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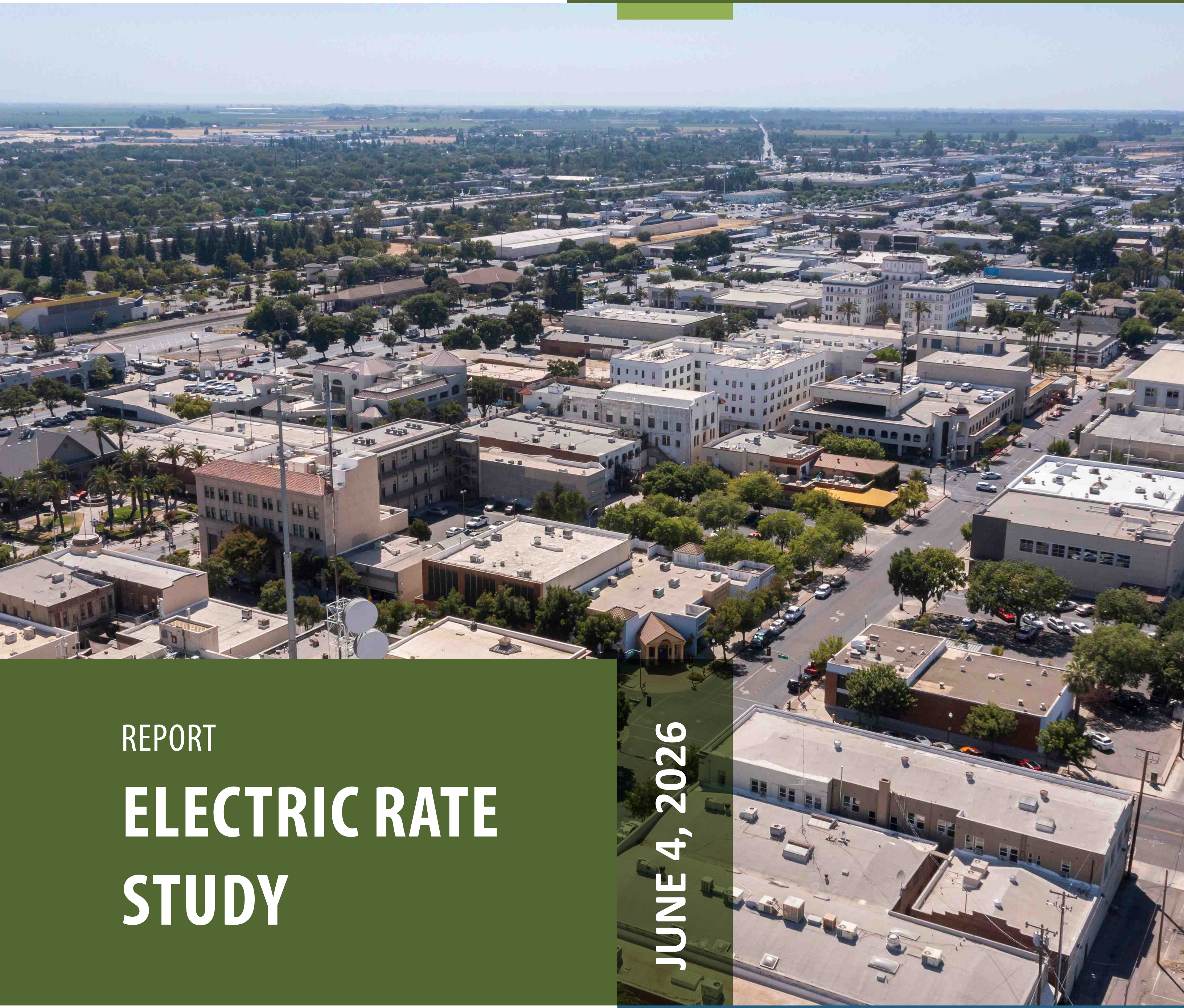

REPORT

ELECTRIC RATE STUDY

JUNE 4, 2026

Prepared for:
Merced Irrigation District
Merced, California

MERCED IRRIGATION DISTRICT
WATER & POWER

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EXECUTIVE SUMMARY

Introduction

In 2025, NewGen Strategies and Solutions, LLC (NewGen) was retained by Merced Irrigation District (MID) to perform an Electric Cost of Service (COS) and Rate Design Study (Study). As part of this Study, NewGen developed a revenue requirement, evaluated financing strategies, and recommended rate changes in fiscal year (FY) 2026. The goal was to evaluate and identify rates required to fund the utility's operating and capital expense needs, while maintaining financial stability over the Study Period of the next three to five years.

This report contains five sections as follows:

- Section 1 – Provides an introduction and brief background to the Study.
- Section 2 – Discusses the development of the revenue requirement.
- Section 3 – Provides the COS results.
- Section 4 – Presents the proposed electric rates.
- Section 5 – Summarizes conclusions and recommendations.

Utility Description

MID is an irrigation district providing electric service within their service area. MID is a public power utility managed by a Board of Directors (Board) that approves changes in policy, improvements to the system, and the financing of improvements. The MID Board's five members are appointed and serve a four-year term.

In May 1996, the Electric Utility began serving retail electricity and is currently serving approximately 15,000 retail electric customers. In 2024 MID's peak demand was 121 megawatts (MW), and retail sales were 532 gigawatt-hours (GWh). The Electric Utility provides power to their customers through a combination of MID-owned generation and purchase power contracts. Currently, MID owns, operates, and maintains the New Exchequer and the McSwain dams, reservoirs, and hydroelectric facilities. MID can generate up to 107 MW of hydroelectric power at zero emissions and has various purchase power contracts from Turlock Irrigation District (TID).

Cost of Service and Rate Design Process Overview

The COS and rate design process includes five steps as follows:

1. ***Determination of the Revenue Requirement*** – This first step examines the utility's financial needs and determines the amount of revenue that must be generated from rates. For public power utilities, the revenue requirement is determined on a "cash basis." A cash basis analysis examines the cash obligations of the utility, such as operations and maintenance (O&M) expenses, debt service, cash-funded capital projects, and Permission Fees. Rates are set such that the utility can pay its bills on an annual going forward basis.

   In preparing our analysis of the electric rates and the development of the revenue requirement, NewGen relied on MID's FY 2026 Budget, the Capital Improvement Plan (CIP) for FY 2026 to FY 2030, records of operation, customer billing data, and other detailed information and data compiled and provided by the MID's management and staff.

2. ***Functionalization and Sub-functionalization of Costs*** – The revenue requirement is then assigned to the particular function or sub-function of the utility. Electric utilities, like MID, typically have power supply, transmission, distribution, and customer service functions. Power supply sub-functions may include utility-owned generation or purchased power from contracts. Distribution sub-functions may include distribution infrastructure by voltage, metering, billing, collection, etc. Customer sub-functions include billing and collections, customer service, meter reading, etc.
3. ***Classification of Costs*** – Once costs are functionalized, costs are then classified based on the underlying nature of the costs. Of particular importance is the determination of fixed versus variable costs. Fixed costs remain a financial obligation of the utility regardless of the amount of energy produced, whereas variable costs fluctuate based on system energy requirements. Further, fixed and variable costs are associated with utility requirements to meet customer demand, energy, and customer service needs.
4. ***Allocation of Costs*** – Once costs are classified, costs are then allocated to the various customer classes. Allocation factors align with cost classification. Therefore, demand-related costs are allocated on measures of class demand, such as class contribution to the system coincident peak (CP). Energy allocation factors are based on energy consumed by customers. Customer allocation factors are based on the number of customers.

These first four steps in the COS process are depicted in the figure below.

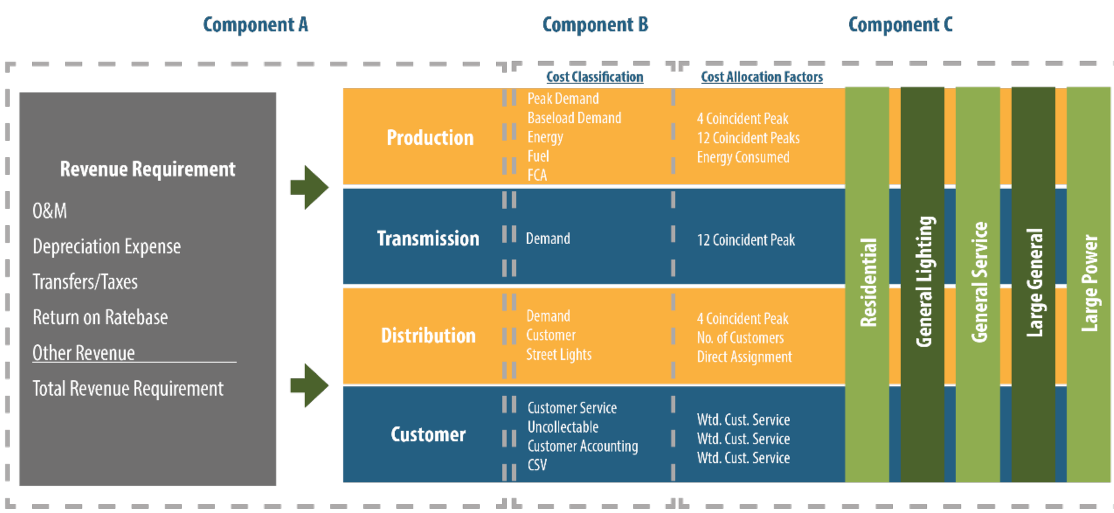

Figure ES-1. Typical Cost of Service Process

5. ***Rate Design*** – The fifth, and final, step is rate design, which translates COS results into rates for each customer class.

Revenue Requirement

NewGen utilized the FY 2026 Budget and 2026 CIP that spans from 2026 to 2030 to develop the base year. After review and discussion with MID staff, the NewGen Project Team (Project Team) adjusted the FY 2026 Budget to account for any unusual or one-time expenses. Projected non-recurring expenses or revenues were identified and incorporated, as appropriate.

Based on the FY 2026 Budget and CIP, NewGen developed a Test Year Revenue Requirement. The Test Year Revenue Requirement reflects the Electric Utility's total cost of providing electric utility services to various rate classes that must be recovered through rate revenues. The Test year Revenue Requirement was calculated by developing an average of the Electric Utility's costs or revenue requirements for the Study Period. Based on the Test Year, NewGen calculated the difference between the projected revenues and revenue requirement. Table ES-1 summarizes the forecasted operating expenses and revenue requirements for the Electric Utility over the Study Period. The Test Year Revenue Requirement of $83,489,775 is the annual revenue requirement and is shown in Table ES-1. The Test Year Revenue Requirement is then compared to the Test Year retail rate revenues. The Test Year rate revenues were calculated and include a $0.067655 per kilowatt-hour (kWh) Power Cost Adjustment (PCA) charge and a $0.00407 per kWh Environmental Charge (EC). The current rate revenues, including the PCA and EC, currently exceed the total revenue requirement by approximately $13.5 million per year or 13.9%.

Table ES-1
Test Year Revenue Requirement

Account	Test Year
O&M Expenses	$75,751,000
Debt Service	$5,836,575
Capital Paid from Current Earnings Other	$8,686,200
Expenses/(Income)	($6,784,000)
Revenue Requirement	**$83,489,775**
Revenues Under Current Rates	$96,952,833
Over (Under) Recovery of Costs	$13,463,058
Over (Under) Recovery of Costs	13.9%

MID plans to address the difference in rate revenues and revenue requirement by decreasing rates. To maintain financial sustainability, MID is required to maintain a 1.2 debt service coverage ratio (DSCR). Over the Study Period, MID's average DSCR exceeds the target and will remain above the required minimum with the proposed rate decreases.

Cost of Service Results

The COS analysis translates the Electric Utility's Test Year Revenue Requirement of $83,489,775 into a revenue requirement by customer class. The Test Year Revenue Requirement is functionalized or "unbundled" into four functions of the system (i.e., power supply, transmission, distribution, and customer service), then classified as customer-, demand-, or energy-related, and finally allocated to each of the customer classes as shown in Table ES-2. The result provides a COS revenue requirement for each customer class, which is then compared to the projected revenues to determine the class rate changes indicated by the COS results.

Table ES-2
Comparison of Current Rate Revenues with Cost of Service Results

Customer Class	Cost of Service	Revenue from Current Rates	Difference ($)	Difference (%)
Agricultural Demand (AG-2)	$551,434	$494,879	$56,556	(10.3%)
Large Demand General Service (ED-1P)	$15,761,217	$18,394,296	($2,633,079)	16.7%
Large Demand General Service Consolidated (ED-2 & ED-2P)	$13,992,007	$16,844,091	($2,852,084)	20.4%
Medium Demand General Service (ED-3)	$6,266,655	$7,587,646	($1,320,990)	21.1%
Medium Demand General Service Voluntary (ED-3V)	$1,745,299	$2,309,141	($563,841)	32.3%
Small Demand General Service (ED-4)	$11,368,159	$13,713,336	($2,345,176)	20.6%
Commercial & Small Industrial General Service (EGS-2)	$4,511,046	$4,757,253	($246,207)	5.5%
Municipal & Non-Profit Medium Demand General Service (MD-3)	$1,246,938	$1,229,158	$17,780	(1.4%)
Municipal & Non-Profit Small Demand General Service (MD-4)	$6,867,549	$7,942,599	($1,075,050)	15.7%
Residential General Service (RES-2)	$18,006,302	$19,427,525	($1,421,223)	7.9%
Streetlighting – Customer Owned and Maintained (LSC)	$236,018	$270,006	($33,988)	14.4%
Streetlighting – District Owned and Maintained (LSC-1)	$15,799	$34,597	($18,798)	119.0%
Flat Rate Service (MEF)	$6,777	$8,356	($1,579)	23.3%
Transmission Rate (TR-1)	$2,914,574	$3,939,951	($1,025,378)	35.2%
Total	**$83,489,775**	**$96,952,833**	**($13,463,058)**	**(13.9%)**

As shown in Table ES-2, the overall COS analysis identifies a 13.9% rate decrease to meet the Electric Utility's revenue requirements. In addition, when evaluated on a customer basis, rate adjustments are indicated for most classes based on their impact to the system.

Based on the COS results, MID implemented a rate decrease aligned with that identified in the revenue requirement. MID set out to decrease annual retail revenues 8.6% for FY 2027. This will be accomplished by increasing base rates and significantly reducing the PCA charge to $0.01/kWh. These rate decreases will still meet the cash operating needs of the utility.

Rate Design

Rate design includes proposed rates to collect the adopted rate decrease and better align with COS results. The MID revenue decreases were applied equally to each retail customer class, which includes the Transmission Service rate class. The proposed decrease better aligns rates with COS and minimizes rate shock.

Based on the revenue requirement to operate the Electric Utility, NewGen recommends rate adjustments in one phase for all rate classes. As only two classes showed a limited increase from the COS results, MID chose to provide rate relief to all customer classes; however, it targeted larger decreases in those customer classes that showed larger differences from the COS. These rate adjustments are proposed to better align rates with the fixed and variable costs identified in the COS analysis. Table ES-3 shows the revenues projected for each customer class. The total revenues reflect the proposed rate decrease. The results of the rate change and revenue generated are provided in Table ES-3.

Table ES-3
Electric Utility Rate Revenue Decrease in One Phase

Class	Test Year Rate Revenue	Revenues after Rate Decrease	% Change
AG-2	$494,879	$484,981	(2.0%)
ED-1P	$18,394,296	$16,440,665	(10.6%)
ED-2	$3,681,435	$3,657,926	(0.6%)
ED-2P	$13,162,657	$11,698,991	(11.1%)
ED-3	$7,587,646	$6,685,125	(11.9%)
ED-3V	$2,309,141	$2,045,554	(11.4%)
ED-4	$13,713,336	$12,050,674	(12.1%)
EGS-2	$4,757,253	$4,672,605	(1.8%)
MD-3	$1,229,158	$1,082,253	(12.0%)
MD-4	$7,942,599	$6,968,583	(12.3%)
RES-2	$19,427,525	$19,064,087	(1.9%)
LSC	$270,006	$242,503	(10.2%)
LSC-1	$34,597	$30,320	(12.4%)
MEF	$8,356	$7,694	(7.9%)
TR-1	$3,939,951	$3,523,780	(10.6%)
Total	**$96,952,833**	**$88,655,740**	**(8.6%)**

Revenue from every class will decrease overall. The rate decreases outlined in Table ES-3 reflect the overall reduction in the Electric Utility's revenue requirement. Ultimately, the proposed rate adjustment is intended to ensure MID's rates are aligned with the cost of providing service, while maintaining sufficient financial resources for ongoing operations.

Section 1
INTRODUCTION

In 2025, NewGen Strategies and Solutions, LLC (NewGen) was retained by Merced Irrigation District (MID) to perform an Electric Cost of Service (COS) and Rate Design Study (Study). As part of this Study, NewGen developed revenue requirements based on the 2026 Budget and five-year Capital Improvement Plan (CIP). MID's budget year runs from April 1 through March 31. All data contained in this report represents the MID budget year unless otherwise stated. This report consists of five sections and an Executive Summary. An appendix is attached containing schedules supporting the information contained in this report.

Background

MID is a public power utility that provides wholesale and retail electric and water service to the community of Merced, California and the surrounding area. MID is managed by a Board of Directors (Board) that approves changes in policy, improvements to the system, and the financing of improvements. The MID Board's five members are elected and serve a four-year term.

In May 1996, the Electric Utility began serving retail electricity and is currently serving approximately 15,000 retail electric customers. In 2024 MID's peak demand was 121 megawatts (MW) and retail sales were 532 gigawatt-hours (GWh). The Electric Utility provides power to their customers through a combination of MID-owned generation and purchase power contracts. Currently, MID owns, operates, and maintains the New Exchequer and the McSwain dams, reservoirs, and hydroelectric facilities. MID can generate up to 107 MW of hydroelectric power at zero emissions and has various purchase power contracts from Turlock Irrigation District (TID).

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   In preparing our analysis of the electric rates and the development of the revenue requirement, NewGen relied on MID's FY 2026 Budget, the CIP for FY 2026 to FY 2030, records of operation, customer billing data, and other detailed information and data compiled and provided by the MID's management and staff.
2. ***Functionalization and Sub-functionalization of Costs*** – The revenue requirement is then assigned to the particular function or sub-function of the utility. Electric utilities, like MID, typically have power supply, transmission, distribution, and customer service functions. Power supply sub-functions may include utility-owned generation or purchased power from contracts. Distribution sub-functions may include distribution infrastructure by voltage, metering, billing, collection, etc. Customer sub-functions include billing and collections, customer service, meter reading, etc.

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These first four steps in the COS process are depicted in the figure below.

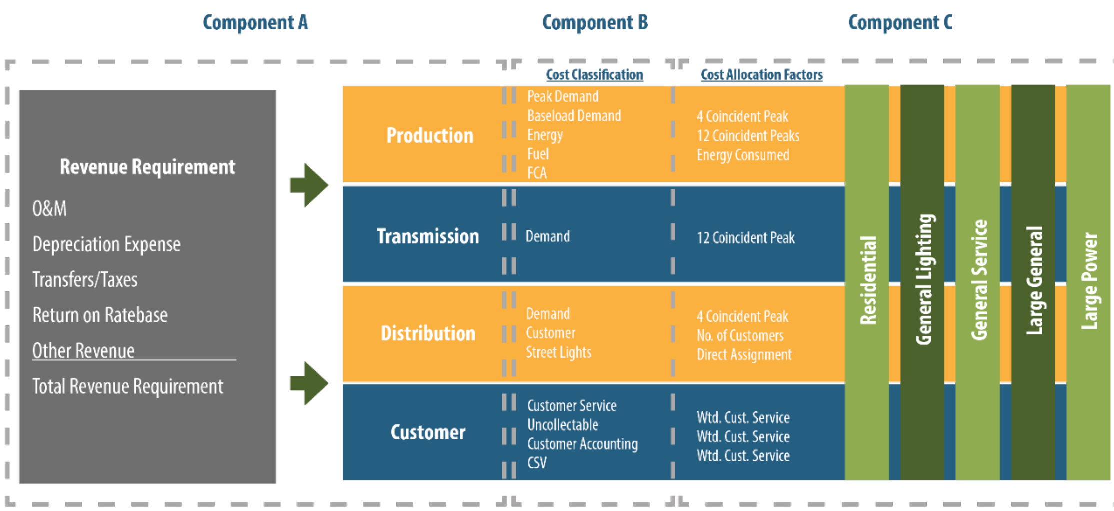

Figure 1-1. Typical Cost of Service Process

5. ***Rate Design*** – The fifth, and final, step is rate design, which translates COS results into rates for each customer class.

Section 2
REVENUE REQUIREMENTS

Developing the Test Year Revenue Requirement is the first step in the COS and rate design process, as shown in Figure 1-1. The Test Year Revenue Requirement for the Electric Utility was based on the 2026 Budget expenses, with adjustments for unusual or one-time expense, the CIP, existing debt amortization schedules, and forecasted escalation assumptions and factors. This Test Year Revenue requirement represented all costs that must be recovered through the Electric Utility's rates. The Test Year Revenue Requirement serves as a basis for determining the overall level of revenue recovery and provides a foundation for the COS analysis.

Projected Energy Requirements

The Electric Utility's forecasted electric consumption is a key driver in projections of expenses and revenues. We relied on load and customer number forecasts provided by the Electric Utility to apply growth to the actual FY 2024 load. The average annual growth rate for load during the Test Year was 2.2%. Table 2-1 displays the Test Year retail sales of electricity, the losses associated with the delivery of electricity, and total required load, all measured in kilowatt-hours (kWh).

Table 2-1
Estimated Energy Requirements

	Retail Sales (kWh)	Losses (kWh)	Total (kWh)
Test Year	506,968,283	24,406,335	531,374,618

O&M Expenses

The first step in developing the revenue requirement forecast was the creation of the base year O&M expenses. MID's 2026 Budget data provided Electric Utility O&M expenses. These budgeted O&M expenses, in addition to the other expenses/revenues (including interest income, capital contributions, miscellaneous revenues, and sales to other utilities), CIP, debt service projections and Permission Fees, supported the development of the Test Year Revenue Requirement.

O&M Account Detail

Table 2-2 below summarizes the Test Year O&M expenses.

Table 2-2
Forecasted O&M Detailed Funds

Account	Test Year
Wage & Employment Benefits	$6,746,000
Outside Services	$1,895,000
Operating Services & Supplies	$2,014,000
Public Purpose Program	$1,001,000
Cost of Power	$58,838,000
Other Expenses	$162,000
Non-Cash Expenses	$5,095,000
Total	**$75,751,000**

Power Supply Expenses

Power supply expenses are the largest portion of the total O&M expenses and are associated with purchased power agreements and spot market purchases to balance MID's needs to meet load. Additional power supply expenses included operating costs for MID-owned generation plants, labor, and other supporting O&M accounts. Table 2-3 summarizes the total power supply expenses.

