Marginal Cost of Distribution Service Study and Implications for Rate Design

Prepared for the Public Service Company of New Hampshire

d/b/a Eversource Energy

June 11, 2024

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1 INTRODUCTION

Eversource Energy ("Eversource", or "The Company"), retained Charles River Project (CRA) to develop a system-wide marginal cost of service (MCOS) study for electricity distribution service in New Hampshire, corresponding with the five-year planning period 2024-2028. CRA has developed a forward-looking MCOS study that is consistent with the Company's prevailing engineering design standards and planning process. In the context of the utility distribution service, a marginal cost analysis requires evaluating the utility's planning and operational response to an anticipated change in the use of the distribution system in a given hour, as well as incremental unit costs driven by changes in customer connections and customer service requirements.

The results of the MCOS study are helpful to inform the direction of reforms that would be suitable for Eversource's distribution rate designs, in terms of structure, and rebalancing of revenue requirement by rate component, the possible improvements in Time of Use (TOU) rates. It provides useful information on the time-differentiated, system-wide average distribution value of load reductions, including those from customer-sited distributed generation (DG), and other distributed energy resources (DERs). It also provides information on the going forward marginal upstream distribution cost of meeting incremental peak load, which may be driven by addition of customers or incremental load by existing customers, such as those related to electric vehicles, or electric heat pump loads.

This report summarizes the approach that CRA has followed to estimate marginal costs for each component of service, and presents a summary of the results by existing time of day as well as a recommendation on potential suitable changes to TOU periods in the near future, based on expectations of system load changes.

2 CONFIGURATION OF THE DISTRIBUTION DELIVERY GRID

The starting point for a MCOS study is identifying the various elements and voltage levels of the Company's distribution system and group them up according to what drives new investment. In particular, the cost components can be grouped into two major categories:

1. Upstream primary distribution grid, which includes:

    - Distribution substations, including the upstream "bulk" stations that are fed from the transmission system (115 kV) and typically convert power to 34 kV or directly to 12 kV; about 85 percent of the customers are connected to the 34.5 kV system through small pole mounted step transformers that convert the load coming from the bulk system to either 12.47 kV or 4.16 kV.

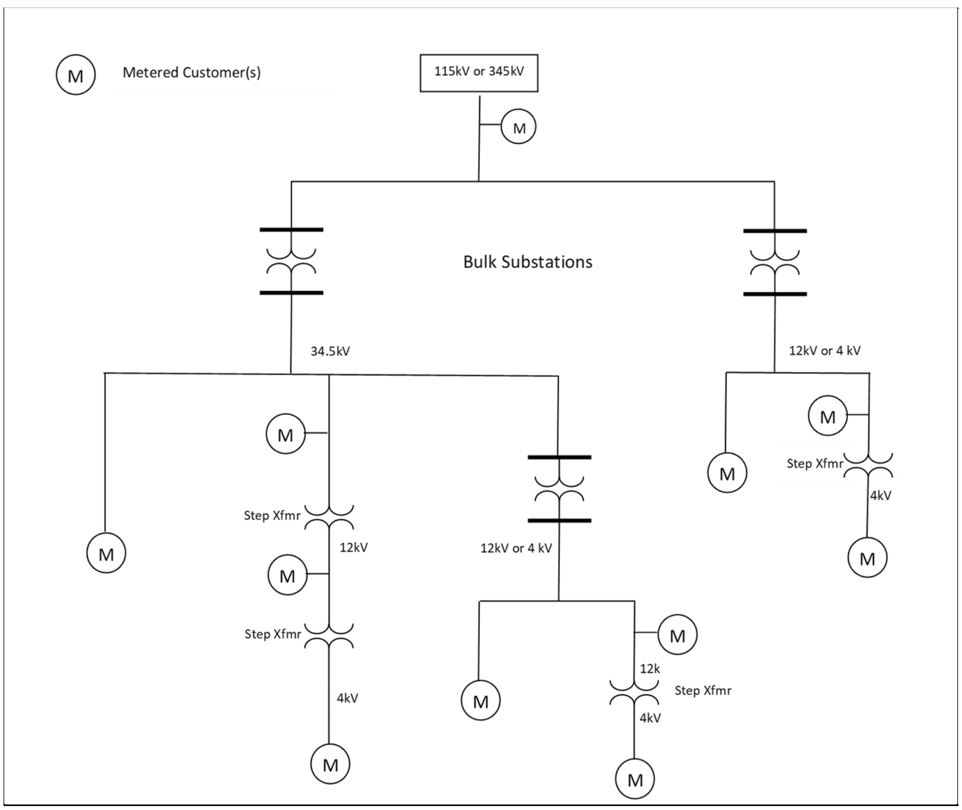
    - Lower voltage (non-bulk) distribution substations that convert load coming from the bulk station to 12 kV or 4 kV.

