year 10 (2029) with consolidation[2,3]	Year 10 (2029) without consolidation[2,3]	Year 11 (2030) with consolidation[4]	Year 11 (2030) without consolidation[2,3]
Revenue Collected					
Residential (UR)	$97,456,815	$121,420,723	$121,420,723	$134,691,875	$135,017,893
GS<50kW (UGe)	$23,037,678	$28,770,504	$28,770,504	$28,030,967	$28,101,853
GS>50kW (UGd)	$28,548,646	$35,752,868	$35,752,868	$31,931,011	$32,017,420
Other	$1,348,816,751	$1,685,459,484	$1,685,459,484	$1,710,108,678	$1,714,555,596
Total	**$1,497,859,890**	**$1,871,403,579**	**$1,871,403,579**	**$1,904,762,530**	**$1,909,692,763**
Revenue Collected per Customer					
Residential (UR)	$424	$469	$469	$515	$517
GS<50kW (UGe)	$1,276	$1,520	$1,520	$1,472	$1,475
GS>50kW (UGd)	$16,413	$19,665	$19,665	$17,458	$17,506
Other	$1,275	$1,504	$1,504	$1,519	$1,523
Total	**$1,146**	**$1,337**	**$1,337**	**$1,353**	**$1,356**

[1] Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.
[2] Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.
[3] External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.
[4] Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus $1.5M in estimated revenue collected from the "combined classes").

Please refer to Exhibit I, Tab 1, Schedule 48 (b) for details on the adjustment factors applied in calculating the Year 11 figures.

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OEB STAFF INTERROGATORY # 12

Reference:
Exhibit A-4-1

Interrogatory:
Questions:
a) Please provide a table which estimates Hydro One and OPDC revenue requirements and revenue requirements per customer:

i. Today (e.g. 2019)
ii. In Year 10 with the proposed consolidation
iii. In Year 10 without the proposed consolidation
iv. In Year 11 with the proposed consolidation, including all costs that are expected to be allocated to OPDC
v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, General Service greater than 50 kW and total of all customer types (i.e. total revenue requirement).

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, pleas ensure that they do.

Response:
a) The tables below provide the requested information for Hydro One's Urban rate classes and OPDC.

OPDC	Today (2019)[1,2,3]	Year 10 (2029) with consolidation[2,3,4]	Year 10 (2029) without consolidation[2,3,5]	Year 11 (2030) with consolidation[6]	Year 11 (2030) without consolidation[2,3,7]
Revenue Requirement					
Residential	$4,471,729	$4,886,300	$7,110,967	$5,073,009	$7,281,348
GS < 50kW	$1,623,718	$1,779,756	$2,602,179	$1,538,976	$2,665,364
GS 50-4,999 kW	$2,400,644	$2,676,069	$3,798,964	$2,385,875	$3,889,680
Other	$363,045	$395,662	$596,908	$588,293	$611,972
Total	**$8,859,135**	**$9,737,786**	**$14,109,018**	**$9,586,153**	**$14,448,364**
Revenue Requirement per Customer					
Residential	$357	$356	$518	$366	$526
GS < 50kW	$1,155	$1,162	$1,699	$997	$1,726
GS 50-4,999 kW	$14,430	$14,958	$21,234	$13,241	$21,587
Other	$90	$95	$143	$140	$146
Total	**$489**	**$496**	**$719**	**$485**	**$731**

[1] Total revenue collected from rates is derived by applying approved IRM increases between 2010 and 2019 to the approved revenue collected from rates in 2010.

[2] External revenues are held constant at 2010 approved values.

[3] Estimated values for revenues related to LV charges have been added to the total distribution revenue collected (refer to Exhibit I, Tab 3, Schedule 9).

[4] Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.7% for 2025-2029.

[5] Total revenue collected (including external revenues) per Exhibit I, Tab 2, Schedule 17.

[6] Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus $0.6M in estimated revenue collected from the "combined classes").

