EXHIBIT 7 – COST ALLOCATION

2023 Cost of Service

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7.1 COST ALLOCATION STUDY REQUIREMENTS

7.1.1 Overview of Cost Allocation

CHEI is submitting cost allocation informational filing consistent with the utility's understanding of the Directions and Policies in the Board's Reports of November 28, 2007, Application of Cost Allocation for Electricity Distributors, and March 31, 2011, Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports") and all subsequent updates.

The main objectives of the original informational filing in 2006 were to provide information on any apparent cross-subsidization among a distributor's rate classifications and to support future rate applications. This information is updated to reflect new parameters and inputs and then used to adjust any cross-subsidization in the proposed rates. CHEI seeks to recover a weighted average cost of capital of 5.47% through rates in the 2023 Test Year. The utility has followed the "Report of the Board on Cost of Capital for Ontario's Regulated Utilities" (December 11, 2009), as well as the "Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities" (January 14, 2016) in determining the applicable cost of capital.

CHEI notes that it is not requesting to eliminate or introduce new classes.

7.1.2 Previously Approved Cost Allocation

The Previously Board Approved ratios are presented as a reference point to the proposed 2023 ratios. As part of its last Cost of Service Rate Application, CHEI updated the cost allocation revenue to cost ratios with 2015 base revenue requirement information. The revenue to cost ratios from the 2015 application are presented below. CHEI notes that there have been no changes in its class composition since 2015.

Table 1 – Previously Approved Ratios (2018 CoS)

Particulars		Settlement Proposal Dec 15 2017	
Customer Class Name		Proposed R/C Ratio	
Residential		0.97	
GS < 50 kW		1.13	
GS > 50 to 4999 kW		1.30	
Unmetered Scattered Load		1.20	
Street Lighting		0.90	

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7.2 PROPOSED COST ALLOCATION (2023)

The Cost Allocation Study allocates the 2023 test year costs to the various customer classes using allocators based on the forecast class loads (kW and kWh) by class, customer counts, etc.

CHEI has used the most up-to-date 2021 OEB-approved Cost Allocation Model and followed the instructions and guidelines issued by the OEB to enter the 2021 data into this model.

7.2.1 Inputs to the Cost Allocation Model

Sheet I3, Trial Balance Data

CHEI populated the information on Sheet I3, Trial Balance Data with the 2023 forecasted data, Target Net Income, PILs, long-term debt interest, and the targeted Revenue Requirement and Rate Base.

Table 2 – Cost Allocation Integrity Check against RRWF (Sheet I3 TB Data)

Return on Deemed Equity	$165,600	
Income Taxes (Grossed up)	$19,099	
Deemed Interest Expense	$95,669	
Service Revenue Requirement	$1,214,031	**From this Sheet**
Revenue Requirement to be Used in this model ($)	$1,214,031	$1,214,031
Rate Base ($)	$4,780,587	
Rate Base to be Used in this model ($)	$4,780,587	$4,780,587

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Table 3 – 2023 Grouped Accounts (Sheet I3 TB Data)

Grouped Accounts	2018 Reclassified Balance	2023 Reclassified Balance
Land and Buildings	$50,000	$56,900
TS Primary Above 50	$0	$0
DS	$1,965,310	$1,991,015
Poles, Wires	$3,764,304	$4,198,531
Line Transformers	$1,273,272	$1,847,438
Services and Meters	$695,158	$890,683
General Plant	$0	$0
Equipment	$75,341	$84,103
IT Assets	$173,001	$225,107
CDM Expenditures and Recoveries	$0	$0
Other Distribution Assets	$0	$0
Contributions and Grants	($1,751,760)	($2,108,164)
Accumulated Amortization	($1,879,790)	($2,708,489)
Non-Distribution Asset	$0	$0
Unclassified Asset	$0	$0
Liability	$0	$0
Equity	($168,495)	($165,600)
Sales of Electricity	$0	$0
Distribution Services Revenue	$0	$0
Late Payment Charges	($11,400)	($11,450)
Specific Service Charges	$0	($7,304)
Other Distribution Revenue	$10,152	($21,996)
Other Revenue - Unclassified	$0	$0
Other Income & Deductions	($28,410)	($8,000)
Power Supply Expenses (Working Capital)	$3,525,627	$3,293,006
Other Power Supply Expenses	$0	$0
Operation (Working Capital)	$36,569	$47,439
Maintenance (Working Capital)	$53,115	$49,486
Billing and Collection (Working Capital)	$192,482	$234,702
Community Relations (Working Capital)	$3,000	$2,988
Community Relations - CDM (Working Capital)	$0	$0
$399,954 **$382,245**	$399,954	
Insurance Expense (Working Capital)	$2,910	$6,451
Bad Debt Expense (Working Capital)	$7,500	$9,604
Advertising Expenses	$2,150	$534
Charitable Contributions	$0	$0
Amortization of Assets	$162,155	$180,507
Other Amortization - Unclassified	$0	$0
Interest Expense - Unclassified	$80,297	$95,669
Income Tax Expense - Unclassified	$4,076	$19,099
Other Distribution Expenses	$2,000	$2,000
Non-Distribution Expenses	$0	$0
Unclassified Expenses	$0	$2,500
Total	$8,620,811	$8,606,713

