EPCOR Electricity Distribution Ontario Inc.

Cost of Service Application

EB-2022-0028

May 27, 2022

Exhibit 7 – Cost Allocation

PROVIDING MORE

Contents

7.0 Cost Allocation

7.1 Cost Allocation Study Overview

EPCOR Electricity Distribution Ontario Inc. ("EEDO") has used the 2022 version of the cost allocation study model and submitted the cost allocation study to reflect 2023 Test Year costs, customer numbers and demand values. The excel workbook has been submitted as part of this application (EEDO 2023 Cost Allocation Model). The 2023 demand values are based on the weather normalized load forecast used to design rates. EEDO has developed weighting factors as outlined below based on an analysis of the costs allocated by each weighting factor and discussions with staff experienced in the subject area.

7.1.1 Weighting Factors

7.1.1.1 Weighting Factor for Services (Account 1855)

As per the suggested methodology on the Cost Allocation instruction sheet the Residential class was given a weighting factor of 1.0. The cost of General Service < 50 kW installations is somewhat higher than Residential is they may require after hours attendances to mitigate against interruptions during normal business hours. Additional time is also required to ensure the demand data is programmed and monitored appropriately. General Service > 50 kW service installation costs also may require after hours attendances to mitigate against interruptions during normal business hours and additional time is also required to ensure the demand data is programmed and monitored appropriately. Additionally, these installations require additional planning and preparation time due to the complexity of the metering equipment so the weighting factor is higher than that of the General Service < 50 kW.

For Street Lighting, Unmetered Scattered Load and Embedded Distributor classes EEDO does not have assets in account 1855 associated with these classes which causes the assigned weighting factor to be set at 0.0.

Table 7.1-1

Weighting Factors for Services

Rate Class	Services Weighting Factor
Residential	1.0
GS < 50 kW	1.5
GS > 50 kW	2.0
Street Light	0.0
USL	0.0

7.1.1.2 Weighting Factor for Billing and Collection (Accounts 5305 – 5340)

In determining the weighting factors for Billing and Collecting, an analysis of Accounts 5305 – 5340, was conducted. Each expense within these accounts was allocated to each rate class with an expense-specific weighting factor. The weighted cost was then multiplied by the number of customers affected in each class to calculate the expense attributed to each class for each expense line item. The sum total expense per line per class was then calculated and divided by the total number of customers in the class to determine the portion of expense related to each class. With the Residential factor set to one, each of the other class factors were calculated.

Through this analysis, EEDO was able to align the Billing and Collection expenses to each rate class and thus calculate the factors shown below in Table 7.1-2.

Table 7.1-2

Weighting Factors for Billing & Collecting

Rate Class	Billing & Collecting Weighting Factor
Residential	1.00
GS < 50 kW	1.04
GS > 50 kW	1.44
Street Light	0.84
USL	0.77

7.1.1.3 Installation Cost per Meter (Sheet I7.1)

Installation costs included in the table below are reflective of 2021 costs including the cost of the meter and the labour and truck for each meter type.

Table 7.1-3

Installation Cost per Meter

Rate Class	Installation Cost
AMI Meters	$481
AMI Meters Commercial	$910
Demand with IT and Interval Capability	$3,830
AMI Commercial with IT	$2,740

7.1.1.4 Weighting Factor for Meter Reading (Sheet I7.2)

EEDO completed an analysis of the costs included in meter reading and assigned the costs to the appropriate type of meter based on the nature of the cost. Based on this activity analysis, EEDO calculated the overall cost per meter and assigned a weighting of 1 for the meter reading costs related to smart AMI meters.

Table 7.1-4

Weighting Factors for Meter Reading

Rate Class	Meter Reading Weighting Factor
AMI Meters	1.00
AMI Meters Commercial	1.00
Demand with IT and Interval Capability	0.38
AMI Commercial with IT	1.00

7.1.2 Unmetered Loads

EEDO communicates with unmetered load customers, including street lighting customers, as the needs arise.

From a street lighting perspective, EEDO has had regular communication with Town of Collingwood staff on changes to rates and connection counts as community expansion takes place.