Table 2-3
Power Supply Expenses

Power Supply	Test Year
TID Purchases	$39,415,000
Resource Adequacy	$12,500,000
Ancillary Services	$765,000
Other Expenses	$2,507,000
Total Power Supply O&M	**$55,187,000**

Transfer to the City General Fund (Permission Fees)

MID budgeted for a permission fee of approximately $1.7 million to the MID Water Department, which applies to all customers.

Debt Service

The debt service represents existing debt. The existing debt service within the Test Year Revenue Requirement includes the Series 2015A and two 2017A Revenue Bonds.

The 2015 bond issues amortization schedule included a 15-year term. Additionally, one of the 2017A bond issues includes a 15-year term, while the other was projected with a 30-year term. MID does not plan to take on any new debt in the immediate future. Table 2-4 summarizes the projected debt service and debt service coverage ratio (DSCR) of the Electric Utility under current MID rates.

Table 2-4
Electric Debt Service

Account	Test Year
Operating Revenues	$103,736,832
Operating Expenses	$75,751,000
Net Revenues Available	$27,985,833
Debt Service	
Existing	$5,836,575
Future	$0
Total	**$5,836,575**
Debt Service Coverage Ratio	**4.8**

Table 2-4 illustrates the Electric Utility's debt, revenues, and expenses. The operating expenses shown in Table 2-4 do not include capital expense. Thus, the substantial portion of Net Revenues Available are used to fund the capital program, as discussed below.

Capital Paid from Current Earnings

The Electric Utility capital expenses are identified within the 2026 Budget and five-year CIP. The utility utilizes a combination of debt, cash from rate revenues, and cash reserves to finance the capital expenses and upgrades. The average annual amount of capital expenses funded from current earnings, rate revenues, or cash reserves included in the Test Year Revenue Requirement, is $8.7 million. Table 2-5 outlines the annual capital outlays paid from annual rate revenues and cash reserves.

Table 2-5
Electric Capital Funded with Current Earnings and Reserves

	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029	Year 5 FY 2030	Average Five-Year
Cash Funded Capital	$11,791,000	$8,130,000	$8,320,000	$8,570,000	$6,620,000	$8,686,200
MID Reserve Contributions	$0	$0	$0	$0	$0-	$0
Net Annual CIP from Current Earnings						**$8,686,200**

Non-Operating Revenue and Other Income (Expenses)

Non-operating Revenues and Other Income and Expenses represent miscellaneous non-operating revenues or expenses and total approximately $6.8 million (net revenues) in the Test Year. This amount reflects non-operating revenues, such as city, county, and other taxes; The California Public Benefits

Charge revenues; and Renewable Portfolio Standard Rider revenues. MID's other revenues primarily include market power sales to the California Independent System Operator (CAISO), greenhouse gas (GHG) allowance revenues, and wind energy resales. These net revenues of about $6.8 million reduce the overall Test Year Revenue Requirement.

Revenue Requirement

There are two primary revenue requirement methodologies employed in the utility industry: the cash basis and the utility basis. The primary difference between the cash basis and the utility basis involves the treatment of depreciation, return on invested capital, and debt service. The cash basis, which is the most common method used by public power utilities, includes debt service but excludes depreciation and return on invested capital in the revenue requirement determination. The cash basis focuses on meeting the cash demands of the utility. The utility basis is most commonly used by private or for-profit utilities, includes deprecation and return on invested capital, but excludes debt service from the revenue requirement determination.

In this COS analysis, the Project Team utilized the cash basis, as it follows the traditional cash-oriented budgeting practices frequently used by government entities. In addition, the cash basis is generally easier to explain to customers since the cash basis attempts to match revenue and expenditures.

NewGen developed the Test Year Revenue Requirement shown below in Table 2-6 at $83,849,775. The existing rate revenues were calculated and include a $0.067655 per kWh Power Cost Adjustment (PCA) charge a a $0.00407 per kWh Environmental Charge (EC). The current rate revenues, including the PCA and EC, currently exceed the total revenue requirement by approximately $13.4 million per year.

Table 2-6
Test Year Revenue Requirement

Account	Average Five-Year
O&M Expenses	$75,751,000
Debt Service	$5,836,575
Capital Paid from Current Earnings	$8,686,200
Other Expenses/(Income)	($6,784,000)
Revenue Requirement	**$83,489,775**
Test Year Projected Revenues	$96,952,833
Over (Under) Recovery of Costs	$13,463,058
Over (Under) Recovery of Costs	13.89%

Section 3
COST OF SERVICE RESULTS

Developing the Test Year Revenue Requirement is the first step in the Rate Study, as shown in Figure 1-1. After determining the system revenue requirement, a COS for each customer class is developed to determine the specific costs to serve each class. Customer class revenues are compared to the class revenue requirement to evaluate the current rate's abilities to fully recover costs. NewGen analyzed the cost to serve each customer class based on the revenue requirement developed in Section 2.

Once completed, the COS results indicate the degree to which existing rates recover the costs to serve customers. The COS results are then used to design new electric rates.

The COS analyses relied on the following key supporting data and analysis:

- Test Year Revenue Requirements and revenues based on current rates
- Total system and customer class demand and energy requirements
- Actual and assumed customer service characteristics
- Information obtained from customer accounts and records

Functionalization of Revenue Requirement

The second step in the COS and rate design process, as shown in Figure 1-1, is to functionalize the revenue requirement. The Electric Utility's rates were unbundled into four functions; power supply, transmission, distribution, and customer service. The assignment of costs by function falls into two general categories: direct assignments and derived allocations. Direct assignments are costs that are readily associated with a specific utility function and are directly assigned to that function. For example, the purchase power contracts are expenses solely related to power supply, therefore, they are directly assigned to that function.

Derived allocators are allocation factors that are based on the sum, average, or weighted effect of different underlying factors. Derived allocators can be complex and should reflect the logical answer to the following question: what underlying activities drive the cost of this item? For example, administrative and general (A&G) expenses are associated with the O&M of all utility functions. Thus, A&G expenses are allocated to each utility function using various derived allocators. Each of the four utility functions Is described below.

Power Supply Function

The power supply function consists of costs associated with power generation, the cost of purchased power, and procuring and administering power supply contracts.

Transmission Function

The transmission function consists of costs associated with operating and maintaining the transmission portion of the electric grid and making capital investments, as necessary. The transmission facilities transmit electricity at high voltage from the generation stations to the distribution system.

Distribution Function

The distribution function consists of costs associated with operating and maintaining the distribution portion of the electric grid and making capital investments, as necessary. The distribution facilities deliver power to the retail customers after it has been transmitted. This includes low voltage distribution lines, distribution poles, underground lines, customer service connections, meters, and lighting-related assets.

Customer Service Function

The customer service function consists of costs associated with operating and maintaining the customer-related facilities to meet customer support needs. This includes, but is not limited to, customer service, billing and collection, and meter reading.

Unbundling of Revenue Requirement

The Test Year Revenue Requirement was unbundled into the four functional areas of the system: power supply, transmission, distribution, and customer. The results of the functional unbundling are summarized in Table 3-1.

Table 3-1
Functionalized Test Year Revenue Requirement

Function	Revenue Requirement	$/kWh	% of Total
Power Supply	$57,436,218	$0.11329	68.79%
Transmission	$4,055,327	$0.00800	4.86%
Distribution	$19,829,246	$0.03911	23.75%
Customer	$2,168,983	$0.00428	2.60%
Total	**$83,489,775**	**$0.16468**	**100.00%**

The power supply function represents 68.8% of the Test Year Revenue Requirement. The distribution function is the second largest cost center representing 23.8% of the Test Year Revenue Requirement. The transmission function represents 4.9% of the Test Year Revenue Requirement, while the remaining 2.6% of the revenue requirement is associated with the customer function.

Classification of Revenue Requirement

The third step in the COS and rate design process is to classify the functionalized revenue requirement. System costs can be classified into four generally accepted rate-making cost classifications: demand or fixed costs, energy or variable costs, customer-related costs, and directly assignable costs. In order to provide a reasonable basis for the assignment of total revenue requirements (costs) to each customer class, costs for each function have been analyzed and classified into four categories as described below.

- ***Demand Costs*** – Capacity (fixed- or demand-related) costs are those costs incurred to maintain a utility system in a state of readiness to serve, enabling it to meet the total combined demands of its customers. Capacity costs include the fixed portion of O&M expenses, debt service, capital expenditures, and other costs that are generally fixed and do not vary materially with the quantity of usage or that cannot be designated specifically as a customer or variable cost.

- ***Energy Costs*** – Energy, or variable costs, are costs that vary directly with energy usage, including such items as fuel, energy-related purchased power, and a portion of O&M expenses.
- ***Customer Costs*** – Customer costs are those costs directly related to the number and type of customers, such as customer accounting, customer service, billing, and meter-related expenses.
- ***Direct Assignment Costs*** – Direct assignment costs are those costs that are readily identifiable and applicable to a particular customer or customer class (e.g., lighting).

Once the costs within each function are assigned to each service category, the demand, energy, customer, and direct assignment component of each service is calculated. As seen in Table 3-2, three major cost categories (demand, energy, and customer) cover most functional costs. This breakdown of demand, energy, customer, and direct assignment costs is later applied to each customer class to facilitate rate design, as provided in Section 4.

Table 3-2
Classified Test Year Revenue Requirement

Classification	Revenue Requirement	$/kWh	% of Total
Power Supply			
Demand	$20,568,312	$0.04057	25%
Energy	$36,931,907	$0.07285	44%
Direct Assignment	($64,000)	($0.00013)	0%
Subtotal	$57,436,218	$0.11329	69%
Transmission			
Demand	$4,055,327	$0.00800	5%
Subtotal	$4,055,327	$0.00800	5%
Distribution			
Demand	$15,909,661	$0.03138	19%
Customer	$3,919,585	$0.00773	5%
Subtotal	$19,829,246	$0.03911	24%
Customer			
Customer	$2,168,983	$0.00428	3%
Subtotal	$2,168,983	$0.00428	3%
Total			
Demand	$40,533,300	$0.07995	49%
Energy	$36,931,907	$0.07285	44%
Customer	$6,088,569	$0.01201	7%
Direct Assignment	($64,000)	($0.00013)	0%
Total Costs	**$83,489,775**	**$0.16468**	**100%**

In total, 44% of the Electric Utility's total revenue requirement is energy-related or variable costs. The remaining 56% of the revenue requirement is fixed in nature and classified as demand, customer, or directly assigned to particular customer classes.

Allocation of Revenue Requirement

The fourth step in the COS and rate design process is to allocate the functionalized, classified revenue requirement to the various customer classes. Customer classes represent aggregations of customers that have similar customer usage characteristics and use the system in a similar manner. These groups of customers have similar COS results, which justify similar rates.

Class Allocation Factors

Based upon actual and assumed customer service and consumption characteristics, NewGen developed various factors for use in allocating the revenue requirement to individual customer classes. These allocations factors reflect accepted ratemaking principles and were based upon embedded cost allocation procedures. Embedded costs are the total system costs assuming utility resources are spread across all customers. Embedded costs are generally based on historical or known costs, such as audited financial statements and/or budgets.

We have developed demand-related, energy-related, customer-related, and direct assignment allocation factors, as described below.

Demand Allocations

Demand allocators are derived based on the demand requirements of individual customers and classes of customers. Costs are allocated to classes based on the class contribution to the system peak, or CP allocators. This is a measure of each class's cost responsibility associated with the infrastructure required to meet the system peak demand. As you move from the generator to the meter, the measure of peak demand responsibility changes from a system perspective (CP), to a class perspective (non-coincident peaks [NCP]), to a customer perspective (demand at meter). Demand contributions at these various points in the system are determined based on advanced metering infrastructure (AMI) and billing data available to MID and NewGen.

For customer class allocation purposes, 12-month CP (12CP) and fourth-month NCP (4NCP) were used to allocated demand-related power supply, transmission, and distribution-related costs. The 12CP allocator was used to allocate baseload-related power supply costs. Transmission costs for the Electric Utility were also allocated using the 12CP method, which aligns with the California market or CAISO allocations and methodologies. Similarly, distribution costs are designed to meet the maximum demands of the localized system or customers; therefore, the 4NCP allocation factor was used. The 4NCP method was used to allocate the distribution system demand-related costs associated with substations, poles, conductors, and distribution transformers.

Table 3-3 compares the various demand allocators utilized in the Study.

Table 3-3
Demand Allocation Factors

Customer Class	12CP (%)	4NCP (%)
AG-2	0.4%	1.0%
ED-1P	18.6%	16.7%
ED-2 & ED-2P	16.5%	16.1%
ED-3	8.1%	8.4%
ED-3V	2.0%	1.8%
ED-4	14.7%	14.9%
EGS-2	4.9%	5.3%
MEF	0.0%	0.0%
LSC	0.1%	0.2%
LSC-1	0.0%	0.0%
MD-3	1.7%	2.1%
MD-4	9.2%	10.1%
RES2	19.2%	23.3%
TR-1	4.5%	0.0%
Total	**100%**	**100%**

Energy Allocations

Energy allocation factors are the basis for allocating costs or expenses classified as variable or energy-related and are assumed to vary directly with kWh sales. Energy-related costs classified as variable were energy costs from fuel, renewable contracts, and spot market purchases. Typically, net energy for load (NEFL), or the energy necessary to supply each customer class, is used to allocate these types of costs to individual customer classes. NEFL is also occasionally called adjusted metered load or energy at generation, as it takes into consideration energy losses that occur on the transmission and distribution system between the power supplier delivery point and the customer's meter. Table 3-4 lists the energy allocation factor utilized in the Study. The table shows the percentage that each customer class contributes to the total NEFL.

Table 3-4
Energy Allocation Factors

Customer Class	Net Energy for Load (%)
AG-2	0.4%
ED-1P	22.9%
ED-2 & ED-2P	19.1%
ED-3	7.7%
ED-3V	2.6%
ED-4	13.3%
EGS-2	4.0%
MEF	0.0%
LSC	0.2%
LSC-1	0.0%
MD-3	1.2%
MD-4	7.5%
RES2	16.2%
TR-1	4.9%
Total	**100%**

Customer Allocations

Customer costs are defined as those costs related to the number of customers and the type of service required. Included in the customer-related costs are the costs associated with meter reading, customer service, sales, billing, collection, and other customer-related activities. The customer allocation factors were largely based on the number of customers in each class.

In allocating certain customer-related costs to the various customer classifications, weighted customer allocation factors were utilized. Weighting reflects that providing customer service for certain types of customers requires more effort and expenses than other types of customers. Weighting factors were developed based on discussion with MID staff, as well as applying industry knowledge and practices. Weighting factors reflect the relationships between the customer classes and the types of equipment or services needed to serve the class and the relative costs of those items. For example, utilities typically have a “key account” customer service representative dedicated to serving large business customers, which results in higher customer service costs for these customers on a per customer basis.

Cost of Service Results

The unbundled COS results by customer class are shown in Table 3-5.

Table 3-5
Unbundled Cost of Service Results

Class	Power Supply	Transmission	Distribution	Customer	Total COS	Demand Related	Energy Related	Customer Related	Total COS
AG-2	$233,948	$17,984	$253,057	$46,446	$551,434	$274,014	$142,735	$134,686	$551,434
ED-1P	$12,290,742	$756,187	$2,693,872	$20,416	$15,761,217	$7,248,241	$8,455,419	$57,557	$15,761,217
ED-2 & ED-2P	$10,422,839	$669,953	$2,766,512	$132,703	$13,992,007	$6,631,413	$7,024,888	$335,707	$13,992,007
ED-3	$4,514,385	$329,903	$1,394,806	$27,561	$6,266,655	$3,343,726	$2,841,140	$81,789	$6,266,655
ED-3V	$1,365,293	$82,693	$293,026	$4,287	$1,745,299	$784,463	$945,879	$14,957	$1,745,299
ED-4	$7,933,957	$597,452	$2,682,406	$154,344	$11,368,159	$6,002,142	$4,903,724	$462,293	$11,368,159
EGS-2	$2,474,033	$197,442	$1,365,922	$473,648	$4,511,046	$2,046,303	$1,472,624	$992,119	$4,511,046
MEF	$5,512	$306	$959	$0	$6,777	$2,816	$3,961	$0	$6,777
LSC	$101,573	$2,296	$97,993	$34,156	$236,018	$53,636	$89,926	$92,456	$236,018
LSC-1	$8,363	$189	$5,777	$1,470	$15,799	$4,416	$7,404	$3,979	$15,799
MD-3	$798,833	$67,771	$363,798	$16,537	$1,246,938	$744,199	$455,102	$47,637	$1,246,938
MD-4	$4,655,850	$373,923	$1,758,153	$79,622	$6,867,549	$3,869,722	$2,759,342	$238,484	$6,867,549
RES2	$9,910,092	$776,808	$6,151,818	$1,167,584	$18,006,302	$8,420,569	$5,970,182	$3,615,551	$18,006,302
TR-1	$2,720,799	$182,420	$1,147	$10,208	$2,914,574	$1,107,638	$1,795,581	$11,355	$2,914,574
Total	**$57,436,218**	**$4,055,327**	**$19,829,246**	**$2,168,983**	**$83,489,775**	**$40,533,300**	**$36,867,907**	**$6,088,569**	**$83,489,775**

Cost of Service Results Compared to Current Revenue

Estimated operating revenues were developed by the Project Team to compare the revenue generated under current rates to the current operating costs of the Electric Utility. Table 3-6 summarizes the variance between the Test Year Revenue Requirement or COS over the five-year Study Period and the annual revenue generated from current rates, by customer class. The results of comparing the projected revenues to the customer class revenue requirements indicate the degree to which existing rates, including the PCA and EC, recover revenues from each customer class on a COS basis and are considered in designing new electric rates.

Table 3-6
Comparison of Current Rate Revenues with COS Results

Customer Class	COS	Test Year Projected Revenue	Difference ($)	Difference (%)
AG-2	$551,434	$494,879	$56,556	11.4%
ED-1P	$15,761,217	$18,394,296	($2,633,079)	(14.3%)
ED-2 & ED-2P	$13,992,007	$16,844,091	($2,852,084)	(16.9%)
ED-3	$6,266,655	$7,587,646	($1,320,990)	(17.4%)
ED-3V	$1,745,299	$2,309,141	($563,841)	(24.4%)
ED-4	$11,368,159	$13,713,336	($2,345,176)	(17.1%)
EGS-2	$4,511,046	$4,757,253	($246,207)	(5.2%)
MEF	$6,777	$8,356	($1,579)	(18.9%)
LSC	$236,018	$270,006	($33,988)	(12.6%)
LSC-1	$15,799	$34,597	($18,798)	(54.3%)
MD-3	$1,246,938	$1,229,158	$17,780	1.4%
MD-4	$6,867,549	$7,942,599	($1,075,050)	(13.5%)
RES2	$18,006,302	$19,427,525	($1,421,223)	(7.3%)
TR-1	$2,914,574	$3,939,951	($1,025,378)	(26.0%)
Total	**$83,489,775**	**$96,952,833**	**($13,463,058)**	**(13.9%)**

As shown in Table 3-6, the overall COS analysis indicates that a rate decrease is indicated to meet the Electric Utility's revenue requirement. Only two classes, Agricultural General Service and Municipal & Non-Profit Medium Demand General Service, indicated upward pressure on rates, while all other classes are currently collecting revenues above their respective COS requirements. Proposed changes to the current electric rates are discussed in Section 4 of this report.

Section 4
PROPOSED RATES

Rate design is the culmination of a COS study where the rates and charges for each customer classification are established in such a manner that the total revenue requirement of the utility will be recovered in the most equitable and consistent manner to the extent reasonable and practical. During rate design, consideration was given to the recovery of fixed costs in the customer and demand charges, as well as phasing in the proposed rates over time.

Rate Design Objectives

In general, proposed and recommended rate structures should meet the following objectives and best practices:

- Rates should be equitable among customer classes and individuals within classes, taking into consideration the costs incurred to serve each customer class.
- Rates should be designed to encourage the most efficient use of the utility's system.
- Rates may take into consideration other important factors, such as competitive concerns, conservation, MID/community policies, etc.
- Rates should be simple and understandable.

Rate design typically combines COS results and policy considerations important to the community. Specific rate design goals for MID include:

- Improving fixed cost recovery based on COS results.
- Align rates with the COS results between and within classes.
- While moving rates toward COS, to the extent possible, minimize customer and class adverse impacts to proposed rates.

Electric Rate Structure

The proposed electric rates include a customer charge, energy charge, demand charge (if applicable), PCA, and EC. The customer, energy, and demand charges are commonly referred to as "base rates," while the PCA and EC are referred to as pass-through adjustment rates. The overall rate strategy for MID included implementing a system average 8.6% decrease, while increasing the base rates and reducing the PCA and EC.

Base Rate Charges

The customer charge should be designed to recover customer-related costs. The expenses to the utility for providing customer-related functions do not change with the energy the customer consumes and should therefore be on a $/month or $/day basis. The energy and PCA/EC charge ($/kWh) should be designed to recover all variable costs, including O&M, fuel, and applicable power supply costs. The demand charge should be designed to recover demand-related costs and should be on a $/kilowatt (kW) month or $/kW day basis.

Customer and demand charges should collect revenues to fund the Electric Utility's fixed costs. However, due to rate design, energy and PCA charges may collect revenues to recover both fixed and variable costs. For customer classes that do not have demand charges, a large portion of fixed costs are collected through the energy charge.

Certain customer classes have seasonal rates that reflect the higher demand periods (e.g., summer) and lower demand periods (e.g., winter) for the Electric Utility system. The High Season is May through October, and the Low Season is November through April. These seasonal charges provide price signals to customers that reflect the higher costs associated with system peaking periods.

Pass-Through Adjustment Charges

Utilities often have adjustment charges that pass through variable costs allowing the utility to fully recover these costs, as the costs are not controlled by the utility. The utility uses the pass-through cost adjustment rates to recover costs when they vary from the projected basis. The MID rates have two adjustment charges, which include the PCA and EC.

The PCA is a mechanism to pass through the power supply market and purchased power cost fluctuations. The PCA passes through charges or credits for any differences in the actual incurred power supply costs to the projected power supply costs to customers without the need for a formal rate change. The PCA is reviewed semi-annually, with any changes going into effect on either November 1 or May 1. MID, upon its discretion, can also utilize electric reserves to offset all or a portion of these costs. As part of this rate plan, the PCA will be set to $0.01/kWh as the new rates are implemented and all remaining purchased power costs will be embedded in the base rates. Embedding a portion of the power supply and purchased power costs in the base rates will provide rate stability to the customers, while still allowing MID the flexibility to charge and/or credit the differences in projected costs and actual costs without the need for a formal rate change.

The EC is designed to properly collect the costs related to renewable energy and GHG emission reduction costs. The EC represents the difference in actual incurred and projected renewable and GHG costs. The EC-related revenues recover costs related to California regulations intended to encourage the use of renewable energy and reduce GHG emissions. MID, upon its discretion, can utilize electric reserves to offset all or a portion of these costs. The current EC charge of $0.00407/kWh will remain in effect with the new rate plan.