On Sheet I4 BO Assets,

I4 Break-out of Assets, CHEI reviewed its primary and secondary assets to ensure that the model uses the most up-to-date information. To update this information, the utility has relied on its 3rd party operations (Sproule Powerline), which has worked on Embrun's distribution system for over

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20 years. CHEI notes that the split was not based on an actual engineering study. Should one be required, CHEI would hire Stantec to conduct a study at an estimated cost of $3,000 to $4,000. The table below shows the utility's updated breakout between primary and secondary from its last cost of service in 2018.

Table 4 – Breakout of Assets (Sheet I4 BO Assets)

Account	Description	BREAK OUT (%) 2018 CoS	BREAK OUT (%) 2023 CoS
1565	Conservation and Demand Management		
1805	Land		
1805-1	Land Station >50 kV		
1805-2	Land Station <50 kV	100.00%	100.00%
1806	Land Rights		
1806-1	Land Rights Station >50 kV		
1806-2	Land Rights Station <50 kV	100.00%	100.00%
1808	Buildings and Fixtures		
1808-1	Buildings and Fixtures > 50 kV		
1808-2	Buildings and Fixtures < 50 KV	100.00%	100.00%
1810	Leasehold Improvements		
1810-1	Leasehold Improvements >50 kV		
1810-2	Leasehold Improvements <50 kV	100.00%	100.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV		
1820	Distribution Station Equipment - Normally Primary below 50 kV		
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)	100.00%	100.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	0.00%	0.00%
1825	Storage Battery Equipment		
1825-1	Storage Battery Equipment > 50 kV		
1825-2	Storage Battery Equipment <50 kV	100.00%	100.00%
1830	Poles, Towers and Fixtures		
1830-3	Poles, Towers, and Fixtures - Sub transmission Bulk Delivery		
1830-4	Poles, Towers and Fixtures - Primary		55.00%
1830-5	Poles, Towers, and Fixtures - Secondary	100.00%	45.00%
1835	Overhead Conductors and Devices		
1835-3	Overhead Conductors and Devices - Sub transmission Bulk Delivery		
1835-4	Overhead Conductors and Devices - Primary		50.00%
1835-5	Overhead Conductors and Devices - Secondary	100.00%	50.00%
1840	Underground Conduit		
1840-3	Underground Conduit - Bulk Delivery		
1840-4	Underground Conduit - Primary		
1840-5	Underground Conduit - Secondary	100.00%	100.00%
1845	Underground Conductors and Devices		
1845-3	Underground Conductors and Devices - Bulk Delivery		
1845-4	Underground Conductors and Devices - Primary		45.00%

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1845-5	Underground Conductors and Devices - Secondary	100.00%	55.00%
1850	Line Transformers		
1855	Services		
1860	Meters		

Sheet I5 Misc Data

In Sheet I5.1, Miscellaneous data, CHEI updated the deemed equity component of rate base, the kilometers of roads in the service area, working capital allowance, the proportion of pole rental revenue from secondary poles, and the monthly service charges.

Table 5 – Miscellaneous Data (Sheet I5 Misc Data)

	2018 CoS	2023 CoS
Structure KM (kms of Roads in Service Area that have distribution line)	30.1	37
Deemed Equity Component of Rate Base (ref: RRWF 7. cell F24)	40%	40%
Working Capital Allowance to be included in Rate Base (%)	7.5%	7.5%
A portion of pole leasing revenue from Secondary - Remainder assumed to be Primary (%)	35%	77%

As instructed by the Board, in Sheet I5.2, Weighting Factors, CHEI has used LDC-specific factors rather than continue to use OEB-approved default factors. The utility has applied service and billing & collecting weightings for each customer classification.

