EXHIBIT 7

COST ALLOCATION

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Exhibit 7: Cost Allocation

Tab 1 (of 3): Cost Allocation Study

OVERVIEW OF COST ALLOCATION

7.1 Cost Allocation Study Requirements

7.1.1 Introduction

The OEB outlined its cost allocation policies in its reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors, and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219). These are referred to here as the "Cost Allocation Reports".

In this Application, NPEI has used the 2020 version 3.7 of the Cost Allocation Model released by the OEB on August 1, 2019 to conduct a 2021 Test Year Cost Allocation study consistent with the OEB's cost allocation policies. The model has been loaded with 2021 Test Year Costs, customer numbers and demand values for NPEI. The 2021 demand values were determined based on the description provided under the Load Profiles section of this Exhibit. The various weighting factors used in the 2021 study have also been explained below.

7.1.2 Load Profiles

In a letter dated June 12, 2015, the OEB requested "distributors to be mindful of material changes to load profiles and propose updates, as appropriate, in cost of service rate applications". NPEI proposes to use the same method as was used in the 2015 Cost of Service application to determine the demand data for the 2021 cost allocation model. This method involves applying a scaling factor to the 2004 weather normalized volumes supporting the 2004 load profiles to determine an estimate of the 2021 weather normalized load profiles. Then the same method applied by Hydro One to the 2004 load profiles to determine the demand data for the original cost allocation study, is applied to the 2021 load profiles to determine the 2021 demand data. NPEI has provided an Excel spreadsheet named "Load profile model 2004 Hydro One data for 2021" to show how the 2021 demand data is determined.

NPEI is the result of the amalgamation of the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd. The former Peninsula West Utilities Ltd. filed a Cost Allocation Informational Filing on March 15, 2007 (EB-2005-0405) (EB-2007-0002). The former Niagara Falls Hydro Inc. prepared its load profiles for all rates classes and received RUN1 data from Hydro One for its hourly load shapes, however NFH did not file a Cost Allocation Informational Filing in 2007 as they were preparing the merger application and considered it to be more useful, prudent and practical to file a Cost of Service Study at the time of rebasing and harmonizing rates for the new merged company. NPEI filed a Cost Allocation Study with the 2011 Cost of Service rate application. The 2011 Cost Allocation Study was based on information from the amalgamated companies. NPEI also filed a Cost Allocation Study with the 2015 Cost of Service rate application.

NPEI attempted to update the actual hourly data by rate class for the 2018 year. NPEI had significant differences in the GS<50 kW and GS > 50 kW rate classes when compared to the actual kWh billed. This was due to many customers having conventional meters in both of these rate classes. NPEI replaced these conventional meters with either a MIST meter or smart meter throughout 2016, 2017, 2018, 2019 and have replaced 23 in 2020. As a result, NPEI will be prepared for the next cost of service application. NPEI will put in place a process to prepare a load profile for the 2020 year. This will provide more than one year of data to review the load profiles for the next cost of service application.

7.1.3 Cost Allocation Inputs

In the March 31, 2011 Cost Allocation Report, the OEB stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are expected to develop their own weighting factors as part of their cost allocation study. NPEI has developed its own weighting factors as outlined below.

Services (Account 1855)

To determine the weighting factor to be used for each customer class, the cost of installing a typical service for each customer class was determined. A weighting factor was determined by assigning the Residential customer class a factor of 1, as required, and determining the relative weights of the rest of the classes. The results are presented in Table 7.1.3-1 below:

Table 7.1.3-1-Weighting Factors-Services

	2021 Test Year	2015 Board Approved
Residential	1.0	1.0
GS<50 kW	2.5	2.5
GS>50 kW	9.0	9.0
Streetlight	0.0	0.0
Sentinel Light	0.0	0.0
Unmetered Scattered Load	0.0	0.0

GS < 50 kW – Factor set at 2.5. A work order for a new service for a small commercial customer usually has more parties including third parties involved, additional approvals, and additional time spent as these services are usually more complex than a residential customer.

GS > 50 kW – Factor set at 9.0. A work order for a new service for a large commercial customer is more complex, involves more resources, requires additional approvals and additional time spent.