Public Benefits Charge

Each electric utility bill prepared by MID shall include a Public Benefits Charge (PBC). The PBC imposed shall be at the rate of 2.85% of the charges made for such electricity, and for any supplemental services or other associated activities directly related to and/or necessary for the provision of electricity to the service user. Please note, the PBC is applied to each customer bill; however, we have not included the PBC amount in the proposed rate tables for each customer class within this section.

Electric Utility Proposed Rates

Based on the COS results, MID implemented a rate reduction of 9% for FY 2026. While the COS results indicate a 13.9% reduction is warranted, the 9% reduction aligns with the results, while allowing flexibility for potential changes in power supply costs in the future.

This section of this report includes proposed rates to collect the needed revenue requirement goals and reflect the rate decreases. The MID revenue decrease was applied to each customer class based on their individual cost responsibility or COS results. The rate decreases vary by customer class, ranging from a 1% to 12% reduction. This allows each rate class to move their rates closer to the COS, while also providing rate or bill relief to all customers.

The proposed Electric Utility rates include a demand charge (where applicable), energy charge, customer charge, PCA, and EC adjustment. In general, the existing rate structure is recommended to remain the same. The use of uniform energy rates across seasons, seasonal demand rates in customer classes with demand charges, and inclining block rates of two tiers in the residential class are all recommended to be continued in the Study.

The proposed rate decrease is applied in one phase for FY 2027. In each customer class, different rate components, such as the customer charge, energy charge, and demand charge, are adjusted individually to result in the targeted rate decrease for each class. Some rate components may not change, while others may decrease more or less than the customer class average decrease. The forecasted revenue generated by the new rates is provided in Table 4-1.

Table 4-1
Electric Utility Rate Revenue – Proposed Rates

Class	Test Year Rate Revenue	Revenues after Rate Decrease	% Change
AG-2	$494,879	$484,981	(2.0%)
ED-1P	$18,394,296	$16,440,665	(10.6%)
ED-2	$3,681,435	$3,657,926	(0.6%)
ED-2P	$13,162,657	$11,698,991	(11.1%)
ED-3	$7,587,646	$6,685,125	(11.9%)
ED-3V	$2,309,141	$2,045,554	(11.4%)
ED-4	$13,713,336	$12,050,674	(12.1%)
EGS-2	$4,757,253	$4,672,605	(1.8%)
MD-3	$1,229,158	$1,082,253	(12.0%)
MD-4	$7,942,599	$6,968,583	(12.3%)
RES-2	$19,427,525	$19,064,087	(1.9%)
LSC	$270,006	$242,503	(10.2%)
LSC-1	$34,597	$30,320	(12.4%)
MEF	$8,356	$7,694	(7.9%)
TR-1	$3,939,951	$3,523,780	(10.6%)
Total	**$96,952,833**	**$88,655,740**	**(8.6%)**

Rate Design Results

For each customer class, the proposed rates and an example monthly customer bill are presented below. Graphs have been included to provide visual information, with respect to current rates, proposed rates, and COS results. Please note, the new rates go into effect in FY 2027 on July 1, 2026.

Agricultural Demand (AG-2)

The Agricultural Demand (AG-2) class is offered to customers if energy is used for agricultural end use that does not change the form of the agricultural product. Table 4-2 compares the current rates, proposed rates for Phase 1 and COS rates.

Table 4-2
Current, Proposed, and COS Rates:
Agricultural Demand (AG-2)

Rate Unit	Current Rates	Recommended Rates	COS
Energy Charge			
Summer	$0.0817	$0.1343	$0.0733
Winter	$0.0817	$0.1343	N/A
Demand Charge			
Summer	$7.50	$7.50	$20.68
Winter	$4.50	$4.50	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate	**$0.2543**	**$0.2492**	**$0.2833**

Note: Summer months are May through October. Winter months are November through April.

While the COS analysis indicated that the current revenues collected for the AG-2 class are below COS levels by approximately 11.4%, MID made a policy decision to allow all classes to receive a rate decrease. Thus, the AG-2 class proposed rates provide a modest rate decrease that is not as significant as other customer classes. The proposed rate adjustments increase the base rate energy charge, while keeping the customer and demand charges unchanged. Although the base rate energy charge increases, the PCA is reduced from $0.0677/kWh to $0.0100/kWh, as excess purchased power costs have been embedded in the base rate. As a result, the total energy charge (base rate plus PCA) decreases. The seasonality in the demand rate is maintained, with a larger differential in the summer to reflect the higher costs of delivering power during those periods. The seasonality is not included in the energy charge.

Figures 4-1 and 4-2 below compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for varying load factors within the AG-2 class. As shown in the figures, even with the proposed Phase 1 rate changes, the rates in the AG-2 rate curve remain close to its COS curve. The figures also show a bar graph representing the number of customers at each load factor interval. At lower usage levels or load factors, the total bill is driven more by the fixed customer charges than the variable energy charges. This results in a higher rate per kWh for lower usage customers than higher usage customers. As a customer's use increases, the rate per kWh decreases slightly. Average monthly peak demand for this class is 17 kW in the summer months and 8 kW in the winter months. As previously noted, summer months are from May through October.

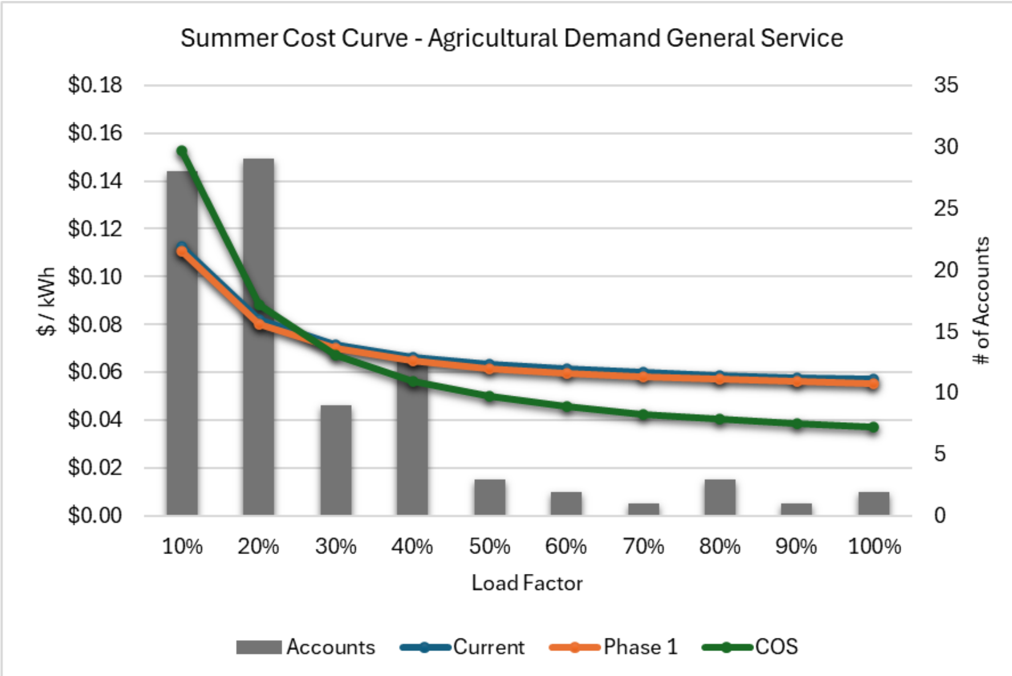

Figure 4-1. Agricultural Demand (AG-2) Summer Cost Curves

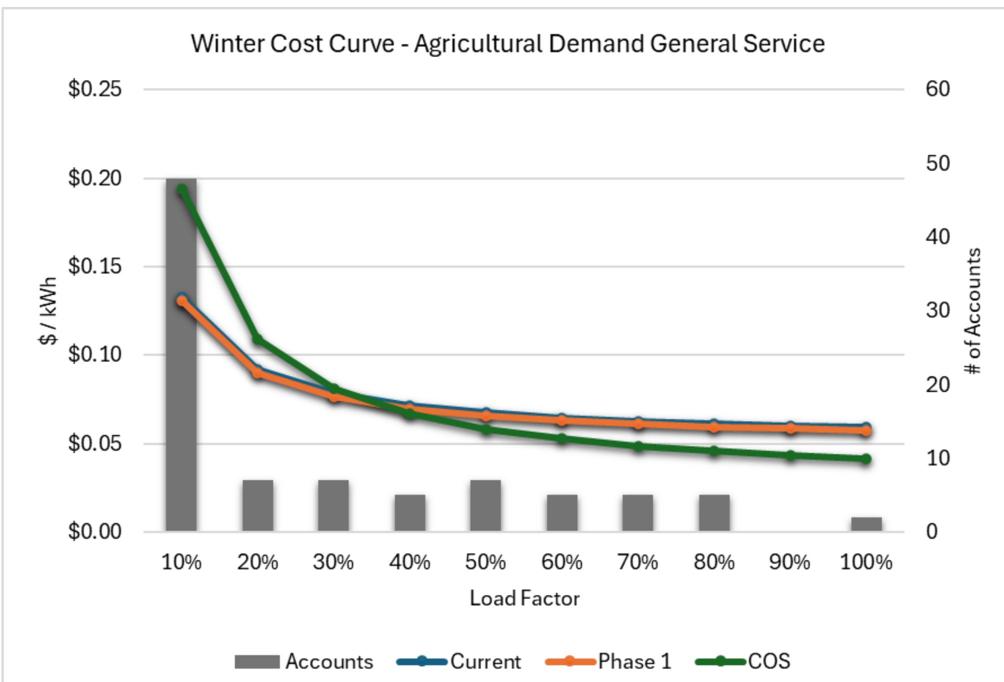

Figure 4-2. Agricultural Demand (AG-2) Winter Cost Curves

Figures 4-3 and 4-4 reflect the monthly bill adjustment per customer that AG-2 accounts will experience in Phase 1. As illustrated in Figure 4-3, many AG-2 customers will experience a bill change of approximately

3% to 1% in Phase 1, reflecting the net reduction in total energy charges resulting from the decrease in the PCA, which more than offsets the increase in the base rate energy charge.

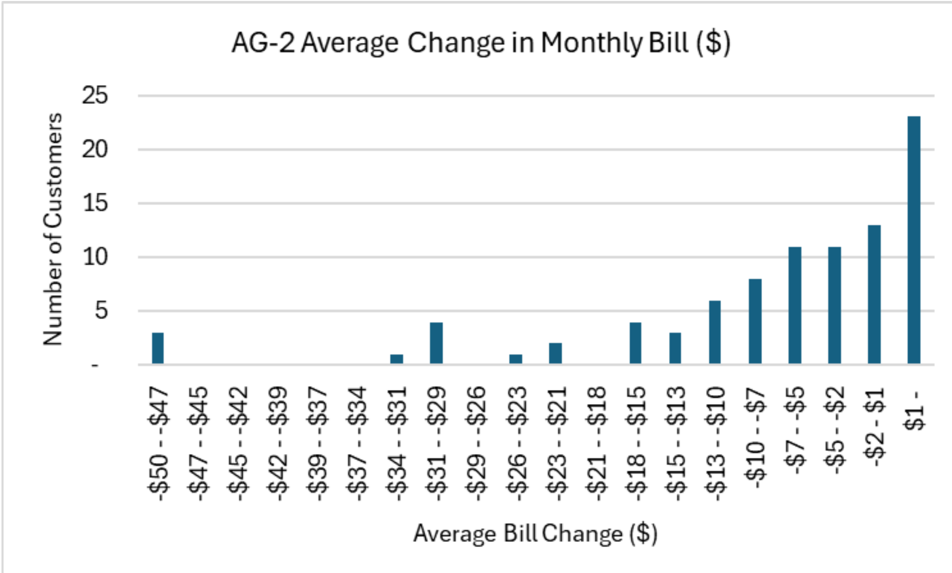

Figure 4-3. Agricultural Demand General Service (AG-2) Monthly Billing Impacts

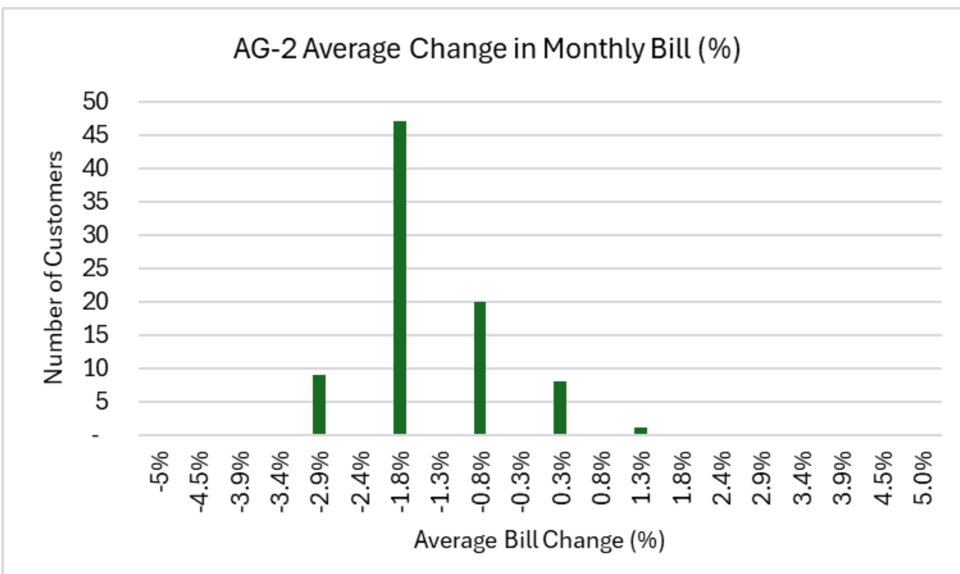

Figure 4-4. Agricultural Demand General Service (AG-2) Monthly Billing Impacts

Large Demand General Service (ED-1P)

The Large Demand General Service (ED-1P) class is offered to industrial and commercial customers having an NCP demand of 15,000 kW or greater in any month during the previous 12 months. Table 4-3 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-3
Current, Proposed, and COS Rates:
Large Demand General Service (ED-1P)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$1,100.00	$1,100.00	$2,398.20
Energy Charge ($/kWh)			
Summer	$0.0486	$0.0834	$0.0721
Winter	$0.0486	$0.0834	N/A
Demand Charge ($/kW)			
Summer	$19.20	$22.50	$32.75
Winter	$19.20	$22.50	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.1568**	**$0.1401**	**$0.1343**

Note: Summer months are May through October. Winter months are November through April.

According to the COS analysis, the Test Year revenues are higher than the COS by approximately 14.3% for the ED-1P class. The current customer charge is under-recovering its COS, while the demand charge is below COS levels. The proposed rates are designed to move this customer class closer to COS levels by increasing the base rate energy charge and the demand charge. The decrease in total energy charge (base rate plus PCA), drives the overall bill reduction for this class.

Figures 4-5 and 4-6 compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for a series of monthly energy usage amounts within the ED-1P class. As shown in the figures, the Phase 1 rate changes move close to the COS curve in the ED-1P class rate curves.

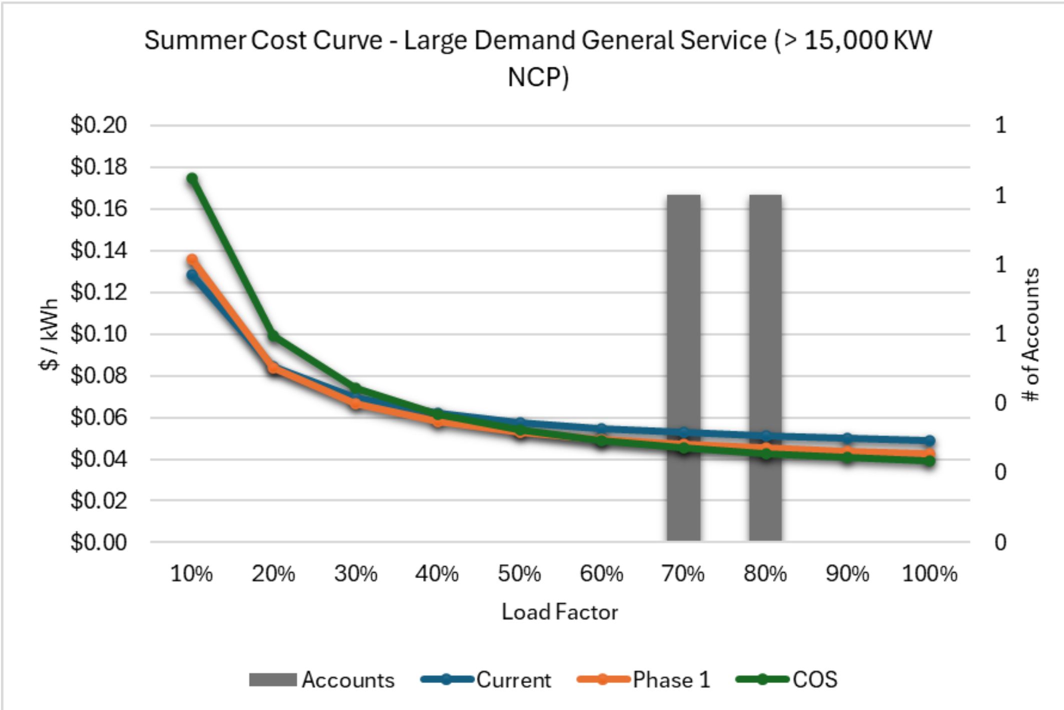

Figure 4-5. Large Demand General Service (ED-1P) Summer Cost Curves

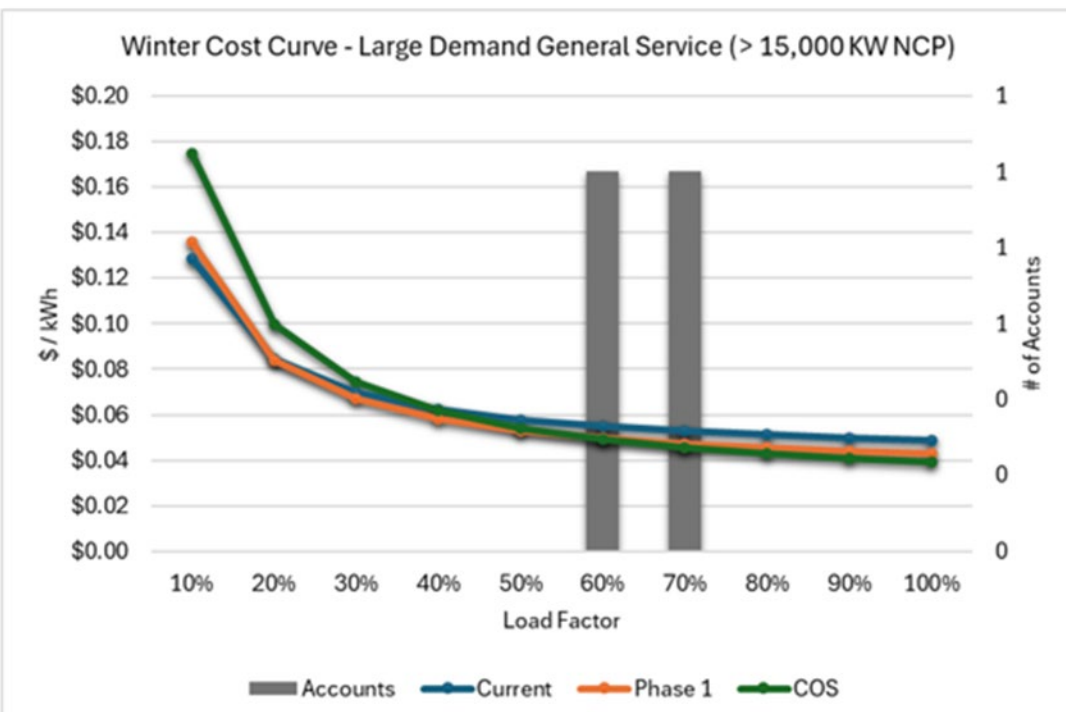

Figure 4-6. Large Demand General Service (ED-1P) Winter Cost Curves

Figures 4-7 and 4-8 reflect the monthly bill adjustment per customer that ED-1P accounts will experience in Phase 1. ED-1P customers will experience an overall bill decrease of approximately 10.6% in Phase 1, driven primarily by the reduction in the PCA, which more than offsets the increase in the base rate energy charge, partially offset by the increase in the demand charge.

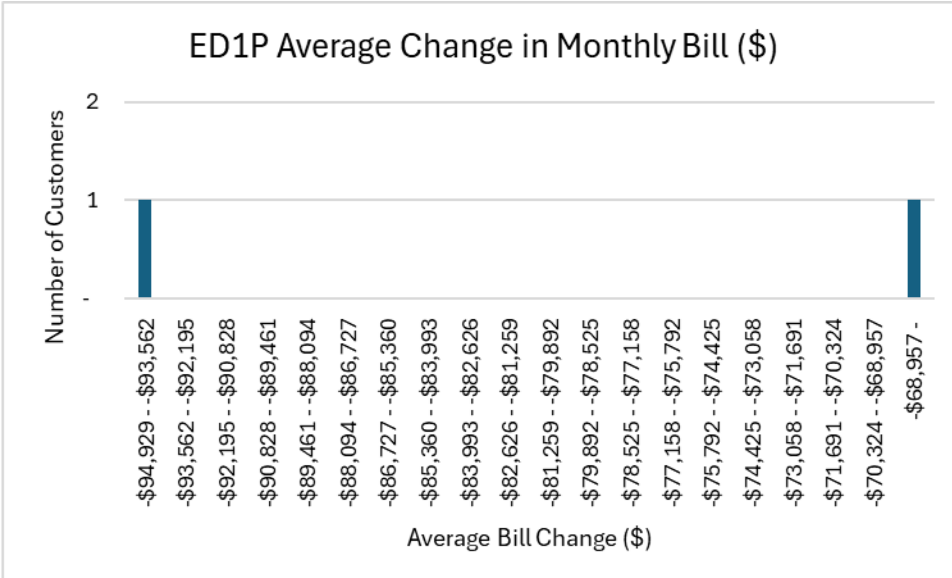

Figure 4-7. Large Demand General Service (ED-1P) Monthly Billing Impacts ($)

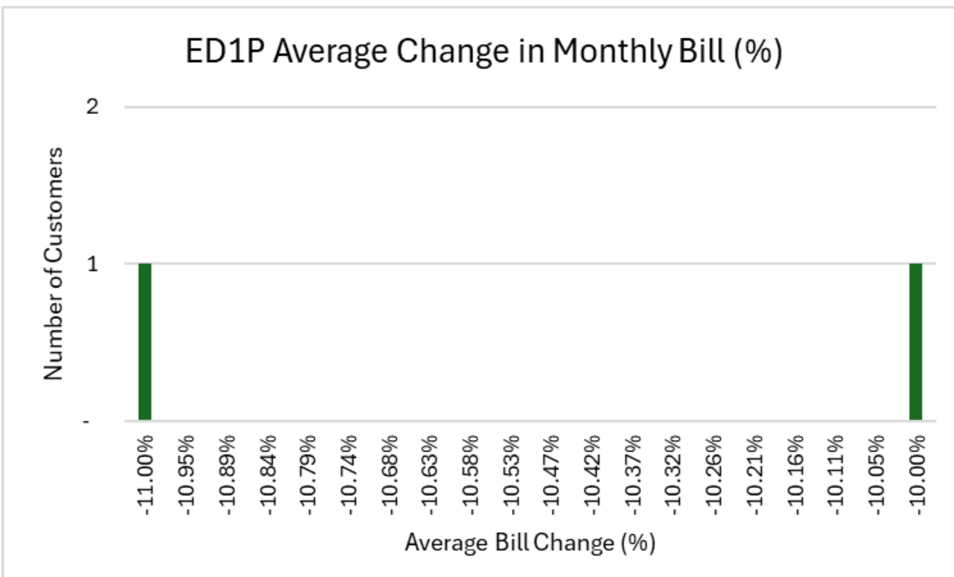

Figure 4-8. Large Demand General Service (ED-1P) Monthly Billing Impacts (%)

Large Demand General Service (ED-2)

The Large Demand General Service (ED-2) class is offered to industrial and commercial customers having a demand of 1,000 kW or greater in any month during the previous 12 months. The COS results show that the Test Year revenues for the ED-2 class are over collecting relative to COS. Energy charges are currently over recovering, while the customer and demand charges are under recovering their COS. Table 4-4 compares the current rates and proposed rates for Phase 1 and COS rates.

