File Number: EB-2015-0083

Date Filed: June 1, 2015

Exhibit 7

COST ALLOCATION

File Number: EB-2015-0083

Date Filed: June 1, 2015

Exhibit 7

Tab 1 of 3

Cost Allocation Study Requirements

Cost Allocation Study

COST ALLOCATION STUDY REQUIREMENTS

Kingston has followed the guidance in the "*Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011*" ("Cost Allocation Policy") and has prepared a Cost Allocation Study ("CAS) for each of the five test years using the Board's v 3.2 Cost Allocation Model ("Board 3.2 CA Model"). The Board 3.2 CA Model has been used to determine the proportion of Kingston Hydro's total revenue requirement that is recoverable from each customer class in each of the test years 2016 - 2020. The revenue-to-cost ratio for each customer class for each test year has been determined using the customer class revenues over costs in each respective test year.

Kingston Hydro engaged the services of Elenchus Research Associates Inc. ("ERA") to provide an appropriate cost allocation study for its 2016 - 2020 Custom IR rate application that is consistent with Section 2.10 Cost Allocation of the Board's Chapter 2 Filing Requirements for Electricity Distribution Companies' Cost of Service Rate Applications Based on a Forward Test Year issued July 18, 2014.

The final report from ERA is filed as *Kingston Hydro 2016 – 2020 Cost Allocation Study ("The CA Report")* in this Exhibit 7 under Tab 1 Schedule 1.

By test year, for each of the test years 2016 through 2020, Input sheets I-6, I-8, Output O-1 and O-2 have been provided under Tab 1 Schedule 2 of this Exhibit. And further the live Excel versions of the 2016-2020 CA models referenced in this Exhibit have been filed with this application. Kingston Hydro's proposed revenue allocation and the

resultant revenue to cost ratios for each of the test years 2016 – 2020 are discussed in Tab 3 of this Exhibit.

Unmetered Load is discussed in Exhibit 7 Tab 2.

Weighting Factors for Service and Billing Costs

In the Cost Allocation Policy Report, the Board stated that weighting factors are included in the Cost Allocation model to ensure that certain costs related to customer classes are properly assigned to the respective classes. The Board also stated that distributors are expected to develop their own weighting factors to be used in the Cost Allocation model. Distributors should only use the default weighting factors under exceptional situations.

Kingston has chosen to develop its own weighting factors for allocation of certain costs rather than use the default weighting factors and has used them in the Cost Allocation models for test years 2016 through 2020. Kingston has used its own weighting factors for Services, and Billing and Collecting.

Services: The Services weighting factors were developed based on Kingston Hydro conducting an evaluation of the costs of providing services to the customer classes.

	Residential	GS <50 kW	GS 50 to 4,999 kW	Large Use	Street Light	Unmetered Scattered Load
Services Weighting Factors	1.0	2.5	7.8	11.5	0.0	0.2

Billing and Collecting: The Billing and Collecting weighting factors used in Kingston's cost allocation models were updated according to Kingston's information on such for each customer class.

		Residential	GS <50 kW	GS 50 to 4,999 kW	Large Use	Street Light	Unmetered Scattered Load
1	Billing and Collecting Weighting Factors	1.0	1.0	10.7	10.4	0.7	0.7

File Number:EB-2015-0083

Exhibit: 7
Tab: 1
Schedule: 1

Date Filed: June 1, 2015

Attachment 1 of 1

Cost Allocation Study

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Kingston Hydro 2016-2020 CA - Custom IR

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Kingston Hydro

25/05/2015

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Table of Contents

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1 INTRODUCTION

Kingston Hydro Corporation ("Kingston Hydro") has prepared its 2016-2020 Custom IR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the July 18, 2014 update to the document entitled *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications* ("Filing Requirements").

Section 2.10 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements on page 48 state:

> *A completed cost allocation study using the Board-approved methodology or a comparable model must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Microsoft Excel spreadsheets. The most current update of the model (version 3.2) will be available on the Board's web site. Appendix 2-P must also be completed.* [1]

Kingston Hydro asked Elenchus Research Associated (Elenchus)[2] to assist it by preparing an appropriate cost allocation study for its 2016-2020 Custom IR rate application.

In addressing the cost allocation issues, Elenchus was guided by the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[3] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report") in which the Board narrowed some revenue to cost ratio ranges, and committed to further consultations on unmetered and standby loads, as well as the Board's decisions in various electricity distributor cost of service proceedings that addressed relevant issues.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on 2016-2020 forward test years, the primary purpose of the cost allocation study ("CA Study") is to determine the

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1 Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications* (July 18, 2014), p. 48.

2 John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Kingston Hydro and documented in this report. John Todd's curriculum vitae is available at www.elenchus.ca.

3 Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, Kingston Hydro's prospective year CA Study for the 2016-2020 test years is based on an allocation of the 2016-2020 test year costs (i.e., the 2016-2020 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Given a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

1.2 KINGSTON HYDRO'S 2011 COST ALLOCATION

The last cost allocation study filed by Kingston Hydro was in 2011 in Proceeding EB-2010-0136, was based on the v 1.2 Cost Allocation Model. The 2016-2020 models were performed in accordance with the internal documentation in the v 3.2 Cost Allocation Model (CA Model).

Kingston Hydro's 2011 CA Study was prepared in accordance with the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[4] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report").

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into four additional sections. Section 2 provides an overview of the Kingston Hydro CA Study, explaining the model run included in the study, as well as the load and cost information used for the run. Section 3 explains the methodology used to develop the 2016-2020 Kingston Hydro models by documenting each step taken in completing the model. Section 4 summarizes the results of the Kingston Hydro CA Study, showing the class revenue requirements and revenue to cost ratios generated by the CA model. Section 5 shows the fixed charge unit costs per

[4] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

month and the fixed charge boundary values as calculated in the cost allocation models for 2016 to 2020.

2 OVERVIEW OF THE KINGSTON HYDRO 2016-2020 CA STUDY

2.1 MODEL RUN INCLUDED IN THE KINGSTON HYDRO COST ALLOCATION STUDY

Section 2.10.3 of the updated Filing Requirements specifies that the third table in Appendix 2-P, "...includes the following information for each class" that should be provided based on:

- *The previously approved ratios most recently implemented by the distributor;*
- *The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and*
- *The ratios that are proposed for the Test Year, which are the proposed class revenues, together with the updated cost allocation model.*

For clarity, the following designations are used.

- Kingston-2011: The Kingston Hydro 2011 revenue to cost ratios.
- Kingston-2016: The version 3.2 CA Model with 2016 loads, costs, and revenues.
- Kingston-2017: The version 3.2 CA Model with 2017 loads, costs, and revenues.
- Kingston-2018: The version 3.2 CA Model with 2018 loads, costs, and revenues.
- Kingston-2019: The version 3.2 CA Model with 2019 loads, costs, and revenues.
- Kingston-2020: The version 3.2 CA Model with 2020 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "This filing must reflect future loads and costs..." and "If updated load profiles are not available, the load profiles of the classes may be the same as those provided by Hydro One for use in the Informational Filing, scaled to match the load forecast as it relates to the respective rate classes", (Section 2.10.1, p. 48)

The Kingston Hydro 2016-2020 models have been prepared using the following load and load profile information:

- Annual Loads (kW and kWh, as appropriate) and customer counts: The 2016-2020 load forecast and customer counts by class being used by Kingston in its application were also used for the 2016-2020 CA models.
- Hourly load profile: The hourly load profiles prepared by Hydro One for the 2006 CAIF were used for all classes except the Large Use class. Updating of the hourly load profiles for this class was necessary because of the small number of customers in this class. Furthermore, actual 2013 hourly load data are available for this class (all customers have interval meters) and the hourly load data does not require weather adjustment, making it a straightforward task to determine the updated hourly load shape of this class in a manner that is consistent with the Hydro One methodology.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2016-2020 models for the following reasons.

1. Elenchus has previously explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as Elenchus is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. It is Elenchus' opinion that there would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information may be available in the future.
4. Both time-of-use commodity pricing and changes to the design of distribution rates are influencing the hourly load profiles of the affected classes; however, it will not be practical to use smart meter data to update the load profiles of the weather sensitive classes until a sufficient number of years of data have been collected to determine demand on a weather normalized basis.

2.3 COST INFORMATION

As noted earlier, the Filing Requirements mandate that the cost allocation models be prepared on the basis of prospective test year information. In the case of Kingston Hydro, the financial information for the forecast years has been prepared at the USoA level with respect to capital assets; however, OM&A spending is expected to be more stable over the period of the Custom IR, and has been forecast at a less granular level.

3 KINGSTON HYDRO COST ALLOCATION STUDY METHODOLOGY

This section documents Elenchus' methodology for the Kingston Hydro Cost Allocation Study, the 2016-2020 CA Models.

3.1 2016-2020 KINGSTON HYDRO CA MODELS

3.1.1 HOURLY LOAD PROFILE (HONI FILE)

For the Kingston Hydro CAIF, HONI provided data files with three worksheets that were to be used as input to the 2006 CAIF:

- Data Summary: actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- Hourly Load Shape by Class: GWh by class for each hour in 2004.
- Input to Cost Allocation Model: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

For all classes except the Large User customer class, the Kingston Hydro hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2016-2020. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2016-2020 load forecast years while maintaining the hourly load shapes.

For the Large User customer class, 2013 actual interval hourly data was used, scaled to levels consistent with the 2016-2020 load forecast years while maintaining the hourly load shapes.