- Trunk-line ("backbone") primary distribution feeders, which start at the low side of the distribution substation and end at the point where the line branches to create a primary tap line. Circuit backbones can operate at 4.16, 12.47, 13.8 and 34.5 kV.

2. At the more local level, Eversource's distribution facilities include local primary taps, primary-to-secondary transformers, switchgear and secondary lines that connect the customer premise to the grid.

A small share of Eversource's service territory customers (about 30 MW) receive electricity from bulk stations that are located in Vermont. Eversource also serves wholesale distribution loads from its system that affect the required capacity at the distribution substation. Figure 1 is a simplified diagram of Eversource's electric distribution system.

Figure 1. Eversource New Hampshire's Electricity Distribution System



3 UPSTREAM DISTRIBUTION MARGINAL COSTS

3.1 Distribution Substation and Trunkline Feeder Marginal Investment

Eversource plans the distribution substations and trunkline feeders based on the forecasted distribution area's peak over time, and expand the capacity of these facilities as needed to meet peak load reliably. Estimating the marginal cost of distribution substation and trunkline feeder cost per kW of peak demand required identifying the budgeted growth-related investments in the Company's capital plan. The latest capital plan available for the MCOS study was for the period 2024-2028. The study computes growth-related capacity expansion project dollars of investment, stated in 2025$, and estimates the marginal investment per kW of added project capacity, which is then restated as investment per kW of peak load carrying capability. Ultimately, a system-wide average marginal cost is estimated taking into account the share of the system peak load that is served in capacity expansion areas relative to the total system peak.

A large share of the projects included in the Company's distribution capital plan are investments driven by the need to modernize the grid, improvements of asset condition, or replacement of aging facilities over the study period. The marginal distribution station cost analysis identified the share of project costs driven by growth-related capacity expansion, separately from the costs of modernizing the transformer or other costs that would take place regardless of changes in peak load.

Investments adding substation capacity to meet peak reliably can be differentiated between those addressing capacity deficiencies from the point of view of base loading conditions (N-0), and those related purely to reliability design violations related to loss of one transformer or feeder (N-1). The first investment type involves expanding a transformer when the peak load is expected to be at or above 95 percent (bulk stations) or 100% (non-bulk stations) of the nameplate rating of the transformer at any point during the five-year forecasted period. For N-1 projects, the criteria that generally drives expansion of transformer capacity in the case of bulk stations requires that the station peak load does not exceed the short-term emergency (STE) rating of the smallest transformer. In some cases, a substation has sufficient capacity to meet N-0 standard criteria if loaded at less than 95 percent, but it may not have sufficient contingency capacity, if for example has insufficient STE in the remaining transformer and/or insufficient circuit tie capacity. Solutions may involve a transformer replacement with larger capacity and/or increased circuit ties.

Our review of the Company's capital plan revealed that only a small number of the bulk related substation projects are intended to resolve capacity deficit to meet peak load under N-0 conditions. The majority of the bulk station projects during the study period are related to reliability tied to N-1 conditions.[1] Projects mainly related to expanding the transformer capacity due to poor asset condition were excluded from the MCOS study.

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[1] The identified N-1 solution depends on the severity of and the likelihood that customers fed from the station could experience loss of service, which has to do with the specific system configuration at the location such the potential to use a neighbour substation via load transfer capability already in place, as well as room for additional load transfer.

The project dollar amounts selected for the study include those substation and feeder projects with a formally identified investment solution in the capital plan, along with an unspecified share amount for primary trunkline feeders for which the Company provided an approximate estimate that would be likely to be related to meeting peak load growth. The capital plan includes detailed budgets for expansion investments for all areas expected to have overloading at stations as well as conceptual solutions where a capacity need has been identified that need to be further studied and likely to be implemented in the outer years of the plan.

The last step of the study involved a detailed analysis of expected distribution substation peak loads over the next five years, to estimate the share of the system that is likely to experience capacity expansion projects. This analysis was helpful to confirm areas for which the Company´s capital expansion plan has not yet identified or formalized a specific solution. This review involved a comparison of year 2028 forecasted peak load for each bulk and non-bulk substation compared to their respective nameplate ratings. A review of the substation loadings over that period determined that about 32 percent of the total retail peak load will be served from bulk distribution substations requiring capacity expansion, and about 1.7 percent will be served from non-bulk substations that are expected to undergo expansion within the five-year period. As a result, the marginal cost for bulk and non-bulk substations, separately averaged for the corresponding capacity-expanding areas, was adjusted by those percentages to estimate system-wide marginal distribution substation and feeder cost through the five-year study period.