[7] Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

Hydro One	Today (2019)[1]	Year 10 (2029) with consolidation[2,3]	Year 10 (2029) without consolidation[2,3]	Year 11 (2030) with consolidation[4]	Year 11 (2030) without consolidation[2,3]
Revenue Requirement					
Residential (UR)	$97,456,815	$121,420,723	$121,420,723	$137,202,655	$137,390,232
GS<50kW (UGe)	$23,037,678	$28,770,504	$28,770,504	$28,015,108	$28,054,505
GS>50kW (UGd)	$28,548,646	$35,752,868	$35,752,868	$31,919,505	$31,966,604
Other	$1,348,816,751	$1,685,459,484	$1,685,459,484	$1,709,828,767	$1,712,281,421
Total	**$1,497,859,890**	**$1,871,403,579**	**$1,871,403,579**	**$1,906,966,036**	**$1,909,692,763**
Revenue Requirement per Customer					
Residential (UR)	$424	$469	$469	$525	$526
GS<50kW (UGe)	$1,276	$1,520	$1,520	$1,471	$1,473
GS>50kW (UGd)	$16,413	$19,665	$19,665	$17,452	$17,478
Other	$1,275	$1,504	$1,504	$1,519	$1,521
Total	**$1,146**	**$1,337**	**$1,337**	**$1,354**	**$1,356**

[1] Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[2] Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.

[3] External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[4] Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus $0.6M in estimated revenue collected from the "combined classes").

b) Confirmed.

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ATTACHMENT 20

PDI Revenue Requirement Assumptions

The "Residual" (Hydro One) Cost to Serve and the "Status Quo" (PDI) Cost to Serve

The model used for the calculation of the Residual Cost to Serve revenue requirement (the revenue requirement calculated by Hydro One, forecasting the results assuming the transaction is approved) is based on the same model used by Hydro One in the calculation of the ESM sharing calculation presented in Exhibit A, Tab 3, Schedule 1.

The model used for the calculation of PDI's Status Quo Cost to Serve revenue requirement is provided by PDI and assumes business continues under their current operations and management model.

List of Assumptions:

- Year 11 OM&A and Capital expenditures for each scenario, Residual Cost to Serve or Status Quo Cost to Serve, are based on the applicable data set lines provided in **Exhibit A, Tab 2, Schedule 1**, Table 1, (adjusted for rounding), inflated by;
  - 2.0% for Hydro One's Residual Cost to Serve scenario %, and
  - For PDI's Status Quo Cost to Serve scenario
    - 2.0% for Capital
    - 2.5% for OM&A

  (i.e. the Year-10 value from **Exhibit A, Tab 2, Schedule 1**, Table 1 is inflated by the percentage (outlined above), applicable to the relevant Cost to Serve scenario, to arrive at Year 11 value).
- Rate Base is calculated based on PDI's 2019 Rate Base forecast.
- Year 1 of the deferred rebasing period for both Residual Cost to Serve and Status Quo Cost to Serve scenarios is assumed to be 2020.
- Rate Base in Year 1 of the Hydro One Residual Cost to Serve scenario, is calculated using the PDI 2019 forecast balance of PDI's NBV of Property, Plant and Equipment ("PP&E"), as acquired from PDI, less PDI's 2019 forecast balance of capital contributions, plus a calculation for working capital.
- Rate base applies the half-year rule. Capital expenditures are treated as 100% in-serviced in the year incurred.
- Working capital rate;
  - Residual Cost to Serve scenario – 7.70% per Hydro One's Distribution's 2018-2022 rate application (EB-2017-0049)

- Status Quo Cost to Serve scenario– 7.5% per OEB's default working capital allowance[1]
- Annual depreciation on the forecast Gross Book Value of PDI assets.
  - The Status Quo Cost to Serve scenario uses the average PDI depreciation rate which is equal to the rolling average of PDI's depreciation expense (actual and forecast) between 2017 and 2030. The average annual rate over the 2017 to 2030 period is approximately 4.0%. For 2030 specifically, that year's average depreciation rate is 3.7%.
  - The Residual Cost to Serve scenario uses Hydro One's OEB-approved depreciation rates.
- Interest expense
  - Residual Cost to Serve scenario (Hydro One rates)[2]
    - Long Term – 4.47%
    - Short Term – 2.29%
  - Status Quo Cost to Serve scenario (Peterborough Distribution rates)[3]
    - Long Term – 4.16%
    - Short Term – 2.29%
- ROE – 9.0% (Residual Cost to Serve and Status Quo Cost to Serve scenario are the same)
- Tax expense used for the Residual Cost to Serve and Status Quo Cost to Serve scenarios are the same; a combined Federal and Provincial tax rate of 26.5%.