3.1.2 DEMAND ALLOCATORS (HONI FILE)

The demand allocators used in the Kingston Hydro-2016-2020 CA models were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2016-2020 hourly load profiles resulting from the preceding step. Using the 2016-2020 hourly load profiles by class, the 12 monthly

coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.1.3 2016-2020 Demand Data (Kingston Hydro-2016-2020 Models)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2016-2020 Kingston Hydro CA Models. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values for GS > 50 and Large User customer classes are not equal to the full class NCP values since not all customers in these customer classes use these facilities. For the same reason, the Secondary 1NCP, 4NCP, and 12NCP values for the GS < 50 customer class is not equal to the full class NCP values. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Kingston Hydro cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	Kingston-2011	Kingston-2016 Status Quo Rates	Kingston-2017 Status Quo Rates	Board Target Range
Residential	91.07	97.08	97.76	85-115
GS < 50 kW	129.90	123.18	119.52	80-120
GS > 50 Regular	108.13	97.24	97.72	80-120
Large Use	85.00	97.92	100.24	85-115
Street Light	104.84	50.02	53.48	70-120
USL	121.18	185.67	119.38	80-120
Total	100.00	100.00	100.00	

Customer Class	Kingston-2018 Status Quo Rates	Kingston-2019 Status Quo Rates	Kingston-2020 Status Quo Rates	Board Target Range
Residential	98.29	99.34	100.50	85-115
GS < 50 kW	117.81	115.96	114.38	80-120
GS > 50 Regular	97.42	96.40	95.11	80-120
Large Use	98.76	94.30	89.67	85-115
Street Light	58.12	62.33	66.51	70-120
USL	118.20	117.16	116.98	80-120
Total	100.00	100.00	100.00	

The Kingston Hydro-2016 ratios (at Status Quo rates) reflect the impact of changes in throughput by class as well as changes in costs from 2011 through the 2016 forecast test years. The Kingston Hydro-2017-2020 ratios (at Status Quo rates) reflect the impact of changes in proposed rates, throughput by class, as well as changes in costs from the rates proposed for the prior year.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	Kingston-2011		Kingston-2016		Kingston-2017	
	$	%	$	%	$	%
Residential	7,166,577	60.9	7,588,980	59.0	7,858,118	59.0
GS < 50 kW	1,700,371	14.4	1,733,432	13.5	1,769,167	13.3
GS > 50 Regular	2,282,143	19.4	2,798,607	21.8	2,927,936	22.0
Large Use	465,454	4.0	496,507	3.9	505,362	3.8
Street Light	111,797	0.9	222,300	1.7	232,617	1.7
USL	49,290	0.4	21,890	0.2	22,380	0.2
Total	11,775,632	100.0	12,861,717	100.0	13,315,581	100.0

Customer Class	Kingston-2018		Kingston-2019		Kingston-2020	
	$	%	$	%	$	%
Residential	8,091,786	58.9	8,305,172	58.5	8,458,081	58.1
GS < 50 kW	1,798,891	13.1	1,828,441	12.9	1,842,379	12.7
GS > 50 Regular	3,062,404	22.3	3,218,732	22.7	3,362,204	23.1
Large Use	527,753	3.8	569,286	4.0	611,270	4.2
Street Light	240,230	1.7	246,329	1.7	249,986	1.7
USL	22,699	0.2	22,918	0.2	22,992	0.2
Total	13,743,763	100.0	14,190,879	100.0	14,546,911	100.0

5 FIXED CHARGE RATES

The Kingston Hydro cost allocation model produced the following customer unit cost per month values:

Table 9: 2016 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC[5] Adjustment
Residential	5.13	7.40	13.53
GS < 50 kW	6.32	9.05	14.82
GS > 50 Regular	60.90	89.80	109.66
Large Use	110.54	174.67	338.86
Street Light	0.40	0.65	6.92
USL	1.51	2.45	6.74

Table 10: 2017 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	5.21	7.50	13.81
GS < 50 kW	6.41	9.19	15.11
GS > 50 Regular	60.98	89.84	109.47
Large Use	112.17	176.63	339.29
Street Light	0.40	0.66	7.22
USL	1.53	2.48	6.90

Table 11: 2018 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	5.31	7.64	14.07
GS < 50 kW	6.55	9.36	15.42
GS > 50 Regular	62.13	91.30	111.06
Large Use	114.03	179.11	349.68
Street Light	0.41	0.67	7.44
USL	1.54	2.51	7.01

[5] PLCC: 'Peak Load Carrying Capacity'

Table 12: 2019 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	5.41	7.75	14.26
GS < 50 kW	6.68	9.49	15.67
GS > 50 Regular	63.18	92.54	112.59
Large Use	115.52	181.32	371.40
Street Light	0.41	0.68	7.61
USL	1.56	2.53	7.10

Table 13: 2020 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	5.47	7.81	14.34
GS < 50 kW	6.75	9.56	15.80
GS > 50 Regular	63.87	93.33	113.54
Large Use	116.41	182.93	386.37
Street Light	0.42	0.69	7.70
USL	1.58	2.56	7.12

In accordance with Board policy,[6] the following boundary values would apply for the fixed monthly service charge:

Table 14: 2016 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	5.13	13.53	12.56	5.13	13.53
GS < 50 kW	6.32	14.82	25.85	6.32	25.85
GS > 50 Regular	60.90	109.66	280.09	60.90	280.09
Large Use	110.54	338.86	5,164.00	110.54	5,164.00
Street Light	0.40	6.92	1.02	0.40	6.92
USL	1.51	6.74	11.55	1.51	11.55

Table 15: 2017 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	5.21	13.81	16.09	5.21	16.09
GS < 50 kW	6.41	15.11	28.43	6.41	28.43
GS > 50 Regular	60.98	109.47	315.17	60.98	315.17
Large Use	112.17	339.29	5,631,55	112.17	5,631,55
Street Light	0.40	7.22	0.89	0.40	7.22
USL	1.53	6.90	6.14	1.53	6.90

[6] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, pages 12-13

Table 16: 2018 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	5.31	14.07	19.62	5.31	19.62
GS < 50 kW	6.55	15.42	29.19	6.55	29.19
GS > 50 Regular	62.13	111.06	324.45	62.13	324.45
Large Use	114.03	349.68	5,827.69	114.03	5,827.69
Street Light	0.41	7.44	1.02	0.41	7.44
USL	1.54	7.01	6.33	1.54	7.01

Table 17: 2019 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	5.41	14.26	23.15	5.41	23.15
GS < 50 kW	6.68	15.67	29.75	6.68	29.75
GS > 50 Regular	63.18	112.59	331.84	63.18	331.84
Large Use	115.52	371.40	6,018.02	115.52	6,018.02
Street Light	0.41	7.61	1.13	0.41	7.61
USL	1.56	7.10	6.51	1.56	7.10

Table 18: 2020 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	5.47	14.34	26.66	5.47	26.66
GS < 50 kW	6.75	15.80	30.34	6.75	30.34
GS > 50 Regular	63.87	113.54	338.30	63.87	338.30
Large Use	116.41	386.37	6,196.24	116.41	6,196.24
Street Light	0.42	7.70	1.24	0.42	7.70
USL	1.58	7.12	6.67	1.58	7.12

However, the new policy for rate design, calls for a fixed charge only for Residential rates. "Electricity distributors will structure residential rates so that all the costs for residential distribution service are collected through a fixed monthly charge."[7] This indicates that the upper boundaries of this guideline should no longer apply to the Residential rate class.

Further, the Board expects to roll this out to other rate classes. "Next, we intend to review the rate design for low-volume general service customers (generally small

[7] Ontario Energy Board, *A New Distribution Rate Design for Residential Electricity Customers* (April 2, 2015), p. 2.

businesses) and coordinate that Rate Design with changes in the larger general service categories, following the same policy reasons." [8] In the interest of rate stability, it seems prudent to not allow the fixed percentage to fall any lower than it currently is for all rate classes – regardless of the maximum boundaries.

While the Board is still finalizing the specific details of the implementation, it is not required of utilities filing for a 2016-2020 Custom IR. However, with a target for implementation of 2019 applicable to all Residential customers, Kingston Hydro needs to increase the Residential fixed charge from $12.56 (presently) to $26.67 in 4 years. The required increase would not be possible by 2019 while holding annual increases under $4.00[9] unless the transition is started in 2016. Kingston is proposing to start implementing the Residential rate design change starting in 2016.

[8] Ibid.
[9] Ibid at 26.

OEB Cost Allocation Model

OEB COST ALLOCATION MODEL

By test year, for each of the test years 2016 through 2020, OEB Cost Allocation Model Input sheets I-6, I-8, Output O-1 and O-2 are presented in the following attachments.

File Number:EB-2015-0083

Exhibit: 7
Tab: 1
Schedule: 2

Date Filed: June 1, 2015

Attachment 1 of 5

OEB CA Input Sheets - 2016

Ontario Energy Board

2015 Cost Allocation Model

EB-2015-0083

Sheet I6.1 Revenue Worksheet - 2016 CA Model - Initial Submission

Total kWhs from Load Forecast	704,804,228

Total kWs from Load Forecast	1,034,965

Deficiency/sufficiency (RRWF 8. cell F51)	- 919,359

Miscellaneous Revenue (RRWF 5. cell F48)	576,998

			1	2	3	6	7	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	704,804,228	183,959,618	93,395,362	271,033,959	153,400,986	1,818,158	1,196,145
Forecast kW	**CDEM**	1,034,965			739,908	290,012	5,046	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		379,230			281,145	98,085		
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**	704,804,228	183,959,618	93,395,362	271,033,959	153,400,986	1,818,158	1,196,145
Existing Monthly Charge			$12.56	$25.85	$280.09	$5,164.00	$1.02	$11.55
Existing Distribution kWh Rate			$0.0154	$0.0106				$0.0141
Existing Distribution kW Rate					$2.0063	$1.0535	$4.6750	
Existing TOA Rate					$0.60	$0.60		
Additional Charges								
Distribution Revenue from Rates		$11,592,897	$6,473,921	$1,905,081	$2,596,995	$491,431	$89,061	$36,408
Transformer Ownership Allowance		$227,538	$0	$0	$168,687	$58,851	$0	$0
Net Class Revenue	**CREV**	$11,365,359	$6,473,921	$1,905,081	$2,428,308	$432,580	$89,061	$36,408

Ontario Energy Board

2015 Cost Allocation Model

EB-2015-0083

Sheet I6.2 Customer Data Worksheet - 2016 CA Model - Initial Submission

			1	2	3	6	7	9
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$151,896	$117,882	$13,971	$20,044	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$52,875	$38,070	$11,632	$3,172			
Number of Bills	CNB	330,996	289,884	35,400	3,972	36	12	1,692
Number of Devices							5,349	
Number of Connections (Unmetered)	CCON	2,802					2,661	141
Total Number of Customers	CCA	27,583	24,157	2,950	331	3	1	141
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	27,583	24,157	2,950	331	3	1	141
Line Transformer Customer Base	CCLT	27,570	24,157	2,950	321		1	141
Secondary Customer Base	CCS	26,672	24,157	2,212	161		1	141
Weighted - Services	CWCS	30,901	24,157	5,464	1,255	-	-	25
Weighted Meter -Capital	CWMC	6,217,648	4,692,522	841,126	674,000	10,000	-	-
Weighted Meter Reading	CWMR	476,712	289,884	37,523	143,938	5,367	-	-
Weighted Bills	CWNB	369,379	289,884	35,400	42,461	373	9	1,252