From a USL perspective EEDO has not had communication with these customers other than to connect new loads.

7.1.3 microFIT Class

EEDO is not proposing to include microFIT as a separate class in the cost allocation model in 2023.

7.1.4 New Customer Class

EEDO is not proposing to include a new customer class. EEDO had previously considered adding an additional class for customers with a demand greater than 5,000kW as one customer was above this threshold for a time. But as this load has remained below this threshold for the past two years, this is no longer a requirement.

7.1.5 Eliminated Customer Class

EEDO is not proposing to eliminate any customer class.

7.1.6 Load Profile Data

In a letter dated June 12, 2015[1], the OEB stated that it expected distributors to be mindful of material changes to load profiles and to propose updates in their respective cost of service applications when warranted. In its last Cost of Service application (EB-2012-0116), EEDO used the load profiles provided by Hydro One in its cost allocation model. The Hydro One profiles were based on 2004 data, and consumption patterns have changed since then due to factors such as technology, macroeconomic changes, conservation programs and time of use pricing.

EEDO has updated the load profiles for all rate classes. Load profiles were derived using weather-normalized 2019-2021 hourly load data; adjustments were made to align the 2019 load profiles with the proposed 2023 Load Forecast (i.e. consumption forecast). The weather-normalization process involves three steps:

a) Derive weather profile of a typical year;
b) Derive the impact of heating degree days ("HDD") and cooling degree days ("CDD") on hourly load; and
c) Adjust actual load to typical load with the degree day impacts.

7.1.6.1 Derivation of Daily Temperatures

The weather profile of a typical year in EEDO's service territory is calculated using average daily temperatures from 2012 to 2021. Average daily temperatures are defined as the average highest to lowest daily temperatures within a month (i.e. average of the coldest January day in each January from 2012 to 2021), rather than average temperatures on a specific calendar date (i.e. the average temperature on each January 1st). This process maintains the shape of the load profiles by determining typical monthly peaks and lows without smoothing those peaks.

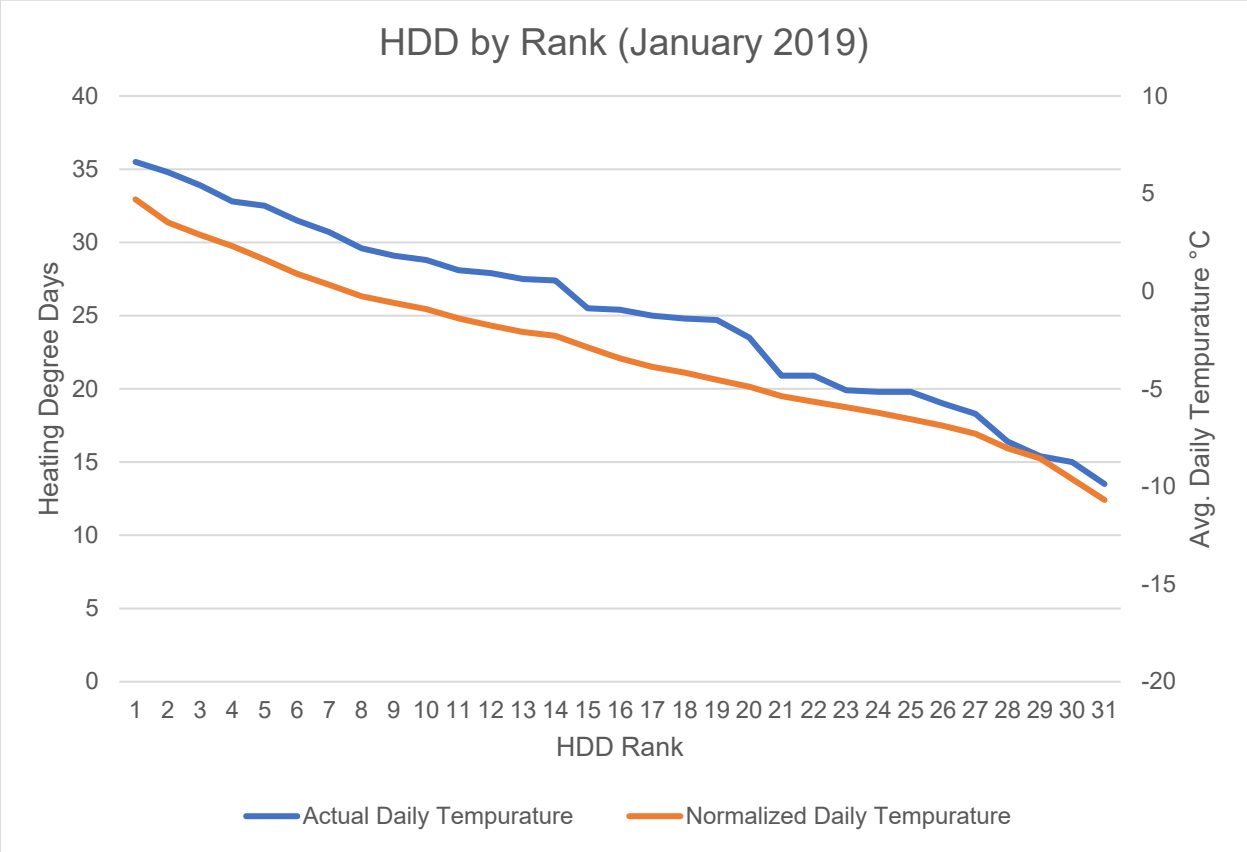
Average daily temperatures are derived by first ranking each day in each month from 2012 to 2021 from highest to lowest by HDD as measured at Environment Canada's Collingwood Weather Station. HDDs and CDDs rely on the same base values as the proposed load forecast for each class instead of the default 18°C. HDD and CDD base values are discussed in further detail in