These weightings are based on a review of time and costs incurred in servicing its customer classes; they are discussed further below:

Table 6 – 2018 Board Approved Weighting Factors (Sheet I5.2 Weighting Factors)

	1 Residential	2 GS <50	3 GS > 50 to 4999 kW	7 Street Light	9 Unmetered Scattered Load
Insert Weighting Factor for Services Account 1855	1.0	2.0	2.0		
Insert Weighting Factor for Billing and Collecting	1.0	1.0	1.0	1.0	1.0

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Table 7 – 2023 Board Approved Weighting Factors (Sheet I5.2 Weighting Factors)

	1	2	3	7	9
	Residential	**GS <50**	**GS > 50 to 4999 kW**	**Street Light**	**Unmetered Scattered Load**
Insert Weighting Factor for Services Account 1855	1.0	2.0	2.0	0.0	0.0
Insert Weighting Factor for Billing and Collecting	1.0	1.2	1.9	8.1	8.1

Table 8 – Determination of billing and collecting weighting factors

2023
Accounts 5305 - 5340

		2023	
5305-Supervision		-	
5310-Meter Reading Expense		-	
5315-Customer Billing	$ 233,256.00	233,256.00	-
5320-Collecting		-	
5325-Collecting- Cash Over and Short		-	
5330-Collection Charges	$ 2,500.00	2,500.00	
5340-Miscellaneous Customer Accounts Expenses		-	

	Residential	GS < 50 *	GS > 50	Unmetered	Street Lighting		Acct
2023 Projected # of Customers (load forecast)	2345	165	9	1	1	2,521.00	
# bills (per tab I6.2 of CA model)	28140	1976	103	12	12	30,243.16	
Bill	0.93	0.07	0.00	0.00	0.00	1.00	
Time allocation	0.90	0.08	0.01	0.01	0.01	1.00	

Examples of Expenses						Total Annual Cost	
5315 - Compensation (combined row for privacy)	$135,634	$123,741	$10,047	$808	$404	$404	
5315 - Customer Billing Supplies (by bills alll class)	$3,500	$3,150	$280	$35	$18	$18	$3,500	5315
5315 - ITM- Web Portal (by bill counts for Res and GS<50)	$2,800	$2,605	$183				$2,800	5315
5315 - Meter Sense (Monthly Fee) Harris (by bill counts for Res and GS<50)	$5,320	$4,950	$348				$5,338	5315
5315 - ORPC - Outside Contract Billing Process	$61,882	$55,694	$4,951	$619	$309	$309	$61,882	5315
5315 - Util-Assist Sync Operator	$10,620	$9,881	$694				$10,620	5315
5315 - Connexo AMI - Honeywell	$9,500	$8,839	$621				$9,500	5315
5315- Harris Option In-Out	$2,500	$2,326	$163				$2,500	
5315- Harris Work Shop	$1,500	$1,350	$120	$15	$8	$8	$1,500	
5330 - Returned Cheques and Reconnection Charges	$2,500	$2,290	$180	$30	$0	$0	$2,500	5330

	$ 235,756.00						
5315 - Customer Billing		214,826.65	17,585.73	1,506.70	738.35	738.35	100,139.55
Total		7.63	8.90	14.59	61.53	61.53	
Weighting (Residential set as standard)		1.00	1.17	1.91	8.06	8.06	

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Sheet I6.1 Revenue

CHEI has populated the I6.1 Revenue Tab with the 2023 proposed load forecast. The utility confirms that the revenue sufficiency/deficiency reconciles with the RRWF, as does the Miscellaneous Revenues. 2022 Board Approved existing rates were entered at rows 33 to 37 of the table.

Table 9 – Revenue Inputs to the CA Model (I6.1 Revenues)

Total kWhs from Load Forecast	29,030,001	
Total kWs from Load Forecast	12,077	
Deficiency/sufficiency (RRWF 8. cell F51)	124,033	
Miscellaneous Revenue (RRWF 5. cell F48)	48,750	