Billing and Collecting

Comparing a residential bill as a base of 1, NPEI reviewed the time spent in billing and customer service and collections on customers in each rate class. NPEI has found that with TOU billing now in place, there are no major differences in rate class billing costs between the residential rate class and the GS<50 kW rate class. There are additional steps in billing when billing GS>50 kW customers with respect to interval read analytics, global adjustment etc. In terms of collection costs, there are a lower number of customers in this class to collect on however, due to the higher dollar values associated with these customers these customers are first priority in monitoring outstanding balances. Also, with GS > 50 kW customers, there is usually more parties involved in the follow up process for collections, notices, and payment arrangements thereby taking more time to collect than a residential customer. In 2017, NPEI received its first Class A customers, where determination of eligibility, education, and on-going customer engagement with many customers in the GS > 50 kW rate class occurred. NPEI reviews on a quarterly basis the load for GS<50 kW customers and GS >50 kW customers to ensure they are in the appropriate rate class. This review as well as the actual transfer of a customer from one rate class to another does not occur with the residential rate class thereby increasing the factor for the GS <50 kW and GS >50 kW rate class when compared to the residential rate class.

NPEI has assigned the following factors;
Residential Service - factor set at 1 per Cost Allocation Instruction

GS< 50 kW – Factor set at 1.5 as there is more time spent when collections are involved on a per bill basis and these customers are reviewed quarterly for appropriateness of rate class based on their load. Billing costs are similar to residential customers for those GS<50 customers on smart meters.

GS > 50 kW – Factor set at 2.0 as there is more time spent on both billing and collection on a per bill basis when issues arise. As well these customers are reviewed quarterly for appropriateness of rate class based on their load. The billing is more complex than the

TOU billing for a residential customer and customer engagement meetings are held for eligible Class A customers.

Streetlight, unmetered loads and sentinel lights – a factor of 0.8 has been assigned as these customers have limited collection activity.

Table 7.1.3-2-Weighting Factors-Billing and Collecting

	2021 Test Year	2015 Board Approved
Residential	1.0	1.0
GS<50 kW	1.5	1.5
GS>50 kW	2.0	2.0
Streetlight	0.8	0.8
Sentinel Light	0.8	0.8
Unmetered Scattered Load	0.8	0.8

Metering Capital-Sheet 1.7.3.3

NPEI followed a similar approach as in the COS 2015 whereby the various types of meters installed were identified and the number of meters installed at the end of 2019 were identified from NPEI's customer information system. The cost to install meters has increased due to the replacement of all 2G technology meters, and the replacement of conventional meters with either a MIST meter or a new smart meter.

Table 7.1.3-3 Metering Capital

	Weighting Factor 2021	Weighting Factor 2015	Weighted average Cost Per Meter 2021	Weighted average Cost Per Meter 2015	$ Change	% Change
Residential	1.00	1.00	157.44	118.55	38.89	32.80%
GS < 50 kW	1.69	1.74	265.86	206.05	59.81	29.03%
GS > 50 kW	21.63	19.08	3,405.95	2,261.47	1,144.48	50.61%

Meter Reading-Sheet I-7.1.3.4

NPEI will have all of the conventional meters replaced with either a smart meter or a MIST meter by August 1, 2020. As at March 31, 2020, NPEI had two MIST meters, and 30 smart meters remaining to be changed from conventional meters to electronically read meters. The conversion of the 600 volt meters requires the assistance of an outside electrician. Meter reading costs for smart meters have been assigned a weighting factor of one. As shown in Table 7.1.3-4 below, the effort and cost for reading other types of meters are compared to the smart meter reading costs to determine an appropriate weight.