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[1] OEB letter to All Licensed Electricity Distributors, '*Allowance for Working Capital for Electricity Distribution Rate Applications*' June 3, 2015

[2] EB-2017-0049 – Exhibit Q 1, Tab 1, Schedule 1

[3] Cost of Capital Parameter Updates for 2018 Cost of Service and Custom Incentive Rate-setting Applications dated November 23, 2017

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SEC INTERROGATORY # 29

Reference:

[Ex. A/5/1, p. 2 and Ex. A/4/1, Table 4, and Ex. I/1/27, p. 3]

Interrogatory:

SEC is concerned with understanding the underlying drivers of the claimed ratepayer savings. With respect to Table 1 in the Update and Table 4 in the pre-filed evidence, please provide a detailed breakdown, for each year, of the components of the "ratepayer savings" of $9.3 million.

Response:

Table 1 in Exhibit A, Tab 5, Schedule 1 shows the savings for PDI customers in Year 11. The LV charges under the status quo will be recovered through a separate rate whereas in the residual cost to serve these costs are recovered in revenue requirement.

The table below provides a breakdown of all revenue requirement components plus LV Charges that make up the savings levels discussed above. OM&A and LV Charges make up approximately 88% of the ratepayer savings. Please refer to Exhibit I, Tab 4, Schedule 7c) for an explanation of the OM&A driver savings.

($000s)	**Hydro One**	**PDI**	**Savings**
OM&A	4,311	12,269	(7,958)
Depreciation	4,106	6,193	(2,087)
Cost of Capital – Debt	2,679	2,350	329
Cost of Capital – Equity	3,717	3,494	223
Tax	807	607	200
Revenue Requirement (without LV Charges)	**15,620**	**24,913**	**(9,293)**
LV Charges	-	1,411	(1,411)
Cost to serve	**15,620**	**26,324**	**(10,704)**

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OEB STAFF INTERROGATORY # 11

Reference:
Exhibit A-4-1

Interrogatory:
Questions:

a) Please provide a table which compares indicative Hydro One and OPDC monthly electricity bills:

i. Today (e.g. 2019)
ii. In Year 10 with the proposed consolidation
iii. In Year 10 without the proposed consolidation
iv. In Year 11 with the proposed consolidation
v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, and General Service greater than 50 kW.

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, please ensure that they do.

c) Please also explain how costs have been allocated to OPDC customers in the response to part a) iv) above.

Response:

a) The tables below provide indicative monthly electricity bills for Hydro One Urban rate classes and OPDC's Residential and General Service customers for the requested scenarios. The total bill calculation excludes the "Rate Rider for Application of Tax Change" (Final Rate Order, EB-2018-0061) and ESM refund.

OPDC	Today - 2019		Year10 - With Consolidation[1]		Year10 - Without Consolidation[2]		Year11 - With Consolidation[3]		Year11 - Without Consolidation[2]	
	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]
Residential (750kWh)	$30.94	$112.48	$35.34	$117.10	$48.97	$131.41	$29.36	$110.82	$50.25	$132.75
GS < 50kW (2,000kWh)	$79.10	$292.72	$90.39	$304.58	$123.80	$339.66	$73.94	$287.30	$127.00	$343.02
GS 50 to 4,999 kW (250kW)	$721.15	$11,614.41	$879.44	$11,793.28	$1,284.63	$12,251.14	$734.51	$11,629.51	$1,316.50	$12,287.15

[1] Indicative distribution rates for year 10 (with consolidation) have been calculated by applying -1% to OPDC's existing rates then holding them constant for 2020-2024 and then applying IRM increase of 1.7% for 2025-2029 (refer to Exhibit I, Tab 6, Schedule 17).