0

			1	2	3	7	9
	ID	Total	Residential	GS <50	GS > 50 to 4999 kW	Street Light	Unmetered Scattered Load
Billing Data							
Forecast kWh	CEN	29,030,001	20,126,172	4,617,010	3,952,566	241,169	93,084
Forecast kW	CDEM	12,077			11,425	652	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		-					
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	29,030,001	20,126,172	4,617,010	3,952,566	241,169	93,084
Existing Monthly Charge			$37.44	$22.34	$194.70	$2.36	$22.39
Existing Distribution kWh Rate				$0.0187			$0.0153
Existing Distribution kW Rate					$4.1379	$21.4175	
Existing TOA Rate							
Additional Charges							
Distribution Revenue from Rates		$1,289,314	$1,053,554	$130,483	$67,385	$31,900	$5,992
Transformer Ownership Allowance		$0	$0	$0	$0	$0	$0
Net Class Revenue	CREV	$1,289,314	$1,053,554	$130,483	$67,385	$31,900	$5,992

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Sheet I6.2 Customer Data

CHEI has populated the I6.2 Customer Data with the required information using the 2023 proposed customer forecast to determine the number of customers, devices, and bills. The utility confirms using a three-year historical average to calculate the late payment charges and bad debt by class.

Table 10 – Customer Inputs to the CA Model (I6.2 Customer Data)

	ID	Total	1 Residential	2 GS <50	3 GS > 50 to 4999 kW	7 Street Light	9 Unmetered Scattered Load
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$11,538	$11,404	$134	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$12,243	$9,512	$2,731			
Number of Bills	CNB	30,243	28,140	1,976	103	12	12
Number of Devices	CDEV					633	17
Number of Connections (Unmetered)	CCON	650				633	17
Total Number of Customers	CCA	2,520	2,345	165	9	1	1
Bulk Customer Base	CCB	-					
Primary Customer Base	CCP	2,546	2,345	165	9	27	1
Line Transformer Customer Base	CCLT	2,546	2,345	165	9	27	1
Secondary Customer Base	CCS	2,520	2,345	165	9	1	1
Weighted - Services	CWCS	2,692	2,345	329	17	-	-
Weighted Meter -Capital	CWMC	319,478	281,248	32,695	5,535	-	-
Weighted Meter Reading	CWMR	3,874	2,345	1,261	269	-	-
Weighted Bills	CWNB	30,843	28,140	2,312	197	97	97

Bad Debt Data							
Historic Year:	2018	7,917	7,917	-			
Historic Year:	2019	13,361	13,163	198			
Historic Year:	2020	13,335	13,133	202			
Three-year average		11,538	11,404	134	-	-	-

Sheet I7.1 Meter Capital

CHEI has updated the meter capital to reflect current and accurate costs per meter.

Table 11 – Meter Capital inputs to the CA Model (I7.1 Meter Capital)

		Residential			GS <50			GS > 50 to 4999 kW	
		1	2	3	1	2	3	1	2
		Number of Meters	Weighted Metering Costs (1)	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs (1)	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs (1)
	Allocation Percentage Weighted Factor			-			-		
	Cost Relative to Residential Average Cost			1.00			1.66		
	Total	2345	281248	120	165	32695	199	9	5535
Meter Types	**Cost per Meter (Installed)**								
Network Meter (Costs to be updated)	182	101	18382			0			0
Smart Meters	157	8	1256		12	1884			0
Demand without IT (usually three-phase)			0			0			0
Demand with IT	615		0		26	15990		9	5535
LDC Specific Smart Meter 1	117	2,236	261610		127	14821			0

Sheet I7.2 Meter Reading

CHEI has updated the meter capital to reflect current and accurate costs per meter. CHEI notes that there have been no changes to its meter reading factors since its last cost of service in 2018.

Table 12 – Meter Reading Inputs to CA Model (I7.2 Meter Reading)

		Residential			GS <50			GS > 50 to 4999 kW		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
Description	Allocation Percentage Weighted Factor			60.53%			32.54%			6.93%
	Cost Relative to Residential Average Cost			1.00			7.66			29.84
	Total	2344.98	2344.98	1.00	164.67	1260.59	7.66	9.00	268.56	29.84
	Factor									
Smart Meter	1.00	2,345	2,345		127	127			0	
Interval	29.84		0		38	1,134		9	269	

Sheet I8 Demand Data

In the previous cost of service rate applications, CHEI relied on load profiles produced by Hydro One Networks Inc. in 2006 using data from 2004 (HONI method). The process involved scaling the initial cost allocation informational filing, using the ratio of the Test Year load forecast to the base year load for each rate class.

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Section 2.1.7 of Chapter 2 filing requirements state that distributors should make best efforts to update all classes' load profiles using the most recent available data.