The final step of the computation of marginal distribution substation cost required using marginal operation and maintenance ("O&M") expenses and loading factors to account for administrative and general ("A&G") expenses. Distribution O&M expenses are a component of marginal distribution cost, since they grow with the amount of plant in service. The MCOS identifies the annual distribution station O&M expenses during the period and divides it by the historical non-coincident distribution substation peak demands the Company's service territory. These expenses increase as the amount of plant in service does. We reviewed the Company's FERC Form 1 reports to identify annual distribution O&M expenses in recent years, 2019-2022. Upon review of the annual expense per kW (in constant dollars) in these years, he most recent four-year average expense was selected to represent future marginal O&M expenses per kW of station peak load. The derivation of annualized cost is provided in Appendix 1.

3.2 Time Differentiation

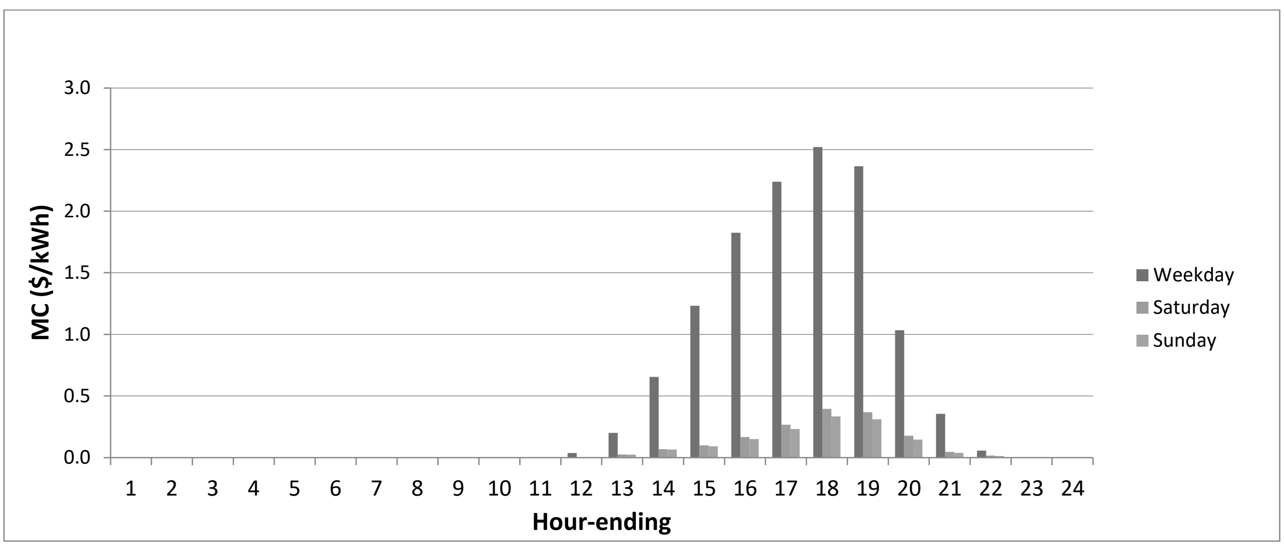
The MCOS produces estimates of marginal distribution costs that vary with timing of coincident peak load on the upstream primary distribution system. An appropriate time-differentiation requires assigning the annualized distribution substation and feeder marginal cost to hours, based on each hour's relative probability of being the annual peak. The probability of peak (PoP) analysis relied on the hourly distribution substation loads during the most three recent years (2021 - 2023). The probability of peak results are calculated by day-type (weekdays, weekends & holidays). The analysis accounted for relative lower carrying capability of this equipment in summer months as compared to the winter months. The allocated hourly costs were then averaged based on the Company's existing year-round time of use (TOU) periods for residential and commercial TOU rates. The existing residential TOU periods and an alternative that would maximize the TOU rate cost-reflectiveness going forward ("Alternative TOU") is included in Table 1.

Table 1. Existing Time of Day Costing Periods and Potential Alternative

Period	Residential TOD2	Alt. TOU with a 6-peak hour period
Peak:	Mo - Fri, 1 pm - 7 pm	Mo - Fri, 2 pm - 8 pm
Off peak:	Mo - Fri, 7 pm –1 pm Weekends, all hours	Mo - Fri, 8 pm - 2 pm Weekends, all hours

Figure 1 shows the resulting hourly probabilities of peak upon analysis of distribution substations, for a typical summer weekday and weekend across the four summer months of June-September. The months of July and August combined represent about 90 percent of the annual probability of peak, with the remaining 10 percent falling in the months of June and September.

