Otter Tail Power Company

MARGINAL COST OF ELECTRICITY SERVICE STUDY

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TABLE OF CONTENTS

1 INTRODUCTION

Charles River Associates was retained to prepare a Marginal Cost of Service Study (MCOS) on behalf of Otter Tail Power Company. This report summarizes the study approach to estimate OTP's overall marginal costs of service applicable during the period 2025 to 2029.

A MCOS study informs the appropriate rate structure, differences in the hourly marginal cost associated with an additional kW of usage, appropriate time-of-use (TOD) periods and price differentials across periods. OTP's electricity marginal cost analysis required a review of the Midwest Independent System Operator (MISO)'s wholesale energy and capacity market rules and prices, expected near-term capacity conditions in the MISO region, transmission tariffs, Company's planned transmission and distribution substations and feeders, local connection costs, and customer data.

The study computes all hourly marginal costs that change with time of day. These include generation capacity, energy, transmission and upstream distribution marginal costs. In addition, the study estimates marginal customer-related and local distribution costs by rate class. This report summarizes the calculation methods employed and the resulting marginal costs.

2 TIME OF DAY PERIODS

The pricing periods used in this study are generally aligned with the peak, mid-peak and off-peak periods that the Company uses for time of day (TOD) rates for large general service rates. The periods differ by season, i.e., a 4-month summer season (June – September) and an 8-month winter (May – October). In order for rates to provide efficient price signals to customers that incentivize economically efficient consumption patterns, rates that vary with usage would ideally reflect as close as possible the underlying marginal unit cost, and the differentials by period. TOD rates should promote efficiency in usage and technology adoption decisions through enhanced, more cost-reflective TOD periods. This is important not just for all customers and particularly so for customers that exhibit increasingly flexible loads, thanks to adoption of electric vehicles (EVs), solar generation and heat pump loads. Table 1 below summarizes the Time of Day (TOD) periods.

Table 1. OTP Time of Day and Seasonal Costing Periods

Summer: June – September	
Peak:	Monday - Friday, 2 pm - 8 pm
Mid-Peak:	Monday - Friday, 12 pm - 2 pm, 8 pm - 10 pm Weekends, 2 pm - 8 pm
Off-Peak:	Monday - Friday, 9 pm – Noon next day; Weekends: 8 pm – 2 pm
Winter: All other months	
Peak:	Monday - Friday, 7 am - 10 am
Mid-Peak:	Monday - Friday, 5 am - 7 am, 10 am - 9 pm
Off-Peak:	Monday - Friday, 9 pm - 5 am Weekends, all hours

3 MARGINAL GENERATION COSTS

3.1 Marginal Energy Costs

In a competitive electricity market, the marginal cost of generation in any given hour includes the market price of energy, as well as the market price of capacity if the change in demand in that hour impacts the risk of loss of load. An increment of native load in any hour requires OTP to purchase more energy at the prevailing market prices or sell less to the market if OTP is a net seller in that hour. As a member of MISO's electricity wholesale market, OTP buys and sells on an hourly basis as needed to achieve the lowest cost of serving its retail customers. To update OTP's marginal energy costs, we relied on the latest forecast available of MISO's forward monthly peak and off-peak prices for the period January 2025 through December 2029.

Forward market prices reflect MISO forward market energy prices for the Intercontinental Exchange (ICE), measured at the OTP node by using historical hourly price differentials between the Indiana node and OTP's node. We converted the monthly energy peak and off-peak forward prices into hourly prices based on average variation in hourly day-ahead LMPs during the two-most recent years.

To convert market prices to energy marginal costs at customers' meters, market prices were adjusted for the financial cost of working capital required and the marginal energy losses incurred from the OTP hub to customer meters. Section 8 presents the marginal energy costs by costing periods.

3.2 Marginal Generation Capacity Costs

OTP's marginal cost of generation capacity is triggered by increments in OTP's capacity obligation under MISO resource adequacy rules. MISO currently has a four-season capacity construct that replaced its single annual resource adequacy requirement. The seasons include summer, fall, winter and spring seasons, each with 3-month duration. The zone 1 market capacity price by season represents OTP's opportunity costs when an OTP customer increases his usage at the time of MISO's seasonal coincident peak.

OTP's marginal generation capacity cost in any hour on a planning basis is a function of: (a) the forecasted market capacity price which varies with the expected level of capacity surplus in MISO-wide region (b) the required planning reserve margin (PRM), and (c) and the probability that each hour is coincident with MISO's seasonal net peak load hour triggering the capacity obligation and a need to potentially procure more or sell less capacity in the market to maintain the required PRM. This

CRA relied on a 5-year forecast (2025-2029) of annual MISO capacity market prices for the MISO zone 1, developed by Wood McKenzie as the starting point. CRA then apportioned the annual price to each of the four seasons taking into account MISO's published information on current and future seasonal PRMs and relative LOLE and expected capacity conditions within the season for the period 2025 - 2029.[1]

To estimate marginal hourly generation capacity costs for the 5-year period, the MCOS study relied on a probability of net peak load analysis conducted for each of the four seasons defined under MISO seasonal construct. Modelling of hourly generation capacity cost allocation involved a review of hourly net system loads in MISO during the prior 3 years, along with identifying the approximate impact on hourly region-wide loads from additions of solar and wind generation expected in MISO during the upcoming 3 years.