CHEI is aware of several processes and methodologies filed in recent applications, all posing a problem for the utility. One particular methodology circulating is proprietary to a group that CHEI is not part of and therefore is unavailable to the utility. But more relevant to CHEI, the inputs to the methodologies filed recently are not available to CHEI at this time as the data required is hosted by another utility which has confirmed that the data cannot be provided.

That said, CHEI is proposing a compromise between the HONI method and the intricate methodologies filed in recent applications.

Summary of Process used to NCP and CP

Below is a summary of the process used.

1. Collect hourly data by rate class for 2016-2020 from CHEI's power bills.
2. Use the per class monthly energy sold for each class to develop a retail per hour load.
   a) CHEI did not back out the supply facility loss fact as it is a constant (1.034) in years past. Theoretically, removing the supply facility losses shouldn't/wouldn't affect the profiles.
3. Since CHEI chose to use actual data, it did not deem it necessary to weather- normalize the data.
4. Calculate an average of the last five years.
   a) Although 2012-Oct 2021 is available, CHEI felt that a five-year average was more reflective of the current profiles than a 10-year average. CHEI notes that the amount of time and resources needed to data-mine through an additional 5 years of hourly data is not available nor reasonable in this case.
5. Use the same methodology of calculating the NCP, 4NCP, and 12NCP used in the HONI method and the recently filed methodologies.
6. The work file has been filed along with this application.

The three following tables show comparisons of the various load profiles. The first table shows the load profiles from the last Board approved cost allocation (2018). The second table shows what the profiles would have looked like if CHEI had used the traditional HONI method for its 2023 Test Year, and the third table shows the profiles using the compromised method proposed in this application.

Table 13 – 2018 Board Approved Load Profiles

Customer Classes		Residential	GS>50kW	Street Lighting	GS<50kW
CO-INCIDENT PEAK (kW)					
1 CP					
Total System CP	DCP1	5367	766	49	819
4 CP					
Total System CP	DCP4	19105	3053	164	3499
12 CP					
Total System CP	DCP12	47960	6774	373	9057
NON CO_INCIDENT PEAK (kW)					

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		Residential	GS>50kW	Street Lighting	GS<50kW
1 NCP					
Classification NCP from Load Data Provider	DNCP1	5734	873	62	1092
4 NCP					
Classification NCP from Load Data Provider	DNCP4	20762	3364	208	4139
12 NCP					
Classification NCP from Load Data Provider	DNCP12	49937	7751	574	11022

Table 14 –2023 Load Profiles using HONI method

Customer Classes		Residential	GS>50kW	Street Lighting	GS<50kW
CO-INCIDENT PEAK (kW)					
1 CP					
Total System CP	DCP1	5040	827	57	795
4 CP					
Total System CP	DCP4	17943	3298	191	3397
12 CP					
Total System CP	DCP12	45044	7319	434	8792
NON CO_INCIDENT PEAK (kW)					
1 NCP					
Classification NCP from Load Data Provider	DNCP1	5385	944	72	1060
4 NCP					
Classification NCP from Load Data Provider	DNCP4	19499	3635	243	4018
12 NCP					
Classification NCP from Load Data Provider	DNCP12	46900	8375	669	10699

Table 15 – 2023 Proposed Load Profiles

Customer Classes		Residential	GS<50	GS>50	USL	SL
CO-INCIDENT PEAK (kW)						
1 CP						
Total System CP	DCP1	4147	829	503	16	33
4 CP						
Total System CP	DCP4	15060	3188	2512	60	157
12 CP						
Total System CP	DCP12	39312	8798	7153	182	452
NON CO_INCIDENT PEAK (kW)						
1 NCP						
Classification NCP from Load Data Provider	DCP1	4147	829	738	18	47
4 NCP						
Classification NCP from Load Data Provider	DCP4	15208	3208	2750	66	176
12 NCP						
Classification NCP from Load Data Provider	DCP12	39312	8798	7153	182	458

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CHEI recognizes that the methodology is simplified compared to other methods filed and commits to 1) obtaining hourly retail data, 2) perfecting its method, or 3) using a more precise method in its next cost of service application.

7.2.2 Outputs to the Cost Allocation Model

The tables below show the output of the Cost Allocation Study.