Figure 1. Hourly Marginal Distribution Cost Profile, June – Sep



Summer weekday hour 1 pm currently is a potential hour of concern from the perspective of distribution planning, in areas where substations experience higher loads earlier in the day. System-wide, the annual peak tends to fall between 4 pm and 7 pm, as captured by the probability of peak analysis. A peak period that concentrates the highest six peak hours starting at 2 pm and ending at 8 pm would better align with the current trend of distribution peaks shifting towards the late evening. This was tested further by running a sensitivity that adjusted hourly historical loads to incorporate a profile of PV loads, based on expected growth of BTM PV capacity by year 2026. The impact of this sensitivity on the choice of periods was moderate given that NH is not expecting a significant growth in PV generation, compared to other states by 2026. Nevertheless, it reinforced the trend by resulting in a higher probability of peak in summer weekday 5 pm to 8 pm, and further decreasing the probability of peak in early to mid-afternoon hours. A regression of hourly marginal cost on potential peak periods using dummy variables and based on the hourly probabilities of peak confirmed that a 6-hour peak period starting at 2 pm and ending at 8 pm would align best with the underlying hourly cost profile, and be more cost-reflective than the current RTOD2 peak period, as well as leading to a slightly higher year-round peak price signal.

4 LOCAL DISTRIBUTION FACILITY COSTS

The local distribution facilities, including secondary lines, line transformers, and local primary taps, are less extensively shared than the distribution substations. Eversource engineers decide on the type of the required facilities using sizing standards that take into consideration the number of customers who are expected to use those facilities, their maximum loads over the service life of the facilities and other parameters such as the level of maximum transformer loading that can be expected to be safe. Thus, the marginal cost of local distribution facilities is strongly influenced by the connected customers' "design demands", i.e., the maximum long-term load that customers may impose on the transformer and conductor. Fluctuations of actual customer demand from month to month or even year to year are not expected to require a change in the installed facility.

Local distribution facility costs were estimated for residential, commercial and industrial customers and type of customer within each major rate class. To estimate the typical installed cost of distribution facilities, Eversource provided an extensive sample of work orders associated with customer connection jobs for single-phase and three-phase customers in the most recent three years (2015-2023). The sample was considered large enough to be representative of the entire service territory. CRA reviewed the work orders and computed the average per kW cost of distribution facilities, after customer contributions as per the line extension policy, as well as average design demand by class. Marginal facilities costs were estimated as the monthly distribution cost per kW of customer's design demand. Separate cost of facilities were estimated for underground vs. overhead, single-phase or three-phase.

The marginal distribution facility O&M expenses were estimated using recent historical data, since a forecast of O&M expenses was not available. The average expense per kW of design demand averaged 2018 -2022 was used as the estimated future distribution facilities O&M expense going forward. The total design demand was the product of customer counts and per-customer average design demand estimates by rate.

1 MARGINAL CUSTOMER COSTS

1.1 Meter and Service Costs

The Company provided current installed cost of meters by class. The average per-meter O&M expense from recent years was used to represent the marginal level of these expenses. The average service drop cost was calculated by applying inflation to the prior MCOS study.

1.2 Customer Accounts and Customer Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are a function of customers on the system. FERC Form 1 recent customer account and service expense levels were divided by class weighted customers to obtain an estimate of customer accounts expense per weighted customer. We estimated that the marginal customer service and informational expenses, which include the costs of disseminating information to consumers, vary with the number of customers on the system and are, therefore, marginal. Expenses associated with EE programs to promote demand side measures, were omitted from the study since they are not marginal with respect to customer additions. The same procedure was used to allocate customer accounts expenses using the class weights developed for these expenses in embedded cost of service study. The average of 2020 through 2022 values was considered a reasonable proxy of the future marginal per-customer expense except for the FERC Acc. 904, for which only the average value of 2022 and 2023 was selected to recognize the declining trend in this expenses.

2 ANNUALIZED MARGINAL COSTS

The MCOS annualized marginal cost for each component of service by multiplying all marginal investment by an annual economic carrying charge, expressed as a percentage, and adjusting the investment per unit by the general plant loading factor and a plant-related A&G loading factor. To these costs, marginal O&M, adjusted by non-plant related A&G expenses, and revenue requirements for working capital, were added to obtain the total annualized marginal unit cost. A summary of the calculation of these components is provided below.

2.1 Loaders

Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. The MCOS estimated loading factors, in particular, plant-related A&G, non-plant-related A&G and general plant loading factors. Accounts not marginal with respect to other expenses or plant were excluded. The MCOS uses a non-plant-related A&G loader estimated based on the average ratio of non-plant-related A&G expenses (FERC Accounts 926 and 408.1) to O&M expenses over the period 2012-2022.

Average property and terrorism insurance rate, which applies to distribution substations only, was used to estimate insurance loading factor. General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. These may grow with electric plant expansion. The MCOS uses a General Plant loader based on a regression of cumulative net additions to general plant on cumulative net additions to total plant (less General plant).