Table 7.1.3-4 – Meter Reading Weights

	Cost Relative To Residential Average Cost 2021 Test Year	Cost Relative To Residential Average Cost 2015 Board Approved	Average Monthly Meter Reading Costs 2021 Test Year	Average Monthly Meter Reading Costs 2015 Board Approved	Allocation Percentage Weighting Factor 2021 Test Year	Allocation Percentage Weighting Factor 2015 Board Approved
Residential	1.00	1.00	$ 0.52	$ 0.32	38.13%	45.91%
GS < 50 kW	5.63	3.07	$ 2.92	$ 0.99	18.76%	13.17%
GS > 50 kW	72.50	48.05	$ 37.65	$ 15.41	43.11%	40.92%

On average the costs to read the meter for the GS < 50 kW and GS > 50 kW rate classes have increased as a result of the switch from a conventional meter to a MIST meter or the conversion from a conventional meter to a smart meter. The costs related to meter reading NPEI's distribution stations and transformer station are included in Account 5310 but for purposes of cost allocation, these expenses have been excluded. The 2021 Test Year includes a total of $869,478 for total meter reading expenses however only $848,898 is allocated to the rate classes on Sheet I7.2 of the Cost Allocation model.

7.1.4 Embedded Distributor

NPEI is not a host distributor for any embedded distributor.

7.1.5 Unmetered Loads

NPEI communicates with unmetered load customers, including streetlighting customers, to assist them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers. This communication takes place on an on-going basis and is not driven by the rate application process.

NPEI has used the "streetlight adjustment factor" to allocate costs to the Streetlighting rate class as outlined in the OEB's June 12, 2015 letter. The streetlight revenue to cost ratio range was tightened as well. Table 7.1.5-1 below outlines the changes from the 2015 Board Approved to the 2021 Test Year.

Table 7.1.5-1 – Unmetered connections

	2021 Test Year	2015 Board Approved
Streetlight	93	1,299
Sentinel	298	303
Unmetered Scattered Load ("USL")	325	422

7.1.6 microFIT class

NPEI is not proposing to include microFIT as a separate class in the cost allocation model in 2021. NPEI understands that the cost allocation model will produce a calculation of unit costs which the OEB may use to update the uniform microFIT rate at a future date.

7.1.7 New Customer Class

NPEI is not proposing to include a new customer class in this Application.

7.1.8 Eliminate a Customer Class

NPEI is not proposing to eliminate a customer class in this Application.

7.1.9 Standby Rates

On April 2, 2015 the OEB issued a Board Policy of Rate Design for Electricity Residential Customers in which the Board stated that it intends to remove the standby charge when the new rate policy is implemented for commercial customers. To date, a new rate policy for commercial customers has not been implemented. Currently, NPEI does not have a standby rate and NPEI is not proposing a new standby rate in this Application.

7.1.10 Sheet I6.2 Customer Data Worksheet

The Bad Debt Data entered is actually for the Historical Years 2016, 2017, and 2018. The cells identifying the historical year are locked and do not allow for input. In summary, the 2016 Bad Debt total was $218,352, 2017 Bad Debt total was $$263,168 and 2018 Bad Debt total was $ 308,528.

Exhibit 7: Cost Allocation

Tab 2 (of 3): Class Revenue Requirements

CLASS REVENUE REQUIREMENTS

7.2.1 Class Revenue Requirements

The data used in the updated cost allocation study is consistent with NPEI's cost data that supports the proposed 2021 Test Year revenue requirement outlined in this Application. NPEI's assets were broken out into primary and secondary distribution functions using updated breakout percentages. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to NPEI, its engineering records, and its customer and financial information systems.

A live Excel version of the updated cost allocation study has been included with the filed application material (EB-2020-0040_NPEI_Appl_2020_Cost_Allocation_Model_20200430). In addition, Appendix 7-1 outlines Input Sheets I-6 and I-8 and Output Sheets O-1 and O-2 (first page only).

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2021 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2021 customer forecast outlined in Exhibit 3.

The following Table 7.2-1 provides the combined allocated OEB Approved cost by rate class from the former 2015 cost allocation study along with the NPEI results from the 2021 cost allocation study.