[1] EB-2012-0083, Review of Cost Allocation Policy for Unmetered Loads, Issuance of New Cost Allocation Policy for Street Lighting Rate Class

Exhibit 3. The average HDDs among equivalently ranked days within a given month are then used as the average HDD for that ranked day in that month. For example, the days in January 2012 are ranked from 1 to 31 by HDD and this is repeated for each year from 2013 to 2021. The average HDD of the January days ranked 1 is calculated to provide the typical highest HDD day in January. All days in January ranked 1 are assigned this calculated average HDD. This process is repeated for the January days ranked 2 to 31. EEDO provides an example of average daily temperatures from 2012 to 2021 and actual temperatures in January 2021 ranked from 1 to 31 in Figure 1 below.

Figure 1

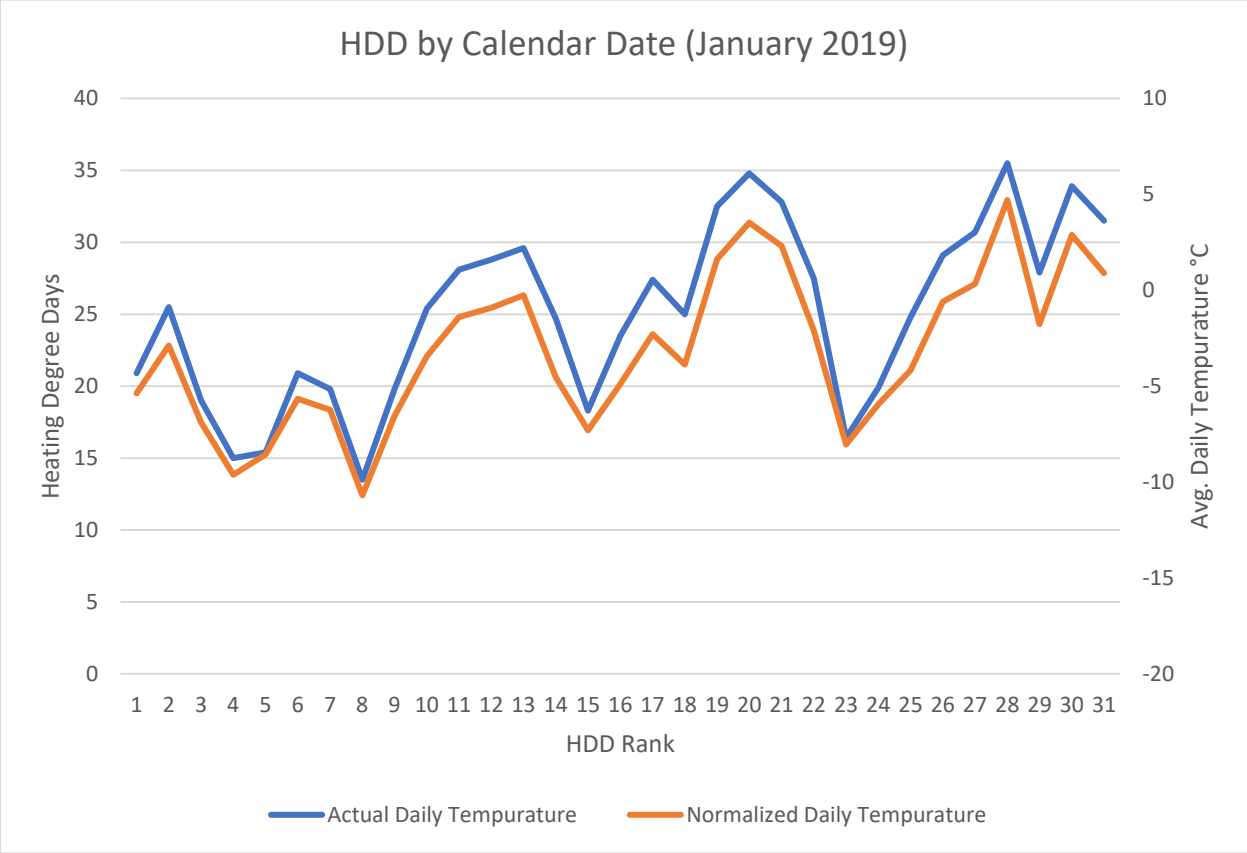
10-Year Avg. Daily HDD and Actual January 2019 HDD by Rank



Average daily temperatures reflect the January normal-weather profile in EEDO's service territory. Figure 2 below displays the same information by calendar date using the average and actual temperatures associated with each ranked day.

Figure 2

10-Year Avg. Daily HDD and Actual January 2019 HDD by Calendar Date



Typical daily CDDs are determined by the same ranking and averaging methodology described above, using average daily CDD data from 2012 to 2021. January 2019 was colder than average January temperatures, so the weather normalization process reduces 2019 loads to reach weather-normalized loads.