In the final step, the hourly probabilities of peak were accumulated by costing period for the two seasons, summer (June-Sep) and winter (Oct – May) that are used in OTP's retail rates. Table 2 in Section 8 summarizes the marginal generation capacity cost averaged for the five-year planning period 2025/26-2029/30.

4 MARGINAL TRANSMISSION COSTS

OTP operates in a joint pricing zone within the Midwest ISO. OTP's transmission system consists of 345 kV, 230 kV, 115 kV, 69 kV and 41.6 kV facilities. Any transmission lines above 100 kV are under the functional control and planning of MISO and included as part of the Network Upgrade Charge (NUC). OTP has operational control of its transmission facilities at or below 100 kV.

These facilities, plus those projects above 115 kV that are below $5 million, are considered by FERC in setting MISO Network Integration Transmission Service (NITS) rate for its Control Area. OTP's control area NITS rate also includes the transmission facilities of Great River Energy (GRE). Both the MISO NITS and NUC charges are constant every month, reflecting 1/12 of the applicable annual revenue requirement per kW.

4.1 Network Integration Transmission Service Rate

The NITS rate is recovered from each transmission user in the OTP Pricing Zone based on their monthly coincident peak loads. An increase in monthly coincident peak triggers an increase in MISO transmission bill, thus, the NITS rate represents a financial marginal cost to OTP.

The forecasted monthly NITS rates for the period 2025-2029 were allocated to hours based on the probability that a given hour is the monthly peak hour in OTP's Control Area. The hourly transmission costs were adjusted by marginal losses and summarized by costing period. Forecasting annual changes to OTP's NITS rate required a review of OTP's transmission budgets for 115-kV below $5 million, 41.6 kV and 69 kV projects expected to come into service by or before 2029, excluding projects that qualify for recovery through the transmission cost rider (TCR). MISO's estimates of annual

[1] MISO Report, "Planning Year 2025-2026 Loss of Load Expectation Study Report". MISO conducts a Loss of Load Expectation (LOLE) study that determines the required resources and Planning Reserve Margin (PRM) required to achieve the target LOLE level for each season, and PRMs calibrated to a LOLE of 1 day in 10 years.

carrying charge to OTP's transmission investment was used to compute an annual incremental revenue requirement for the OTP Pricing Zone's NITS. Projections of 12 monthly OTP's control area CPs were used to estimate annual changes to OTP's NITS charge.

Section 8 provides the time-differentiated marginal transmission costs, averaged for 2025-2029 and stated both on a per-kWh and a per-kW basis.

4.2 Network Upgrade Charge

To estimate the second component of the financial transmission marginal cost, the NUC rate, we relied on MISO's calculation of projected annual revenue requirement as per Schedule 26. The cost of all new projects rated 345 kV and above with a project cost of $5M or greater is allocated through a hybrid method, so that 20% of the costs are allocated on a system-wide basis and the remaining 80% are allocated to planning sub-regions (West, Central and East) and pricing zones under a method that differs between economic and reliability projects. Costs of transmission projects rated below 345-kV, get allocated on a zonal basis based on each pricing zone's contribution to MISO's average 12 CPs. To estimate the NUC charges corresponding to the OTP Pricing Zone for the period 2025 through 2029, MISO's NUC-related annual transmission revenue requirements for OTP's pricing zone were divided by the sum of 12 CPs in the OTP zone to establish the corresponding NUC rate. The projected NUC charges were time-differentiated using the probability of peak analysis of OTP's control area.

4.3 Multi-Value Projects

In addition to the NITS and NUC charges, MISO included a transmission project rate category designated to recover the cost of Multi-Value Projects. These projects are driven by energy policy mandates and can address various reliability and/or economic issues, affecting multiple transmission zones. FERC determines, on an annual basis, a Multi-Value Project Usage Rate (MUR) on a per-MWh basis to recover these costs. OTP is required to pay these costs for every kWh of its native load and therefore it is a financial marginal cost component. The MCOS study calculates the MUR rate adjusted by energy losses at each voltage level of service.

4.4 Marginal Ancillary Service Costs

OTP must procure ancillary services in MISO markets to meet OTP's incremental net load in a given hour. The two types of ancillary services considered in the analysis are regulation and operating reserves (spinning and supplemental). The MCOS study relies on a forecast of average annual hourly cost stated in dollars per MWh, estimated for years 2025-2029. The expected average hourly cost was adjusted by marginal losses at each service voltage level and working capital, and time-differentiated using as a proxy hourly variation of energy market prices.