Table 7.2-1 – Allocated Costs

	2015 Board Approved Allocation Study	%	2021 Proposed Cost Allocation Study	%
Residential	20,747,538	69.2%	26,201,616	69.2%
GS < 50 kW	3,173,270	10.6%	4,058,338	10.7%
GS > 50 kW	5,536,411	18.5%	7,261,574	19.2%
Sentinel Lighting	88,456	0.3%	91,375	0.2%
USL	108,156	0.4%	91,894	0.2%
Street Lighting	316,689	1.1%	135,878	0.4%
Total	29,970,520	100.0%	37,840,675	100.0%

Exhibit 7: Cost Allocation

Tab 3 (of 3): Revenue-to-Cost Ratios

REVENUE TO COST RATIOS

7.3 Revenue-to-Cost Ratio Overview

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the March 31, 2011 Cost Allocation Board Report, the Board established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7.3-1 below. The Streetlight class is shown with the targets as established in the OEB's June 12, 2015 letter. In addition, Table 7.3-1 provides the approved revenue to cost ratios from NPEI's 2015 Cost of Service (EB-2014-0096) compared to the proposed ratios and the OEB Min and Max targets.

Table 7.3-1 – Revenue-to-Cost Ratios

	2015 Board Approved Cost Allocation Study	2021 Cost Allocation Study	2021 Proposed Ratios	OEB Target	
				Min	Max
Residential	91.65%	94.24%	94.24%	85%	115%
GS < 50 kW	120.00%	116.96%	116.96%	80%	120%
GS > 50 kW	120.00%	108.82%	110.71%	80%	120%
Sentinel Lighting	119.83%	126.04%	120.00%	80%	120%
Unmetered Scattered Load	91.65%	96.43%	96.43%	80%	120%
Street Lighting	91.65%	217.09%	120.00%	80%	120%

7.3.1 Cost Allocation Results and Analysis

The 2021 Cost Allocation study shows that the Residential, GS < 50 kW, GS > 50 kW, and Unmetered Scattered Load rate classes fall within the OEB target range. The Sentinel Lighting and Street Lighting rate classes resulted in revenue-to-cost ratios above the OEB's Max target. NPEI is proposing to use the Max target revenue-to-cost ratio for these two rate classes. As a note, the GS > 50 kW rate class is the balancing class.

Table 7.3-2 below shows the proposed class revenue for this Application. This class revenue will be used in Exhibit 8 to design the proposed distribution charges for this Application.

Table 7.3-2 – Calculated Class Revenue

	2021 Base Revenue at Existing Rates	2021 Proposed Base Revenue Allocated at Existing Rates Proportion	2021 Proposed Base Revenue	Miscellaneous Revenue
Residential	20,983,817	22,531,540	22,531,540	2,161,859
GS < 50 kW	4,114,496	4,417,972	4,417,972	328,862
GS > 50 kW	6,928,887	7,439,947	7,577,389	461,736
Sentinel Lighting	76,021	81,628	81,628	5,321
Unmetered Scattered Load	102,299	109,845	104,329	6,984
Street Lighting	268,595	288,406	156,479	6,575
	32,474,115	34,869,338	34,869,338	2,971,337

Appendix 7-1
OEB Cost Allocation Model – Sheets I6, I8, O1 and O2 (first page only)

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2020 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet - Hydro One prepared

Total kWhs from Load Forecast	1,286,841,405
Total kWs from Load Forecast	1,788,455
Deficiency/sufficiency (RRWF 8. cell F51)	- 2,395,224
Miscellaneous Revenue (RRWF 5. cell F48)	2,971,337

Billing Data

			1	2	3	7	8	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Forecast kWh	**CEN**	1,286,841,405	454,614,210	131,961,769	694,096,099	4,469,101	218,613	1,481,614
Forecast kW	**CDEM**	1,788,455			1,775,257	12,545	653	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		773,798			773,798			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	1,286,841,405	454,614,210	131,961,769	694,096,099	4,469,101	218,613	1,481,614

Existing Monthly Charge			$33.67	$40.15	$109.12	$1.26	$18.03	$20.73
Existing Distribution kWh Rate			$0.0000	$0.0146				$0.0144
Existing Distribution kW Rate					$3.5671	$4.9783	$22.4995	
Existing TOA Rate					$0.60			
Additional Charges								
Distribution Revenue from Rates		$32,938,394	$20,983,817	$4,114,496	$7,393,166	$268,595	$76,021	$102,299
Transformer Ownership Allowance		$464,279	$0	$0	$464,279	$0	$0	$0
Net Class Revenue	**CREV**	$32,474,115	$20,983,817	$4,114,496	$6,928,887	$268,595	$76,021	$102,299