Bad Debt Data

Historic Year:	95,865	74,398	8,817	12,650			
Historic Year:	170,966	132,681	15,725	22,560			
Historic Year:	188,857	146,566	17,370	24,921			
Three-year average	**151,896**	**117,882**	**13,971**	**20,044**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2016 CA Model - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	131,875	45,069	16,841	51,632	17,775	425	133
Bulk Delivery CP	BCP1	131,875	45,069	16,841	51,632	17,775	425	133
Total Sytem CP	DCP1	131,875	45,069	16,841	51,632	17,775	425	133
4 CP								
Transformation CP	TCP4	480,220	180,458	54,489	171,788	71,561	1,381	543
Bulk Delivery CP	BCP4	480,220	180,458	54,489	171,788	71,561	1,381	543
Total Sytem CP	DCP4	480,220	180,458	54,489	171,788	71,561	1,381	543
12 CP								
Transformation CP	TCP12	1,273,067	377,958	162,893	476,418	252,370	1,789	1,639
Bulk Delivery CP	BCP12	1,273,067	377,958	162,893	476,418	252,370	1,789	1,639
Total Sytem CP	DCP12	1,273,067	377,958	162,893	476,418	252,370	1,789	1,639
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	159,193	50,212	23,000	57,075	28,337	425	144
Primary NCP	PNCP1	159,193	50,212	23,000	57,075	28,337	425	144
Line Transformer NCP	LTNCP1	127,576	50,212	23,000	53,795		425	144
Secondary NCP	SNCP1	98,365	50,212	16,745	30,839		425	144
4 NCP								
Classification NCP from Load Data Provider	DNCP4	584,453	196,644	78,511	198,981	108,046	1,698	573
Primary NCP	PNCP4	584,453	196,644	78,511	198,981	108,046	1,698	573
Line Transformer NCP	LTNCP4	464,325	196,644	78,511	186,899		1,698	573
Secondary NCP	SNCP4	350,087	196,644	57,164	94,009		1,698	573
12 NCP								
Classification NCP from Load Data Provider	DNCP12	1,462,094	448,397	200,857	526,111	279,967	5,095	1,667
Primary NCP	PNCP12	1,462,094	448,397	200,857	526,111	279,967	5,095	1,667
Line Transformer NCP	LTNCP12	1,089,597	448,397	200,857	433,581		5,095	1,667
Secondary NCP	SNCP12	849,964	448,397	146,242	248,562		5,095	1,667

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Sheet O1 Revenue to Cost Summary Worksheet - 2016 CA Model - Initial Submission

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	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$11,365,359	$6,473,921	$1,905,081	$2,428,308	$432,580	$89,061	$36,408
mi	Miscellaneous Revenue (mi)	$576,998	$369,662	$76,009	$96,507	$18,604	$14,925	$1,290
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$11,942,357	$6,843,583	$1,981,090	$2,524,815	$451,185	$103,986	$37,698
	Factor required to recover deficiency (1 + D)	1.0809						
	Distribution Revenue at Status Quo Rates	$12,284,719	$6,997,605	$2,059,185	$2,624,737	$467,572	$96,265	$39,353
	Miscellaneous Revenue (mi)	$576,998	$369,662	$76,009	$96,507	$18,604	$14,925	$1,290
	Total Revenue at Status Quo Rates	$12,861,717	$7,367,268	$2,135,194	$2,721,244	$486,177	$111,191	$40,643
	Expenses							
di	Distribution Costs (di)	$2,850,863	$1,526,566	$404,694	$704,304	$152,339	$57,781	$5,179
cu	Customer Related Costs (cu)	$1,562,697	$1,178,516	$162,854	$202,255	$3,504	$12,981	$2,587
ad	General and Administration (ad)	$2,717,249	$1,648,617	$353,523	$567,391	$98,256	$44,692	$4,771
dep	Depreciation and Amortization (dep)	$1,889,986	$1,090,470	$266,506	$420,983	$78,379	$30,926	$2,723
INPUT	PILs (INPUT)	$227,171	$126,855	$32,285	$53,448	$9,701	$4,490	$392
INT	Interest	$1,460,689	$815,664	$207,587	$343,664	$62,379	$28,872	$2,521
	Total Expenses	$10,708,655	$6,386,687	$1,427,448	$2,292,045	$404,559	$179,743	$18,173
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,153,061	$1,202,293	$305,984	$506,563	$91,947	$42,558	$3,717
	Revenue Requirement (includes NI)	$12,861,717	$7,588,980	$1,733,432	$2,798,607	$496,507	$222,300	$21,890
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$67,845,601	$37,957,561	$9,670,553	$15,952,856	$2,809,685	$1,338,525	$116,420
gp	General Plant - Gross	$8,982,484	$5,000,901	$1,276,984	$2,124,530	$387,333	$177,264	$15,471
accum dep	Accumulated Depreciation	($27,861,376)	($15,717,678)	($3,986,582)	($6,484,776)	($1,072,792)	($551,840)	($47,709)
co	Capital Contribution	($2,848,475)	($1,492,579)	($406,687)	($738,609)	($153,560)	($52,456)	($4,584)
	Total Net Plant	$46,118,234	$25,748,205	$6,554,268	$10,854,001	$1,970,667	$911,494	$79,599
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$83,328,902	$21,761,535	$11,040,900	$32,036,209	$18,131,927	$216,843	$141,486
	OM&A Expenses	$7,130,810	$4,353,699	$921,071	$1,473,950	$254,100	$115,454	$12,537
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$90,459,712*	*$26,115,234*	*$11,961,971*	*$33,510,159*	*$18,386,027*	*$332,297*	*$154,023*
	Working Capital	$11,759,762	$3,394,980	$1,555,056	$4,356,321	$2,390,184	$43,199	$20,023
	Total Rate Base	$57,877,996	$29,143,186	$8,109,324	$15,210,321	$4,360,851	$954,692	$99,622
		Rate Base Input equals Output						
	Equity Component of Rate Base	$23,151,198	$11,657,274	$3,243,730	$6,084,129	$1,744,340	$381,877	$39,849
	Net Income on Allocated Assets	$2,153,061	$980,580	$707,746	$429,199	$81,617	($68,552)	$22,470
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,153,061	$980,580	$707,746	$429,199	$81,617	($68,552)	$22,470
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	97.08%	123.18%	97.24%	97.92%	50.02%	185.67%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($919,359)	($745,397)	$247,658	($273,793)	($45,322)	($118,314)	$15,808
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($221,712)	$401,762	($77,363)	($10,330)	($111,110)	$18,753
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	8.41%	21.82%	7.05%	4.68%	-17.95%	56.39%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2016 CA Model - Initial Submission

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	6	7	9
	Residential	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.13	$6.32	$60.90	$110.54	$0.40	$1.51
Customer Unit Cost per month - Directly Related	$7.40	$9.05	$89.80	$174.67	$0.65	$2.45
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.53	$14.82	$109.66	$338.86	$6.92	$6.74
Existing Approved Fixed Charge	$12.56	$25.85	$280.09	$5,164.00	$1.02	$11.55

File Number:EB-2015-0083

Exhibit: 7
Tab: 1
Schedule: 2

Date Filed: June 1, 2015

Attachment 2 of 5

OEB CA Input Sheets - 2017

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Sheet I6.1 Revenue Worksheet - 2017 CA Model - Initial Submission

Total kWhs from Load Forecast	696,862,250

Total kWs from Load Forecast	1,030,196

Deficiency/sufficiency (RRWF 8. cell F51)	- 492,639

Miscellaneous Revenue (RRWF 5. cell F48)	583,921

			1	2	3	6	7	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	696,862,250	180,751,226	90,657,781	269,787,738	152,672,282	1,821,740	1,171,483
Forecast kW	**CDEM**	1,030,196			736,506	288,634	5,056	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		377,472			279,853	97,619		
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**	696,862,250	180,751,226	90,657,781	269,787,738	152,672,282	1,821,740	1,171,483
Existing Monthly Charge			$16.09	$28.43	$315.17	$5,631.55	$0.89	$6.14
Existing Distribution kWh Rate			$0.0129	$0.0107				$0.0122
Existing Distribution kW Rate					$2.0718	$1.1247	$9.4722	
Existing TOA Rate					$0.60	$0.60		
Additional Charges								
Distribution Revenue from Rates		$12,465,504	$7,025,659	$1,959,743	$2,823,133	$527,362	$105,147	$24,460
Transformer Ownership Allowance		$226,483	$0	$0	$167,912	$58,571	$0	$0
Net Class Revenue	**CREV**	$12,239,021	$7,025,659	$1,959,743	$2,655,221	$468,791	$105,147	$24,460

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Sheet I6.2 Customer Data Worksheet - 2017 CA Model - Initial Submission

			1	2	3	6	7	9
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$151,896	$117,882	$13,971	$20,044	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$52,875	$38,070	$11,632	$3,172			
Number of Bills	CNB	332,364	291,732	34,812	4,116	36	12	1,656
Number of Devices							5,361	
Number of Connections (Unmetered)	CCON	2,805					2,667	138
Total Number of Customers	CCA	27,697	24,311	2,901	343	3	1	138
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	27,697	24,311	2,901	343	3	1	138
Line Transformer Customer Base	CCLT	27,684	24,311	2,901	333		1	138
Secondary Customer Base	CCS	26,793	24,311	2,176	167		1	138
Weighted - Services	CWCS	31,011	24,311	5,375	1,300	-	-	25
Weighted Meter -Capital	CWMC	6,245,592	4,722,437	827,155	686,000	10,000	-	-
Weighted Meter Reading	CWMR	480,608	291,732	36,935	146,574	5,367	-	-
Weighted Bills	CWNB	372,151	291,732	34,812	44,000	373	9	1,225

Bad Debt Data

Historic Year:		95,865	74,398	8,817	12,650			
Historic Year:		170,966	132,681	15,725	22,560			
Historic Year:		188,857	146,566	17,370	24,921			
Three-year average		**151,896**	**117,882**	**13,971**	**20,044**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2017 CA Model - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	130,272	44,283	16,348	51,395	17,690	425	131
Bulk Delivery CP	BCP1	130,272	44,283	16,348	51,395	17,690	425	131
Total Sytem CP	DCP1	130,272	44,283	16,348	51,395	17,690	425	131
4 CP								
Transformation CP	TCP4	474,336	177,310	52,892	170,998	71,221	1,383	532
Bulk Delivery CP	BCP4	474,336	177,310	52,892	170,998	71,221	1,383	532
Total Sytem CP	DCP4	474,336	177,310	52,892	170,998	71,221	1,383	532
12 CP								
Transformation CP	TCP12	1,258,280	371,366	158,118	474,228	251,171	1,792	1,605
Bulk Delivery CP	BCP12	1,258,280	371,366	158,118	474,228	251,171	1,792	1,605
Total Sytem CP	DCP12	1,258,280	371,366	158,118	474,228	251,171	1,792	1,605
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	157,243	49,336	22,326	56,813	28,202	425	141
Primary NCP	PNCP1	157,243	49,336	22,326	56,813	28,202	425	141
Line Transformer NCP	LTNCP1	125,776	49,336	22,326	53,548		425	141
Secondary NCP	SNCP1	96,854	49,336	16,255	30,697		425	141
4 NCP								
Classification NCP from Load Data Provider	DNCP4	577,287	193,214	76,210	198,067	107,533	1,702	561
Primary NCP	PNCP4	577,287	193,214	76,210	198,067	107,533	1,702	561
Line Transformer NCP	LTNCP4	457,728	193,214	76,210	186,041		1,702	561
Secondary NCP	SNCP4	344,542	193,214	55,488	93,577		1,702	561
12 NCP								
Classification NCP from Load Data Provider	DNCP12	1,444,613	440,576	194,970	523,692	278,637	5,105	1,633
Primary NCP	PNCP12	1,444,613	440,576	194,970	523,692	278,637	5,105	1,633
Line Transformer NCP	LTNCP12	1,073,871	440,576	194,970	431,587		5,105	1,633
Secondary NCP	SNCP12	836,690	440,576	141,956	247,419		5,105	1,633