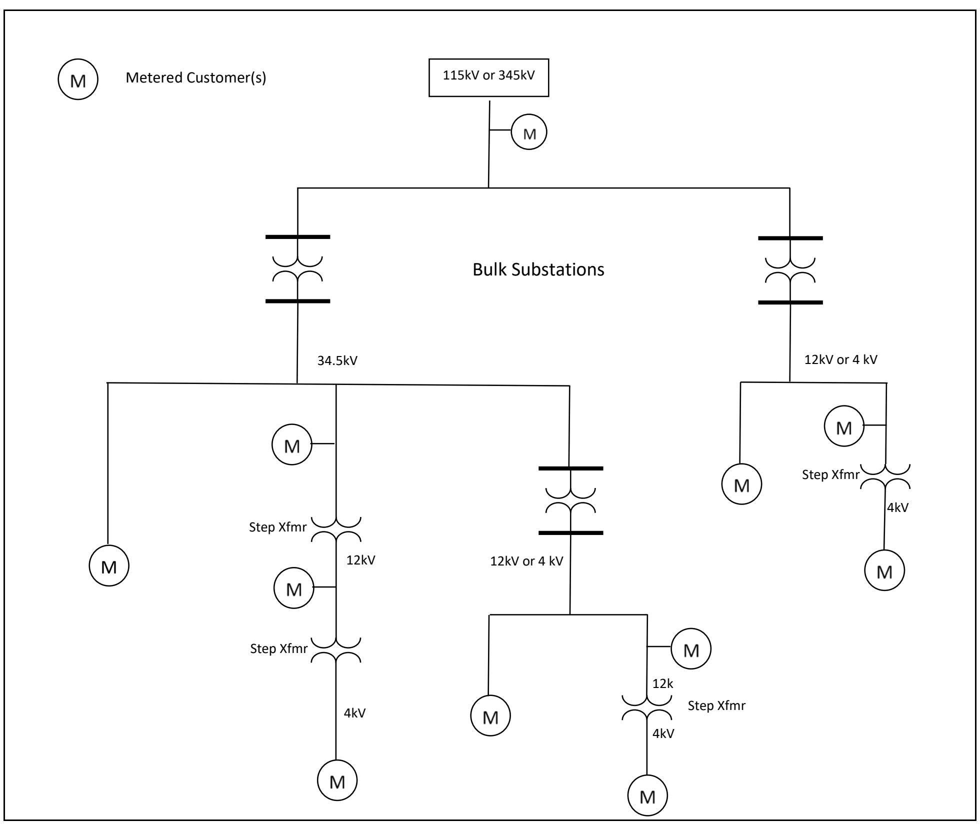
5 MARGINAL DISTRIBUTION COSTS

In estimating marginal costs of distribution, it is important to understand the configuration of OTP's grid and what drives new investment in each segment. The incremental unit costs of service can be estimated for four main categories:

1. Upstream distribution substations that are fed from the transmission system (115kV) and typically convert power to 34.5 kV.
2. Distribution substations that generally convert the power from 34.5 kV to 12 kV or directly 4 kV, and trunk-line primary feeders.
3. Local distribution facilities (line transformers, local primary taps, and secondary conductors)
4. Customer-related facilities and functions, including:
   a) Meters and service drops, and
   b) Customer-related services (*e.g.*, meter-reading, billing, accounting, customer information and customer service).

Figure 1 represents a simplified illustration of OTP's electric distribution system.

Figure 1. OTP's Illustrative Electric Delivery System Diagram



5.1 Distribution Substation and Trunkline Feeder Costs

The distribution stations and trunkline feeders from the substation to the point where the line branches to create a primary tap line are expanded as the distribution area peak demands grow. Estimating the marginal cost of distribution substation and trunkline feeder cost per kW of demand required identifying the budgeted growth-related investments in OTP's most recent capital expansion plan. The sum of OTP's growth-related investment (stated in 2025 dollars) was divided by the estimated total growth in distribution substation non-coincident peak demands over the same period to obtain marginal investment per kW.

Distribution O&M expenses are a component of marginal distribution cost, since they grow with the amount of plant in service. OTP's annual distribution station O&M expenses for the period 2020 - 2023 were divided by historical annual non-coincident substation peak demands during the same period. After reviewing the trend in expenses per kW (restated in 2025 dollars), the 4-year average of O&M per-kW expense was used as a reasonable proxy for the marginal substation O&M expense.

To time differentiate the annualized distribution substation cost, the relative probability of distribution peak for months, day-types (weekdays, Saturday, and Sunday) were estimated based on historical hourly loads across OTP distribution substations. The analysis accounted for the relative lower carrying capability of this equipment in summer months as compared to the winter months. Peak demand loss factors were developed from OTP's loss study.

5.2 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. OTP 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.

Marginal facilities costs were estimated as the monthly distribution cost per kW of customer's design demand. The design demands for various scenarios are affected by density (rural versus urban areas), whether it is a single customer vs. multi-unit building, whether customers connected use all electric appliances or have gas space heating, and the installation is underground or overhead, single-phase or three-phase.