2.2 Economic Carrying Charges

To convert estimates of marginal distribution plant investment into annual costs requires estimating an economic carrying charge that reflects the elements of revenue requirement associated with incremental plant. Inputs to the economic carrying charge calculation include: the utility's incremental cost of capital (mix of debt and equity and their respective long-term market costs), the expected inflation rate for that type of plant, net of technical progress, and the average service life and patterns of failure ("Iowa curve") for each type of plant. The ECC calculation uses the average long-term incremental cost of debt and the long-term incremental cost of equity over the next ten years.

2.3 Working capital

The computation of working capital includes cash, materials, supplies and prepayments. The revenue requirement associated to working capital reflects the Company's weighted average cost of capital plus an income tax component that recognizes the taxable equity portion of the return on capital.

3 SUMMARY OF MARGINAL UNIT COSTS

3.1 Marginal Distribution Substation and Trunkline Feeder Costs

Table 2 shows the system-wide average marginal distribution station and primary trunkline feeder costs stated on a per-kW-month basis for a secondary-connected customer. The results are shown by peak/off-peak periods using three alternatives.

Table 2. Time-differentiated Year-Round System-Wide Marginal Upstream Distribution Costs stated as per-kW and per kWh Costs

	Marginal Costs On a per-kW basis		Marginal Costs On a per-kWh basis	
	Marginal Cost of Dist. Sub At Secondary	Marginal Cost of Dist. Sub At Primary	Marginal Cost Dist. Sub At Secondary	Marginal Cost Dist. Sub At Primary
	(2025 $/ kW-mo)	(2025 $/ kW-mo)	(2025 $/kWh)	(2025 $/kWh)
Under Current Residential TOU Periods				
Peak	$1.045	$1.039	$0.00837	$0.00832
Off-Peak	$0.225	$0.224	$0.00037	$0.00037
Annual Average	**$1.270**	**$1.263**	**$0.00174**	**$0.00173**
Under Current Commercial TOU Periods				
Peak	$1.167	$1.161	$0.00431	$0.00429
Off-Peak	$0.103	$0.102	$0.00022	$0.00022
Annual Average	**$1.270**	**$1.263**	**$0.00174**	**$0.00173**
ALTERNATIVE TOU				
TOU Peak 2 pm - 8pm				
Annual On-Peak Av	$1.082	$1.076	$0.00866	$0.00862
Annual Off-Peak Av	$0.188	$0.187	$0.00031	$0.00031

3.2 Marginal Local Distribution Facilities Costs

Table 3 summarizes the monthly marginal local distribution facilities costs, stated as a fixed monthly cost per kW of customer's design demand (which may be the basis for a per-contract or customer-specific subscription demand). It is also stated as a fixed per customer cost by class, using the average customer design demand. Local distribution facilities cost in the fixed charge assumes that the average kW of transformer capacity required per customer is representative of the majority of the customers in the same class.

Table 3: Monthly Marginal Local Distribution Facilities Costs

Customer Class		Monthly Distribution Facilities Cost (after CIAC) per kW of Design Demand	Average Customer Design Demand	Monthly Facilities Cost for the Average Custome
		(2025 $/kW/mo)	(kW)	($/Cust/mo.)
R-P&L	Residential Power & Light	$3.30	7.5	$24.76
R-OTOD	Residential OTOD	$3.30	10.0	$33.01
R-C-WH	Residential Controlled WH	$3.30	0.8	$2.64
R-LCS	Residential LCS	$3.30	2.5	$8.25
R-UC-WH	Residential Uncontrolled WH	$3.30	0.8	$2.64
GS-P&L-P1	General Service Power & Light 1 Phase	$3.30	17.0	$56.12
GS-P&L-P3	General Service Power & Light 3 Phase	$1.91	82.0	$156.57
GS-OTOD-P1	General Service OTOD 1 Phase	$3.30	17.0	$56.12
GS-OTOD-P3	General Service OTOD 3 Phase	$1.91	82.0	$156.57
GS-UC-WH	General Service Uncontrolled WH	$3.30	0.70	$2.31
GS-LCS-P1	General Service LCS 1 Phase	$3.30	4.77	$15.75
GS-LCS-P3	General Service LCS 3 Phase	$1.91	4.8	$9.11
GS-SH	General Service Space Heating	$3.30	4.1	$13.40

3.3 Marginal Monthly Customer Costs

Table 4 summarizes the monthly marginal customer cost by customer class.