Table 4-4
Current, Proposed, and COS Rates:
Large Demand General Service (ED-2)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$1,100.00	$1,100.00	$2,151.97
Energy Charge ($/kWh)			
Summer	$0.0667	$0.1090	$0.0723
Winter	$0.0667	$0.1090	N/A
Demand Charge ($/kW)			
Summer	$20.00	$25.00	$33.12
Winter	$10.00	$15.00	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.1865**	**$0.1853**	**$0.1741**

Note: Summer months are May through October. Winter months are November through April.

The proposed rates are designed to move this customer class closer to COS levels. The current customer charge remains unchanged in Phase 1 The base rate energy charge increases but total energy charges decrease. The demand charges increase to improve fixed cost recovery, and the seasonality of the demand rate is maintained.

Figures 4-9 and 4-10 compare the unit costs ($/kWh) for the current rates, one phase of rate adjustments, and the COS for a series of monthly energy usage amounts within the ED-2 class. As shown in the figures, in Phase 1 of the rate changes, the ED-2 class rate curve moves closer to its COS curve. The proposed rates closely mirror the current rates. The figure also shows a bar graph representing the number of customers at each load factor interval. There is a small amount customers in this rate class. These customers have an average peak monthly summer demand of 861 kW and an average peak monthly winter demand of 694 kW.

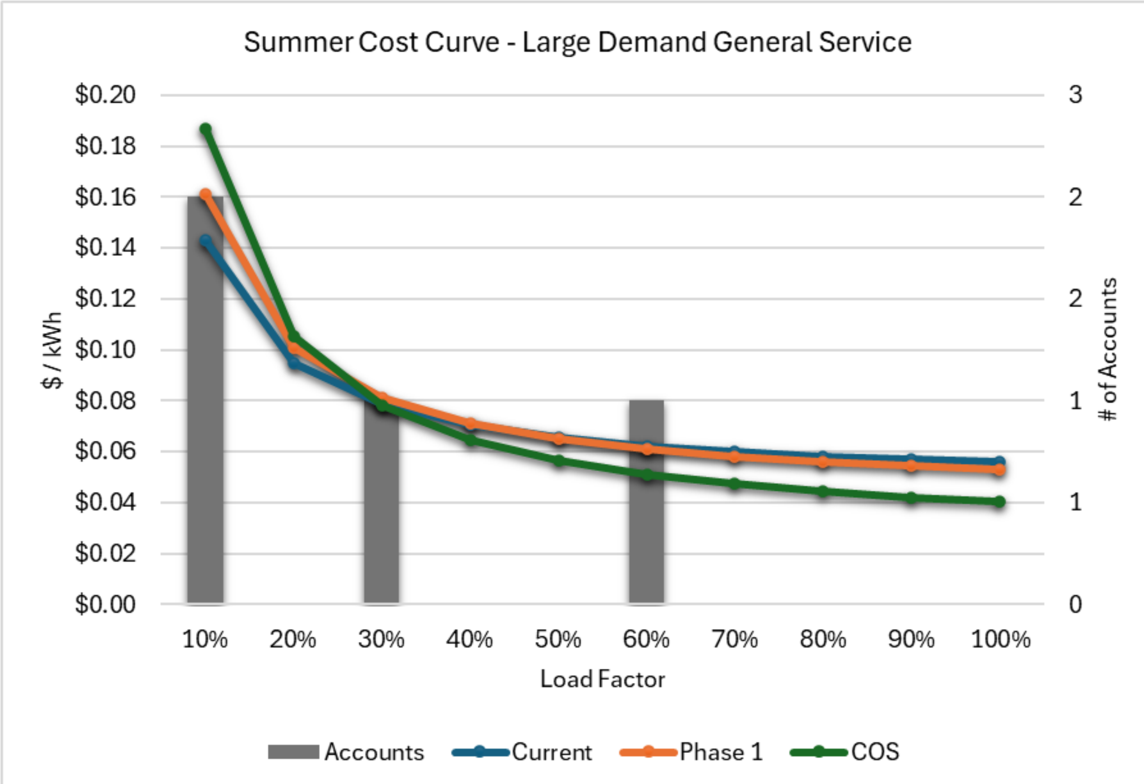

Figure 4-9. Large Demand General Service (ED-2) Summer Cost Curve

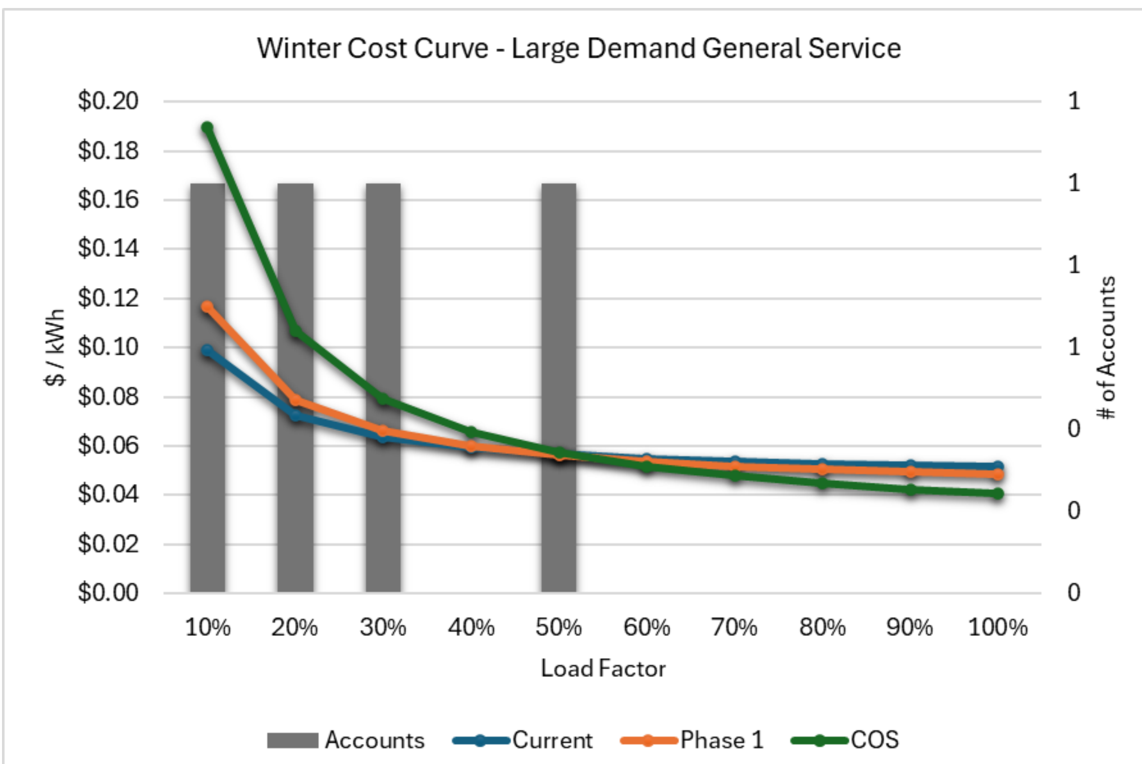

Figure 4-10. Large Demand General Service (ED-2) Winter Cost Curve

Figures 4-11 and 4-12 reflect the monthly bill adjustment per customer that ED-2 accounts will experience in Phase 1. During the rate adjustments proposed for Phase 1, customers will experience an overall bill decrease of approximately 0.6%, reflecting the net reduction in total energy charges from the PCA decrease, partially offset by the increase in demand charges.

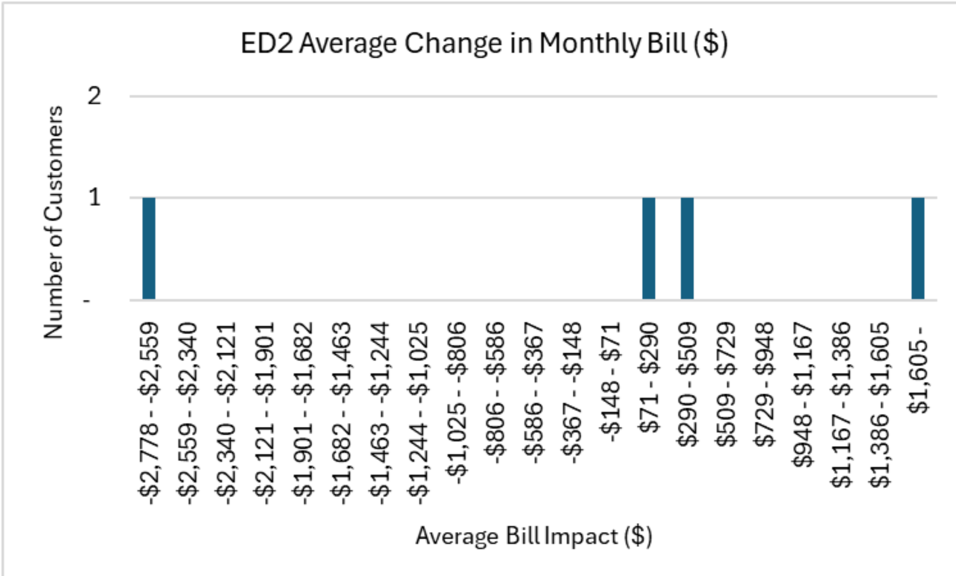

Figure 4-11. Large Demand General Service (ED-2) Monthly Billing Impacts

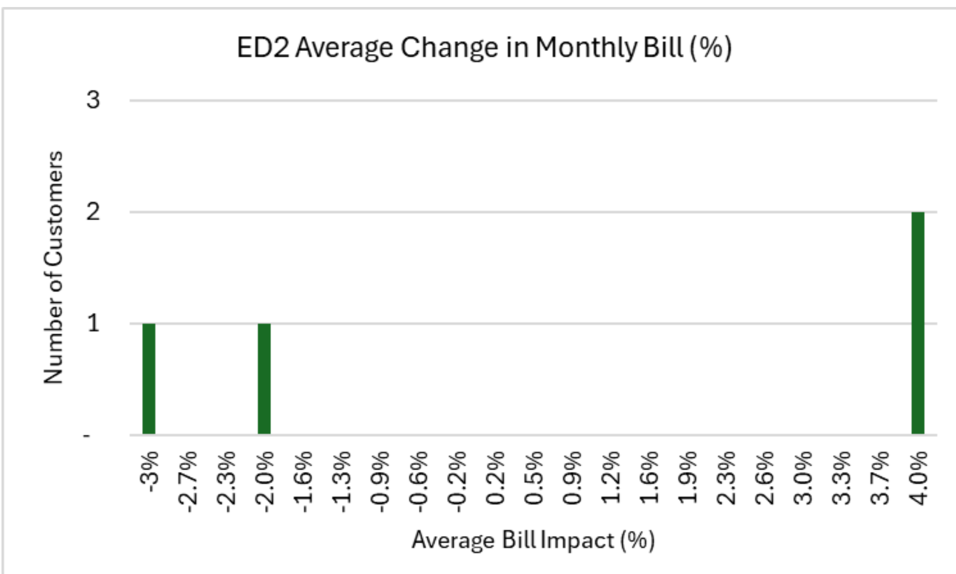

Figure 4-12. Large Demand General Service (ED-2) Monthly Billing Impacts

Large Demand Primary Service (ED-2P)

Large Demand Primary Service (ED-2P) customers are commercial and industrial entities that require a demand of at least 1,000 kW in any month out of the previous 12 months. The main differentiator from the previous class (ED-2) is the delivery voltage is a minimum of 12,000 volts or primary distribution voltage.

Table 4-5
Current, Proposed, and COS Rates:
Large Demand General Service (ED-2)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$1,535.00	$1,535.00	$2,151.97
Energy Charge ($/kWh)			
Summer	$0.0608	$0.0892	$0.0723
Winter	$0.0608	$0.0892	N/A
Demand Charge ($/kW)			
Summer	$27.00	$33.00	$33.12
Winter	$10.00	$15.00	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.1701**	**$0.1512**	**$0.1364**

Note: Summer months are May through October. Winter months are November through April.

Table 4-5 compares the current rates, proposed rates for Phase 1 and COS rates. According to the COS analysis, the Test Year revenues exceed the COS for the ED-2P class. The proposed rates are designed to move this customer class closer to COS levels by increasing the base rate energy charge and increasing both the summer and winter demand charges to improve fixed cost recovery.

Figures 4-13 and 4-14 compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for a series of monthly energy usage amounts within the ED-2P class. As shown in the figures, the Phase 1 rate changes move the ED-2P class rate curve closer to its COS curve.

The figures also show a bar graph representing the number of customers at each load factor interval. At lower usage levels or load factors, the total bill is driven more by the fixed customer charges than the variable energy charges. This results in a higher rate per kWh for lower usage than higher usage customers. As a customer’s use increases, the rate per kWh decreases slightly. Customers in the ED-2P class have an average peak monthly demand of 1,869 kW in the summer and 1,565 kW in the winter.

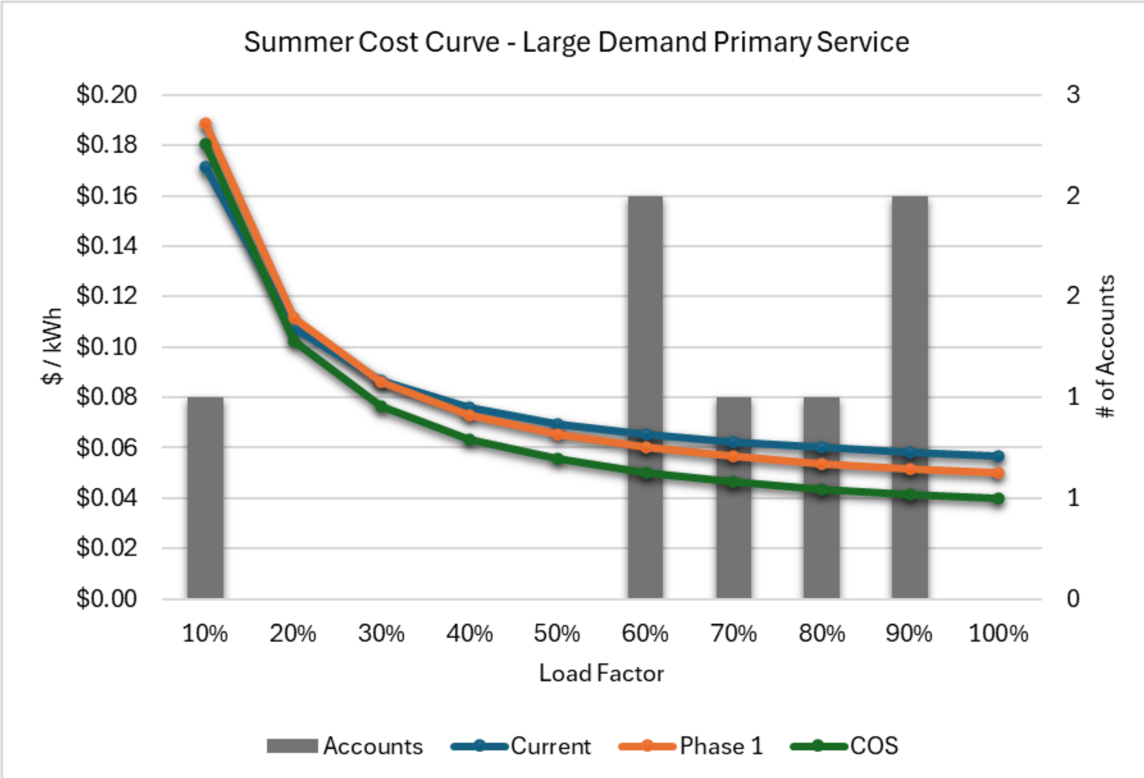

Figure 4-13. Large Demand Primary Service (ED-2P) Summer Cost Curves

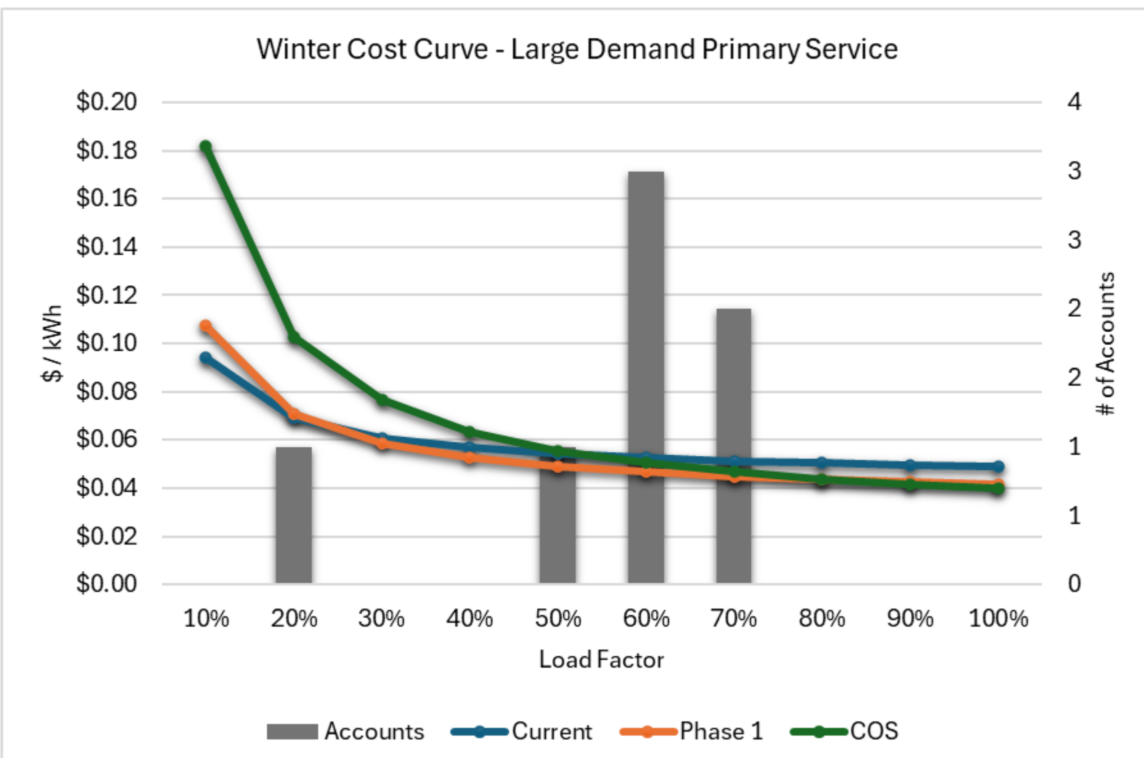

Figure 4-14. Large Demand Primary Service (ED-2P Winter Cost Curves

Figures 4-15 and 4-16 reflect the monthly bill adjustment per customer that ED-2P accounts will experience in Phase 1. Customers will experience an overall bill decrease ranging from approximately 7% to 12% in Phase 1, driven primarily by the reduction in the PCA, which more than offsets the increases in the base rate energy charge and demand charges.

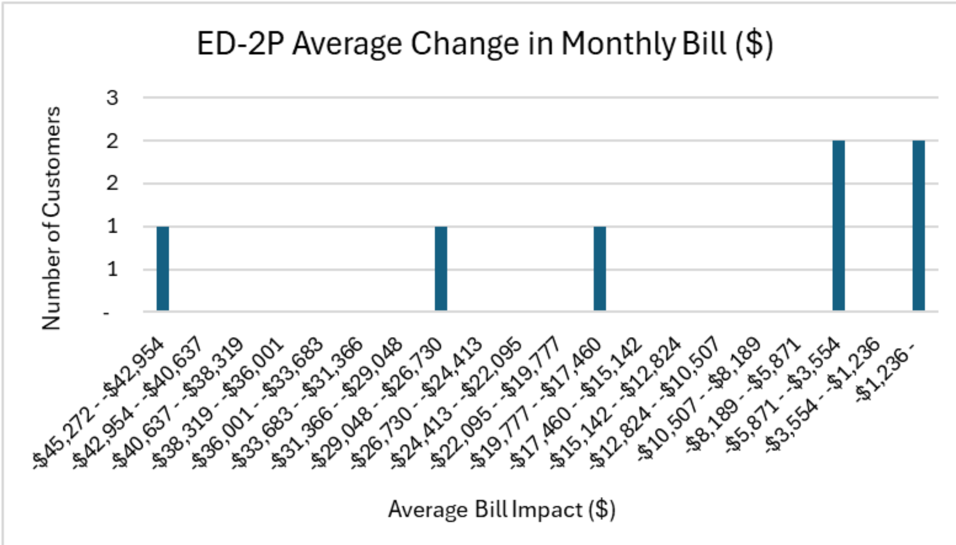

Figure 4-15. Large Demand Primary Service (ED-2P) Billing Impacts ($)

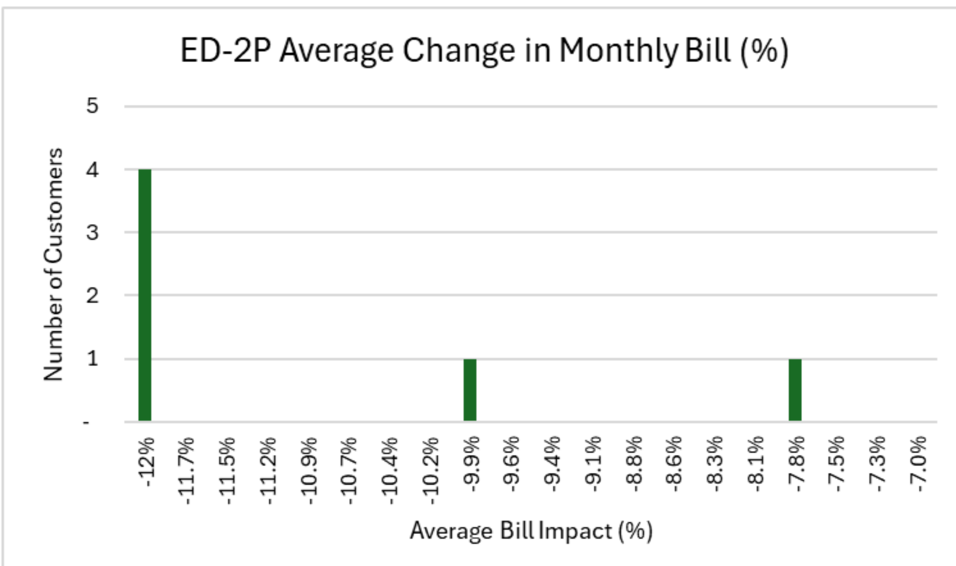

Figure 4-16. Large Demand Primary Service (ED-2P) Billing Impacts (%)

Medium Demand General Service (ED-3)

Medium Demand General Service (ED-3) customers are industrial and commercial electric customers, having a demand of 500 kW or greater for one month of the past 12 months but less than 1,000 kW.