7.1.6.2 Impact of HDD and CDD on Hourly Load

The impact of HDDs and CDDs on hourly load is calculated with a regression of three years of actual hourly loads (2019 to 2021) on daily HDDs and CDDs. The regression results provide the estimated impact of a change in degree days on load.

Temperatures impact load differently depending on the time of the day and consequently HDD and CDD variables are converted to interaction variables between degree days and the hour of the

day. There are 24 variables for each of HDD and CDD, equal to the actual degree days in the corresponding hour, and 0 in all other hours. A set of 24 binary variables, equal to 1 in the corresponding hour and 0 in all other hours; COVIDHDD and COVIDCDD variables equal to 0 in all days until March 16, 2020 and equal to the relevant HDD or CDD in each hour thereafter; a trend variable; a Weekend binary variable; and a Holiday binary variable are also included.[2] The resulting coefficients reflect the impact of one HDD or CDD that considers different impacts depending on the hour of the day.

7.1.6.3 Adjust Actual Load to Typical Load

Actual 2019 hourly load is adjusted by calculating the difference between actual daily temperatures and the corresponding ranked typical daily temperature (as identified in Figure 2) and applying the regression coefficient to the difference. The year 2019 was selected as the base year to scale to avoid irregular consumption patterns in 2020 and 2021 caused by the COVID-19 pandemic that are expected to diminish by the 2023 Test Year.