[2] Indicative distribution rates for year 10 and year 11 (without consolidation) have been calculated using the percentage increase in rates revenue requirement compared to 2019 (refer to Exhibit I, Tab 1, Schedule 12).

[3] Indicative distribution rates for year 11 (with consolidation) have been derived through the rate design process consistent with the cost allocation model provided in Exhibit I, Tab 1, Schedule 10, Attachement 2

[4] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period

Hydro One	Today - 2019		Year10 - With Consolidation[1]		Year10 - Without Consolidation[1]		Year11 - With Consolidation[2]		Year11 - Without Consolidation[1]	
	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]
Residential (UR 750kWh)	$34.26	$121.77	$43.72	$131.71	$43.72	$131.71	$42.25	$130.17	$44.87	$132.92
GS < 50kW (UGe 2,000kWh)	$81.60	$306.91	$105.88	$332.41	$105.88	$332.41	$102.25	$328.60	$108.84	$335.52
GS > 50 kW (UGd 250kW)	$2,559.27	$30,087.07	$3,347.54	$30,977.82	$3,347.54	$30,977.82	$3,237.03	$30,852.95	$3,440.78	$31,083.18

[1] Indicative distribution rates for year 10 (with and without consolidation) and year 11 (without consolidation) have been calculated using the compound annual growth rate between 2018 and 2022 and then applying it to 2022 rates.

[2] Indicative distribution rates for year 11 (with consolidation) have been derived through the rate design process consistent with the cost allocation model provided in Exhibit I, Tab 1,Schedule 10, Attachement 2.

[3] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period.

b) Confirmed.

c) Hydro One has produced a Cost Allocation Model (CAM) for Year 11 (2030) which allocates the total costs to various customer classes including proposed rate classes for OPDC's Residential and General Service customers. Please refer to Exhibit I, Tab 1, Schedule 9 for details and assumptions for this CAM run.

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utilities.[299] Further, "ring fencing" does not avoid the issues of allocating common costs, or the fact that Hydro One no longer charges upstream distribution rates. [300]

Hydro One argued with respect to the use of external studies of its acquisition policies that the OEB does not regulate Hydro One's management of its business strategies. As a result, it would not be appropriate for the OEB to order a third-party review of its acquisition policies.[301]

Findings

The OEB finds that Hydro One's proposed cost allocation to the Acquired Utilities does not reflect the OEB's decisions in the related Hydro One acquisition proceedings.

In approving the acquisition of Norfolk, Haldimand and Woodstock,[302] the OEB directed Hydro One to maintain records of the cost to serve these utilities in order to inform the rate-setting process at the completion of the respective deferral periods. Hydro One has not maintained these records. Hydro One accepted the approvals but did not adhere to these conditions of approval. It is not acceptable to accept approval of a proposal without adhering to the direction that accompanied the approval. Hydro One did not seek to have the OEB vary its decisions to accommodate the departure from the OEB's directions that is illustrated in Hydro One's evidence in this rate-setting application

This rate-setting application now before the OEB was specifically identified in the acquisition proceeding decisions as Hydro One's opportunity to demonstrate that the cost structures it presented in making its case that the no harm test had been met had led to the anticipated rates for customers being lower than they otherwise would have been.

In the Norfolk acquisition decision,[303] the OEB provided its expectation that a downward impact on cost structures would tend to decrease rates, whereas an upward impact on cost structures would tend to increase rates.

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[299] The OEB's legislative authority arises from Section 86 of the *Ontario Energy Board Act, 1998.*

[300] Hydro One Reply Argument, page 167.

[301] Hydro One Reply Argument, page 167-168.

[302] EB-2013-0196/EB-2013-0187/EB-2013-0198 (Norfolk),EB-2014-0244 (Haldimand) and EB-2014-0213 (Woodstock).