Table 4-6
Current, Proposed, and COS Rates:
Medium Demand General Service (ED-3)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$350.00	$350.00	$454.38
Energy Charge ($/kWh)			
Summer	$0.0678	$0.0881	$0.0733
Winter	$0.0678	$0.0881	N/A
Demand Charge ($/kW)			
Summer	$28.00	$33.00	$30.64
Winter	$10.00	$15.00	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.1959**	**$0.1726**	**$0.1618**

Note: Summer months are May through October. Winter months are November through April.

Table 4-6 compares the current rates, proposed rates for Phase 1, and COS rates. According to the COS analysis, the Test Year revenues exceed the COS by approximately 17.4% for the ED-3 class. The customer and demand charges are under recovering their COS. The proposed rates are designed to move this customer class closer to COS levels by increasing the base rate energy charge and the demand charge to improve fixed cost recovery. The reduction in the PCA charge results in a total bill reduction. The seasonality of the demand rate is maintained, with a larger differential in the summer to reflect the higher costs of delivering power during those periods.

Figures 4-17 and 4-18 compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for a series of monthly energy usage amounts within the ED-3 class. As shown in the figures, the Phase 1 rate changes move the ED-3 class rate curves closer to their COS curve.

The figures also show a bar graph representing the number of customers at each load factor interval. The majority of customers in this rate class have a 50% load factor in the summer and 40% in the winter. At lower usage levels or load factors, the total bill is driven more by the fixed customer charges than the variable energy charges. This results in a higher rate per kWh for lower usage customers than higher usage customers. As a customer’s use increases, the rate per kWh decreases slightly. Customers in the ED-3 class have an average peak monthly demand of 635 kW in the summer and 578 kW in the winter.

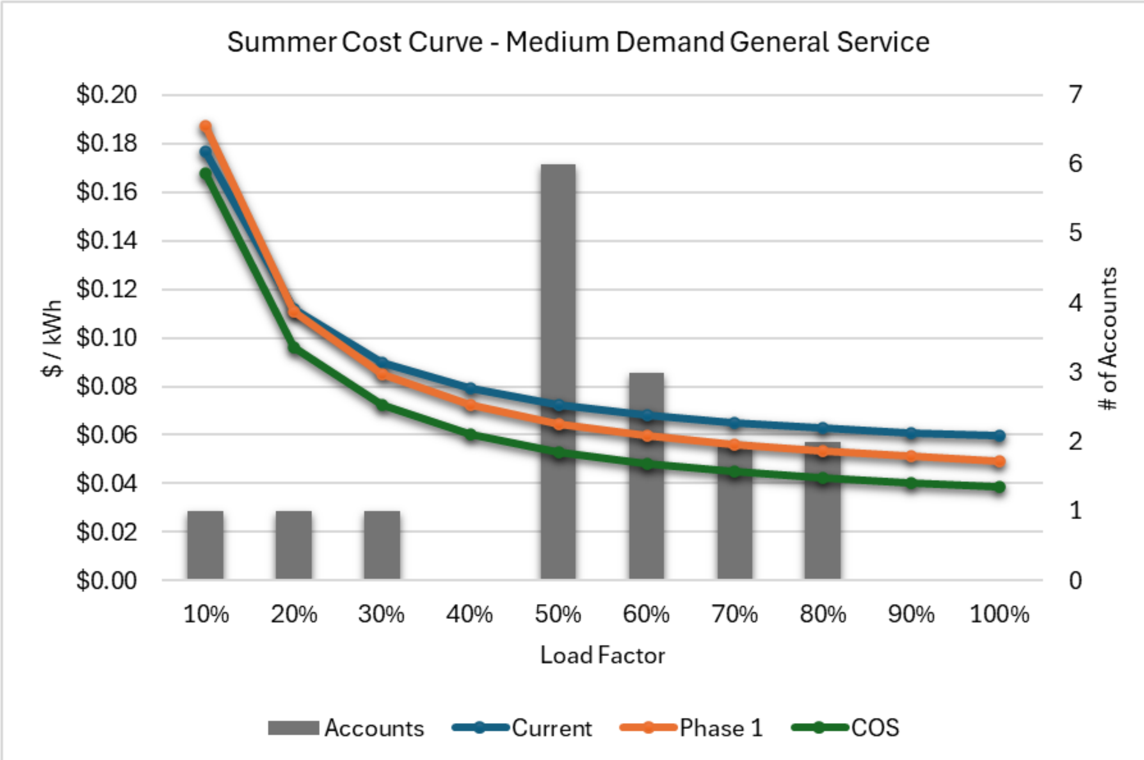

Figure 4-17. Medium Demand General Service (ED-3) Summer Cost Curves

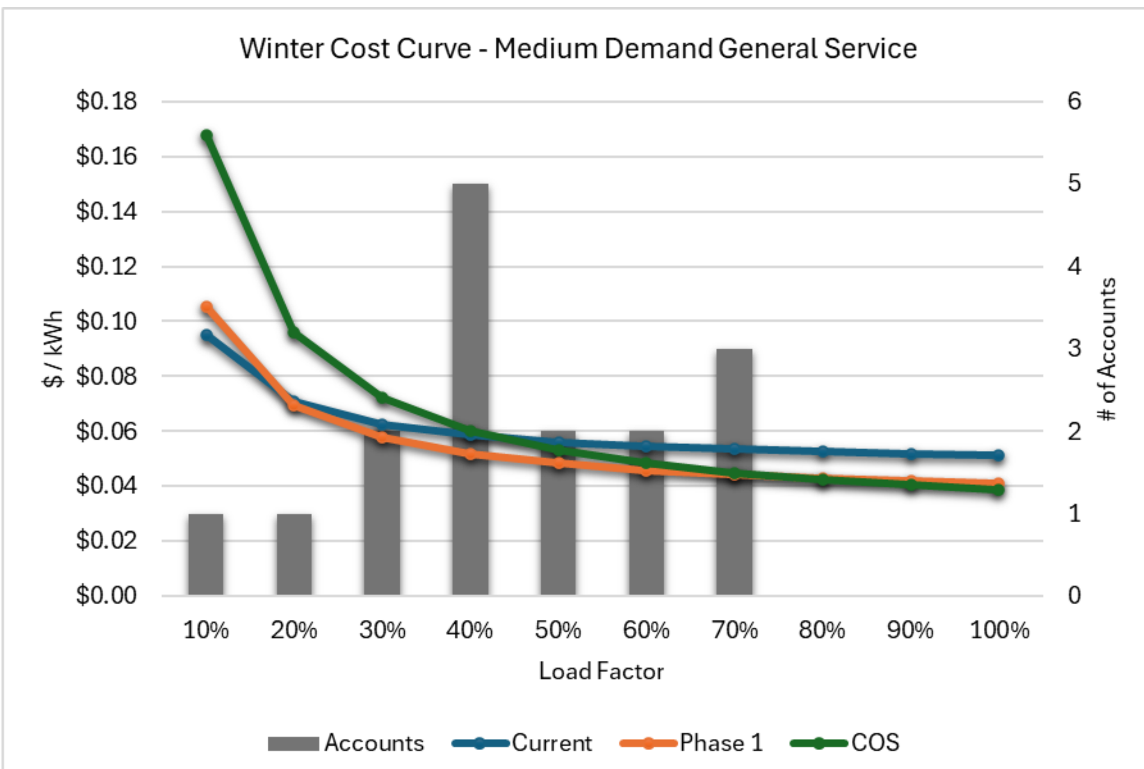

Figure 4-18. Medium Demand General Service (ED-3) Winter Cost Curves

Figures 4-19 and 4-20 reflect the monthly bill adjustment per customer that ED-3 accounts will experience in Phase 1. ED-3 customers will experience an overall bill decrease of approximately 11.9% in Phase 1, reflecting the net reduction in total energy charges from the PCA decrease, partially offset by the increase in demand charges.

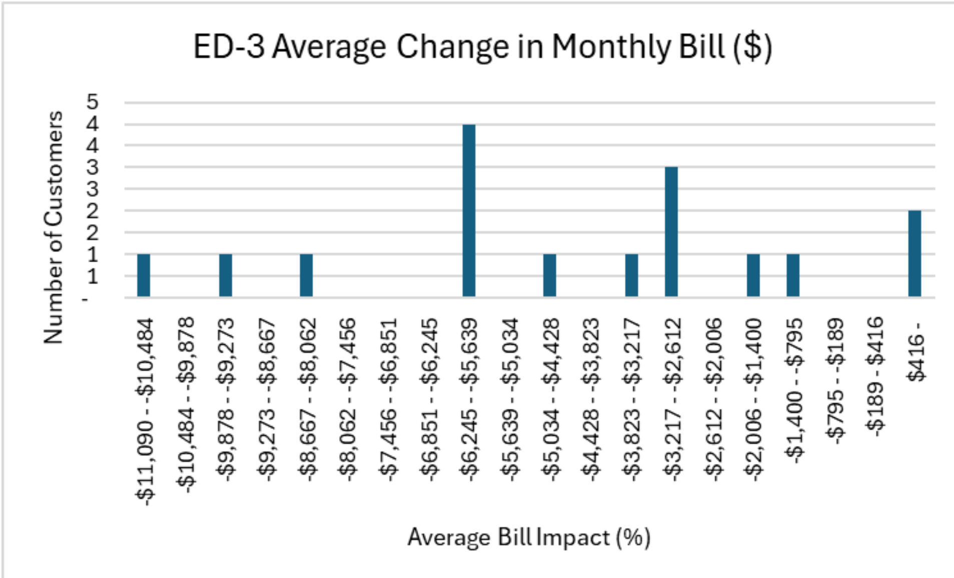

Figure 4-19. Medium Demand General Service (ED-3) Billing Impacts ($)

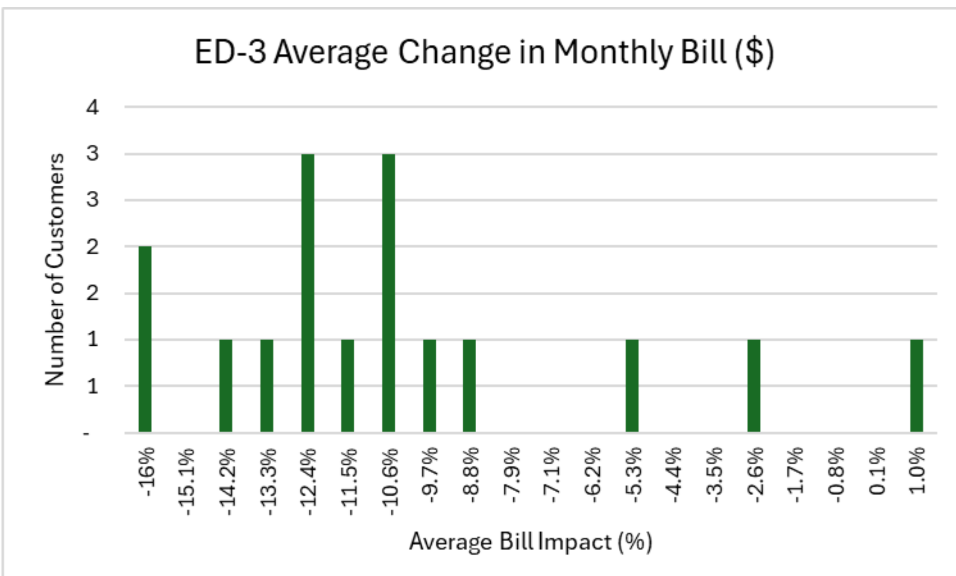

Figure 4-20. Medium Demand General Service (ED-3) Billing Impacts (%)

Medium Demand General Service Voluntary (ED-3V)

The Medium Demand General Service Voluntary (ED-3V) class is a voluntary schedule offered to industrial commercial customers having a demand of 200 kW or greater in any month during the previous 12 months, but less than 500 kW, and an annual load factor of at least 70%.

Table 4-7 compares the current rates, proposed rates for Phase 1, and COS rates. According to the COS analysis, the Test Year revenues over collect relative to COS by approximately 24.4% for the ED-3V class. The customer charge is slightly above its COS level.

Table 4-7
Current, Proposed, and COS Rates:
Medium Demand General Service Voluntary (ED-3V)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$200.00	$200.00	$178.06
Energy Charge ($/kWh)			
Summer	$0.0699	$0.0991	$0.0733
Winter	$0.0699	$0.0991	N/A
Demand Charge ($/kW)			
Summer	$30.00	$32.00	$34.74
Winter	$10.00	$17.50	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.1790**	**$0.1586**	**$0.1353**

Note: Summer months are May through October. Winter months are November through April.

Figures 4-21 and 4-22 compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for various load factors for customers within the ED-3V class. As shown in the figures, the Phase 1 rate changes move the class rate curves closer to their COS curves. The figures also show a bar graph representing the number of customers at each energy usage interval. At higher load factors or energy usage, the total bill is driven less by the fixed customer and demand charges than the energy charges. This results in a lower rate per kWh for higher usage customers than lower usage customers. A typical customer in this class has an average peak monthly demand of 286 kW in the summer and 252 kW in the winter.

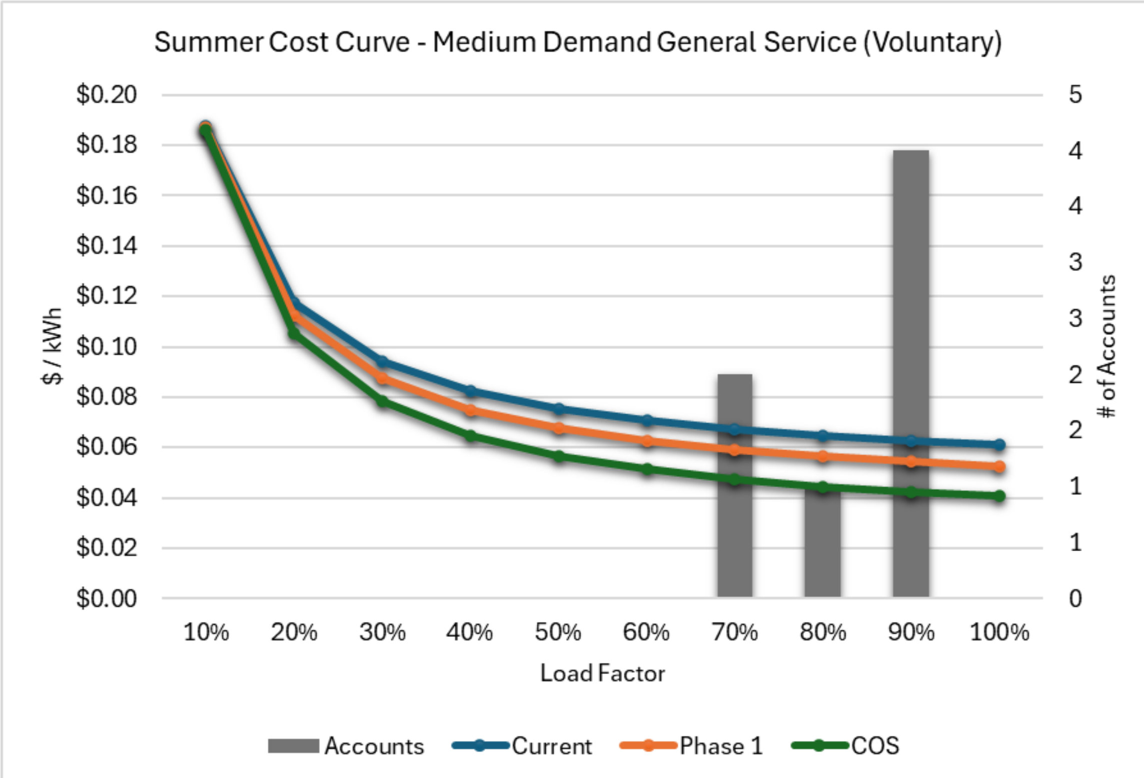

Figure 4-21. Medium Demand General Service Voluntary (ED-3V) Summer Cost Curves

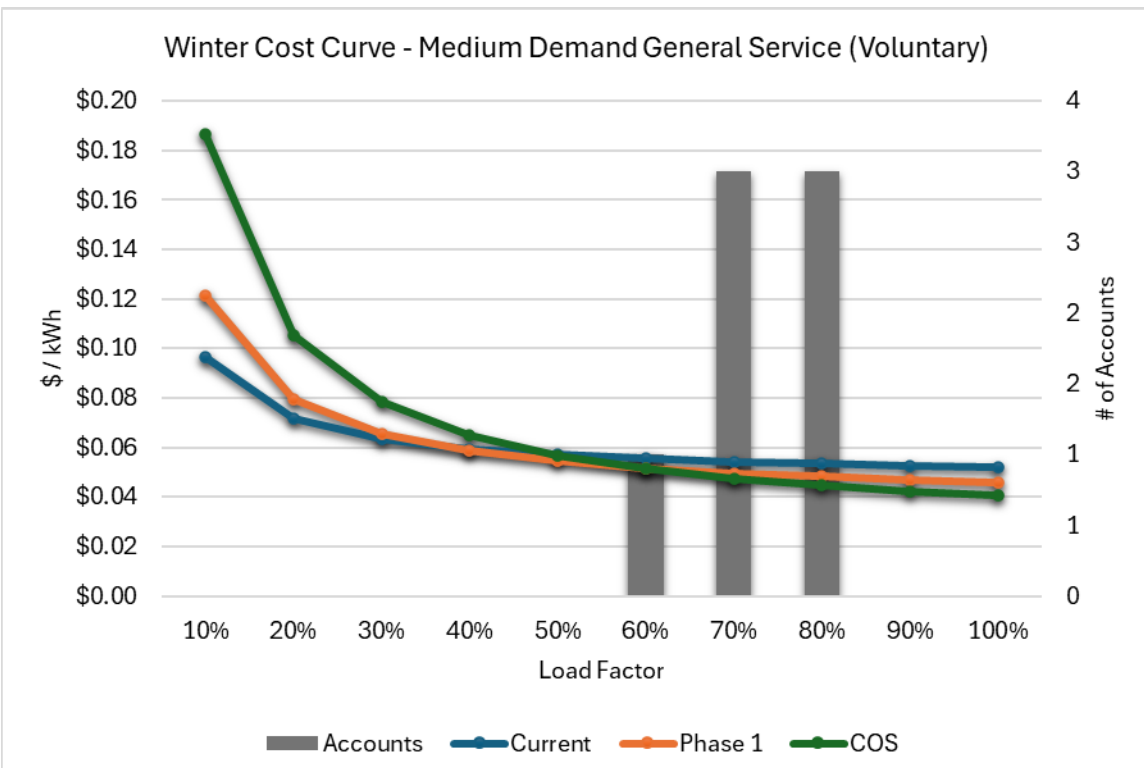

Figure 4-22. Medium Demand General Service Voluntary (ED-3V) Winter Cost Curves

Figures 4-23 and 4-24 reflect the monthly bill adjustment per customer account that will be experienced in Phase 1. As shown, most customers will experience a bill decrease of approximately 11.4% in Phase 1, reflecting the net reduction in total energy charges from the PCA decrease, partially offset by the increase in demand charges.

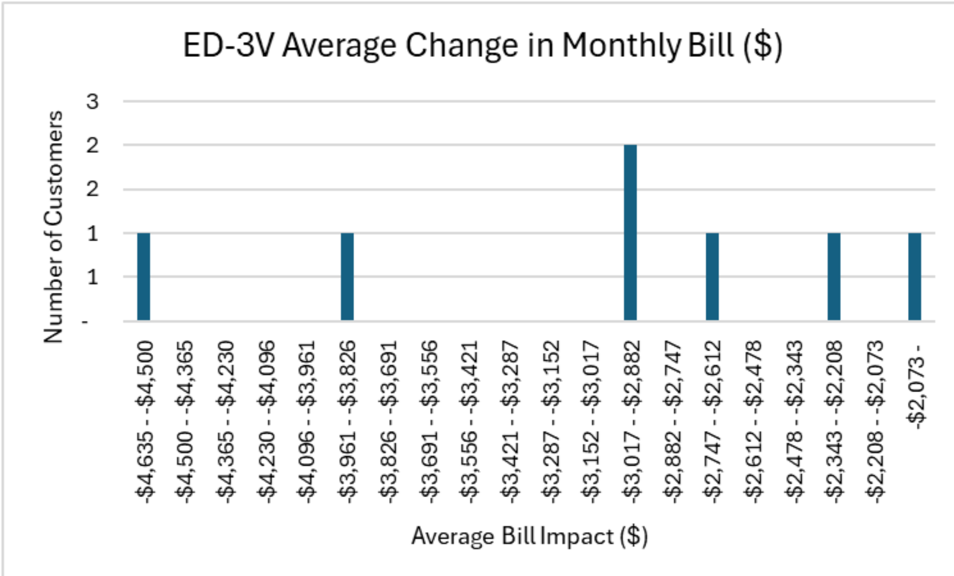

Figure 4-23. Medium Demand General Service Voluntary (ED-3V) Monthly Billing Impacts ($)

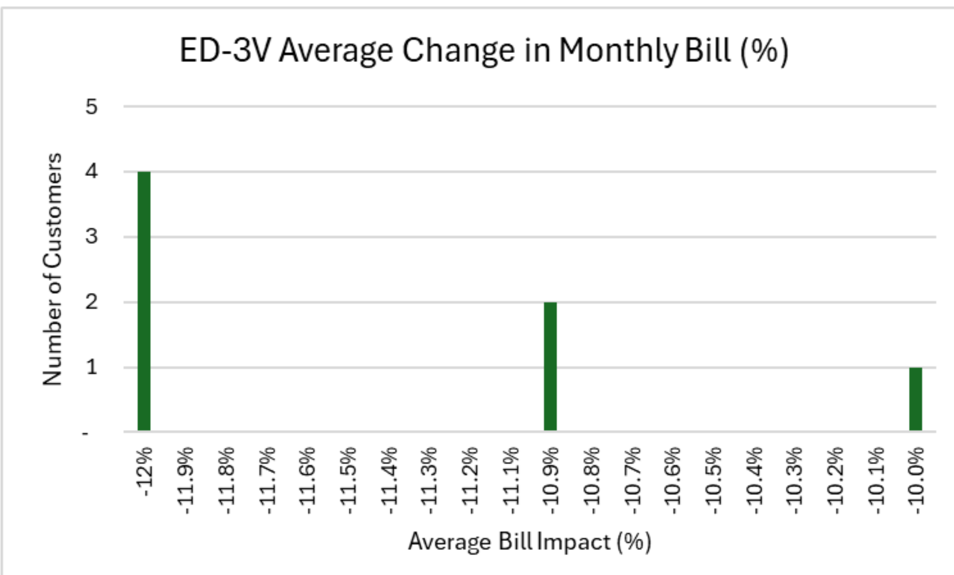

Figure 4-24. Medium Demand General Service Voluntary (ED-3V) Monthly Billing Impacts (%)

Small Demand General Service (ED-4)

The Small Demand General Service (ED-4) class includes industrial and commercial customers whose power needs exceed 35 kW of demand but is less than 500 kW in any month in the previous 12 months.