Table 4. Monthly Marginal Customer Costs

Customer Class		Monthly Marginal Customer Cost	Sum of Monthly Marginal Dist. Facilities Cost and Customer Cost
		($/Cust/mo.)	($/Cust/mo.)
R-P&L	Residential Power & Light	$18.14	$42.90
R-OTOD	Residential OTOD	$25.73	$58.74
R-C-WH	Residential Controlled WH	$2.96	$5.60
R-LCS	Residential LCS	$3.52	$11.77
R-UC-WH	Residential Uncontrolled WH	$2.91	$5.55
GS-P&L-P1	General Service Power & Light 1 Phase	$19.96	$76.08
GS-P&L-P3	General Service Power & Light 3 Phase	$36.90	$193.47
GS-OTOD-P1	General Service OTOD 1 Phase	$26.04	$82.16
GS-OTOD-P3	General Service OTOD 3 Phase	$37.01	$193.57
GS-UC-WH	General Service Uncontrolled WH	$4.48	$6.79
GS-LCS-P1	General Service LCS 1 Phase	$4.99	$20.74
GS-LCS-P3	General Service LCS 3 Phase	$11.62	$20.73
GS-SH	General Service Space Heating	$3.81	$17.21
GV (w/o Rate B)	Rate GV	$89.78	$89.78
GV-B (<115 KV)	Rate GV – (Rate B; < 115 KV level)	$89.76	$89.76
LG (w/o Rate B)	Rate LG	$99.23	$99.23
LG-B (<115 KV)	Rate LG – (Rate B; < 115 KV level)	$99.22	$99.22

4 USING MARGINAL COSTS IN RATE DESIGN

Economic theory holds that economic efficiency is maximized when customers face prices that reflect the marginal cost of using more units of the product or service. In the context of utility service, economic efficiency means achieving an efficient use of the grid so that expansion of the infrastructure and resources is done at the lowest overall cost while maintaining reliability. System-wide marginal costs are helpful for setting retail rates, both for determining the proper time-differentiation as well as to guide the level of the kWh and kW charges. Cost recovery of sunk costs (the difference between class marginal costs and class allocated fixed costs) should primarily be reconciled as much as possible through the least elastic portions of the bill, namely the basic fixed charge, to reduce deviation of customer's usage from efficient electricity use when pricing at marginal costs. Table 5 below summarizes the marginal unit cost by component and shown in two alternative ways for the facilities costs and for the primary marginal cost.

Table 5. Summary of Marginal Unit Costs by Rate Class

		Local Distribution Facility Marginal Costs		Primary Distribution Marginal Cost (*Existing TOU Periods*)		
		Per cust.	Per kW		Demand	Energy
Service Classification	**Customer Cost**	**Monthly Facilities Cost per Customer**	**Montly per Design Demand kW**	**TOU Period**	**Per-kW of Metered Max Demand**	**Restated as $/kWh**
	($/Cust./mo)	**($/Cust./mo)**	**($/kW-mo)**		**($/kW-mo)**	**($/kWh)**
R-P&L	18.14	24.76	3.30	All	1.270	0.00174
R-OTOD	25.73	33.01	3.30	On-Peak	1.045	0.00837
				Off-Peak	0.225	0.00037
R-C-WH	2.96	2.64	3.30	All	1.270	0.00174
R-LCS	3.52	8.25	3.30	All	1.270	0.00174
R-UC-WH	2.91	2.64	3.30	All	1.270	0.00174
GS-P&L-P1	19.96	56.12	3.30	All	1.270	0.00174
GS-P&L-P3	36.90	156.57	1.91	All	1.263	0.00173
GS-OTOD-P1	26.04	56.12	3.30	On-Peak	1.167	0.00431
				Off-Peak	0.103	0.00022
GS-OTOD-P3	37.01	156.57	1.91	On-Peak	1.161	0.00429
				Off-Peak	0.102	0.00022
GS-UC-WH	4.48	2.31	3.30	All	1.270	0.00174
GS-LCS-P1	4.99	15.75	3.30	All	1.270	0.00174
GS-LCS-P3	11.62	9.11	1.91	All	1.263	0.00173
GS-SH	3.81	13.40	3.30	All	1.270	0.00173
GV	89.78			All	1.263	0.00173
GV-B (<115 KV)	89.76	na	n/a	All	1.263	0.00173
LG	99.23	na	na	All	1.263	0.00173

APPENDIX A: DERIVATION OF ANNUALIZED MARGINAL COSTS

Tables A.1 through A.5 show the steps used in the derivation of the annualized marginal distribution substation and trunkline feeder costs, annualized marginal cost of local distribution facilities, and the annualized marginal customer-related costs.