Table 16 –Outputs to the CA model (O1 Revenue to Cost|RR)

	Total	1 Residential	2 GS <50	3 GS > 50 to 4999 kW	7 Street Light	9 Unmetered Scattered Load
Distribution Revenue at Existing Rates	$1,289,314	$1,053,554	$130,483	$67,385	$31,900	$5,992
Miscellaneous Revenue (mi)	$48,750	$40,578	$5,393	$665	$1,982	$133
		Miscellaneous Revenue Input equals Output				
Total Revenue at Existing Rates	**$1,338,064**	**$1,094,132**	**$135,876**	**$68,049**	**$33,882**	**$6,124**
Factor required to recover deficiency (1 + D)	0.9038					
Distribution Revenue at Status Quo Rates	$1,165,281	$952,202	$117,931	$60,902	$28,831	$5,415
Miscellaneous Revenue (mi)	$48,750	$40,578	$5,393	$665	$1,982	$133
Total Revenue at Status Quo Rates	**$1,214,031**	**$992,780**	**$123,324**	**$61,567**	**$30,813**	**$5,548**
Expenses						
Distribution Costs (di)	**$59,190**	$42,154	$8,438	$6,865	$1,552	$180
Customer Related Costs (cu)	**$282,040**	$252,051	$19,843	$1,655	$7,576	$915
General and Administration (ad)	**$411,927**	$354,243	$34,526	$10,856	$10,981	$1,320
Depreciation and Amortization (dep)	**$180,507**	$133,011	$24,804	$18,523	$3,685	$484
PILs (INPUT)	**$19,099**	$13,749	$2,797	$2,225	$277	$51
Interest	**$95,669**	$68,870	$14,010	$11,147	$1,385	$257
Total Expenses	**$1,048,432**	**$864,078**	**$104,419**	**$51,272**	**$25,456**	**$3,208**
Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Allocated Net Income (NI)	**$165,600**	$119,212	$24,251	$19,295	$2,398	$444
Revenue Requirement (includes NI)	**$1,214,031**	$983,290	$128,669	$70,567	$27,853	$3,652
		Revenue Requirement Input Equals Output				
Rate Base Calculation						
Net Assets						
Distribution Plant - Gross	**$8,984,567**	$6,526,711	$1,254,793	$976,349	$200,507	$26,206
General Plant - Gross	**$309,211**	$222,727	$44,097	$35,061	$6,428	$898
Accumulated Depreciation	**($2,708,489)**	($2,005,256)	($366,461)	($270,191)	($58,984)	($7,597)
Capital Contribution	**($2,108,164)**	($1,521,174)	($276,931)	($219,681)	($82,894)	($7,484)
Total Net Plant	**$4,477,124**	**$3,223,008**	**$655,498**	**$521,539**	**$65,057**	**$12,023**
Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	**$3,293,006**	$2,287,143	$522,125	$446,020	$27,214	$10,504
OM&A Expenses	**$753,157**	$648,448	$62,808	$19,376	$20,109	$2,416
Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0
Subtotal	*$4,046,164*	*$2,935,591*	*$584,933*	*$465,397*	*$47,324*	*$12,920*
Working Capital	**$303,462**	**$220,169**	**$43,870**	**$34,905**	**$3,549**	**$969**
Total Rate Base	**$4,780,587**	**$3,443,177**	**$699,368**	**$556,444**	**$68,606**	**$12,992**
		Rate Base Input Equals Output				

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Equity Component of Rate Base	**$1,912,235**	**$1,377,271**	**$279,747**	**$222,577**	**$27,443**	**$5,197**
Net Income on Allocated Assets	**$165,600**	**$128,702**	**$18,905**	**$10,295**	**$5,357**	**$2,340**
Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	**$165,600**	**$128,702**	**$18,905**	**$10,295**	**$5,357**	**$2,340**
RATIOS ANALYSIS						
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**100.97%**	**95.85%**	**87.25%**	**110.62%**	**151.90%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**$124,033**	$110,843	$7,207	($2,517)	$6,028	$2,472
		Deficiency Input equals Output				
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	$9,490	($5,346)	($9,000)	$2,959	$1,896
RETURN ON EQUITY COMPONENT OF RATE BASE	8.66%	9.34%	6.76%	4.63%	19.52%	45.03%

Table 17 –Outputs to the CA model (O2 Fixed Charge|Floor|Ceiling)

	1	2	3	7	9
Summary	**Residential**	**GS <50**	**GS > 50 to 4999 kW**	**Streetlight**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$9.21	$10.22	$20.64	$0.99	$4.55
Customer Unit Cost per month - Directly Related	$19.61	$22.44	$41.16	$2.19	$10.10
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$23.02	$26.37	$45.01	$3.26	$11.62
Existing Approved Fixed Charge	$37.44	$22.34	$194.70	$2.36	$22.39

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7.3 ALLOCATION OF REVENUE REQUIREMENT TO EACH CLASS

7.3.1 Class Revenue Analysis

Table 18 below shows the results of the cost allocation. These results compare and analyze the distribution costs and help the utility determine its 2023 proposed ratios.