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2020 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet - Hydro One prepared

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$263,350	$219,413	$31,456	$12,481	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$370,875	$257,083	$43,650	$69,968	$69	$6	$98
Number of Bills	CNB	690,720	623,220	54,492	9,720	84	3,024	180
Number of Devices	CDEV					13,634		
Number of Connections (Unmetered)	CCON	703				94	283	325
Total Number of Customers	CCA	57,560	51,935	4,541	810	7	252	15
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	57,837	51,935	4,541	810	551		
Line Transformer Customer Base	CCLT	57,760	51,935	4,519	755	551		
Secondary Customer Base	CCS	57,253	51,935	4,541	777			
Weighted - Services	CWCS	70,281	51,935	11,353	6,993	-	-	-
Weighted Meter -Capital	CWMC	12,142,719	8,176,646	1,207,256	2,758,817	-	-	-
Weighted Meter Reading	CWMR	848,898	323,646	159,295	365,957	-	-	-
Weighted Bills	CWNB	727,028	623,220	81,738	19,440	67	2,419	144

Bad Debt Data

		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Historic Year:	2015	218,352	177,126	41,081	144			
Historic Year:	2016	263,168	211,047	16,343	35,778			
Historic Year:	2017	308,528	270,066	36,943	1,519			
Three-year average		**263,350**	**219,413**	**31,456**	**12,481**	**-**	**-**	**-**

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2020 Cost Allocation Model

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Sheet I8 Demand Data Worksheet - Hydro One prepared

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
			1	2	3	7	8	9
		CP Sanity Check	Pass	Pass	Check 4CP	Check 12CP	Check 12CP	Check 12CP
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	236,858	98,744	29,932	108,182	-	-	-
Bulk Delivery CP	BCP1	236,858	98,744	29,932	108,182	-	-	-
Total Sytem CP	DCP1	236,858	98,744	29,932	108,182	-	-	-
4 CP								
Transformation CP	TCP4	903,634	381,463	86,786	435,385	-	-	-
Bulk Delivery CP	BCP4	903,634	381,463	86,786	435,385	-	-	-
Total Sytem CP	DCP4	903,634	381,463	86,786	435,385	-	-	-
12 CP								
Transformation CP	TCP12	2,379,403	966,519	229,417	1,175,237	6,108	276	1,845
Bulk Delivery CP	BCP12	2,379,403	966,519	229,417	1,175,237	6,108	276	1,845
Total Sytem CP	DCP12	2,379,403	966,519	229,417	1,175,237	6,108	276	1,845
NON CO_INCIDENT PEAK								
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP								
Classification NCP from Load Data Provider	DNCP1	257,419	101,625	36,507	117,685	1,043	77	481
Primary NCP	PNCP1	257,419	101,625	36,507	117,685	1,043	77	481
Line Transformer NCP	LTNCP1	#DIV/0!	101,625	36,330	109,694	1,043	77	481
Secondary NCP	SNCP1	586,796	101,625	36,330	447,240	1,043	77	481
4 NCP								
Classification NCP from Load Data Provider	DNCP4	986,244	393,041	120,797	466,234	4,167	260	1,744
Primary NCP	PNCP4	986,244	393,041	120,797	466,234	4,167	260	1,744
Line Transformer NCP	LTNCP4	954,001	393,041	120,212	434,577	4,167	260	1,744
Secondary NCP	SNCP4	966,664	393,041	120,212	447,240	4,167	260	1,744
12 NCP								
Classification NCP from Load Data Provider	DNCP12	2,568,026	1,037,817	261,371	1,251,598	12,361	628	4,252
Primary NCP	PNCP12	2,568,026	1,037,817	261,371	1,251,598	12,361	628	4,252
Line Transformer NCP	LTNCP12	2,481,775	1,037,817	260,105	1,166,613	12,361	628	4,252
Secondary NCP	SNCP12	2,517,035	1,037,817	261,371	1,200,607	12,361	628	4,252

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Sheet O1 Revenue to Cost Summary Worksheet - Hydro One prepared