Table 4-8 compares the current and proposed rates for Phase 1. According to the COS analysis, the Test Year revenues exceed the COS by approximately 17.1% in the ED-4 class. The customer and demand charges are under recovering their COS. For the proposed rates, the base rate energy charge increases, and the demand charge increases to better align with COS results and improve fixed cost recovery. Total energy charges decrease.

Table 4-8
Current, Proposed, and COS Rates:
Small Demand General Service (ED-4)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$130.00	$130.00	$152.87
Energy Charge ($/kWh)			
Summer	$0.0704	$0.0885	$0.0733
Winter	$0.0704	$0.0885	N/A
Demand Charge ($/kW)			
Summer	$25.00	$27.50	$28.82
Winter	$10.00	$17.50	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.2051**	**$0.1802**	**$0.1700**

Note: Summer months are May through October. Winter months are November through April.

Figures 4-25 and 4-26 compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for various load factors per month for customers within the ED-4 class. As shown in the figures, the Phase 1 rate changes move the class rate curve closer to its COS curve.

The figure also shows a bar graph representing the number of customers at each energy usage interval. Customers in this class have a large spread of load factors ranging from 10% to 80%, with the average around 50%. At lower usage levels or load factors, the total bill is driven more by the fixed customer charges than the variable energy charges. This results in a higher rate per kWh for lower usage than higher usage customers. As a customer’s use increases, the rate per kWh decreases slightly. Customers in the ED-4 class have an average peak monthly demand of 76 kW in the summer and 61 kW in the winter.

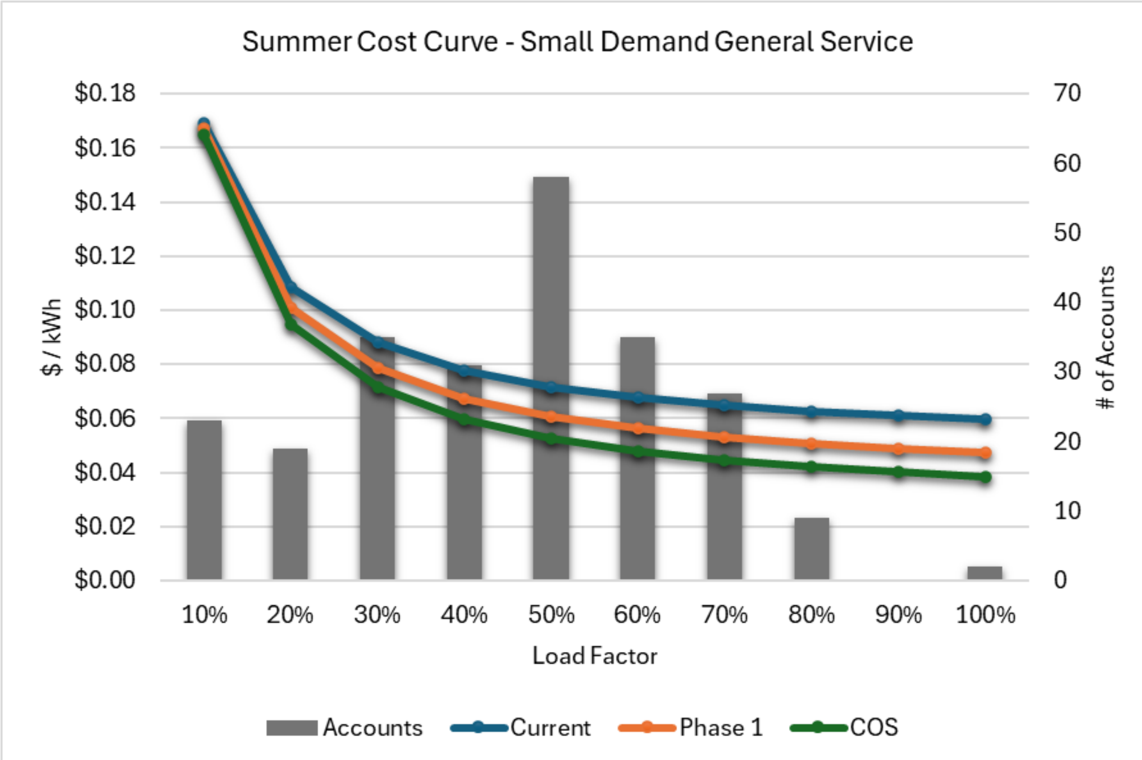

Figure 4-25. Small Demand General Service (ED-4) Summer Cost Curves

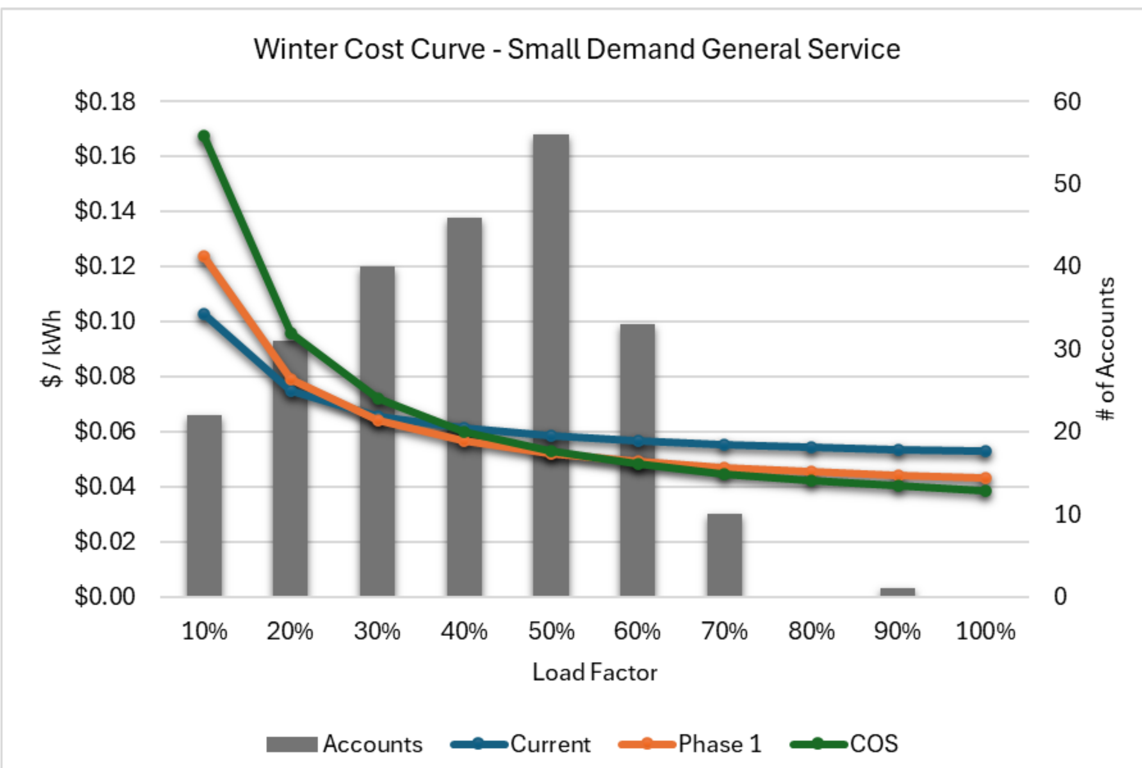

Figure 4-26. Small Demand General Service (ED-4) Winter Cost Curves

Figures 4-27 and 4-28 reflect the monthly bill adjustment per customer account that will be experienced in Phase 1. As shown, most customers will experience an overall bill decrease of approximately 12.1% in Phase 1, reflecting the net reduction in total energy charges from the PCA decrease, partially offset by the increase in demand charges.

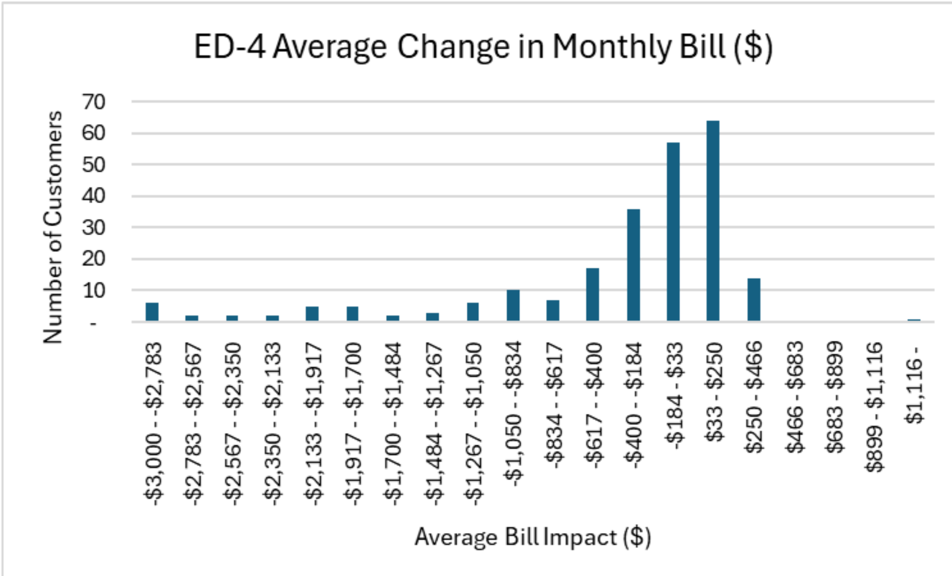

Figure 4-27. Small Demand General Service (ED-4) Monthly Billing Impact ($)

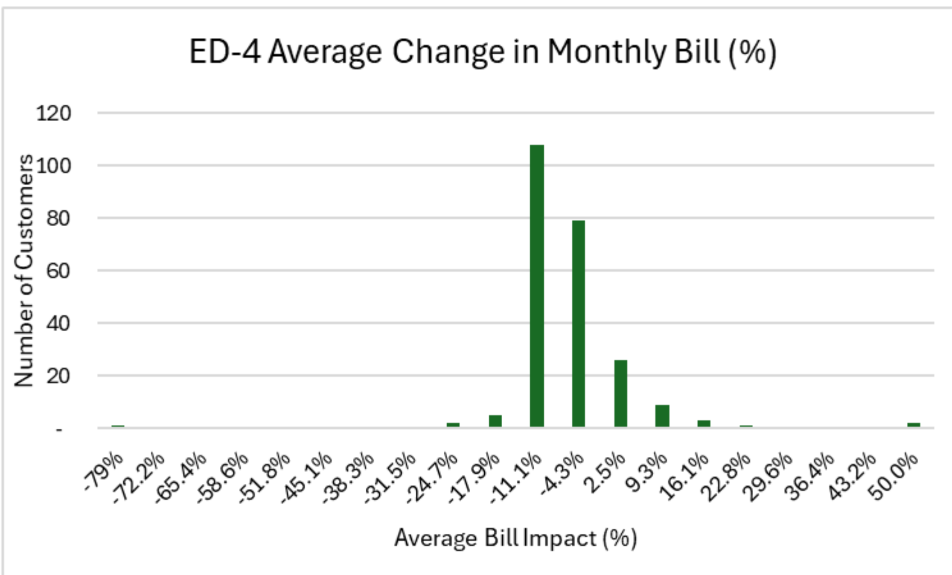

Figure 4-28. Small Demand General Service (ED-4) Monthly Billing Impact (%)

Commercial & Small Industrial General Service (EGS-2)

The Commercial & Small Industrial General Service (EGS-2) class includes small industrial and commercial customers whose power needs do not exceed 35 kW for a month in any of the past 12 months.

Table 4-9 compares the current and proposed rates for Phase 1. According to the COS analysis, the Test Year revenues exceed the COS by approximately 5.2% in the Commercial & Small Industrial General Service class. The customer charge is under-recovering its COS. The customer charge is under-recovering its COS. For the proposed rates, the base rate energy charge increases, and the customer charge remains unchanged. Total energy charges are decreasing, moving the average rate closer to COS.

Table 4-9
Current, Proposed, and COS Rates:
Commercial & Small Industrial General Service (EGS-2)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)			
Single Phase	$55.00	$55.00	$71.27
Three Phase	$82.50	$82.50	$71.27
Energy Charge ($/kWh)			
Summer	$0.1125	$0.1659	$0.0733
Winter	$0.1125	$0.1659	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.2369**	**$0.2327**	**$0.2247**

Note: Summer months are May through October. Winter months are November through April.

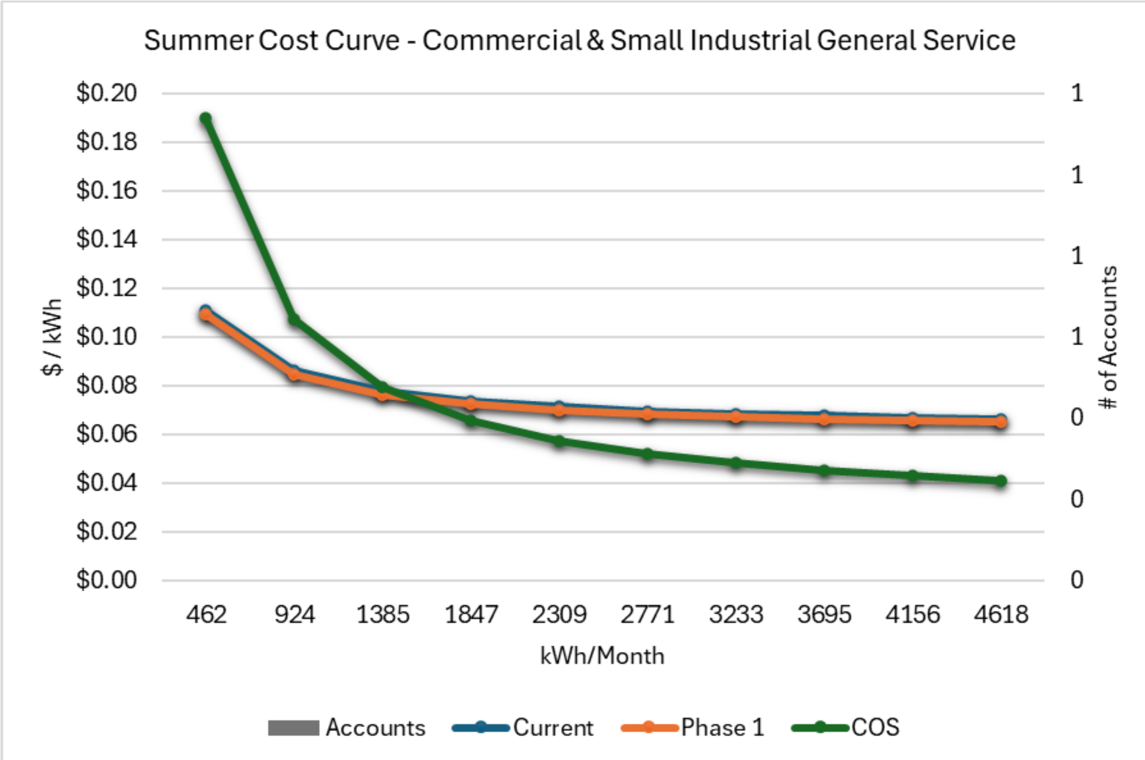

Figure 4-29. Commercial & Small Industrial General Service (EGS-2) Summer Cost Curves

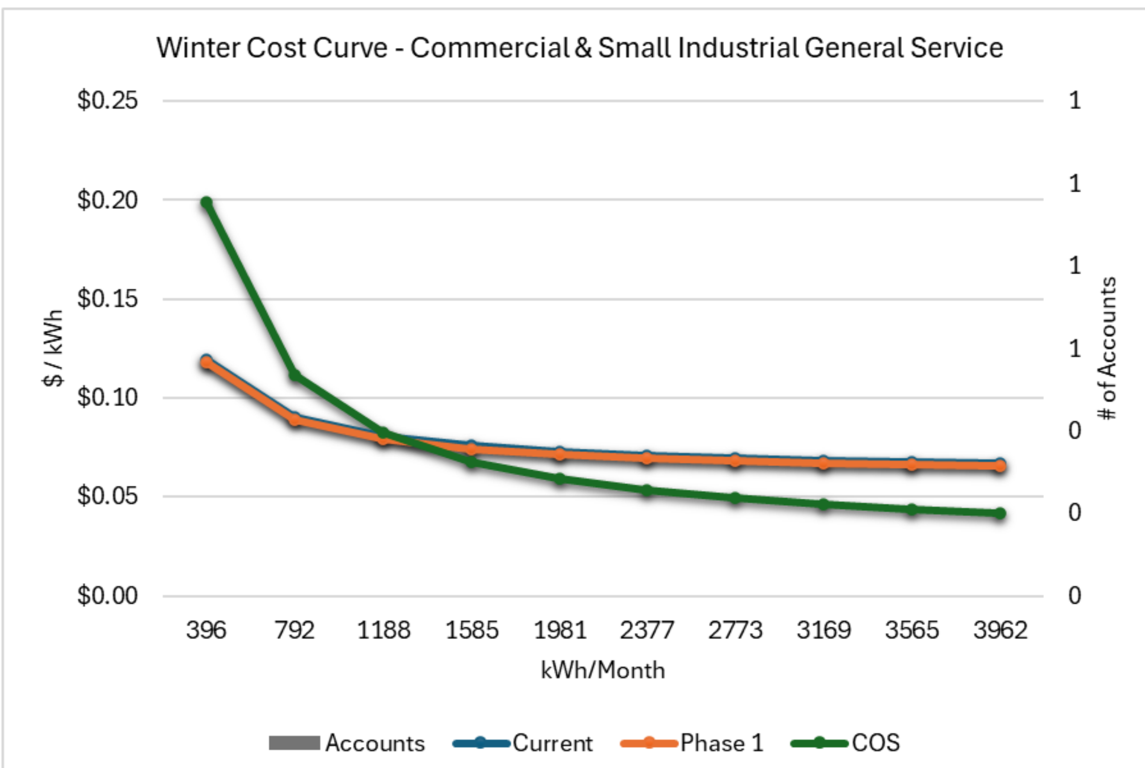

Figure 4-30. Commercial & Small Industrial General Service (EGS-2) Winter Cost Curves

Figures 4-31 through 4-34 reflect the monthly bill adjustment per customer account that EGS-2 accounts will experience in Phase 1, shown separately for single phase and three phase customers. Customer bills in the EGS-2 class will experience an overall bill decrease of approximately 1.8%. Reflecting the net reduction in total energy charges driven by the decrease in the PCA, which offsets the increase in the base rate energy charge. Because the EGS-2 class does not have a demand charge, the bill impact is driven entirely by the change in total energy charges (base rate plus PCA).