Table 18 - Results of the Cost Allocation Study

Cost Allocation Results	REVENUE ALLOCATION (sheet O1)						
Customer Class Name	Service Rev Req (row40)		Misc. Revenue (mi) (row19)		Base Rev Req		Rev2Cost Expenses %
Residential	983,290	80.99%	40,578	83.24%	942,711	80.90%	100.97%
General Service < 50 kW	128,669	10.60%	5,393	11.06%	123,277	10.58%	95.85%
General Service > 50 to 4999 kW	70,567	5.81%	665	1.36%	69,902	6.00%	87.25%
Unmetered Scattered Load	3,652	0.30%	133	0.27%	3,520	0.30%	151.90%
Street Lighting	27,853	2.29%	1,982	4.07%	25,872	2.22%	110.62%
TOTAL	**1,214,031**	**100.00%**	**48,750**	**100.00%**	**1,165,281**	**100.00%**	

Table 19 below shows the allocation percentage and base revenue requirement allocation under existing rates, cost allocation results, and proposed 2018 proposed allocation.

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Table 19- Base Revenue Requirement Under 3 Scenarios

Customer Class Name	Proposed Base Revenue Requirement %					
	Cost Allocation Results		Existing Rates		Proposed Allocation	
Residential	80.90%	942,711	81.72%	952,284	81.27%	947,069
General Service < 50 kW	10.58%	123,277	10.12%	117,941	10.12%	117,947
General Service > 50 to 4999 kW	6.00%	69,902	5.23%	60,908	5.76%	67,080
Unmetered Scattered Load	0.30%	3,520	0.46%	5,315	0.36%	4,250
Street Lighting	2.22%	25,872	2.47%	28,833	2.48%	28,935
TOTAL	100.00%	1,165,281	100.00%	1,165,281	100.00%	1,165,281

Table 20 below shows the revenue offset allocation which resulted from the Cost Allocation Study (Sheet O1).

Table 20 - Revenue Offset Allocation as per Cost Allocation Study

Customer Class Name	Revenue Offsets	
	%	$
Residential	83.24%	40,578
General Service < 50 kW	11.06%	5,393
General Service > 50 to 4999 kW	1.36%	665
Unmetered Scattered Load	0.27%	133
Street Lighting	4.07%	1,982
TOTAL	100.00%	48,750

Table 21 shows the allocation of the service revenue requirement under the same three scenarios.

Table 21 - Service Revenue Requirement Under 3 Scenarios

Customer Class Name	Service Revenue Requirement $		
	Existing Rates	Cost Allocation	Proposed Allocation
Residential	992,862	983,290	987,648
General Service < 50 kW	123,334	128,669	123,339
General Service > 50 to 4999 kW	61,572	70,567	67,744
Unmetered Scattered Load	5,448	3,652	4,383
Street Lighting	30,815	27,853	30,917
TOTAL	1,214,031	1,214,031	1,214,031

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7.4 REVENUES-TO-COST RATIOS

7.4.1 Adjustment to Revenue to Cost Ratios

Table **23** on the next page shows Appendix 2-P of the Board Appendices, while Table 13 below shows the utility's proposed ratios. The Appendix provides information on previously approved ratios and proposed ratios. The section following Appendix 2-P addresses the method and logic used to update the ratios from the Cost Allocation study to the proposed ratios.