Local distribution facility costs were estimated for residential, commercial and industrial customers and type of customer within each major rate class. The analysis used different connection scenarios. OTP provided transformer size and conductor costs from OTP's work order system, as well as an estimate of number of customers typically connected under each scenario. To obtain an estimate of residential customer design demand, we divided transformer capacity by the number of customers expected to be served, adjusted by a percentage of typical transformer utilization level provided by OTP to state the cost as a dollar per kW of long-term maximum demand as opposed to cost per required capacity. The streetlighting marginal distribution feeder cost was estimated on a per-fixture basis.

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 for the period 2020 -2023 was used as the estimated future distribution facilities O&M expense per kW of design demand. The total design demand was the product of customer counts and per-customer average design demand estimates by rate.

6 MARGINAL CUSTOMER COSTS

6.1 Meter and Service Costs

OTP provided current installed cost of a typical AMI meter, since OTP expects full deployment of smart meters over the next two years. The average per-meter O&M expense from recent years was used to represent the marginal level of these expenses. The MCOS study separately calculated meter requirements for small power producers, which vary with the specific rider and/or jurisdictional legislation. When a bi-directional and/or a generation meter are required for reporting purposes, there are incremental installed meter costs compared to the standard meter. The MCOS study calculated these incremental costs by DG rate category.

6.2 Customer Accounts and Customer Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are a function of customers on the system. OTP's 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 CIP and EEP, programs mandated by MN and SD to promote demand side measures, were omitted from the study since they are not marginal with respect to customer additions. Other non-marginal customer account and customer service and informational subaccounts were also excluded. 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 2021 through 2024 values was considered a reasonable proxy of the future marginal per-customer expense.

7 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.

7.1 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 2012-2023.

For plant-related A&G, two A&G FERC accounts were identified to vary with the amount of plant in service: FERC Account 935 and FERC Account 924. Account 935 was regressed on cumulative net additions to total electric plant, all in constant dollars. 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 and 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).

7.2 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 OTP's 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 average long-term incremental cost of debt and the long-term incremental cost of equity and the expected inflation rate for that type of plant, net of technical progress.

7.3 Working capital

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

8 SUMMARY OF MARGINAL COSTS

8.1 Marginal costs time-differentiated by season and time of day

The time-differentiated marginal costs (including energy, generation capacity, transmission and distribution substation costs), in 2025$, were averaged over the 2025-2029 timeframe for each of the current periods in TOD rates. Tables 2 and 3 show the results on a per-kWh basis and on a per-kW basis, respectively.

Table 2. Summary of 2025-2029 Time-differentiated Marginal Costs ($ per-kWh)

	Summer Season			Winter Season		
	Peak	Mid-Peak	Off-Peak	Peak	Mid-Peak	Off-Peak
	--------------------------- (2025 Cents per kWh) --------------------------					
Secondary						
Energy	7.5413	5.6499	3.5711	6.0076	5.4997	4.3026
Generation Capacity	11.3801	3.9179	0.1973	1.9311	0.3890	0.0000
Op. Reserves	0.1128	0.0847	0.0536	0.0883	0.0810	0.0633
Transmission NITS/NUC	3.0413	1.0459	0.1484	4.9520	1.1583	0.1279
Transmission MUR	0.2541	0.2523	0.2507	0.2599	0.2579	0.2564
Distribution Substation	1.8885	0.5524	0.0352	5.1309	1.1771	0.6073
Total TOU	**24.2182**	**11.5030**	**4.2563**	**18.3699**	**8.5629**	**5.3575**
Seasonal	**9.2321**			**7.7654**		
Annual	**8.25566**					
Primary						
Energy	7.3341	5.5017	3.4794	5.7722	5.2922	4.1335
Generation Capacity	10.8917	3.7490	0.1887	1.8102	0.3646	0.0000
Op. Reserves	0.1097	0.0824	0.0522	0.0858	0.0787	0.0616
Transmission NITS + NUC	2.9140	1.0024	0.1423	4.6852	1.0980	0.1205
Transmission MUR	0.2473	0.2491	0.2479	0.2546	0.2531	0.2521
Distribution Substation	1.8238	0.5334	0.0340	4.9552	1.1367	0.5865
Total TOU	**23.3206**	**11.1180**	**4.1445**	**17.5631**	**8.2234**	**5.1541**
Seasonal	**8.9267**			**7.4553**		
Annual	**7.9471**					
Transmission						
Energy	7.1506	5.3730	3.4030	5.5965	5.1407	4.0201
Generation Capacity	10.1240	3.4839	0.1752	1.6298	0.3283	0.0000
Op. Reserves	0.1067	0.0802	0.0508	0.0834	0.0766	0.0599
Transmission NITS/NUC	2.7133	0.9338	0.1326	4.2788	1.0058	0.1092
Transmission MUR	0.2411	0.2402	0.2394	0.2439	0.2429	0.2422
Total	**20.3358**	**10.1111**	**4.0011**	**11.8324**	**6.7944**	**4.4315**
Seasonal	**8.1069**			**6.0104**		
Annual	**6.7111**					