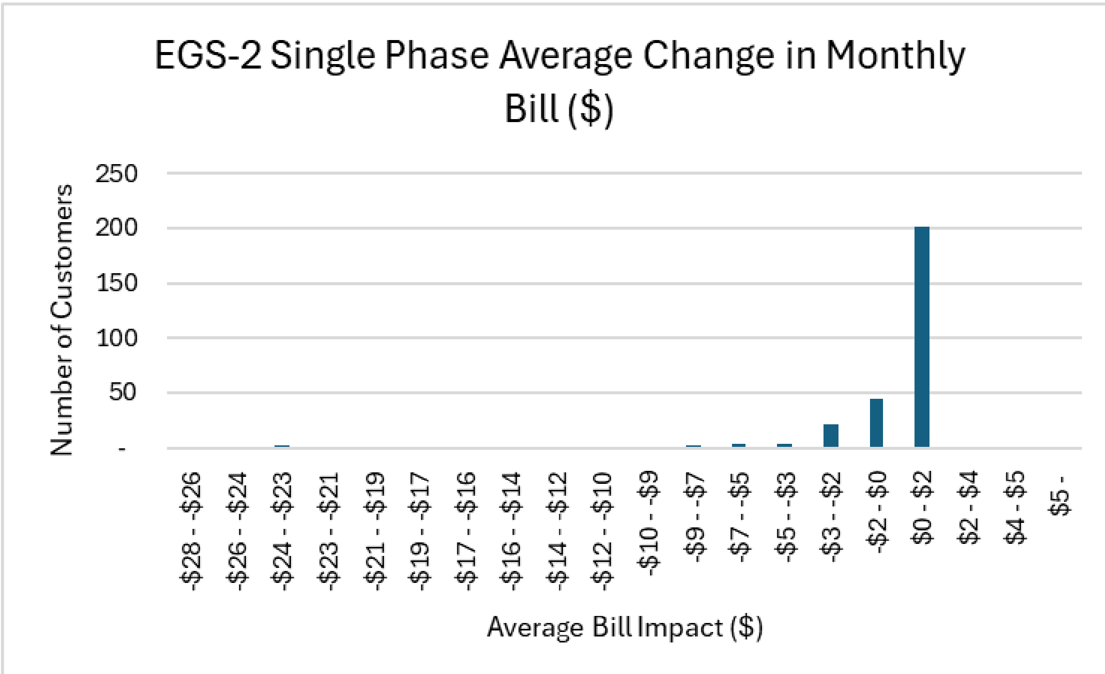

Figure 4-31. Commercial & Small Industrial General Service (EGS-2 Single Phase) Monthly Billing Impact ($)

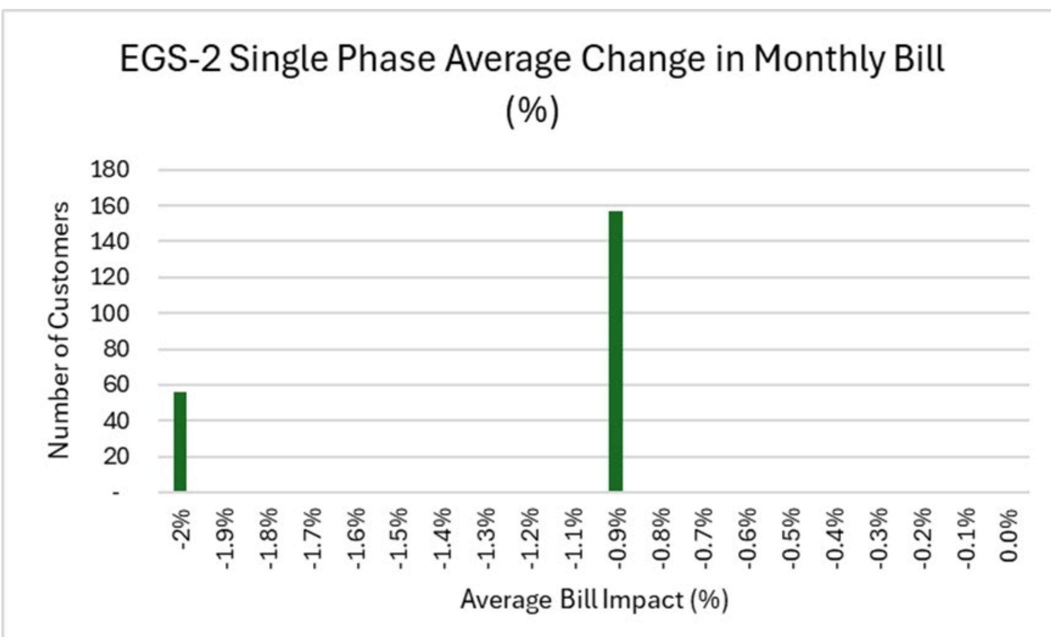

Figure 4-32. Commercial & Small Industrial General Service (EGS-2 Single Phase) Monthly Billing Impact (%)

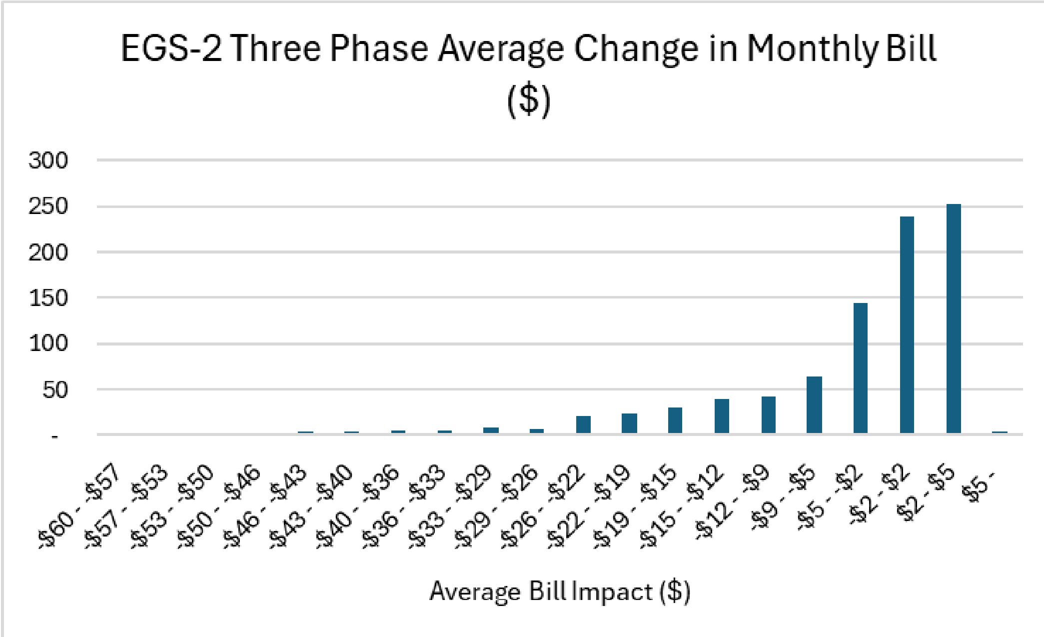

Figure 4-33. Commercial & Small Industrial General Service (EGS-2 Three Phase) Monthly Billing Impact ($)

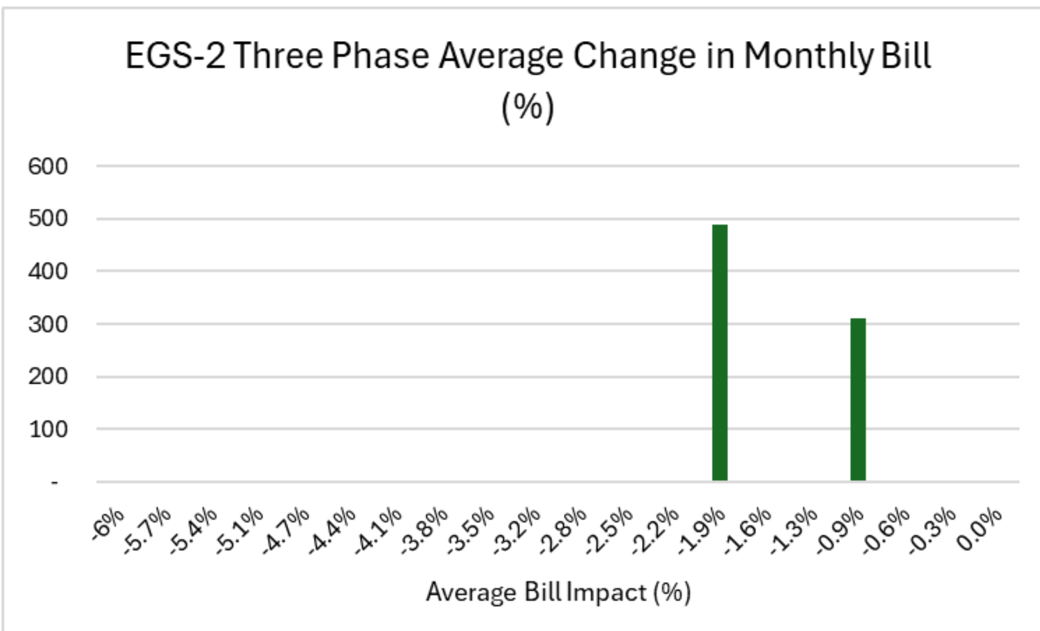

Figure 4-34. Commercial & Small Industrial General Service (EGS-2 Three Phase) Monthly Billing Impact (%)

Municipal & Non-Profit Medium Demand General Service (MD-3)

The Municipal & Non-Profit Medium Demand General Service (MD-3) class is offered to municipal and non-profit customers with a demand of 500 kW or greater in any month during the previous 12 months but less than 1,000 kW. Table 4-10 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-10
Current, Proposed, and COS Rates:
Municipal & Non-Profit Medium Demand General Service (MD-3)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$350.00	$350.00	$661.62
Energy Charge ($/kWh)			
Summer	$0.0628	$0.0798	$0.0733
Winter	$0.0628	$0.0798	N/A
Demand Charge ($/kW)			
Summer	$26.00	$31.00	$35.27
Winter	$10.00	$15.00	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.1981**	**$0.1744**	**$0.2010**

Note: Summer months are May through October. Winter months are November through April.

According to the COS analysis, the Test Year revenues are slightly below COS levels by approximately 1.4% for the MD-3 class, making it one of two classes currently under recovering its COS. While the class is slightly under recovering the COS, the class is heavily impacted by distributed energy resources or rooftop solar behind the customer meter. MID made a policy decision to align their rate change with the ED-3 class as they are similar classes, and MD-3's class characteristics are heavily impacted by rooftop solar. The customer and demand charges are under recovering their COS. The proposed rates are designed to move this customer class closer to COS levels by increasing the base rate energy charge and the demand charge. The seasonality of the demand rate is maintained.

Figures 4-35 and 4-36 below compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for varying load factors within the MD-3 class. As shown in the figures, even with the proposed Phase 1 rate changes, the rates in the MD-3 rate curve remain close to its COS curve. Customers in the MD-3 class have an average peak monthly demand of 275 kW in the summer and 311 kW in the winter.

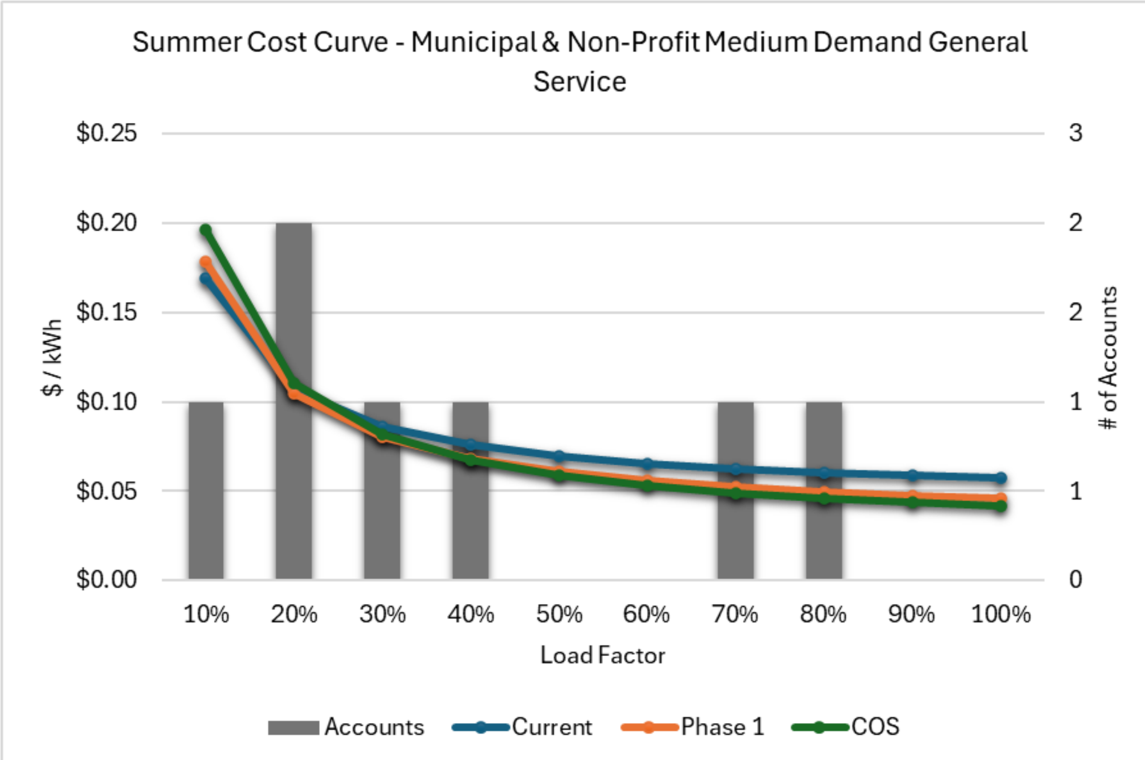

Figure 4-35. Municipal & Non-Profit Medium Demand General Service (MD-3) Summer Cost Curves

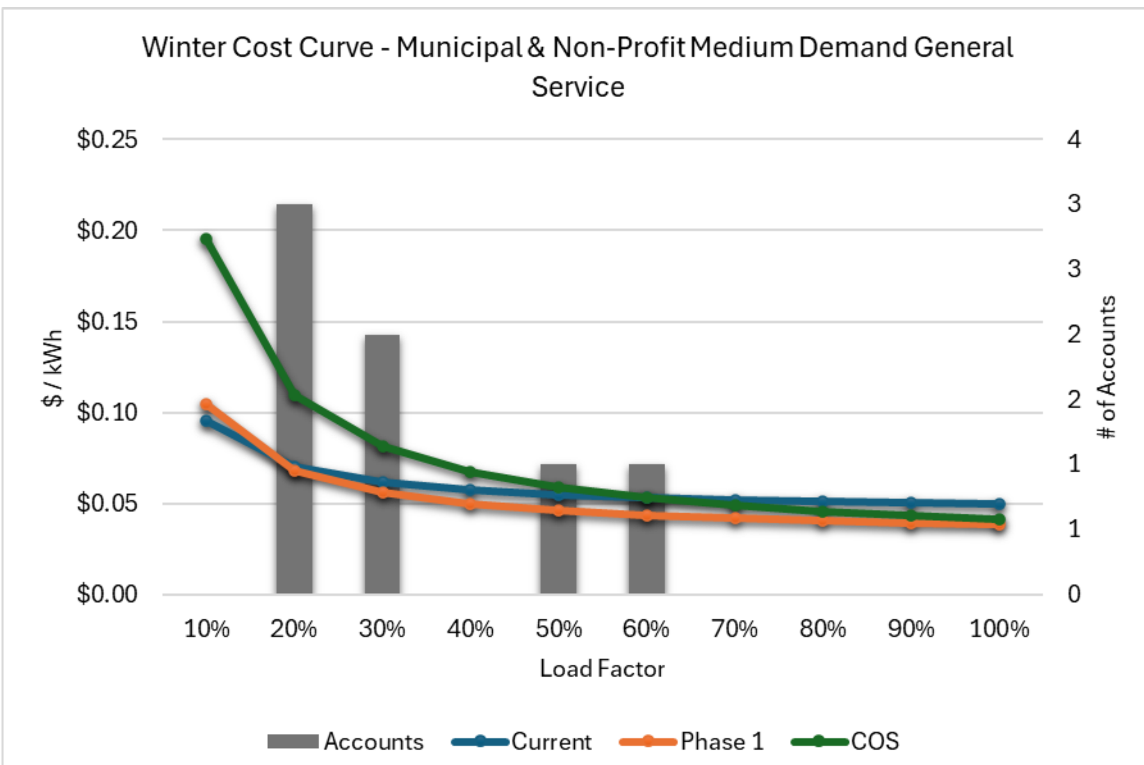

Figure 4-36. Municipal & Non-Profit Medium Demand General Service (MD-3) Winter Cost Curves

Figures 4-37 and 4-38 reflect the monthly bill adjustment per customer that MD-3 accounts will experience in Phase 1. MD-3 customers will experience an overall bill decrease of approximately 12.0% in Phase 1, reflecting the net reduction in total energy charges from the PCA decrease, partially offset by the increases in the base rate energy charge and demand charges.

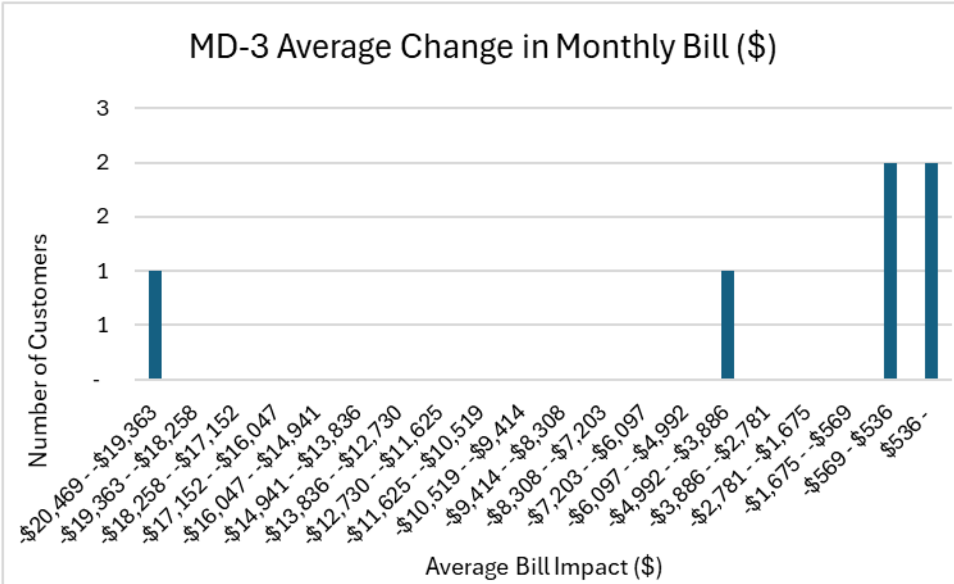

Figure 4-37. Municipal & Non-Profit Medium Demand General Service (MD-3) Monthly Billing Impacts ($)

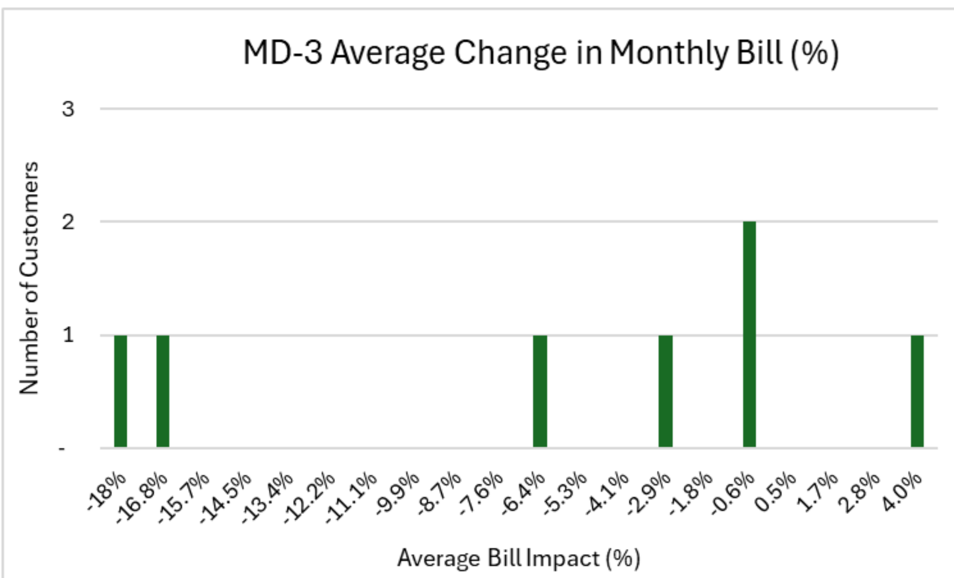

Figure 4-38. Municipal & Non-Profit Medium Demand General Service (MD-3) Monthly Billing Impacts (%)

Municipal & Non-Profit Small Demand General Service (MD-4)

The Municipal & Non-Profit Small Demand General Service (MD-4) class is offered to municipal and non-profit customers whose power needs exceed 35 kW but are less than 500 kW in any month during the previous 12 months. Table 4-11 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-11
Current, Proposed, and COS Rates:
Municipal & Non-Profit Small Demand General Service (MD-4)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$130.00	$130.00	$152.87
Energy Charge ($/kWh)			
Summer	$0.0663	$0.0816	$0.0733
Winter	$0.0663	$0.0816	N/A
Demand Charge ($/kW)			
Summer	$22.50	$25.00	$25.20
Winter	$9.00	$15.00	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.2111**	**$0.1852**	**$0.1825**

Note: Summer months are May through October. Winter months are November through April.

According to the COS analysis, the Test Year revenues exceed the COS by approximately 13.5% for the MD-4 class. The customer and demand charges are under recovering their COS. The proposed rates are designed to move this customer class closer to COS levels by increasing the base rate energy charge and the demand charges to improve fixed cost recovery. The seasonality of the demand rate is maintained.

Figures 4-39 and 4-40 below compare the unit costs ($/kWh) for the current rates, the proposed Phase 1 rates, and the COS for varying load factors within the MD-4 class. As shown in the figures, even with the proposed Phase 1 rate changes, the rates in the MD-4 rate curve remain close to its COS curve. Customers in the MD-4 class have an average peak monthly demand of 111 kW in the summer and 86 kW in the winter.

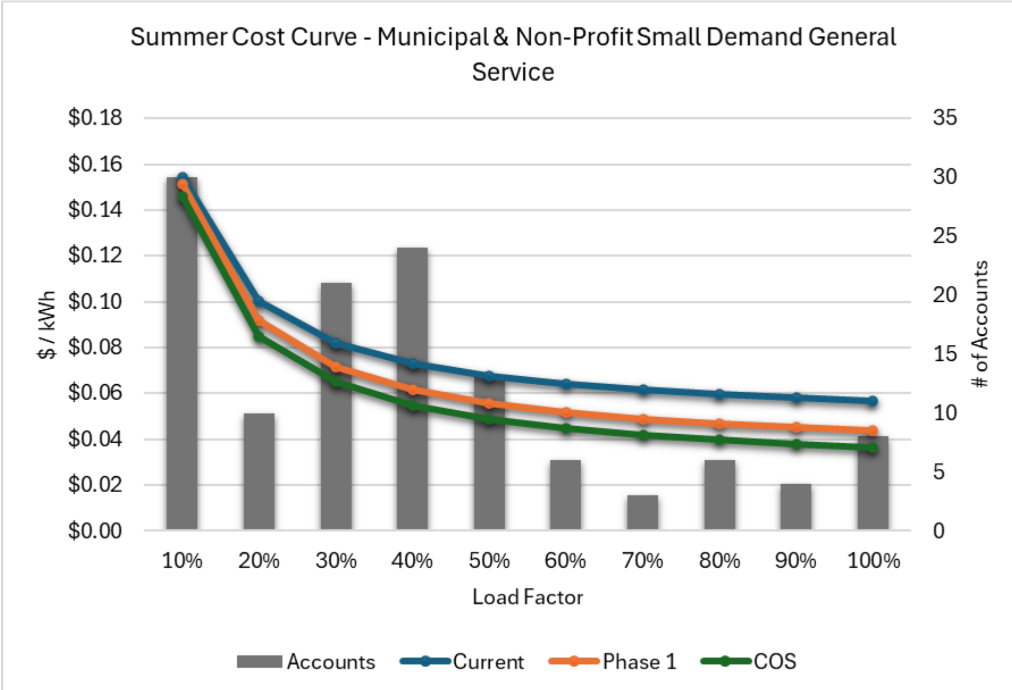

Figure 4-39. Municipal & Non-Profit Small Demand General Service (MD-4) Summer Cost Curves

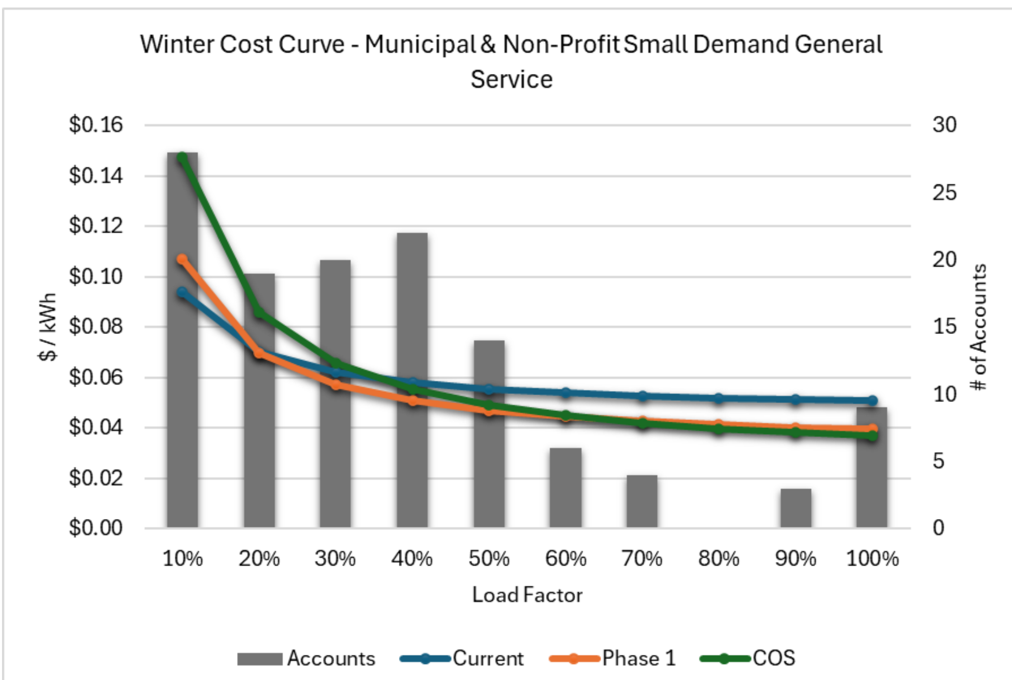

Figure 4-40. Municipal & Non-Profit Small Demand General Service (MD-4) Winter Cost Curves

Figures 4-41 and 4-42 reflect the monthly bill adjustment per customer that MD-4 accounts will experience in Phase 1. MD-4 customers will experience an overall bill decrease of approximately 12.3% in Phase 1, reflecting the net reduction in total energy charges from the PCA decrease, partially offset by the increases in the base rate energy charge and demand charges.