[303] EB-2013-0196/EB-2013-0187/EB-2013-0198 *Decision and Order,* July 3, 2014, p. 16.

In the Norfolk decision, the OEB found that:

> Based on Hydro One's evidence and submissions, the Board considers it probable that there will be significant downward pressure on NDPI's OM&A and capital costs because of efficiencies due to geographic integration, economies of scale, integration of common administrative and management functions and asset management, lower financing costs and integrated planning of the distribution system.[304]

The OEB concluded in the Norfolk application that the Applicant had satisfied the no harm test and provided conditions. One of the conditions was as follows:

> That with its first rates application that includes costs associated with NPDI's service area, HONI file a report with the Board delineating:
>
> a. The costs for NPDI's service area tracked separately;
>
> b. The savings achieved as a result of the acquisition; and
>
> c. The portion of NPDI's and HONI's costs that are incremental costs incurred in connection with the acquisition.[305]

The Haldimand and Woodstock approvals contained similar determinations and conditions.[306]

Hydro One has not demonstrated that the evidence it relied on to gain approval of the acquisitions has led to no harm to the customers of the Acquired Utilities with respect to rates. Hydro One not only had the opportunity to do so, it was the OEB's expectation that it do so.

Hydro One has stated that the OEB reviewed and approved the acquisitions of the Acquired Utilities, and that the purpose of the current proceeding is not to re-open those OEB approvals. While a reversal of the approvals granted is not a consideration in this case, the basis of the OEB's approval of the acquisitions is now being tested in a tangible and impactful proposal for rates to be charged to all of Hydro One's customers. Hydro One's evidence related to its anticipated future costs to serve the Acquired

[304] *Ibid*, p. 21.
[305] *Ibid*, p. 25.
[306] EB-2014-0244 (Haldimand County Hydro Inc. Acquisition) *Decision and Order,* March 12, 2015, Section 3.1.1, p. 1 and Section 5, p. 3 and EB-2014-0213 (Woodstock Hydro Services Inc. Acquisition) *Decision and Order,* September 11, 2015, pp. 7-8 and p. 21.

Utilities that it provided in the acquisition proceedings has a direct bearing on the OEB's consideration of the appropriateness of Hydro One's rates proposed in this proceeding.

The OEB denies Hydro One's rates proposals with respect to the Acquired Utilities for the following reasons.

1) Hydro One's proposal contains simplistically derived and questionable estimates of revenue requirement comparisons to demonstrate adherence to the no harm requirement. The OEB accepts VECC's submission that given the wide range of past rate adjustments, the rebasing rate increase for any utility can vary widely from the 6.3% average.[307]

2) Hydro One's proposal is based on a cost allocation approach that recognizes the existing assets of the Acquired Utilities as being distinguishable and at a lower cost than its legacy assets by using adjustment factors. It intends to revisit this approach and proposes to recalibrate the adjustment factors over time as assets are renewed in the acquired service areas. The new assets will be included in Hydro One's existing asset pool at a higher cost and result in a lowering of the adjustment factors over time.

   OEB staff submitted that Hydro One's proposal is reasonable because the adjustment factors are, in effect, performing a direct allocation of assets and depreciation to the Acquired Utilities. OEB staff accepted that where costs associated with specific rate classes are known, direct allocation is appropriate. OEB staff submitted that Hydro One's proposal to use the adjustment factors for capital and the allocation of OM&A costs based on the cost allocation model is a reasonable proxy for reflecting the cost to serve.

   The OEB accepts that Hydro One's proposal adheres to some basic cost allocation principles that may be acceptable in a general sense. However, it is not acceptable to ignore the basis on which the approvals for acquiring the utilities were granted.

   As SEC argued, Hydro One's rate proposal is based on a snapshot of the existing asset base in the acquired service area. The OEB agrees and based on Hydro One's failure to demonstrate that its costs are the same or lower in its evidence,[308] finds that the proposal will result in one of the two following negative outcomes.