Table 3. Summary of 2025-2029 Time-Differentiated Marginal Capacity Costs ($ per-kW)

	Summer Season			Winter Season		
	Peak	Mid-Peak	Off-Peak	Peak	Mid-Peak	Off-Peak
	------------------------------ $/kW ------------------------------					
Secondary						
Monthly Costs per kW						
Generation Capacity	$15.02	$5.45	$0.91	$1.26	$1.10	$0.00
Transmission	$4.01	$1.45	$0.68	$3.23	$3.28	$0.49
Distribution Substation	$2.49	$0.77	$0.16	$3.35	$3.33	$2.31
Total	$21.53	$7.67	$1.76	$7.84	$7.70	$2.80
Seasonal	**$30.95**			**$18.34**		
Annual	**$22.55**					
Primary						
Monthly Costs per kW						
Generation Capacity	$14.38	$5.21	$0.87	$1.18	$1.03	$0.00
Transmission	$3.85	$1.39	$0.66	$3.06	$3.10	$0.46
Distribution Substation	$2.41	$0.74	$0.16	$3.23	$3.21	$2.23
Total	$20.63	$7.35	$1.68	$7.47	$7.35	$2.69
Seasonal	**$29.66**			**$17.51**		
Annual	**$21.57**					
Transmission						
Monthly Costs per kW						
Generation Capacity	$13.36	$4.84	$0.81	$1.06	$0.93	$0.00
Transmission	$3.58	$1.30	$0.61	$2.79	$2.84	$0.42
Total	$16.95	$6.14	$1.42	$3.86	$3.77	$0.42
Seasonal	**$24.50**			**$8.04**		
Annual	**$13.55**					

8.2 Marginal Local Distribution Facilities Costs

Table 4 summarizes the monthly marginal local distribution facilities costs, stated in two ways: as a fixed monthly cost per kW of customer's design demand, and as a fixed per customer cost by class, using the class typical per-customer design demand. This component of costs does not change with variations in energy usage, as a result it is in principle appropriate to recover in the monthly fixed charge or for a per-contract demand charge. When recovered in the fixed charge it assumes that the local distribution facilities cost incurred for the average customer is representative of the majority of the customers in the same class.

Table 4: Monthly Marginal Local Distribution Facilities Costs

Customer Class	Monthly Facility Cost per kW of Design Demand	Estimate of Typical Design Demand by Customer	Monthly Facility Cost per Customer
	($/kW)	kW	($/customer/mo.)
Residential			
Single Family Urban	$1.98	9.0	$17.80
Single Family Rural	$2.77	9.0	$24.90
Apartment Gas	$1.78	5.0	$8.91
Apartment Electric	$1.56	9.0	$14.06
Farm	$2.90	20.0	$57.99
Small Commercial			
Stand-Alone customer 1-ph, OH	$1.25	18.0	$22.44
Stand-Alone customer 3ph, OH	$1.65	40.0	$66.01
Shared-customer 3ph, OH	$1.67	40.0	$66.69
Stand-Alone customer 1ph, UG	$3.15	18.0	$56.77
Stand-Alone 3ph, UG	$3.56	40.0	$142.44
Large Commercial (Secondary)			
101-150kVa, 3ph	$1.47	125.0	$183.99
151-300kVa, 3ph	$1.11	230.0	$256.37
301-500kVa, 3ph	$0.88	400.0	$351.99
501-1000 kVa, 3ph	$0.82	775.0	$633.90
Large Commercial (Primary)			
101-500kVa, 3ph	$0.48	500.0	$238.58
501-1000 kVa, 3ph	$0.82	1,000.0	$817.94
Very Large Commercial (Secondary)			
1001-1500 kVa, 3ph	$0.72	1,250.0	$902.61
1501-2000 kVa, 3ph	$0.66	1,750.0	$1,148.92
Very Large Commercial (Primary)			
3000 kVa (LGS), 3ph	$0.54	2,500.0	$1,362.25
5000 kVa (LGS TOU), 3ph	$0.45	4,000.0	$1,787.76

8.3 Marginal Monthly Customer Costs

Table 5 summarizes the monthly marginal customer cost by customer class. Table 6 summarizes the monthly marginal cost for small power producers by rate class.