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Sheet O1 Revenue to Cost Summary Worksheet - 2017 CA Model - Initial Submission

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	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$12,239,021	$7,025,659	$1,959,743	$2,655,221	$468,791	$105,147	$24,460
mi	Miscellaneous Revenue (mi)	$583,921	$373,698	$75,808	$99,188	$18,933	$15,020	$1,273
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$12,822,942	$7,399,357	$2,035,551	$2,754,409	$487,724	$120,167	$25,733
	Factor required to recover deficiency (1 + D)	1.0403						
	Distribution Revenue at Status Quo Rates	$12,731,660	$7,308,452	$2,038,626	$2,762,098	$487,661	$109,379	$25,444
	Miscellaneous Revenue (mi)	$583,921	$373,698	$75,808	$99,188	$18,933	$15,020	$1,273
	Total Revenue at Status Quo Rates	$13,315,581	$7,682,150	$2,114,434	$2,861,286	$506,594	$124,400	$26,718
	Expenses							
di	Distribution Costs (di)	$2,901,238	$1,551,570	$405,908	$724,646	$155,125	$58,802	$5,189
cu	Customer Related Costs (cu)	$1,589,263	$1,198,740	$162,388	$208,860	$3,538	$13,179	$2,559
ad	General and Administration (ad)	$2,762,850	$1,675,710	$353,848	$583,514	$99,459	$45,553	$4,766
dep	Depreciation and Amortization (dep)	$2,031,310	$1,174,788	$282,103	$455,858	$81,839	$33,806	$2,917
INPUT	PILs (INPUT)	$260,323	$145,781	$36,483	$61,679	$10,682	$5,249	$449
INT	Interest	$1,538,108	$861,339	$215,561	$364,429	$63,114	$31,014	$2,652
	Total Expenses	$11,083,092	$6,607,927	$1,456,291	$2,398,986	$413,755	$187,603	$18,531
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,232,488	$1,250,191	$312,877	$528,950	$91,606	$45,015	$3,850
	Revenue Requirement (includes NI)	$13,315,581	$7,858,118	$1,769,167	$2,927,936	$505,362	$232,617	$22,380
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$71,397,289	$40,027,276	$10,027,114	$16,912,142	$2,890,057	$1,419,517	$121,183
gp	General Plant - Gross	$9,568,771	$5,342,228	$1,341,360	$2,278,938	$397,311	$192,479	$16,455
accum dep	Accumulated Depreciation	($29,757,628)	($16,803,873)	($4,190,506)	($6,982,163)	($1,146,658)	($584,671)	($49,758)
co	Capital Contribution	($2,848,475)	($1,489,094)	($400,366)	($747,241)	($154,910)	($52,360)	($4,505)
	Total Net Plant	$48,359,957	$27,076,537	$6,777,602	$11,461,677	$1,985,799	$974,966	$83,375
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$82,386,452	$21,381,425	$10,716,799	$31,887,441	$18,044,963	$217,260	$138,563
	OM&A Expenses	$7,253,351	$4,426,020	$922,143	$1,517,020	$258,121	$117,534	$12,513
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$89,639,803***	***$25,807,445***	***$11,638,942***	***$33,404,462***	***$18,303,085***	***$334,795***	***$151,076***
	Working Capital	$11,653,174	$3,354,968	$1,513,062	$4,342,580	$2,379,401	$43,523	$19,640
	Total Rate Base	$60,013,131	$30,431,505	$8,290,665	$15,804,257	$4,365,200	$1,018,489	$103,015
		Rate Base Input equals Output						
	Equity Component of Rate Base	$24,005,252	$12,172,602	$3,316,266	$6,321,703	$1,746,080	$407,396	$41,206
	Net Income on Allocated Assets	$2,232,488	$1,074,223	$658,143	$462,300	$92,838	($63,203)	$8,187
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,232,488	$1,074,223	$658,143	$462,300	$92,838	($63,203)	$8,187
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	97.76%	119.52%	97.72%	100.24%	53.48%	119.38%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($492,639)	($458,761)	$266,384	($173,527)	($17,638)	($112,450)	$3,353
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($175,968)	$345,266	($66,650)	$1,232	($108,218)	$4,338
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	8.82%	19.85%	7.31%	5.32%	-15.51%	19.87%

Ontario Energy Board

2015 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2017 CA Model - Initial Submission

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	6	7	9
	Residential	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.21	$6.41	$60.98	$112.17	$0.40	$1.53
Customer Unit Cost per month - Directly Related	$7.50	$9.19	$89.84	$176.63	$0.66	$2.48
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.81	$15.11	$109.47	$339.29	$7.22	$6.90
Existing Approved Fixed Charge	$16.09	$28.43	$315.17	$5,631.55	$0.89	$6.14

File Number:EB-2015-0083

Exhibit: 7
Tab: 1
Schedule: 2

Date Filed: June 1, 2015

Attachment 3 of 5

OEB CA Output Sheets - 2018

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2015 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet - 2018 CA Model - Initial Submission

Total kWhs from Load Forecast	688,547,472

Total kWs from Load Forecast	1,024,792

Deficiency/sufficiency (RRWF 8. cell F51)	- 452,305

Miscellaneous Revenue (RRWF 5. cell F48)	580,278

			1	2	3	6	7	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	688,547,472	177,434,297	87,909,490	268,358,409	151,872,625	1,825,321	1,147,330
Forecast kW	**CDEM**	1,024,792			732,604	287,122	5,066	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		375,478			278,370	97,108		
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**	688,547,472	177,434,297	87,909,490	268,358,409	151,872,625	1,825,321	1,147,330
Existing Monthly Charge			$19.62	$29.18	$324.45	$5,827.69	$1.02	$6.33
Existing Distribution kWh Rate			$0.0088	$0.0111				$0.0126
Existing Distribution kW Rate					$2.1689	$1.1613	$10.7827	
Existing TOA Rate					$0.60	$0.60		
Additional Charges								
Distribution Revenue from Rates		$12,936,467	$7,321,697	$1,974,802	$2,951,635	$543,232	$120,391	$24,711
Transformer Ownership Allowance		$225,287	$0	$0	$167,022	$58,265	$0	$0
Net Class Revenue	**CREV**	$12,711,180	$7,321,697	$1,974,802	$2,784,613	$484,967	$120,391	$24,711

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Sheet I6.2 Customer Data Worksheet - 2018 CA Model - Initial Submission

			1	2	3	6	7	9
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$151,896	$117,882	$13,971	$20,044	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$52,875	$38,070	$11,632	$3,172			
Number of Bills	CNB	333,696	293,592	34,236	4,200	36	12	1,620
Number of Devices							5,373	
Number of Connections (Unmetered)	CCON	2,808					2,673	135
Total Number of Customers	CCA	27,808	24,466	2,853	350	3	1	135
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	27,808	24,466	2,853	350	3	1	135
Line Transformer Customer Base	CCLT	27,795	24,466	2,853	340		1	135
Secondary Customer Base	CCS	26,912	24,466	2,140	170		1	135
Weighted - Services	CWCS	31,103	24,466	5,286	1,327	-	-	24
Weighted Meter -Capital	CWMC	6,276,014	4,752,546	813,469	700,000	10,000	-	-
Weighted Meter Reading	CWMR	484,883	293,592	36,359	149,566	5,367	-	-
Weighted Bills	CWNB	374,307	293,592	34,236	44,898	373	9	1,199

Bad Debt Data

Historic Year:		95,865	74,398	8,817	12,650			
Historic Year:		170,966	132,681	15,725	22,560			
Historic Year:		188,857	146,566	17,370	24,921			
Three-year average		**151,896**	**117,882**	**13,971**	**20,044**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2018 CA Model - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	128,597	43,470	15,852	51,123	17,598	426	128
Bulk Delivery CP	BCP1	128,597	43,470	15,852	51,123	17,598	426	128
Total Sytem CP	DCP1	128,597	43,470	15,852	51,123	17,598	426	128
4 CP								
Transformation CP	TCP4	468,193	174,057	51,289	170,092	70,848	1,386	521
Bulk Delivery CP	BCP4	468,193	174,057	51,289	170,092	70,848	1,386	521
Total Sytem CP	DCP4	468,193	174,057	51,289	170,092	70,848	1,386	521
12 CP								
Transformation CP	TCP12	1,242,814	364,551	153,325	471,715	249,855	1,796	1,572
Bulk Delivery CP	BCP12	1,242,814	364,551	153,325	471,715	249,855	1,796	1,572
Total Sytem CP	DCP12	1,242,814	364,551	153,325	471,715	249,855	1,796	1,572
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	155,211	48,431	21,649	56,512	28,054	426	139
Primary NCP	PNCP1	155,211	48,431	21,649	56,512	28,054	426	139
Line Transformer NCP	LTNCP1	123,909	48,431	21,649	53,264		426	139
Secondary NCP	SNCP1	95,292	48,431	15,762	30,535		426	139
4 NCP								
Classification NCP from Load Data Provider	DNCP4	569,809	189,669	73,899	197,017	106,969	1,705	550
Primary NCP	PNCP4	569,809	189,669	73,899	197,017	106,969	1,705	550
Line Transformer NCP	LTNCP4	450,878	189,669	73,899	185,055		1,705	550
Secondary NCP	SNCP4	338,811	189,669	53,806	93,081		1,705	550
12 NCP								
Classification NCP from Load Data Provider	DNCP12	1,426,361	432,492	189,059	520,918	277,178	5,115	1,599
Primary NCP	PNCP12	1,426,361	432,492	189,059	520,918	277,178	5,115	1,599
Line Transformer NCP	LTNCP12	1,057,566	432,492	189,059	429,301		5,115	1,599
Secondary NCP	SNCP12	822,967	432,492	137,652	246,109		5,115	1,599

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Sheet O1 Revenue to Cost Summary Worksheet - 2018 CA Model - Initial Submission