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[307] Exh. Q-1-1, Attach. 6, p. 1 Filed: 2017-12-21.
[308] Oral Hearing Transcript Volume 11, page 16-17.

a) In the absence of recalibration of the adjustment factors, an undue subsidy from Hydro One's legacy customers would be required.

b) In the situation where the calibration of the adjustment factors is commensurate with asset renewal at Hydro One's higher costs, harm in the form of relatively higher rates to the customers of the Acquired Utilities would need to be imposed.

3) Hydro One argued that its proposal adheres to previous OEB determinations with respect to treating the Acquired Utilities as separate rate classes and that its proposal to do so is in response to OEB direction. The OEB does not accept Hydro One's contention. The OEB has provided clear guidance with respect to its expectations that evidence of lower cost structures relied on in acquisition proposals are expected to result in concomitant lower rates. Hydro One would be expected to apply any distinguishable cost causation analysis relied on in an acquisition application to any customers that met the identified cost causation criteria whether they are new or legacy customers. The OEB did not direct Hydro One to isolate the Acquired Utilities in its cost allocation methodology. Hydro One has not demonstrated that its proposal is equitable to all customers.

4) Hydro One's cost allocation evidence indicates that in the absence of adjustment factors, Hydro One's long term costs to serve the Acquired Utilities are higher than the costs of those previous utilities. This is in direct contradiction to the evidence relied on in its acquisition proposals.

The OEB's approach to considering acquisition proposals has been articulated in previous decisions and related policy documents.[309] Most importantly for consideration in this application are the OEB findings in the acquisition approvals that are the subject of Hydro One's current rate proposal.

The Norfolk acquisition decision contained the OEB's rationale for focusing on comparative cost structures in its approach to facilitating effective and efficient utility consolidation. The following statements from that decision explain the OEB's expectations with respect to purchase offers and underpinning cost structures.

> The intent of the framework established by the 2007 Report is that the amount of a premium paid by a purchaser would be determined by the purchaser's ability to serve the acquired service area at a lower cost over a given period. The

[309] Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations,* January 19, 2016.

> difference between the actual cost of service and revenues generated during the given rate deferral period is intended to provide the purchaser with the funds to cover the transaction costs of the acquisition, including any premiums. This aspect of the framework acts as a positive economic factor in the consolidation marketplace by favoring the purchaser that is able to serve the acquired service area at the lowest cost. The Board's future rate setting (whether or not on a harmonized basis) will be based on forward costs, and a purchaser should not expect that the revenues from future rates will provide any funds to cover any purchase premium.[310]

It is clear that the OEB's framework for consolidations is intended to ensure costs to serve a given service area following an acquisition will be no higher than they otherwise would have been.

> In accordance with the 2007 Report, the Board's decision will not consider future rates at this time. However, as indicated in the Motion Decision, in applying the no harm test it is appropriate for the Board to assess the cost structures that will be introduced as a result of the acquisition, in comparison to the cost structures that underpin NPDI's current rates. A downward impact on cost structures would tend to decrease rates, whereas an upward impact on cost structures would tend to increase rates. This will occur regardless of what decision is taken concerning rate harmonization at the time of rate rebasing.[311]

It is clear that the OEB's framework for consolidations is focused on the comparison of proposed costs to serve a given service area with that of the incumbent's costs.

While the comparison of proposed costs is the main focus of consideration of an acquisition proposal, the OEB has found that all of its statutory objectives are considered in applying the no harm test. Quality of service and reliability, including the capacity to meet modern customer expectations, are also considered. The focus of the analysis regarding the Acquired Utilities in this proceeding is solely on the cost comparisons because the acquisition approvals relied on Hydro One's cost forecasts.

An objective of the OEB's consolidation framework is to ensure that the consolidation of the distribution sector results in beneficial outcomes for customers. The negative impacts of suboptimal consolidations are long lasting and stifling to economic

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[310] EB-2013-0196/EB-2013-0187/EB-2013-0198 *Decision and Order,* July 3, 2014, p. 15.
[311] *Ibid,* p. 16.

improvements in the sector due to the removal of opportunities for the optimal consolidation envisioned in the OEB framework.