Table 5. Monthly Marginal Customer Costs

		Monthly Marginal Customer Cost (2025 $/acc/mo.)
	Residential	
9.01	Residential Service	$18.08
9.02	Residential Demand Control	$21.28
9.04	Residential Service Time of Day	$18.89
14.01	Residential Water Heating Control Rider	$5.53
14.04	Residential Controlled Service - Large Dual Fuel Rider	$23.34
14.05	Residential Controlled Service - Small Dual Fuel Rider	$7.43
14.06	Residential Controlled Service - Deferred Load Rider	$6.48
14.07	Residential Fixed Time of Service Rider	$7.73
	Commercial and Industrial	
9.03	Farm Service	$21.43
10.01	Small General Service <20 kW	$20.07
10.02	General Service >= 20 kW	$48.77
10.03	General Service - Time of Use	$59.86
10.04	Large General Service (Secondary)	$83.94
	Large General Service (Primary)	$276.58
10.05	Large General Service - Time of Day (Secondary)	$84.33
	Large General Service - Time of Day (Primary)	$276.58
14.01	Commercial Water Heating Control Rider	$5.53
14.02	LGS - Real Time Pricing Rider (Secondary)	$63.06
	LGS - Real Time Pricing Rider (Primary)	$252.93
14.04	Commercial Controlled Service - Large Dual Fuel Rider	$33.90
14.05	Commercial Controlled Service - Small Dual Fuel Rider	$6.51
14.06	Commercial Controlled Service - Deferred Load	$26.10
14.07	Commercial Fixed Time of Service Rider	$23.52
	Miscellaneous	
11.05, 11.06	Other Public Authority	$35.40
11.02	Irrigation Service	$36.69
11.03	Outdoor Lighting	$2.55
11.03 11.04	Outdoor Lighting (unmetered)	$0.77

Table 6. Monthly Marginal *Incremental* Customer Cost of Small Power Producers by Rate Class

	Monthly *Incremental* Small PP Customer Cost (2025$ /acc./mo.)
Residential Small Power Producer	
Residential	$0.415
Residential Demand Control	$0.415
Commercial and Industrial Small Power Producer	
Small General Service <20 kW	$0.916
General Service >= 20 kW	$0.916
Farm Service	$0.107
General Service - Time of Use	$0.998
Large General Service (Secondary)	$0.998
Large General Service (Primary)	$1.011
Large General Service - Time of Day (Secondary)	$0.998
Large General Service - Time of Day (Primary)	$0.998
Commercial Controlled Service - Large Dual Fuel Rider	$0.956
Commercial Controlled Service - Small Dual Fuel Rider	$0.023
Miscellaneous	
Other Public Authority	$1.149
Irrigation Service	$0.233

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 annualized marginal customer-related costs.

Table A.1. Annualized Distribution Substation Costs

	2025 $/kW
Marginal Investment per kW	$912.11
With General Plant Loading	964.01
Annual Economic Carrying Charge Related to Capital Investment	7.49%
A&G Loading (plant related)	0.14%
Total Annual Carrying Charge	7.62%
Annualized Costs	73.50
O&M Expenses	3.35
With A&G	3.46
Subtotal	76.96
Material, Supplies and Prepayments	9.94
Cash Working Capital Allowance	0.23
Revenue Requirement for Working Capital	0.88
Total Distribution Substation Annual Cost	$77.83

Table A.2 Annualized Distribution Facilities Costs, Residential, Farm, Small Commercial

	Residential & Farm					**Small Commercial**				
	Single Family Urban	Single Family Rural	Apartment Gas	Apartment Electric	Farm	Stand-Alone customer 1-ph, OH	Stand-Alone customer 3ph, OH	Shared-customer 3ph, OH	Stand-Alone customer 1ph, UG	Stand-Alone 3ph, UG
Marginal Investment per kW of Design Demand	$271.16	$409.14	$236.84	$198.42	$432.35	$143.21	$213.84	$216.80	$476.85	548.06
General Plant Loading	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569
Annual Economic Carrying Charge Related to Capital Investment	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
A&G Loading (plant-related)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Total Annual Carrying Charge	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
Annualized Costs	$18.35	$27.68	$16.02	$13.42	$29.25	$9.69	$14.47	$14.67	$32.26	$37.08
Annual O&M Expense per kW of Design Demand	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94
With A&G Loading x 1.0337	5.10	5.10	5.10	5.10	5.10	5.10	5.10	5.10	5.10	5.10
Subtotal Distribution Facilities Marginal Costs	$23.45	$32.79	$21.13	$18.53	$34.36	$14.79	$19.57	$19.77	$37.37	$42.19
Working Capital Rev. Req.										
Material, Supplies and Prepayments	$0.26	$0.39	$0.22	$0.19	$0.41	$0.13	$0.20	$0.20	$0.45	$0.52
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-y	**$23.74**	**$33.20**	**$21.38**	**$18.75**	**$34.79**	**$14.96**	**$19.80**	**$20.01**	**$37.85**	**$42.73**