Table A.1. Annualized Distribution Substation Costs

	System-Wide Average Station and trunkline feeder (2025 $/kW)
System-Wide Marginal Investment per kW of added peak load carrying capability (2024 - 2028)	$126.06
Economic Carrying Charge	7.60%
General Plant Loader	1.0981
Plant-related A&G Loader	1.0002
Subtotal Annualized Capital Costs	$10.52
O&M Expenses	
Annual Marginal O&M Expenses per kW of Peak Load	$3.71
A&G Loading 1.033 (Non-plant Related)	1.033
Working Capital Revenue Requirement	
Material, Supplies and Prepayments	$0.094
Cash Working Capital Allowance	$0.044
Total Annualized Marginal Station Cost ($/kW-yr)	**$14.49**

Table A.2 Annualized Distribution Facilities Costs, Residential, GS

	Residential Power & Light	Residential OTOD	Residential Controlled WH	Residential LCS	Residential Uncontrolled WH	General Service Power & Light 1 Phase	General Service Power & Light 3 Phase	General Service OTOD 1 Phase	General Service OTOD 3 Phase
	----------------- (2025 $ per kW of Design Demand) -----------------								
Marginal Investment per kW of Design Demand	$270.55	$270.55	$270.55	$270.55	$270.55	$270.55	$138.90	$270.55	$138.90
General Plant Loading	1.0981	1.0981	1.0981	1.0981	1.0981	1.0981	1.0981	1.0981	1.0981
Annual Economic Carrying Charge Related to Capital Investment	8.29%	8.29%	8.29%	8.29%	8.29%	8.29%	8.29%	8.29%	8.29%
Annualized Costs	$24.63	$24.63	$24.63	$24.63	$24.63	$24.63	$12.64	$24.63	$12.64
Annual O&M Expense per kW of Design Demand	$14.15	$14.15	$14.15	$14.15	$14.15	$14.15	$9.73	$14.15	$9.73
With A&G Loading x 1.0332									
	14.62	14.62	14.62	14.62	14.62	14.62	10.05	14.62	10.05
Subtotal Distribution Facilities Marginal Costs	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$22.69	$39.24	$22.69
Working Capital Rev. Req.									
Material, Supplies and Prepayments	0.20	0.20	0.20	0.20	0.20	0.20	0.10	0.20	0.10
Cash Working Capital Allowance	0.17	0.17	0.17	0.17	0.17	0.17	0.12	0.17	0.12
Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-yr)	**$39.61**	**$39.61**	**$39.61**	**$39.61**	**$39.61**	**$39.61**	**$22.91**	**$39.61**	**$22.91**

Table A.3. Annualized Customer-Related Marginal Costs for Residential Customers

	Residential Power & Light	Residential OTOD	Residential Controlled WH	Residential LCS	Residential Uncont. WH
Installed Meter Cost	$169.27	$713.73	$168.39	$171.65	$164.69
With General Plant Loading	$185.87	$783.75	$184.91	$188.49	$180.85
Annual ECC related to Capital Investment	8.60%	8.60%	8.60%	8.60%	8.60%
Subtotal Annualized Meter Costs	$15.99	$67.41	$15.90	$16.21	$15.55
Meter O&M Expenses with A&G Loading	$12.06	$50.87	$12.00	$12.24	$11.74
Installed Service Cost	$1,497.06	$1,497.06	$0.00	$0.00	$0.00
With General Plant Loading x 1.0981	$1,643.92	$1,643.92	$0.00	$0.00	$0.00
Annual ECC related to Capital Investment	8.29%	8.29%	8.29%	8.29%	8.29%
Annualized Service Drop Costs	136.26	136.26	-	-	-
Customer services					
Customer Accounts net of Uncoll.	$39.51	$39.51	$7.01	$12.92	$7.01
Customer Service & Informational Expenses	$0.14	$0.14	$0.00	$0.00	$0.00
With A&G Loading x 1.0332					
(Non-plant Related)	$40.97	$40.97	$7.24	$13.35	$7.24
Uncollectible expenses	$10.43	$10.43	$0.00	$0.00	$0.00
Sub-total Annualized Cost of Meter, Service and Customer Expenses	$215.71	$305.94	$35.15	$41.80	$34.54
Working Capital Rev. Req.					
Material, Supplies and Prepayments	$1.37	$1.81	$0.14	$0.14	$0.14
Cash Working Capital	$0.61	$1.05	$0.22	$0.29	$0.22
Total Annual Customer Marginal Costs	**$217.69**	**$308.81**	**$35.51**	**$42.23**	**$34.89**