After 2019 weather-normalized demand is derived for each hour, the load in each hour is adjusted by the same factor such that the sum of hourly loads is equal to the proposed 2023 Load Forecast (i.e. consumption forecast).

Table 7.1-5 below provides the calculations used to adjust actual January 1, 2019 weather variables to typical weather for the Residential class.

[2] There are a total of 77 independent variables, however, the set of 72 for hourly HDD, hourly CDD and binary Hour variables have only three non-zero values in each observation. The values are 0 in each hour other than the HDD, CDD, and binary hour variables that correspond to the hour of the observation. This regression is similar to 24 regressions, one for each hour of the day.

Table 7.1-5

January 1 Hour 1 Residential Example

Date	Hour	Temp °C	HDD	HDD Rank	Average HDD at Rank	CDD	CDD Rank	Average CDD at Rank
		A	B = 18 - A	C	D	E	F	G
1-Jan	1	-2.9	20.9	21	19.5	0	10	0

Date	Hour	2019 Load (kW)	HDD Diff.	HDD1 Coef.	CDD Diff.	CDD1 Coef.	2019 Normal Load (kW)
		H	I = D - B	J	K = G - E	L	M = H + (I * J) + (K * L)
1-Jan	1	16,508	-1.4	317.5	0	583.9	16,064

Date	Hour	2019 Normal Load (kW)	Sum of 2019 Normal Loads	2023 Forecast Consumption	2019 to 2021 Load Adjustment	2021 Normal Load (kW)
		M	N	O	P = O / N	Q = M * P
1-Jan	1	16,064	134,810,703	137,646,072	1.0210	16,401

The HDD on January 1st, 2019 was 20.9 HDD, which was the 21st highest HDD in the month. The 21st highest January HDD in each year from 2012 to 2021 was, on average, 19.5 HDD. The difference, -1.4 HDD, is multiplied by the "HDD Hour 1" coefficient of 317.5 from the load profile regression to produce the -444.5 kW adjustment. This adjustment is applied to actual load in the first hour of January 1, 2019 (16,508 kW) to reach the weather-normalized load (16,064 kW). The 2023 Residential load forecast is 2.1% higher than the sum of 2019 weather-normalized hourly loads and as such, the January 1, 2023 weather-normalized demand increases to 16,401 kW.

GS < 50 kW and GS > 50 kW load profiles are derived by the same methodology. The Street Light class is not weather sensitive and as such its loads are not weather-normalized. The USL hourly load was assumed to have a constant load. After load profiles are derived for all classes, total system and class-specific peaks within each month are compiled to produce Coincident Peak ("CP") and Non-Coincident Peak ("NCP") figures used in Tab "I8 Demand Data" of the OEB's Cost Allocation Model. EEDO provides a model illustrating how demand data was derived as "EEDO 2023 Demand Data Model" accompanying this submission. This model provides detailed

calculations for the Residential load profile, however, derivations for the other classes and historic weather data has been removed to reduce the size of the model.

7.1.7 Embedded Distributor

EEDO does not have an Embedded Distributor rate class.

7.2 Class Revenue Requirements

The allocated cost by rate class for the 2012 Cost of Service filing and the 2023 updated study are provided in the following Table 7.2-1.

Table 7.2-1

Allocated Cost

Rate Class	2012 Board Approved Cost Allocation Study	%	Costs Allocated in the 2023 Study	%
Residential	$5,552,711	68.76%	$7,046,357	69.02%
GS < 50 kW	$1,192,782	14.77%	$1,419,671	13.91%
GS > 50 kW	$1,104,816	13.68%	$1,638,652	16.05%
Street Light	$219,370	2.72%	$95,464	0.94%
USL	$5,432	0.07%	$8,351	0.08%
Total	**$8,075,110**	**100.0%**	**$10,208,496**	**100.00%**

7.3 Revenue-to-Cost Ratios

The Board has established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7.3-1 below. In addition, Table 7.3-2 also provides EEDO's revenue to cost ratios from the 2013 Cost of Service application, the updated 2023 cost allocation study and the proposed 2023 to 2027 ratios. Sheet 11 of the RRWF is attached as Exhibit 7, Tab 2, Appendix 1.