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	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$12,711,180	$7,321,697	$1,974,802	$2,784,613	$484,967	$120,391	$24,711
mi	Miscellaneous Revenue (mi)	$580,278	$371,243	$74,274	$99,598	$18,985	$14,938	$1,240
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$13,291,458	$7,692,940	$2,049,076	$2,884,211	$503,952	$135,328	$25,951
	Factor required to recover deficiency (1 + D)	1.0356						
	Distribution Revenue at Status Quo Rates	$13,163,485	$7,582,227	$2,045,072	$2,883,698	$502,224	$124,675	$25,590
	Miscellaneous Revenue (mi)	$580,278	$371,243	$74,274	$99,598	$18,985	$14,938	$1,240
	Total Revenue at Status Quo Rates	$13,743,763	$7,953,470	$2,119,345	$2,983,297	$521,209	$139,612	$26,830
	Expenses							
di	Distribution Costs (di)	$2,952,525	$1,574,804	$406,908	$746,353	$159,513	$59,749	$5,197
cu	Customer Related Costs (cu)	$1,616,281	$1,219,887	$162,001	$214,908	$3,571	$13,382	$2,532
ad	General and Administration (ad)	$2,809,215	$1,701,386	$354,061	$600,569	$102,172	$46,273	$4,755
dep	Depreciation and Amortization (dep)	$2,165,400	$1,250,298	$295,929	$491,940	$88,192	$35,979	$3,062
INPUT	PILs (INPUT)	$328,052	$183,179	$45,298	$78,776	$13,613	$6,627	$559
INT	Interest	$1,587,944	$886,685	$219,267	$381,316	$65,896	$32,077	$2,704
	Total Expenses	$11,459,417	$6,816,240	$1,483,464	$2,513,860	$432,958	$194,086	$18,809
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,284,346	$1,275,546	$315,427	$548,544	$94,795	$46,144	$3,890
	Revenue Requirement (includes NI)	$13,743,763	$8,091,786	$1,798,891	$3,062,404	$527,753	$240,230	$22,699
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$74,509,601	$41,705,778	$10,303,785	$17,853,064	$3,046,930	$1,475,820	$124,223
gp	General Plant - Gross	$10,051,344	$5,596,495	$1,388,183	$2,425,313	$421,709	$202,574	$17,070
accum dep	Accumulated Depreciation	($31,791,818)	($17,946,560)	($4,404,672)	($7,531,443)	($1,239,413)	($617,857)	($51,872)
co	Capital Contribution	($2,848,475)	($1,485,327)	($394,071)	($756,062)	($156,315)	($52,268)	($4,432)
	Total Net Plant	$49,920,652	$27,870,385	$6,893,225	$11,990,871	$2,072,911	$1,008,270	$84,989
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$80,979,625	$20,880,189	$10,337,787	$31,553,193	$17,856,893	$216,563	$134,999
	OM&A Expenses	$7,378,021	$4,496,077	$922,970	$1,561,829	$265,256	$119,404	$12,485
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$88,357,646*	*$25,376,266*	*$11,260,757*	*$33,115,023*	*$18,122,149*	*$335,967*	*$147,484*
	Working Capital	$11,486,494	$3,298,915	$1,463,898	$4,304,953	$2,355,879	$43,676	$19,173
	Total Rate Base	$61,407,146	$31,169,300	$8,357,123	$16,295,824	$4,428,791	$1,051,946	$104,162
		Rate Base Input equals Output						
	Equity Component of Rate Base	$24,562,858	$12,467,720	$3,342,849	$6,518,330	$1,771,516	$420,778	$41,665
	Net Income on Allocated Assets	$2,284,346	$1,137,230	$635,881	$469,436	$88,251	($54,473)	$8,021
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,284,346	$1,137,230	$635,881	$469,436	$88,251	($54,473)	$8,021
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	98.29%	117.81%	97.42%	98.76%	58.12%	118.20%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($452,305)	($398,846)	$250,184	($178,193)	($23,801)	($104,901)	$3,252
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($138,316)	$320,454	($79,108)	($6,544)	($100,617)	$4,131
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	9.12%	19.02%	7.20%	4.98%	-12.95%	19.25%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2018 CA Model - Initial Submission

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	6	7	9
	Residential	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.31	$6.55	$62.13	$114.03	$0.41	$1.54
Customer Unit Cost per month - Directly Related	$7.64	$9.36	$91.30	$179.11	$0.67	$2.51
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.07	$15.42	$111.06	$349.68	$7.44	$7.01
Existing Approved Fixed Charge	$19.62	$29.18	$324.45	$5,827.69	$1.02	$6.33

File Number:EB-2015-0083

Exhibit:	7
Tab:	1
Schedule:	2

Date Filed: June 1, 2015

Attachment 4 of 5

OEB CA Output Sheets - 2019

Ontario Energy Board

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Sheet I6.1 Revenue Worksheet - 2019 CA Model - Initial Submission

Total kWhs from Load Forecast	679,960,822
Total kWs from Load Forecast	1,018,888
Deficiency/sufficiency (RRWF 8. cell F51)	- 432,289
Miscellaneous Revenue (RRWF 5. cell F48)	590,370

			1	2	3	6	7	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	679,960,822	174,038,354	85,166,503	266,781,651	151,021,736	1,828,903	1,123,675
Forecast kW	**CDEM**	1,018,888			728,299	285,513	5,076	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		373,298			276,734	96,564		
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**	679,960,822	174,038,354	85,166,503	266,781,651	151,021,736	1,828,903	1,123,675
Existing Monthly Charge			$23.15	$29.75	$331.84	$6,018.02	$1.13	$6.51
Existing Distribution kWh Rate			$0.0045	$0.0115				$0.0129
Existing Distribution kW Rate					$2.2643	$1.1979	$12.0276	
Existing TOA Rate					$0.60	$0.60		
Additional Charges								
Distribution Revenue from Rates		$13,392,199	$7,623,164	$1,980,800	$3,070,690	$558,665	$134,073	$24,807
Transformer Ownership Allowance		$223,979	$0	$0	$166,040	$57,938	$0	$0
Net Class Revenue	**CREV**	$13,168,220	$7,623,164	$1,980,800	$2,904,650	$500,726	$134,073	$24,807

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Sheet I6.2 Customer Data Worksheet - 2019 CA Model - Initial Submission

			1	2	3	6	7	9
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$151,896	$117,882	$13,971	$20,044	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$52,875	$38,070	$11,632	$3,172			
Number of Bills	CNB	335,040	295,464	33,660	4,284	36	12	1,584
Number of Devices							5,385	
Number of Connections (Unmetered)	CCON	2,811					2,679	132
Total Number of Customers	CCA	27,920	24,622	2,805	357	3	1	132
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	27,920	24,622	2,805	357	3	1	132
Line Transformer Customer Base	CCLT	27,907	24,622	2,805	347		1	132
Secondary Customer Base	CCS	27,033	24,622	2,104	174		1	132
Weighted - Services	CWCS	31,196	24,622	5,197	1,353	-	-	24
Weighted Meter -Capital	CWMC	6,306,632	4,782,849	799,783	714,000	10,000	-	-
Weighted Meter Reading	CWMR	489,171	295,464	35,783	152,557	5,367	-	-
Weighted Bills	CWNB	376,474	295,464	33,660	45,796	373	9	1,172

Bad Debt Data

Historic Year:		95,865	74,398	8,817	12,650			
Historic Year:		170,966	132,681	15,725	22,560			
Historic Year:		188,857	146,566	17,370	24,921			
Three-year average		**151,896**	**117,882**	**13,971**	**20,044**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2019 CA Model - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	126,868	42,638	15,357	50,822	17,499	427	125
Bulk Delivery CP	BCP1	126,868	42,638	15,357	50,822	17,499	427	125
Total Sytem CP	DCP1	126,868	42,638	15,357	50,822	17,499	427	125
4 CP								
Transformation CP	TCP4	461,856	170,725	49,688	169,093	70,451	1,389	510
Bulk Delivery CP	BCP4	461,856	170,725	49,688	169,093	70,451	1,389	510
Total Sytem CP	DCP4	461,856	170,725	49,688	169,093	70,451	1,389	510
12 CP								
Transformation CP	TCP12	1,226,853	357,574	148,541	468,944	248,456	1,799	1,539
Bulk Delivery CP	BCP12	1,226,853	357,574	148,541	468,944	248,456	1,799	1,539
Total Sytem CP	DCP12	1,226,853	357,574	148,541	468,944	248,456	1,799	1,539
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	153,118	47,504	20,974	56,180	27,897	427	136
Primary NCP	PNCP1	153,118	47,504	20,974	56,180	27,897	427	136
Line Transformer NCP	LTNCP1	121,992	47,504	20,974	52,951		427	136
Secondary NCP	SNCP1	93,692	47,504	15,270	30,355		427	136
4 NCP								
Classification NCP from Load Data Provider	DNCP4	562,108	186,038	71,594	195,860	106,370	1,708	538
Primary NCP	PNCP4	562,108	186,038	71,594	195,860	106,370	1,708	538
Line Transformer NCP	LTNCP4	443,846	186,038	71,594	183,968		1,708	538
Secondary NCP	SNCP4	332,946	186,038	52,128	92,534		1,708	538
12 NCP								
Classification NCP from Load Data Provider	DNCP12	1,407,547	424,214	183,160	517,857	275,625	5,125	1,566
Primary NCP	PNCP12	1,407,547	424,214	183,160	517,857	275,625	5,125	1,566
Line Transformer NCP	LTNCP12	1,040,843	424,214	183,160	426,778		5,125	1,566
Secondary NCP	SNCP12	808,925	424,214	133,357	244,663		5,125	1,566

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Sheet O1 Revenue to Cost Summary Worksheet - 2019 CA Model - Initial Submission