Table A.4. Annualized Customer-Related Marginal Costs for General Service

	GS P&L 1 Phase	GS P&L 3Phase	GS OTOD 1 Phase	GS OTOD 3 Phase	GS Uncont. WH	GS LCS 1 Phase	GS LCS 3 Phase	GS Space Heating
Installed Meter Cost	$277.42	$752.74	$713.73	$760.23	$277.42	$277.42	$752.74	$222.81
With General Plant Loading	$304.64	$826.59	$783.75	$834.80	$304.64	$304.64	$826.59	$244.67
Annual ECC related to Capital Investment	8.60%	8.60%	8.60%	8.60%	8.60%	8.60%	8.60%	8.60%
Subtotal Annualized Meter Costs	$26.20	$71.09	$67.41	$71.80	$26.20	$26.20	$71.09	$21.04
Meter O&M Expenses with A&G Loading	$19.77	$53.65	$50.87	$54.19	$19.77	$19.77	$53.65	$15.88
Installed Service Cost	$1,497.06	$2,844.76	$1,497.06	$2,844.76	$0.0	$0.0	$0.0	$0.0
With General Plant Loading x 1.0981	$1,643.92	$3,123.83	$1,643.92	$3,123.83	$0.0	$0.0	$0.0	$0.0
Annual ECC related to Capital Investment	8.29%	8.29%	8.29%	8.29%	8.29%	8.29%	8.29%	8.29%
Annualized Service Drop Costs	136.26	258.93	136.26	258.93	-	-	-	-
Customer services								
Customer Accounts net of Uncoll.	$47.98	$47.98	$47.98	$47.98	$7.01	$12.92	$12.92	$8.06
Customer Service & Informational Expenses	$0.141	$0.141	$0.141	$0.141	$0.0	$0.0	$0.0	$0.0
With A&G Loading x 1.0332 (Non-plant Related)	$49.72	$49.72	$49.72	$49.72	$7.24	$13.35	$13.35	$8.33
Uncollectible expenses	$5.29	$5.29	$5.29	$5.29	$0.00	$0.00	$0.00	$0.00
Sub-total Annualized Cost of Meter, Service and Customer Expenses	$237.24	$438.68	$309.55	$439.92	$53.22	$59.33	$138.10	$45.25
Working Capital Rev. Req.								
Material, Supplies and Prepayments	$1.46	$2.95	$1.81	$2.96	$0.23	$0.23	$0.62	$0.18
Cash Working Capital	$0.80	$1.19	$1.15	$1.19	$0.31	$0.38	$0.77	$0.28
Total Annual Customer Marginal Costs	**$239.50**	**$442.82**	**$312.52**	**$444.07**	**$53.76**	**$59.93**	**$139.49**	**$45.72**

Table A.5. Annualized Customer-Related Marginal Costs Large Commercial Customers

	GV (w/o Rate B)	GV-B (<115 KV)	LG (w/o Rate B)	LG-B (<115 KV)
Installed Meter Cost	$752.74	$752.74	$1,120.96	$1,120.96
With General Plant Loading x 1.0981	$826.59	$826.59	$1,230.93	$1,230.93
Annual ECC related to Capital Investment	8.60%	8.60%	8.60%	8.60%
Annualized Meter Costs	$71.09	$71.09	$105.87	$105.87
Meter O&M Expenses with A&G loading	$53.65	$53.65	$79.90	$79.90
Customer services				
Customer Accounts less Uncoll.	$450.92	$450.92	$450.92	$450.92
Customer Service & Informational Expenses	$446.15	$446.01	$425.76	$425.62
With A&G Loading x 1.0332 (Non-plant Related)	$926.85	$926.71	$905.78	$905.64
Uncollectible expenses	$13.83	$13.83	$86.99	$86.99
Sub-total Annualized Cost of Meter and Customer Expenses	$1,065.44	$1,065.29	$1,178.54	$1,178.40
Working Capital Rev. Req.				
Material, Supplies and Prepayments	$0.62	$0.62	$0.92	$0.92
Cash Working Capital	$11.26	$11.25	$11.32	$11.31
Total Annual Customer Marginal Costs	**$1,077.31**	**$1,077.16**	**$1,190.78**	**$1,190.63**

Table A.6. Annualized Customer-Related Marginal Costs Streetlighting

	Rate OL			Rate EOL
	HP-Sodium	Metal Halide	LED	LED
Installed Service Cost	$86.75	$73.64	31.83	86.75
With General Plant Loading x 1.0981	$95.26	$80.86	$34.95	$95.26
Annual ECC related to Capital Investment	8.29%	8.29%	8.29%	8.29%
Annualized Service Drop Costs	7.90	6.70	2.90	7.90
Customer services				
Customer Accounts less Uncoll.	$3.45	$3.45	$3.45	$3.45
Customer Service & Informational Expenses	$0.00	$0.00	$0.00	$0.00
With A&G Loading x 1.0332 (Non-plant Related)	$3.56	$3.56	$3.56	$3.56
Uncollectible expenses	$0.01	$0.01	$0.01	$0.01
Sub-total Annualized Cost of Service Drop and Customer Service	11.47	10.28	6.47	11.46
Working Capital Rev. Req.				
Material, Supplies and Prepayments	$0.07	$0.06	$0.03	$0.07
Cash Working Capital	$0.04	$0.04	$0.04	$0.04
Total Annual Customer Marginal Costs	**11.58**	**10.38**	**6.54**	**11.57**