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue at Existing Rates	$32,474,115	$20,983,817	$4,114,496	$6,928,887	$268,595	$76,021	$102,299
mi	Miscellaneous Revenue (mi)	$2,971,337	$2,161,859	$328,862	$461,736	$6,575	$6,984	$5,321
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$35,445,452	$23,145,676	$4,443,358	$7,390,622	$275,170	$83,005	$107,620
	Factor required to recover deficiency (1 + D)	1.0738						
	Distribution Revenue at Status Quo Rates	$34,869,338	$22,531,540	$4,417,972	$7,439,947	$288,406	$81,628	$109,845
	Miscellaneous Revenue (mi)	$2,971,337	$2,161,859	$328,862	$461,736	$6,575	$6,984	$5,321
	Total Revenue at Status Quo Rates	$37,840,675	$24,693,399	$4,746,835	$7,901,683	$294,981	$88,612	$115,166
	Expenses							
di	Distribution Costs (di)	$6,872,765	$4,466,838	$710,448	$1,622,401	$34,312	$16,349	$22,416
cu	Customer Related Costs (cu)	$7,296,377	$5,764,190	$879,327	$631,376	$695	$19,064	$1,725
ad	General and Administration (ad)	$6,214,868	$4,451,134	$691,149	$1,028,673	$16,866	$15,501	$11,545
dep	Depreciation and Amortization (dep)	$8,442,650	$5,593,534	$865,007	$1,900,969	$38,250	$19,037	$25,852
INPUT	PILs (INPUT)	$334,085	$219,632	$33,816	$77,022	$1,696	$813	$1,106
INT	Interest	$2,887,958	$1,898,578	$292,322	$665,810	$14,659	$7,030	$9,559
	Total Expenses	$32,048,704	$22,393,906	$3,472,070	$5,926,252	$106,478	$77,795	$72,204
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$5,791,971	$3,807,710	$586,269	$1,335,321	$29,400	$14,099	$19,171
	Revenue Requirement (includes NI)	$37,840,675	$26,201,616	$4,058,338	$7,261,574	$135,878	$91,894	$91,375
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$309,864,707	$205,200,479	$31,384,057	$69,895,803	$1,564,338	$772,730	$1,047,299
gp	General Plant - Gross	$52,281,699	$34,665,707	$5,345,730	$11,707,446	$260,588	$128,320	$173,906
accum dep	Accumulated Depreciation	($157,819,664)	($104,111,167)	($15,780,508)	($36,171,626)	($815,060)	($399,420)	($541,883)
co	Capital Contribution	($47,704,186)	($32,642,599)	($5,069,054)	($9,494,976)	($217,238)	($119,842)	($160,477)
	Total Net Plant	$156,622,556	$103,112,421	$15,880,226	$35,936,647	$792,628	$381,788	$518,846
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$157,344,654	$55,805,347	$16,126,675	$84,660,148	$545,104	$26,665	$180,715
	OM&A Expenses	$20,384,010	$14,682,162	$2,280,924	$3,282,450	$51,873	$50,914	$35,686
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$177,728,664*	*$70,487,509*	*$18,407,599*	*$87,942,598*	*$596,978*	*$77,579*	*$216,401*
	Working Capital	$13,329,650	$5,286,563	$1,380,570	$6,595,695	$44,773	$5,818	$16,230
	Total Rate Base	$169,952,205	$108,398,984	$17,260,796	$42,532,341	$837,402	$387,607	$535,076
		Rate Base Input equals Output						
	Equity Component of Rate Base	$67,980,882	$43,359,594	$6,904,318	$17,012,937	$334,961	$155,043	$214,030
	Net Income on Allocated Assets	$5,791,971	$2,299,494	$1,274,765	$1,975,431	$188,502	$10,818	$42,962
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$5,791,971	$2,299,494	$1,274,765	$1,975,431	$188,502	$10,818	$42,962

Ontario Energy Board

2020 Cost Allocation Model

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Sheet O1 Revenue to Cost Summary Worksheet - Hydro One prepared