Table 22 – Proposed Revenue Allocation

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Target Range	
				Floor	Ceiling
Residential	1.01	1.00	0.01	**0.85**	**1.15**
General Service < 50 kW	0.96	0.96	0.00	**0.80**	**1.20**
General Service > 50 to 4999 kW	0.87	0.96	-0.09	**0.80**	**1.20**
Unmetered Scattered Load	1.52	1.20	0.32	**0.80**	**1.20**
Street Lighting	1.11	1.11	0.00	**0.80**	**1.20**

Table 23 - OEB Appendix 2-P

A) Allocated Costs				
Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	**%**
Residential	$687,249.00	77.36%	$983,289.58	80.99%
General Service < 50 kW	$107,690.00	12.12%	$128,669.26	10.60%
General Service > 50 to 4999 kW	$69,528.00	7.83%	$70,566.78	5.81%
Unmetered Scattered Load	$5,498.00	0.62%	$3,652.29	0.30%
Street Lighting	$18,461.00	2.08%	$27,853.40	2.29%
		0.00%		0.00%
Total	$888,426.00	100.00%	$1,214,031.32	100.00%

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B) Calculated Class Revenues

Classes (same as previous table)	(from CA - O1 row 18)			
	Column 7B Load Forecast (LF) X current approved rates	**Column 7C** L.F. X current approved rates X (1 + d)	**Column 7D** LF X proposed rates	**Column 7E** Miscellaneous Revenue
Residential	$942,711.28	$952,284.03	$947,069.44	$40,578.31
General Service < 50 kW	$123,276.55	$117,941.08	$117,946.60	$5,392.72
General Service > 50 to 4999 kW	$69,902.20	$60,907.68	$67,079.68	$664.58
Unmetered Scattered Load	$3,519.62	$5,315.01	$4,250.08	$132.67
Street Lighting	$25,871.62	$28,833.46	$28,935.47	$1,981.78
Total	$1,165,281.27	$1,165,281.27	$1,165,281.27	$48,750.05

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

Class		Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
		Most Recent Year:	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
		2018			
		%	%	%	%
Residential			100.97	100.44	85 - 115
General Service < 50 kW			95.85	95.86	80 - 120
General Service > 50 to 4999 kW			87.25	96.00	80 - 120
Unmetered Scattered Load			149.16	120.00	80 - 120
Street Lighting			110.63	111.00	85 - 115

D) Proposed Revenue-to-Cost Ratios

Class		Proposed Revenue-to-Cost Ratios			Policy Range
		2023	2024	2025	
		%	%	%	%
Residential		100.44			85 - 115
General Service < 50 kW		95.86			80 - 120
General Service > 50 to 4999 kW		96.00			80 - 120
Unmetered Scattered Load		120.00			80 - 120
Street Lighting		111.00			85 - 115

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Table 24 below shows the utility's proposed Revenue to Cost reallocation based on an analysis of the suggested results from the Cost Allocation Study vs. the Board imposed floor and ceiling ranges.

Table 24 – 2018 Allocation

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Target Range		Shortfall Reconciliation
				Floor	Ceiling	
Residential	1.01	1.00	0.01	0.85	1.15	5,132.2
General Service < 50 kW	0.96	0.96	0.00	0.80	1.20	-15.7
General Service > 50 to 4999 kW	0.87	0.96	-0.09	0.80	1.20	-6,177.3
Unmetered Scattered Load	1.52	1.20	0.32	0.80	1.20	1,165.3
Street Lighting	1.11	1.11	0.00	0.80	1.20	-104.5

* Ratios highlighted in pink fell outside of the floor to ceiling range.

The proposed Revenue to Cost ratio is adjusted by changing the allocation percentage for each class. The utility reviews and assesses the bill impacts for each class before adjusting the Revenue to Cost ratios.

The Residential class showed little cross-subsidization; therefore, CHEI did not propose any changes other than absorbing a small shortfall of $5,132 related to the GS50-4999kW and USL class.

The calculated ratio for Streetlight class fell above the imposed upper limit (ceiling) of 1.20%; as such, the utility proposes to bring it back down to the ceiling from 1.20. The utility understands that the revenue to cost ratio adjustment seems steep for a one-step adjustment; however, the total amount collected is relatively small; therefore, the impact on other classes is minimal. The reduction in revenue to cost ratio would reduce rates; therefore, the utility does not anticipate any pushback from the USL customer class.

In line with previous board policy, CHEI adjusted the R/C which feel lower than 1.00 to be equal. Therefore, both GS <50 and GS 50-4999 were adjusted upwards to a R/C ratio of 0.96.

Street Lighting was kept at 1.11 as it fell within the ranges.

The proposed cost re-allocation results in the shortfall allocation shown in the table below.

Table 25 Table of Shortfall reallocation

Customer Class Name	Shortfall Reconciliation
Residential	5,132.2
General Service < 50 kW	-15.7
General Service > 50 to 4999 kW	-6,177.3
Unmetered Scattered Load	1,165.3
Street Lighting	-104.5