Table A.3. Annualized Distribution Facilities Costs, Large Commercial

	Large Commercial (Secondary)				Large Commercial (Primary)		Very Large Commercial (Secondary TOU)		Very Large Commercial (Primary)	
	101-150kVa, 3ph	151-300kVa, 3ph	301-500kVa, 3ph	501-1000 kVa, 3ph	101-500kVa, 3ph	501-1000 kVa, 3ph	1001-1500 kVa, 3ph	1501-2000 kVa, 3ph	3000 kVa (LGS), 3ph	5000 kVa (LGS TOU), 3ph
Marginal Investment per kW of Design Demand	$182.65	$120.15	$79.10	$68.25	$8.64	$14.39	$51.48	$40.01	$50.42	$33.29
General Plant Loading	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569
Annual Economic Carrying Charge Related to Capital Investment	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
A&G Loading (plant-related)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Total Annual Carrying Charge	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
Annualized Costs	$12.36	$8.13	$5.35	$4.62	$0.58	$0.97	$3.48	$2.71	$3.41	$2.25
Annual O&M Expense per kW of Design Demand	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94	$4.94	$2.96	$2.96
With A&G Loading x 1.0337	5.10	5.10	5.10	5.10	5.10	5.10	5.10	5.10	3.06	3.06
Subtotal Distribution Facilities Marginal Costs	$17.46	$13.23	$10.46	$9.72	$5.69	$6.08	$8.59	$7.81	$6.47	$5.31
Working Capital Rev. Req.										
Material, Supplies and Prepayments	$0.17	$0.11	$0.07	$0.06	$0.01	$0.01	$0.05	$0.04	$0.05	$0.03
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.02
Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-yr)	**$17.66**	**$13.38**	**$10.56**	**$9.82**	**$5.73**	**$6.12**	**$8.67**	**$7.88**	**$6.54**	**$5.36**

Table A.4. Annualized Customer-Related Marginal Costs - I

	Residential								General Service			Farm
	Residential Service	Residential Demand Control	Residential Service Time of Day	Residential Water Heating Control Rider	Residential Controlled Service - Large Dual Fuel Rider	Residential Controlled Service - Small Dual Fuel Rider	Residential Fixed Time of Service Rider	Residential Controlled Service - Deferred Load Rider	Small General Service <20 kW	General Service >= 20 kW	General Service - Time of Use	Farm Service
												---
Installed Meter Cost	$234.85	$554.00	$293.80	$554.00	$1,849.20	$800.00	$704.52	$545.95	$349.00	$1,716.80	$620.80	$694.82
With General Plant Loading	$248.21	$585.52	$310.52	$585.52	$1,954.42	$845.52	$744.61	$577.01	$368.86	$1,814.48	$656.12	$734.36
Subtotal Annualized Meter Costs	$21.88	$51.62	$27.38	$51.62	$172.30	$74.54	$65.65	$50.87	$32.52	$159.97	$57.84	$64.74
With A&G Loading (Plant Related)	$21.93	$51.74	$27.44	$51.74	$172.69	$74.71	$65.79	$50.99	$32.59	$160.33	$57.98	$64.89
Meter O&M Expenses	$13.22	$21.15	$17.19	$13.22	$101.59	$13.22	$13.22	$13.22	$21.15	$162.54	$325.08	$21.15
Meter O&M with A&G loading	$13.67	$21.87	$17.77	$13.67	$105.01	$13.67	$13.67	$13.67	$21.87	$168.02	$336.04	$21.87
Sub-total Meter Installed Cost	**$35.60**	**$73.60**	**$45.20**	**$65.40**	**$277.71**	**$88.38**	**$79.46**	**$64.65**	**$54.46**	**$328.35**	**$394.01**	**$86.75**
Installed Service Cost	$1,408.17	$1,408.17	$1,408.17	-	-	-	-	-	$1,623.65	$2,620.85	$1,623.65	$1,577.67
With General Plant Loading x 1.0569	$1,488.29	$1,488.29	$1,488.29	-	-	-	-	-	$1,716.03	$2,769.98	$1,716.03	$1,667.44
Annualized Service Drop Costs	$94.98	$94.98	$94.98	-	-	-	-	-	$109.51	$176.77	$109.51	$106.41
Subtotal Service with Plant-related A&G	**$95.28**	**$95.28**	**$95.28**	-	-	-	-	-	**$109.86**	**$177.33**	**$109.86**	**$106.74**
Customer services												
Customer Accounts Expenses	$68.72	$68.72	$68.72	$0.25	$0.00	$0.00	$9.88	$9.88	$59.66	$59.66	$59.66	$48.69
Customer Service & Informational Expenses	$12.55	$12.55	$12.55	$0.05	$0.00	$0.00	$2.17	$2.17	$12.05	$12.05	$142.78	$10.36
Sub-total Cust. Expenses with A&G Loading	**$84.01**	**$84.01**	**$84.01**	**$0.31**	**$0.00**	**$0.00**	**$12.46**	**$12.46**	**$74.13**	**$74.13**	**$209.26**	**$61.04**
Working Capital Rev. Req.												
Material, Supplies and Prepayments	$1.55	$1.85	$1.60	$0.52	$1.74	$0.75	$0.66	$0.51	$1.86	$4.08	$2.11	$2.14
Cash Working Capital	$0.56	$0.61	$0.58	$0.08	$0.59	$0.08	$0.15	$0.15	$0.55	$1.36	$3.08	$0.47
Total Annual Marginal Customer Costs	**$216.99**	**$255.34**	**$226.67**	**$66.31**	**$280.03**	**$89.21**	**$92.73**	**$77.77**	**$240.85**	**$585.25**	**$718.32**	**$257.15**