Hydro One argued that the OEB does not regulate Hydro One's management of its business strategies. The OEB agrees, however, the OEB does have the mandate and responsibility to respond to the outcome of those strategies. If the outcome is counter to the public interest objective that was clearly articulated in the OEB's decisions approving Hydro One's proposed acquisitions, it is appropriate for the OEB to consider the consequences.

Hydro One's rates proposal in this proceeding does not reflect the OEB's determinations in its acquisition decisions. Hydro One had the opportunity to inform the OEB prior to completing its approved transactions if it did not anticipate being able to deliver on the OEB's clear expectations. The OEB finds that any shortfall in revenue requirement that results from Hydro One's costs being higher than its current and future approved revenues associated with the Acquired Utilities shall be absorbed by Hydro One and not form any part of the overall revenue requirement.

Hydro One may apply to the OEB for a rate adjustment mechanism under the Price Cap IR approach to be applied to the current base rates for the Acquired Utilities, to take effect at the end of the respective deferred rebasing periods.

The determination that Hydro One is to absorb revenue shortfalls associated with its cost to operate the Acquired Utilities eliminates the negative impact that Hydro One's rate proposal would have had on its customers. It does not however undo the negative impact that these acquisitions have caused to the smooth and effective consolidation of the sector.

The OEB has a mandate to ensure the financial viability of the sector. The OEB considers matters of consolidation to be of utmost importance to the financial viability of the sector. The ongoing cost of ownership of these entities to Hydro One and the lost opportunity for actual improvements in distribution sector efficiency are negative impacts that run counter to the objectives of the OEB's consolidation framework. The record of this proceeding and these determinations are available for consideration in future related OEB hearings.

Hydro One has included the cost of an integrated system operation centre (ISOC) to be built in Orillia in its stated revenue requirement. A question arose in this proceeding with respect to the relationship between Hydro One's intent to construct the ISOC and its proposal to acquire Orillia Power Distribution Corporation (OPDC).[312] Hydro One's evidence in this proceeding is that it intends to construct the ISOC irrespective of whether or not it acquires OPDC. Hydro One also filed evidence supporting the Orillia location as the recommended alternative.

The OEB takes note of this issue here as it relates to the consolidation framework that the OEB has put in place. Hydro One has a major presence in the province with its transmission and distribution systems being the most expansive network in the province. Hydro One has many efficient and effective options for facility placements to meet its ongoing needs. Local economic development associated with the siting of these facilities is not a determinative consideration for the OEB in approving acquisitions, or in approving rates to cover the associated cost. In Hydro One's case, with its numerous efficient placement options, the positive economic development will occur wherever the facility is situated. The OEB's consideration of long-term acquisition-related impact on rates is not influenced by Hydro One's choice of the location of new facilities and the concomitant local shareholder's motivation to sell.

The OEB directs Hydro One to place the revenue requirement associated with the forecast cost of this ISOC in an asymmetric variance account to be offset by the revenue requirement at the actual cost. If the revenue requirement at the actual cost is lower than the revenue requirement at the forecast cost, Hydro One will be required to return the difference to its customers. The account balance will be considered for disposition in Hydro One's next rebasing application.

3.10 DEFERRAL AND VARIANCE ACCOUNTS

3.10.1 Disposition of Balances (Issue 57)

Hydro One is seeking to dispose of a total debit balance of $8.3 million with respect to its deferral and variance accounts, representing the principal balances in its Group 1 accounts as of December 31, 2014 and Group 2 accounts as of December 31, 2016, with interest calculated to December 31, 2017.

In its original application, Hydro One sought disposition of its Group 1 and 2 principal balances as of December 31, 2016. However, the OEB issued a letter to Hydro One indicating that it will be undertaking an audit of Hydro One's Regulated Price Plan

[312] On April 12, 2018, the OEB issued its EB-2016-0276 *Decision and Order* denying Hydro One's application to acquire OPDC. On September 26, 2018, Hydro One filed a new application (EB-2018-0270) to acquire OPDC. This is presently under review by the OEB.