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**94.24%**	**116.96%**	**108.82%**	**217.09%**	**96.43%**	**126.04%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**($2,395,224)**	($3,055,940)	$385,020	$129,049	$139,291	($8,889)	$16,245
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**$0**	($1,508,217)	$688,497	$640,109	$159,102	($3,282)	$23,791
RETURN ON EQUITY COMPONENT OF RATE BASE	8.52%	5.30%	18.46%	11.61%	56.28%	6.98%	20.07%

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2020 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Hydro One prepared

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$7.35	$13.29	$79.28	$0.33	$3.95	$0.32
Customer Unit Cost per month - Directly Related	$10.35	$18.77	$109.70	$0.56	$5.70	$0.49
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$33.76	$47.98	$168.64	$76.01	$26.92	$17.90
Existing Approved Fixed Charge	$33.67	$40.15	$109.12	$1.26	$18.03	$20.73

Appendix 7-2
OEB RRWF – Sheets 11 and 12 (Cost Allocation)

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Revenue Requirement Workform (RRWF) for 2020 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 20,940,354	69.18%	$ 26,201,616	69.24%
2	General Service < 50 kW	$ 3,203,396	10.58%	$ 4,058,338	10.72%
3	General Service > 50 kW	$ 5,604,282	18.52%	$ 7,261,574	19.19%
4	Unmetered Scattered Load	$ 109,566	0.36%	$ 91,375	0.24%
5	Sentinel	$ 89,264	0.29%	$ 91,894	0.24%
6	Streetlight	$ 320,851	1.06%	$ 135,878	0.36%
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20					
	Total	$ 30,267,713	100.00%	**$ 37,840,675**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 37,840,675.30**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 20,983,817	$ 22,531,540	$ 22,531,540	$ 2,161,859
2	General Service < 50 kW	$ 4,114,496	$ 4,417,972	$ 4,417,972	$ 328,862
3	General Service > 50 kW	$ 6,928,887	$ 7,439,947	$ 7,577,389	$ 461,736
4	Unmetered Scattered Load	$ 102,299	$ 109,845	$ 104,329	$ 5,321
5	Sentinel	$ 76,021	$ 81,628	$ 81,628	$ 6,984
6	Streetlight	$ 268,595	$ 288,406	$ 156,479	$ 6,575
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	Total	$ 32,474,115	$ 34,869,338	$ 34,869,338	$ 2,971,337

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential	91.65%	94.24%	94.24%	85 - 115
2	General Service < 50 kW	120.00%	116.96%	116.96%	80 - 120
3	General Service > 50 kW	120.00%	108.82%	110.71%	80 - 120
4	Unmetered Scattered Load	119.83%	126.04%	120.00%	80 - 120
5	Sentinel	91.65%	96.43%	96.43%	80 - 120
6	Streetlight	91.65%	217.09%	120.00%	80 - 120
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(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [(11)]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2021	2022	2023	
1	Residential	94.24%	94.24%	94.24%	85 - 115
2	General Service < 50 kW	116.96%	116.96%	116.96%	80 - 120
3	General Service > 50 kW	110.71%	110.71%	110.71%	80 - 120
4	Unmetered Scattered Load	120.00%	120.00%	120.00%	80 - 120
5	Sentinel	96.43%	96.43%	96.43%	80 - 120
6	Streetlight	120.00%	120.00%	120.00%	80 - 120
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(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2020 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2021 and 2022 Price Cap IR models, as necessary. For 2021 and 2022, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	51,935
kWh	454,614,210

Proposed Residential Class Specific Revenue Requirement[1]	$ 22,531,540.39

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 33.67
Distribution Volumetric Rate ($/kWh)	$ -

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	33.67	51,935	$ 20,983,817.40	100.00%
Variable	0	454,614,210	$ -	0.00%
TOTAL	-	-	$ 20,983,817.40	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	0

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 22,531,540.39	36.15	$ 22,529,403.00
Variable	$ -	0	$ -
TOTAL	$ 22,531,540.39	-	$ 22,529,403.00

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. The change in residential rate design is almost complete and distributors should have either 0 or 1 year remaining. If the distributor has fully transitioned to fixed rates put "0" in cell D40. If the distributor has proposed an additional transition year because the change in the residential rate design will result in the fixed charge increasing by more than $4/year, put "1" in cell D40.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)