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	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$13,168,220	$7,623,164	$1,980,800	$2,904,650	$500,726	$134,073	$24,807
mi	Miscellaneous Revenue (mi)	$590,370	$376,982	$74,438	$103,005	$19,645	$15,071	$1,228
	Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$13,758,590	$8,000,146	$2,055,237	$3,007,655	$520,372	$149,144	$26,036
	Factor required to recover deficiency (1 + D)	1.0328						
	Distribution Revenue at Status Quo Rates	$13,600,509	$7,873,419	$2,045,826	$3,000,004	$517,164	$138,474	$25,622
	Miscellaneous Revenue (mi)	$590,370	$376,982	$74,438	$103,005	$19,645	$15,071	$1,228
	Total Revenue at Status Quo Rates	$14,190,879	$8,250,401	$2,120,264	$3,103,009	$536,810	$153,545	$26,850
	Expenses							
di	Distribution Costs (di)	$3,004,730	$1,596,180	$407,600	$769,435	$165,661	$60,659	$5,196
cu	Customer Related Costs (cu)	$1,643,758	$1,241,412	$161,586	$221,064	$3,605	$13,587	$2,505
ad	General and Administration (ad)	$2,856,360	$1,724,936	$354,047	$619,141	$106,617	$46,884	$4,734
dep	Depreciation and Amortization (dep)	$2,257,625	$1,295,728	$303,316	$521,922	$96,689	$36,862	$3,107
INPUT	PILs (INPUT)	$385,492	$213,004	$52,395	$94,638	$17,124	$7,690	$642
INT	Interest	$1,683,767	$930,366	$228,851	$413,363	$74,794	$33,588	$2,805
	Total Expenses	$11,831,732	$7,001,625	$1,507,795	$2,639,563	$464,491	$199,269	$18,988
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,359,147	$1,303,547	$320,646	$579,168	$104,795	$47,060	$3,930
	Revenue Requirement (includes NI)	$14,190,879	$8,305,172	$1,828,441	$3,218,732	$569,286	$246,329	$22,918
	Revenue Requirement Input equals Output							
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$78,246,601	$43,514,560	$10,647,038	$19,072,546	$3,355,185	$1,529,930	$127,342
gp	General Plant - Gross	$10,533,844	$5,806,736	$1,431,988	$2,596,517	$471,293	$209,800	$17,510
accum dep	Accumulated Depreciation	($33,939,211)	($19,115,077)	($4,624,500)	($8,137,011)	($1,358,240)	($650,487)	($53,896)
co	Capital Contribution	($2,848,475)	($1,481,264)	($387,799)	($765,104)	($157,776)	($52,175)	($4,356)
	Total Net Plant	$51,992,759	$28,724,954	$7,066,727	$12,766,948	$2,310,462	$1,037,068	$86,599
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$80,381,134	$20,586,212	$10,066,727	$31,529,069	$17,848,138	$218,093	$132,895
	OM&A Expenses	$7,504,848	$4,562,528	$923,233	$1,609,640	$275,883	$121,129	$12,434
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$87,885,981*	*$25,148,740*	*$10,989,960*	*$33,138,709*	*$18,124,021*	*$339,223*	*$145,329*
	Working Capital	$11,425,178	$3,269,336	$1,428,695	$4,308,032	$2,356,123	$44,099	$18,893
	Total Rate Base	$63,417,937	$31,994,290	$8,495,422	$17,074,980	$4,666,585	$1,081,167	$105,492
	Rate Base Input equals Output							
	Equity Component of Rate Base	$25,367,175	$12,797,716	$3,398,169	$6,829,992	$1,866,634	$432,467	$42,197
	Net Income on Allocated Assets	$2,359,147	$1,248,775	$612,468	$463,446	$72,319	($45,723)	$7,862
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,359,147	$1,248,775	$612,468	$463,446	$72,319	($45,723)	$7,862
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	99.34%	115.96%	96.40%	94.30%	62.33%	117.16%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($432,289)	($305,026)	$226,796	($211,077)	($48,915)	($97,185)	$3,117
	Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($54,771)	$291,822	($115,722)	($32,477)	($92,784)	$3,932
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	9.76%	18.02%	6.79%	3.87%	-10.57%	18.63%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2019 CA Model - Initial Submission

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	6	7	9
	Residential	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.41	$6.68	$63.18	$115.52	$0.41	$1.56
Customer Unit Cost per month - Directly Related	$7.75	$9.49	$92.54	$181.32	$0.68	$2.53
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.26	$15.67	$112.59	$371.40	$7.61	$7.10
Existing Approved Fixed Charge	$23.15	$29.75	$331.84	$6,018.02	$1.13	$6.51

File Number:EB-2015-0083

Exhibit: 7
Tab: 1
Schedule: 2

Date Filed: June 1, 2015

Attachment 5 of 5

OEB CA Output Sheets - 2020

Ontario Energy Board

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Sheet I6.1 Revenue Worksheet - 2020 CA Model - Initial Submission

Total kWhs from Load Forecast	671,053,252

Total kWs from Load Forecast	1,012,398

Deficiency/sufficiency (RRWF 8. cell F51)	- 327,325

Miscellaneous Revenue (RRWF 5. cell F48)	600,697

			1	2	3	6	7	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	671,053,252	170,554,076	82,425,355	265,034,716	150,106,113	1,832,484	1,100,508
Forecast kW	**CDEM**	1,012,398			723,530	283,782	5,086	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		370,900			274,922	95,978		
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**	671,053,252	170,554,076	82,425,355	265,034,716	150,106,113	1,832,484	1,100,508
Existing Monthly Charge			$26.66	$30.34	$338.30	$6,196.24	$1.24	$6.67
Existing Distribution kWh Rate			$0.0000	$0.0119				$0.0132
Existing Distribution kW Rate					$2.3580	$1.2331	$13.2134	
Existing TOA Rate					$0.60	$0.60		
Additional Charges								
Distribution Revenue from Rates		$13,841,429	$7,927,298	$1,984,994	$3,183,778	$572,996	$147,511	$24,852
Transformer Ownership Allowance		$222,540	$0	$0	$164,953	$57,587	$0	$0
Net Class Revenue	**CREV**	$13,618,889	$7,927,298	$1,984,994	$3,018,825	$515,409	$147,511	$24,852

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Sheet I6.2 Customer Data Worksheet - 2020 CA Model - Initial Submission

			1	2	3	6	7	9
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$151,896	$117,882	$13,971	$20,044	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$52,875	$38,070	$11,632	$3,172			
Number of Bills	CNB	336,408	297,348	33,096	4,368	36	12	1,548
Number of Devices							5,397	
Number of Connections (Unmetered)	CCON	2,814					2,685	129
Total Number of Customers	CCA	28,034	24,779	2,758	364	3	1	129
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	28,034	24,779	2,758	364	3	1	129
Line Transformer Customer Base	CCLT	28,021	24,779	2,758	354		1	129
Secondary Customer Base	CCS	27,154	24,779	2,068	177		1	129
Weighted - Services	CWCS	31,290	24,779	5,108	1,380	-	-	23
Weighted Meter -Capital	CWMC	6,337,728	4,813,346	786,382	728,000	10,000	-	-
Weighted Meter Reading	CWMR	493,482	297,348	35,219	155,548	5,367	-	-
Weighted Bills	CWNB	378,665	297,348	33,096	46,694	373	9	1,146

Bad Debt Data

Historic Year:		95,865	74,398	8,817	12,650			
Historic Year:		170,966	132,681	15,725	22,560			
Historic Year:		188,857	146,566	17,370	24,921			
Three-year average		**151,896**	**117,882**	**13,971**	**20,044**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2020 CA Model - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	125,081	41,785	14,863	50,489	17,393	428	123
Bulk Delivery CP	BCP1	125,081	41,785	14,863	50,489	17,393	428	123
Total Sytem CP	DCP1	125,081	41,785	14,863	50,489	17,393	428	123
4 CP								
Transformation CP	TCP4	455,296	167,307	48,089	167,985	70,024	1,392	499
Bulk Delivery CP	BCP4	455,296	167,307	48,089	167,985	70,024	1,392	499
Total Sytem CP	DCP4	455,296	167,307	48,089	167,985	70,024	1,392	499
12 CP								
Transformation CP	TCP12	1,116,840	335,888	130,701	427,576	219,495	1,803	1,377
Bulk Delivery CP	BCP12	1,116,840	335,888	130,701	427,576	219,495	1,803	1,377
Total Sytem CP	DCP12	1,116,840	335,888	130,701	427,576	219,495	1,803	1,377
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	150,953	46,553	20,299	55,812	27,728	428	133
Primary NCP	PNCP1	150,953	46,553	20,299	55,812	27,728	428	133
Line Transformer NCP	LTNCP1	120,017	46,553	20,299	52,604		428	133
Secondary NCP	SNCP1	92,049	46,553	14,779	30,156		428	133
4 NCP								
Classification NCP from Load Data Provider	DNCP4	554,144	182,314	69,289	194,577	105,725	1,712	527
Primary NCP	PNCP4	554,144	182,314	69,289	194,577	105,725	1,712	527
Line Transformer NCP	LTNCP4	436,605	182,314	69,289	182,763		1,712	527
Secondary NCP	SNCP4	326,930	182,314	50,449	91,928		1,712	527
12 NCP								
Classification NCP from Load Data Provider	DNCP12	1,388,075	415,721	177,265	514,466	273,954	5,135	1,534
Primary NCP	PNCP12	1,388,075	415,721	177,265	514,466	273,954	5,135	1,534
Line Transformer NCP	LTNCP12	1,023,639	415,721	177,265	423,984		5,135	1,534
Secondary NCP	SNCP12	794,516	415,721	129,065	243,061		5,135	1,534

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Sheet O1 Revenue to Cost Summary Worksheet - 2020 CA Model - Initial Submission

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	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$13,618,889	$7,927,298	$1,984,994	$3,018,825	$515,409	$147,511	$24,852
mi	Miscellaneous Revenue (mi)	$600,697	$382,791	$74,600	$106,552	$20,331	$15,206	$1,217
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$14,219,586	$8,310,088	$2,059,595	$3,125,377	$535,741	$162,716	$26,069
	Factor required to recover deficiency (1 + D)	1.0240						
	Distribution Revenue at Status Quo Rates	$13,946,214	$8,117,828	$2,032,703	$3,091,381	$527,797	$151,056	$25,449
	Miscellaneous Revenue (mi)	$600,697	$382,791	$74,600	$106,552	$20,331	$15,206	$1,217
	Total Revenue at Status Quo Rates	$14,546,911	$8,500,618	$2,107,303	$3,197,933	$548,129	$166,262	$26,667
	Expenses							
di	Distribution Costs (di)	$3,057,884	$1,617,799	$408,270	$793,297	$171,740	$61,577	$5,200
cu	Customer Related Costs (cu)	$1,671,701	$1,263,282	$161,186	$227,323	$3,638	$13,794	$2,476
ad	General and Administration (ad)	$2,904,300	$1,748,254	$353,930	$638,618	$111,322	$47,461	$4,715
dep	Depreciation and Amortization (dep)	$2,304,335	$1,316,387	$303,868	$541,511	$102,534	$36,942	$3,092
INPUT	PILs (INPUT)	$430,318	$234,581	$57,435	$108,446	$20,732	$8,423	$701
INT	Interest	$1,747,122	$952,417	$233,189	$440,299	$84,172	$34,198	$2,846
	Total Expenses	$12,115,660	$7,132,721	$1,517,878	$2,749,494	$494,138	$202,396	$19,031
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,431,252	$1,325,360	$324,500	$612,709	$117,132	$47,590	$3,961
	Revenue Requirement (includes NI)	$14,546,911	$8,458,081	$1,842,379	$3,362,204	$611,270	$249,986	$22,992
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$82,116,876	$45,283,842	$10,977,231	$20,418,479	$3,728,296	$1,578,535	$130,494
gp	General Plant - Gross	$10,939,344	$5,952,608	$1,460,470	$2,765,644	$528,847	$213,982	$17,793
accum dep	Accumulated Depreciation	($36,156,094)	($20,296,769)	($4,841,753)	($8,785,842)	($1,493,327)	($682,458)	($55,945)
co	Capital Contribution	($2,848,475)	($1,476,884)	($381,554)	($774,372)	($159,297)	($52,081)	($4,286)
	Total Net Plant	$54,051,651	$29,462,797	$7,214,394	$13,623,908	$2,604,519	$1,057,978	$88,056
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$79,324,426	$20,173,504	$9,742,244	$31,321,005	$17,739,016	$218,509	$130,148
	OM&A Expenses	$7,633,885	$4,629,336	$923,386	$1,659,238	$286,701	$122,833	$12,392
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$86,958,311*	*$24,802,840*	*$10,665,630*	*$32,980,243*	*$18,025,716*	*$341,342*	*$142,540*
	Working Capital	$11,304,580	$3,224,369	$1,386,532	$4,287,432	$2,343,343	$44,374	$18,530
	Total Rate Base	$65,356,231	$32,687,166	$8,600,926	$17,911,340	$4,947,862	$1,102,352	$106,586
		Rate Base Input equals Output						
	Equity Component of Rate Base	$26,142,493	$13,074,867	$3,440,370	$7,164,536	$1,979,145	$440,941	$42,634
	Net Income on Allocated Assets	$2,431,252	$1,367,897	$589,425	$448,438	$53,991	($36,135)	$7,636
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,431,252	$1,367,897	$589,425	$448,438	$53,991	($36,135)	$7,636
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	100.50%	114.38%	95.11%	89.67%	66.51%	115.98%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($327,325)	($147,992)	$217,216	($236,827)	($75,529)	($87,270)	$3,077
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$42,537	$264,925	($164,271)	($63,141)	($83,724)	$3,674
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	10.46%	17.13%	6.26%	2.73%	-8.19%	17.91%