Table A.5. Annualized Customer-Related Marginal Costs - II

	Large General Service		Large General Service				Commercial Riders					Other Rates			
	Large General Service (Secondary)	Large General Service (Primary)	LGS - Real Time Pricing Rider (Secondary)	LGS - Real Time Pricing Rider (Primary)	Large General Service - Time of Day (Secondary)	Large General Service - Time of Day (Primary)	Commercial Water Heating Control Rider	Commercial Controlled Service - Large Dual Fuel Rider	Commercial Controlled Service - Small Dual Fuel Rider	Commercial Controlled Service - Deferred Load	Commercial Fixed Time of Service Rider	Irrigation Service	Other Public Authority	Outdoor Lighting	Outdoor Lighting (unmetered)
Installed Meter Cost	$2,193.57	$12,068.29	$2,243.33	$12,068.29	$2,243.33	$12,068.29	$554.00	$2,521.64	$594.71	$1,505.30	$1,177.30	$1,379.30	$607.17	$234.85	-
With General Plant Loading	$2,318.38	$12,754.97	$2,370.98	$12,754.97	$2,370.98	$12,754.97	$585.52	$2,665.12	$628.55	$1,590.95	$1,244.29	$1,457.78	$641.71	$248.21	-
Subtotal Annualized Meter Costs	$204.39	$1,124.49	$209.03	$1,124.49	$209.03	$1,124.49	$51.62	$234.96	$55.41	$140.26	$109.70	$128.52	$56.57	$21.88	-
With A&G Loading (Plant Related)	$204.85	$1,127.04	$209.50	$1,127.04	$209.50	$1,127.04	$51.74	$235.49	$55.54	$140.58	$109.95	$128.81	$56.70	$21.93	-
Meter O&M Expenses	$325.08	$1,625.41	$325.08	$1,625.41	$325.08	$1,625.41	$13.22	$162.54	$21.15	$162.54	$162.54	$101.59	$162.54	$0.00	-
															-
Meter O&M with A&G loading	$336.04	$1,680.19	$336.04	$1,680.19	$336.04	$1,680.19	$13.67	$168.02	$21.87	$168.02	$168.02	$105.01	$168.02	$0.00	-
Sub-total Meter Installed Cost	**$540.89**	**$2,807.23**	**$545.54**	**$2,807.23**	**$545.54**	**$2,807.23**	**$65.40**	**$403.51**	**$77.40**	**$308.60**	**$277.97**	**$233.82**	**$224.72**	**$21.93**	-
Installed Service Cost	$3,721.81	$4,136.65	-	-	$3,721.81	$4,136.65	-	-	-	-	-	$896.03	$1,738.98	$102.31	$114.10
With General Plant Loading x 1.0569	$3,933.58	$4,372.03	-	-	$3,933.58	$4,372.03	-	-	-	-	-	$947.01	$1,837.93	108.13	$120.59
Annualized Service Drop Costs	$251.03	$279.01	-	-	$251.03	$279.01	-	-	-	-	-	$60.44	$117.29	6.90	$7.70
Subtotal Service with Plant-related A&G	**$251.82**	**$279.88**	**-**	**-**	**$251.82**	**$279.88**	**-**	**-**	**-**	**-**	**-**	**$60.63**	**$117.66**	**6.92**	**$7.72**
Customer services															
Customer Accounts Expenses	$56.48	$56.48	$56.48	$56.48	$56.48	$56.48	$0.25	$0.00	$0.00	$0.00	$0.00	$112.94	$62.51	$1.10	$1.10
Customer Service & Informational Expenses	$142.78	$142.78	$142.78	$142.78	$142.78	$142.78	$0.05	$0.00	$0.00	$2.17	$2.17	$24.75	$13.70	$0.24	$0.24
Sub-total Cust. Expenses with A&G Loading	**$205.98**	**$205.98**	**$205.98**	**$205.98**	**$205.98**	**$205.98**	**$0.31**	**$0.00**	**$0.00**	**$2.24**	**$2.24**	**$142.33**	**$78.78**	**$1.39**	**$1.39**
Working Capital Rev. Req.															
Material, Supplies and Prepayments	$5.57 #	$15.26	$2.11	$11.37	$5.62	$15.26	$0.52	$2.37	$0.56	$1.42	$1.11	$2.14	$2.21	$0.32	$0.11
Cash Working Capital	$3.06	$10.55	$3.06	$10.55	$3.06	$10.55	$0.08	$0.94	$0.12	$0.95	$0.95	$1.41	$1.39	$0.01	$0.01
Total Annual Marginal Customer Costs ($ /account/yr)	**$1,007.32**	**$3,318.91**	**$756.69**	**$3,035.13**	**$1,012.01**	**$3,318.91**	**$66.31**	**$406.82**	**$78.09**	**$313.21**	**$282.27**	**$440.33**	**$424.76**	**$30.56**	**$9.22**