Table 7.3-1

Revenue to Cost Ratios

Rate Class	2012 Board Approved	2023 Cost Allocation Study	2023-2027 Proposed Ratios	OEB Target Min to Max	
Residential	101.90%	98.67%	99.22%	85%	115%
GS < 50 kW	94.10%	103.43%	103.43%	80%	120%
GS > 50 kW	95.90%	92.43%	99.22%	80%	120%
Street Light	120.00%	278.61%	120.00%	80%	120%
USL	120.00%	82.67%	99.22%	80%	120%

The 2023 cost allocation study indicates the revenue to cost ratio for the Street Light and Unmetered Scattered Load classes are outside the Board's acceptable range. For 2023, it is proposed that the ratio for Street Light be decreased to the maximum value of the Board's acceptable range. To maintain revenue neutrality, EEDO proposes to increase revenues from USL and General Service > 50 kW, the two classes with the lowest Revenue to Cost Ratios. The revenue to cost ratios of the General Service > 50 kW and USL classes are within the target range and remain the lowest revenue to cost ratios after the revenue reallocation from Street Light.

The following Table 7.3-2 provides information on calculated class revenue. The resulting 2023 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7.3-2

Calculated Class Revenue

Rate Class	2023 Base Revenue at Existing Rates	2023 Proposed Base Revenue at Status Quo Rates	2023 Proposed Base Revenue at Proposed Rates	Miscellaneous Revenue
Residential	$5,560,750	$6,378,380	$6,417,084	$574,291
GS < 50 kW	$1,195,726	$1,371,541	$1,371,541	$96,871
GS > 50 kW	$1,228,297	$1,408,900	$1,520,230	$105,636
Street Light	$219,204	$251,434	$100,018	$14,539
USL	$5,432	$6,231	$7,613	$673
Total	$8,209,408	$9,416,486	$9,416,486	$792,010

APPENDIX A – Revenue Requirement Workform – Tab 11 – Cost Allocation

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2022 Filers

Cost Allocation and Rate Design

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

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

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 5,552,711	68.76%	$ 6,935,524	67.94%
2	GS<50kW	$ 1,192,782	14.77%	$ 1,377,335	13.49%
3	GS>50kW	$ 1,104,816	13.68%	$ 1,789,388	17.53%
4	Streetlighting	$ 219,370	2.72%	$ 97,592	0.96%
5	USL	$ 5,432	0.07%	$ 8,658	0.08%
20					
	Total	$ 8,075,110	100.00%	**$ 10,208,496**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 10,208,495.72**	

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

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

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

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 5,560,750	$ 6,378,380	$ 6,378,380	$ 567,165
2	GS<50kW	$ 1,195,726	$ 1,371,541	$ 1,371,541	$ 94,146
3	GS>50kW	$ 1,228,297	$ 1,408,900	$ 1,556,765	$ 115,299
4	Streetlighting	$ 219,204	$ 251,434	$ 102,402	$ 14,708
5	USL	$ 5,432	$ 6,231	$ 7,398	$ 692
20					
	Total	$ 8,209,408	$ 9,416,486	$ 9,416,486	$ 792,010

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

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

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

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

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	101.90%	100.14%	100.14%	85 - 115
2	GS<50kW	94.10%	106.41%	106.41%	80 - 120
3	GS>50kW	95.90%	85.18%	93.44%	80 - 120
4	Streetlighting	120.00%	272.71%	120.00%	80 - 120
5	USL	120.00%	79.96%	93.44%	80 - 120
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

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

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

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

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2022	2023	2024	
1	Residential	100.14%	100.14%	100.14%	85 - 115
2	GS<50kW	106.41%	106.41%	106.41%	80 - 120
3	GS>50kW	93.44%	93.44%	93.44%	80 - 120
4	Streetlighting	120.00%	120.00%	120.00%	80 - 120
5	USL	93.44%	93.44%	93.44%	80 - 120
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.