Ontario Energy Board

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2020 CA Model - Initial Submission

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	6	7	9
	Residential	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.47	$6.75	$63.87	$116.41	$0.42	$1.58
Customer Unit Cost per month - Directly Related	$7.81	$9.56	$93.33	$182.93	$0.69	$2.56
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.34	$15.80	$113.54	$386.37	$7.70	$7.12
Existing Approved Fixed Charge	$26.66	$30.34	$338.30	$6,196.24	$1.24	$6.67

Host Distributor

HOST DISTRIBUTOR

Kingston Hydro confirms it is not a host distributor to any distributor within its service territory.

File Number: EB-2015-0083

Date Filed: June 1, 2015

Exhibit 7

Tab 2 of 3

Unmetered Load

Unmetered Load

UNMETERED LOAD

Unmetered Load refers to three customer classes - Street Lighting, Sentinel Lighting and unmetered scattered load ("USL") - that are not metered because they consist of relatively small dispersed loads with electricity consumption that is predictable and can be determined based on the characteristics of the connected load (for example, light size or cable TV amplifier rating). In the current Cost Allocation ("CA") Model, different allocation factors are used for these customer classes and metering costs are not allocated to them.

The fact that these classes are not metered creates unique issues in ensuring that the CA Model appropriately allocates costs in a manner that is reflective of the cost causality principle.

Kingston has a separate customer class for USL and a separate customer class for Street Lighting in its current Tariff of Rates and Charges.

USL Customer Class

Kingston has consistent with its past cost of service application, included as part of this 2016 Custom IR Application, a separate USL rate class in CA Models for test years 2016 through 2020 and on the proposed Tariff of Rates and Charges.

Street Lighting Customer Class

In Kingston's 2006 CA model and updated 2011 CA model used in its 2011 Cost of Service Application (EB-2010-0136) relay/service entrance switches, or daisy chains, were used as connection points to allocate cost to the Street Lighting customer class. In previous CA models a device (light) to connection ratio of 10:1 had been used.

Consistent with the past, Kingston has used daisy chaining in this Application however the weighted average ratio of device (light) to connection has been updated as a result of the internal street light connection ratio survey conducted by Kingston in early 2015.

To determine the average number of street lights served by electrical service connections within its territory, staff undertook a survey of all existing streetlight service connections including a count of the streetlights. Data supplied from the geographic information system was utilized as the base dataset and staff was able to determine the information shown in Table 1 through field verification:

Table 1: Street Light Device to Connection Survey Results

Ratio (Streetlights : Service Drop)	Number of Streetlights	Number of Service Drops
1:1	2,066	2,066
2:1	82	41
3:1	99	33
4:1	160	40
5:1	145	29
6:1	162	27
7:1	182	26
8:1	176	22
9:1	216	24
10:1	1,110	111
11:1	231	21
12:1	120	10
13:1	143	11
14:1	28	2
15:1	30	2
Total	**4,950**	**2,465**

Based on the above data, the current average streetlight to service connection ratio is 2.01:1 for those surveyed. This updated device to connection ratio has been used in the CA models for test years 2016 through 2020.

Kingston has communicated with the Street lighting customers to assist in the understanding of the effect of this light to connection change with respect to the proposed changes to the level of the street lighting rates and bill impacts. Further detail with regard to customer engagement for this customer class may be found in Exhibit 1

of this application. Proposed class revenue requirements and revenue to cost ratios for this customer class may be found in Exhibit 7 Tab 3. Proposed rates and rates mitigation, and Street Lighting bill impacts may be found in Exhibit 8.

File Number: EB-2015-0083

Date Filed: June 1, 2015

Exhibit 7

Tab 3 of 3

Class Revenue Requirements and Revenue to Cost Ratios

Class Revenue Requirements

CLASS REVENUE REQUIREMENTS

The OEB's Appendix 2-P Tables 1 through 4 grouped by each test year 2016 – 2020 may be found in Exhibit 7 Tab 3 Schedule 2 Attachments 1, 2, 3, 4, and 5.

The first table in each Appendix 2-P, for each test year, shows the test year class revenue requirements, produced in Output sheet O-1 of the Board cost allocation model. This table for each of the test years 2016 – 2020 includes a comparison Kingston's most recent 2011 cost allocation study filed with the Board.

Kingston's calculated class revenues are presented in Appendix 2-P Table 2, for each test year. Table 2 shows three revenue scenarios by rate class, and each scenario is based on the forecast of class billing quantities for the test year. More specifically the scenarios are the forecast quantities multiplied by: a) existing rates, b) prorated existing rates that yield test year base revenue requirement, and c) the proposed class revenues. Table 2 for each test year also shows the allocation of miscellaneous revenue to the rate classes, an output from the cost allocation model. The proposed class revenue amounts for each test year are used in Exhibit 8 Rate Design to design Kingston's proposed distribution charges for the test years.

Revenue-to-Cost Ratios

REVENUE TO COST RATIOS

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. This is shown by rate classification and is the ratio of distribution revenue collected by rate classification compared to the costs allocated to the classification. A ratio lower than the Board's floor for that rate class indicates the rate classification is under-contributing and is being subsidized by other classes of customers. A ratio greater than the Board's ceiling indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011 (Cost Allocation Policy Report) established updated "target ranges" for the revenue-to-cost ratios for each customer class. Table 1 below provides a summary of Kingston's most recent 2011 Board approved revenue-to-cost ratios, the status quo revenue-to-cost ratios from 2016-2020 CA models Output sheets O-1, for each of the customer classes, and each customer class' target range.

Table 1: Revenue-to-Cost Ratios (Status Quo)

Class	Previously Approved Ratios	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Policy Range
	Most Recent Year: 2011	2016	2017	2018	2019	2020	
	%	%	%	%	%	%	%
Residential	93.28	97.08	97.76	98.29	99.34	100.50	85 - 115
GS < 50 kW	120.00	123.18	119.52	117.81	115.96	114.38	80 - 120
GS 50 to 4,999 kW	107.00	97.24	97.72	97.42	96.40	95.11	80 - 120
Large Use	93.00	97.92	100.24	98.76	94.30	89.67	85 - 115
Street Lighting	104.00	50.02	53.48	58.12	62.33	66.51	70 - 120
Unmetered Scattered	120.00	185.67	119.38	118.20	117.16	115.98	80 - 120
Standby Approved on							

For 2016, a review of the status quo revenue to cost ratios reveals that GS < 50kW, Street Lighting and Unmetered Scattered Load customer classes are starting with revenue-to-cost (R/C) ratios greater or less than the upper or lower end of the target range. For the GS < 50 kW and Unmetered Scattered Load customer classes Kingston is proposing to re-align R/C ratios by moving these R/C ratios to the upper or lower boundary, as appropriate, and to adjust the other class ratios only as required to reconcile with the overall approved revenue requirement.

For rate mitigation reasons, Kingston is proposing to move its Street Lighting class R/C ratio in equal yearly increments so as to reach the lower end of the target range by test year 2020. More specifically, the starting 2016 R/C ratio is 50.02% and the lower end of the target range for this class is 70% and Kingston is proposing to move the R/C ratio by 4% each year so that by 2020 this R/C ratio is at 70%.

Appendix 2-P Table 3 for each test year provides detail of the rebalancing of R/C ratios for the test year. Appendix 2-P Table 4 for test year 2020 summarizes the proposed revenue to cost ratios for each of the test years.

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OEB Appendix 2-P (Tables 1-4) - 2016

Appendix 2-P
Cost Allocation - 2016

Please complete the following four tables.

A) Allocated Costs

2016

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 7,166,577	60.86%	$ 7,588,980	59.00%
GS < 50 kW	$ 1,700,371	14.44%	$ 1,733,432	13.48%
GS 50 to 4,999 kW	$ 2,282,143	19.38%	$ 2,798,607	21.76%
Large Use	$ 465,454	3.95%	$ 496,507	3.86%
Street Lighting	$ 111,797	0.95%	$ 222,300	1.73%
Unmetered Scattered Load (USL)	$ 49,290	0.42%	$ 21,890	0.17%
Standby Approved on an Interim Basis	$ -	0.00%	$ -	0.00%
		0.00%		0.00%
		0.00%		0.00%
Total	$ 11,775,632	100.00%	$ 12,861,717	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

2016

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 6,473,921	$ 6,997,605	$ 7,041,606	$ 369,662
GS < 50 kW	$ 1,905,081	$ 2,059,185	$ 2,004,110	$ 76,009
GS 50 to 4,999 kW	$ 2,596,995	$ 2,624,737	$ 2,638,852	$ 96,507
Large Use	$ 491,431	$ 467,572	$ 470,057	$ 18,604
Street Lighting	$ 89,061	$ 96,265	$ 105,117	$ 14,925
Unmetered Scattered Load (USL)	$ 36,408	$ 39,353	$ 24,978	$ 1,290
Standby Approved on an Interim Basis	$ -	$ -	$ -	$ -
0				
Total	$ 11,592,897	$ 12,284,719	$ 12,284,719	$ 576,998
	existing	(1 + d)		

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios
2016

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	93.28	97.08	97.66	85 - 115
GS < 50 kW	120.00	123.18	120.00	80 - 120
GS 50 to 4,999 kW	107.00	97.24	97.74	80 - 120
Large Use	93.00	97.92	98.42	85 - 115
Street Lighting	104.00	50.02	54.00	70 - 120
Unmetered Scattered Load (USL)	120.00	185.67	120.00	80 - 120
Standby Approved on an Interim Basis	0.00			
0				

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios
2016

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2016	2017	2018	2019	2020	
	%	%	%	%	%	%
Residential	97.66					85 - 115
GS < 50 kW	120.00					80 - 120
GS 50 to 4,999 kW	97.74					80 - 120
Large Use	98.42					85 - 115
Street Lighting	54.00					70 - 120
Unmetered Scattered Load (USL)	120.00					80 - 120
Standby Approved on an Interim Basis						0
						0
0						

Note
1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2014. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (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'.

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OEB Appendix 2-P (Tables 1-4) - 2017

Appendix 2-P
Cost Allocation - 2017

Please complete the following four tables.

A) Allocated Costs

2017

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 7,166,577	60.86%	$ 7,858,118	59.01%
GS < 50 kW	$ 1,700,371	14.44%	$ 1,769,167	13.29%
GS 50 to 4,999 kW	$ 2,282,143	19.38%	$ 2,927,936	21.99%
Large User	$ 465,454	3.95%	$ 505,362	3.80%
Street Lighting	$ 111,797	0.95%	$ 232,617	1.75%
Unmetered Scattered Load (USL)	$ 49,290	0.42%	$ 22,380	0.17%
Standby Approved on an Interim Basis		0.00%		0.00%
		0.00%		0.00%
		0.00%		0.00%
Total	$ 11,775,632	100.00%	$ 13,315,581	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

2017

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 7,025,659	$ 7,308,452	$ 7,312,223	$ 373,698
GS < 50 kW	$ 1,959,743	$ 2,038,626	$ 2,022,956	$ 75,808
GS 50 to 4,999 kW	$ 2,655,221	$ 2,762,098	$ 2,764,919	$ 99,188
Large User	$ 468,791	$ 487,661	$ 486,429	$ 18,933
Street Lighting	$ 105,147	$ 109,379	$ 119,898	$ 15,020
Unmetered Scattered Load (USL)	$ 24,460	$ 25,444	$ 25,236	$ 1,273
Standby Approved on an Interim Basis				
0				
Total	$ 12,239,021	$ 12,731,660	$ 12,731,659	$ 583,921
	existing	1 + d		

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios
2017

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	93%	97.76	97.81	85 - 115
GS < 50 kW	120%	119.52	118.63	80 - 120
GS 50 to 4,999 kW	107%	97.72	97.82	80 - 120
Large User	93%	100.24	100.00	85 - 115
Street Lighting	104%	53.48	58.00	70 - 120
Unmetered Scattered Load (USL)	120%	119.38	118.45	80 - 120
Standby Approved on an Interim Basis	0%			
0				

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios
2017

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2016	2017	2018	2019	2020	
	%	%	%	%	%	%
Residential	97.66	97.81				85 - 115
GS < 50 kW	120.00	118.63				80 - 120
GS 50 to 4,999 kW	97.74	97.82				80 - 120
Large User	98.42	100.00				85 - 115
Street Lighting	54.00	58.00				70 - 120
Unmetered Scattered Load (USL)	120.00	118.45				80 - 120
Standby Approved on an Interim Basis						0
						0
0						

Note
1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2014. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (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'.

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OEB Appendix 2-P (Tables 1-4) - 2018

Appendix 2-P
Cost Allocation - 2018

Please complete the following four tables.

A) Allocated Costs

2018

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 7,166,577	60.86%	$ 8,091,786	58.88%
GS < 50 kW	$ 1,700,371	14.44%	$ 1,798,891	13.09%
GS 50 to 4,999 kW	$ 2,282,143	19.38%	$ 3,062,404	22.28%
Large User	$ 465,454	3.95%	$ 527,753	3.84%
Street Lighting	$ 111,797	0.95%	$ 240,230	1.75%
Unmetered Scattered Load (USL)	$ 49,290	0.42%	$ 22,699	0.17%
Standby Approved on an Interim Basis	$ -	0.00%	$ -	0.00%
		0.00%		0.00%
		0.00%		0.00%
Total	$ 11,775,632	100.00%	$ 13,743,763	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

2018

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 7,321,697	$ 7,582,227	$ 7,587,594	$ 371,243
GS < 50 kW	$ 1,974,802	$ 2,045,072	$ 2,028,630	$ 74,274
GS 50 to 4,999 kW	$ 2,784,613	$ 2,883,698	$ 2,885,546	$ 99,598
Large User	$ 484,967	$ 502,224	$ 502,315	$ 18,985
Street Lighting	$ 120,391	$ 124,675	$ 134,005	$ 14,938
Unmetered Scattered Load (USL)	$ 24,711	$ 25,590	$ 25,390	$ 1,240
Standby Approved on an Interim Basis				
0				
Total	$ 12,711,180	$ 13,163,485	$ 13,163,482	$ 580,278

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios
2018

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	93%	98.29	98.36	85 - 115
GS < 50 kW	120%	117.81	116.90	80 - 120
GS 50 to 4,999 kW	107%	97.42	97.48	80 - 120
Large User	93%	98.76	98.78	85 - 115
Street Lighting	104%	58.12	62.00	70 - 120
Unmetered Scattered Load (USL)	120%	118.20	117.32	80 - 120
Standby Approved on an Interim Basis	0%			
0				

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios
2018

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2016	2017	2018	2019	2020	
	%	%	%	%	%	%
Residential	97.66	97.81	98.36			85 - 115
GS < 50 kW	120.00	118.63	116.90			80 - 120
GS 50 to 4,999 kW	97.74	97.82	97.48			80 - 120
Large User	98.42	100.00	98.78			85 - 115
Street Lighting	54.00	58.00	62.00			70 - 120
Unmetered Scattered Load (USL)	120.00	118.45	117.32			80 - 120
Standby Approved on an Interim Basis						0
						0
0						

Note
1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2014. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (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'.

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OEB Appendix 2-P (Tables 1-4) - 2019

Appendix 2-P
Cost Allocation - 2019

Please complete the following four tables.

A) Allocated Costs

2019

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 7,166,577	60.86%	$ 8,305,172	58.52%
GS < 50 kW	$ 1,700,371	14.44%	$ 1,828,441	12.88%
GS 50 to 4,999 kW	$ 2,282,143	19.38%	$ 3,218,732	22.68%
Large User	$ 465,454	3.95%	$ 569,286	4.01%
Street Lighting	$ 111,797	0.95%	$ 246,329	1.74%
Unmetered Scattered Load (USL)	$ 49,290	0.42%	$ 22,918	0.16%
Standby Approved on an Interim Basis	$ -	0.00%	$ -	0.00%
		0.00%		0.00%
		0.00%		0.00%
Total	$ 11,775,632	100.00%	$ 14,190,879	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

2019

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 7,623,164	$ 7,873,419	$ 7,876,091	$ 376,982
GS < 50 kW	$ 1,980,800	$ 2,045,826	$ 2,033,755	$ 74,438
GS 50 to 4,999 kW	$ 2,904,650	$ 3,000,004	$ 3,000,540	$ 103,005
Large User	$ 500,726	$ 517,164	$ 517,192	$ 19,645
Street Lighting	$ 134,073	$ 138,474	$ 147,506	$ 15,071
Unmetered Scattered Load (USL)	$ 24,807	$ 25,622	$ 25,426	$ 1,228
Standby Approved on an Interim Basis				$ -
0				
Total	$ 13,168,220	$ 13,600,509	$ 13,600,509	$ 590,370

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios
2019

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	93%	99.34	99.37	85 - 115
GS < 50 kW	120%	115.96	115.30	80 - 120
GS 50 to 4,999 kW	107%	96.40	96.42	80 - 120
Large User	93%	94.30	94.30	85 - 115
Street Lighting	104%	62.33	66.00	70 - 120
Unmetered Scattered Load (USL)	120%	117.16	116.30	80 - 120
Standby Approved on an Interim Basis	0%			
0				

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios
2019

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2016	2017	2018	2019	2020	
	%	%	%	%	%	%
Residential	97.66	97.81	98.36	99.37		85 - 115
GS < 50 kW	120.00	118.63	116.90	115.30		80 - 120
GS 50 to 4,999 kW	97.74	97.82	97.48	96.42		80 - 120
Large User	98.42	100.00	98.78	94.30		85 - 115
Street Lighting	54.00	58.00	62.00	66.00		70 - 120
Unmetered Scattered Load (USL)	120.00	118.45	117.32	116.30		80 - 120
Standby Approved on an Interim Basis						0
						0
0						

Note
1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2014. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (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'.

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OEB Appendix 2-P (Tables 1-4) - 2020

Appendix 2-P
Cost Allocation - 2020

Please complete the following four tables.

A) Allocated Costs

2020

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 7,166,577	60.86%	$ 8,458,081	58.14%
GS < 50 kW	$ 1,700,371	14.44%	$ 1,842,379	12.67%
GS 50 to 4,999 kW	$ 2,282,143	19.38%	$ 3,362,204	23.11%
Large User	$ 465,454	3.95%	$ 611,270	4.20%
Street Lighting	$ 111,797	0.95%	$ 249,986	1.72%
Unmetered Scattered Load (USL)	$ 49,290	0.42%	$ 22,992	0.16%
Standby Approved on an Interim Basis	$ -	0.00%	$ -	0.00%
		0.00%		0.00%
		0.00%		0.00%
Total	$ 11,775,632	100.00%	$ 14,546,911	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

2020

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 7,927,298	$ 8,117,828	$ 8,108,995	$ 382,791
GS < 50 kW	$ 1,984,994	$ 2,032,703	$ 2,032,580	$ 74,600
GS 50 to 4,999 kW	$ 3,018,825	$ 3,091,381	$ 3,091,577	$ 106,552
Large User	$ 515,409	$ 527,797	$ 527,827	$ 20,331
Street Lighting	$ 147,511	$ 151,056	$ 159,785	$ 15,206
Unmetered Scattered Load (USL)	$ 24,852	$ 25,449	$ 25,447	$ 1,217
Standby Approved on an Interim Basis				
0				
Total	$ 13,618,889	$ 13,946,214	$ 13,946,210	$ 600,697

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios
2020

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	93%	100.50	100.40	85 - 115
GS < 50 kW	120%	114.38	114.37	80 - 120
GS 50 to 4,999 kW	107%	95.11	95.12	80 - 120
Large User	93%	89.67	89.68	85 - 115
Street Lighting	104%	66.51	70.00	70 - 120
Unmetered Scattered Load (USL)	120%	115.98	115.97	80 - 120
Standby Approved on an Interim Basis	0%			
0				

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios
2020

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2016	2017	2018	2019	2020	
	%	%	%	%	%	%
Residential	97.66	97.81	98.36	99.37	100.40	85 - 115
GS < 50 kW	120.00	118.63	116.90	115.30	114.37	80 - 120
GS 50 to 4,999 kW	97.74	97.82	97.48	96.42	95.12	80 - 120
Large User	98.42	100.00	98.78	94.30	89.68	85 - 115
Street Lighting	54.00	58.00	62.00	66.00	70.00	70 - 120
Unmetered Scattered Load (USL)	120.00	118.45	117.32	116.30	115.97	80 - 120
Standby Approved on an Interim Basis						0
						0
0						

Note
1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2014. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (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'.