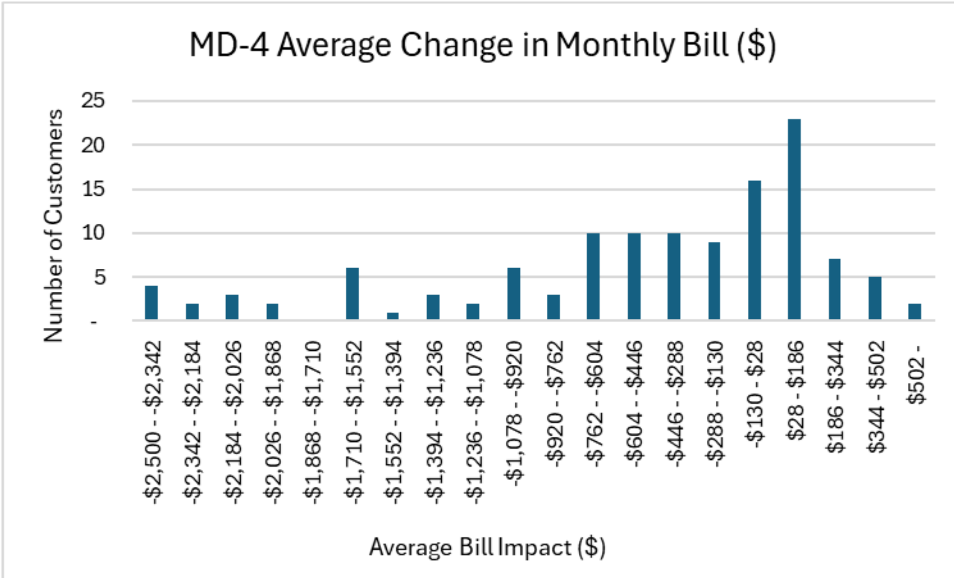

Figure 4-41. Municipal & Non-Profit Small Demand General Service (MD-4) Monthly Billing Impacts ($)

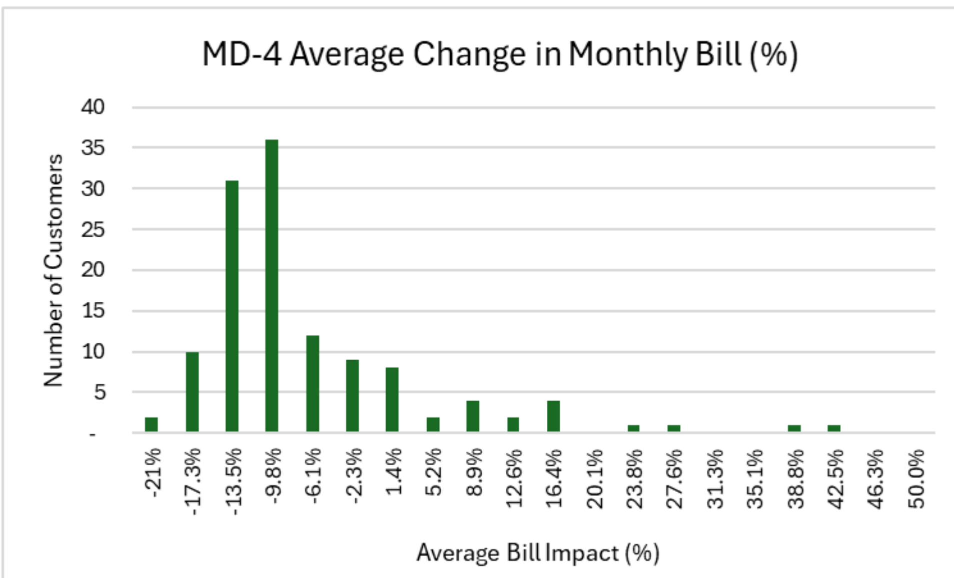

Figure 4-42. Municipal & Non-Profit Small Demand General Service (MD-4) Monthly Billing Impacts (%)

Residential General Service (RES-2)

The Residential General Service (RES-2) class serves residential customers and uses an inclining block rate structure with two energy tiers to encourage conservation. Table 4-12 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-12
Current, Proposed, and COS Rates:
Residential General Service (RES-2)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$30.00	$30.00	$26.34
Energy Charge ($/kWh)			
Tier 1 (0 to 716 kWh summer / 0 to 486 kWh winter)	$0.0817	$0.1388	$0.0733
Tier 2 (above 716 kWh summer / above 486 kWh winter)	$0.2085	$0.2556	$0.0733
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.2387**	**$0.2342**	**$0.2212**

Note: Summer months are May through October. Winter months are November through April.

The RES-2 Net Energy Metering 2.0 (NEM 2.0) rate serves residential customers. It uses an energy rate and introduces a demand charge for both summer and winter. Table 4-13 compares the current rates, proposed rates for Phase 1, and COS rates. The RES-2 NEM 2.0 rate is available to residential customers who apply for net metering after MID has reached its NEM 1.0 enrollment cap. As MID has reached its NEM 1.0 enrollment cap, new applicants are enrolled under the NEM 2.0 rate schedule, which includes a demand charge for both summer and winter periods in addition to the energy rate.

Table 4-13
Current, Proposed, and COS Rates:
Residential General Service (RES-2 NEM 2.0)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$65.00	$30.00	$26.34
Energy Charge ($/kWh)	$0.0608	$0.1388	$0.0733
Demand Charge ($/kW)			
Summer	N/A	$8.19	$20.34
Winter	N/A	$5.19	N/A
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.2421**	**$0.2376**	N/A
Excess Generation Credit	$0.0495	$0.0495	N/A

Note: Summer months are May through October. Winter months are November through April.

According to the COS analysis, the Test Year revenues exceed the COS by approximately 7.3% for the RES-2 class. The residential class does not include a demand charge; therefore, all demand-related costs are recovered through the energy charge. The proposed rates increase both the Tier 1 and Tier 2 base rate energy charges. The net effect on the PCA reduction is a modest decrease in the total energy charge (base rate plus PCA), moving rates closer to COS levels. The inclining block structure is maintained, with Tier 2 set at a higher rate to reflect higher usage.

Figures 4-45 and 4-46 reflect the monthly bill adjustment per customer that RES-2 accounts will experience in Phase 1. Residential customers will experience an overall bill decrease of approximately 1.9% in Phase 1, reflecting the net reduction in total energy charges resulting from the decrease in the PCA, which more than offsets the increase in the base rate energy charges.

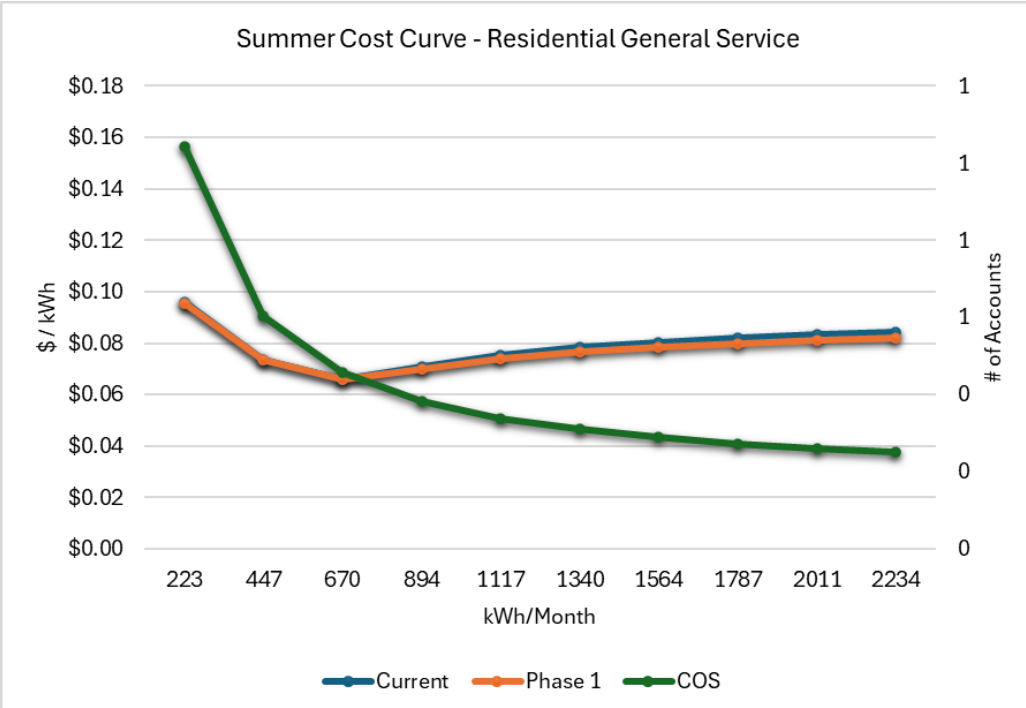

Figure 4-43. Residential General Service (RES-2) Summer Cost Curves

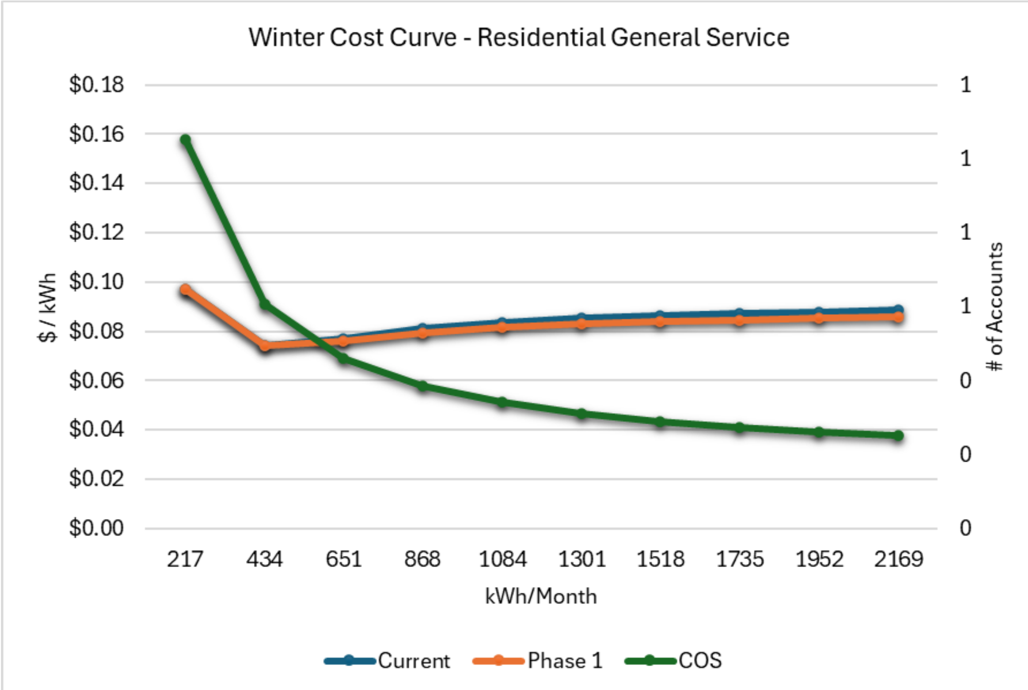

Figure 4-44. Residential General Service (RES-2) Winter Cost Curves

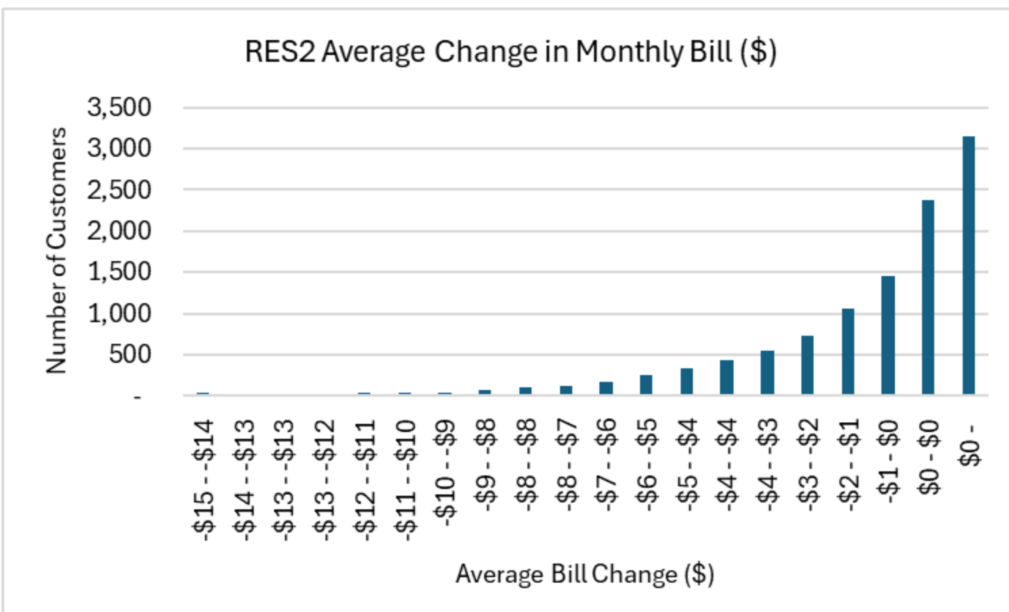

Figure 4-45. Residential General Service (RES-2) Monthly Billing Impacts ($)

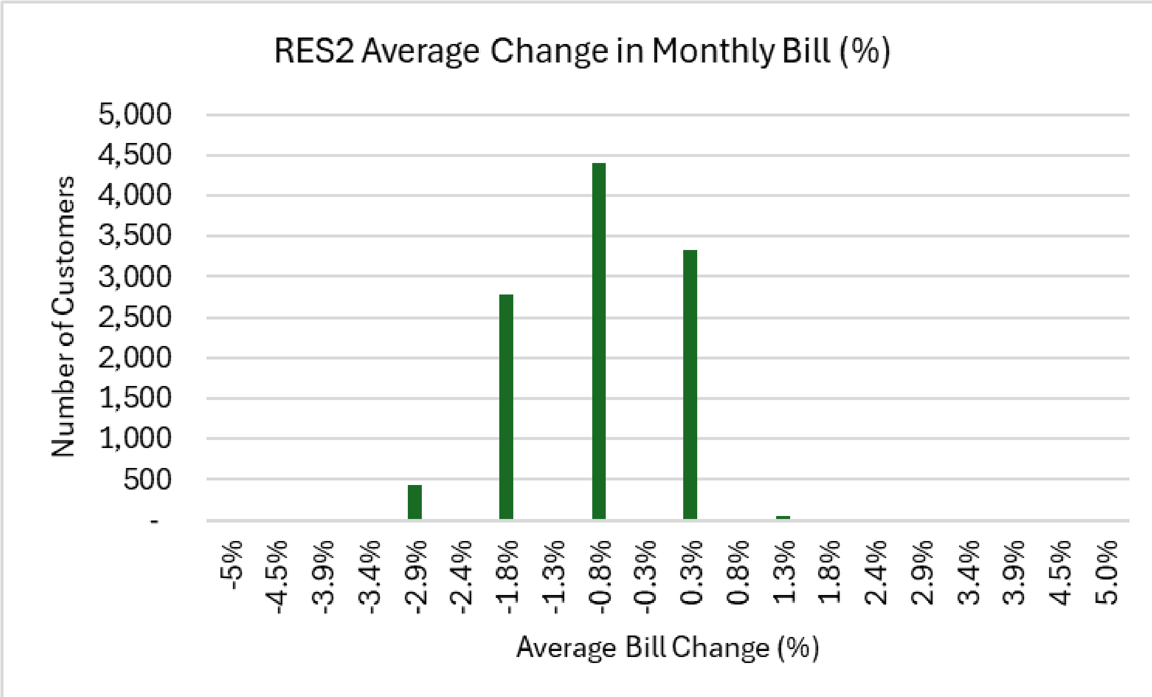

Figure 4-46. Residential General Service (RES-2) Monthly Billing Impacts (%)

Streetlighting – Customer Owned and Maintained (LSC)

The Streetlighting – Customer Owned and Maintained (LSC) schedule applies to outdoor public area lighting for streets, alleys, highways, and similar publicly dedicated spaces. It is available to cities, counties, lighting districts, and other public entities where MID supplies electrical energy only, and the customer furnishes, installs, owns, operates, and fully maintains all lighting equipment, including switching and associated fixtures. Rates are structured on a per fixture, per month basis by wattage, reflecting the estimated monthly energy consumption for each fixture size. Table 4-14 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-14
Current, Proposed, and COS Rates:
Streetlighting – Customer Owned and Maintained (LSC)

Rate Unit	kWh / Month / Fixture	Current Rates	Recommended Rates	COS
50 Watts	17	$2.24	$2.8887	$5.88
70 Watts	29	$4.01	$5.1210	$5.88
100 Watts	41	$5.70	$7.2525	$5.88
150 Watts	60	$7.91	$10.0438	$5.88
200 Watts	81	$10.30	$13.0540	$5.88
250 Watts	100	$12.99	$16.4466	$5.88
310 Watts	121	$15.21	$19.2465	$5.88
301 Watts	159	$19.68	$24.8841	$5.88
PCA Adjustment ($/kWh)	N/A	$0.067655	$0.010000	N/A
EC Adjustment ($/kWh)	N/A	$0.004070	$0.004070	N/A

Note: Fixture charge is per fixture per month. PCA and EC adjustments are applied per kWh consumed.

According to the COS analysis, the Test Year revenues exceed the COS by approximately 12.6% for the LSC class. The proposed rates are designed to move this customer class closer to COS levels by increasing the per fixture monthly charges across all wattage categories. The rate structure is maintained on a per fixture, per month basis, with charges scaled by estimated monthly energy consumption. LSC customers will experience an overall bill decrease of approximately 10.2% in Phase 1, reflecting the reduction in the PCA adjustment.

Streetlighting – District Owned and Maintained (LSC-1)

The Streetlighting – District Owned and Maintained (LSC-1) schedule applies to MID-owned and maintained lighting installations that illuminate streets, highways, and other publicly dedicated outdoor areas utilizing MID distribution facilities. Unlike the LSC schedule, the district is responsible for furnishing, installing, operating, and maintaining all lighting equipment under this rate. Rates are structured on a per fixture, per month basis by wattage, reflecting the estimated monthly energy consumption and the additional costs associated with district ownership and maintenance. Table 4-15 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-15
Current, Proposed, and COS Rates:
Streetlighting – District Owned and Maintained (LSC-1)

Rate Unit	kWh / Month / Fixture	Current Rates	Recommended Rates	COS
70 Watts	29	$9.51	$10.3407	$9.14
100 Watts	41	$12.19	$13.2369	$9.14
150 Watts	60	$14.19	$15.3983	$9.14
200 Watts	81	$18.52	$20.0775	$9.14
250 Watts	100	$20.62	$22.3469	$9.14
400 Watts	159	$28.15	$30.4844	$9.14
PCA Adjustment ($/kWh)	N/A	$0.067655	$0.010000	N/A
EC Adjustment ($/kWh)	N/A	$0.004070	$0.004070	N/A

Note: Fixture charge is per fixture per month. PCA and EC adjustments are applied per kWh consumed.

According to the COS analysis, the Test Year revenues exceed the COS by approximately 54.3% for the LSC-1 class, reflecting that current fixture charges fall well below the cost of providing district-owned and maintained service. The proposed rates are designed to move this customer class closer to COS levels by increasing the per fixture monthly charges across all wattage categories. The per fixture rate structure is maintained, with higher charges than the LSC schedule to reflect the additional costs associated with district ownership and maintenance of lighting equipment. LSC-1 customers will experience an overall bill decrease of approximately 12.4% in Phase 1, driven primarily by the reduction in the PCA adjustment.

Flat Rate Service (MEF)

The Flat Rate Service (MEF) schedule applies to small, constant, non-metered incidental electrical loads for utilities, state agencies, and applicable special districts where the customer owns and maintains the equipment. Because these loads are non-metered, rates are structured as a flat monthly charge by estimated wattage band rather than by measured energy consumption. Table 4-16 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-16
Current, Proposed, and COS Rates:
Flat Rate Service (MEF)

Rate Unit	kWh / Month / Fixture	Current Rates	Recommended Rates	COS
0–200 Watts	26	$10.16	$15.7394	$23.53
201–300 Watts	64	$15.14	$23.4231	$23.53
301–500 Watts	102	$20.11	$31.0913	$23.53
501–800 Watts	166	$28.47	$43.9899	$23.53
801–1,200 Watts	256	$40.25	$62.1653	$23.53
1,201–1,600 Watts	523	$80.61	$124.4366	$23.53
PCA Adjustment ($/kWh)	N/A	$0.067655	$0.010000	N/A
EC Adjustment ($/kWh)	N/A	$0.004070	$0.004070	N/A

Note: Fixture charge is per fixture per month. PCA and EC adjustments are applied per kWh consumed.

According to the COS analysis, the Test Year revenues exceed the COS by approximately 18.9% for the MEF class. Current flat monthly charges are below COS levels across all wattage bands. The proposed rates are designed to move this customer class closer to COS levels by increasing the per wattage band monthly charges. The flat rate structure is maintained, with charges scaled by estimated monthly energy consumption within each wattage range. MEF customers will experience an overall bill decrease of approximately 7.9% in Phase 1, driven primarily by the reduction in the PCA adjustment.

Large Demand Transmission Service (TR-1)

The Large Demand Transmission Service (TR-1) class is offered to customers with a demand of 5,000 kW or greater who take service at transmission voltage of 115 kilovolts (kV). Table 4-17 compares the current rates, proposed rates for Phase 1, and COS rates.

Table 4-17
Current, Proposed, and COS Rates:
Large Demand Transmission Service (TR-1)

Rate Unit	Current Rates	Recommended Rates	COS
Customer Charge ($/Month)	$1,000.00	$1,000.00	$946.21
Energy Charge ($/kWh)	$0.0610	$0.0867	$0.0708
Demand Charge ($/kW)	$10.00	$17.00	$19.72
EC Adjustment	$0.0041	$0.0041	N/A
PCA Adjustment	$0.0677	$0.0100	N/A
Average Rate ($/kWh)	**$0.1553**	**$0.1389**	**$0.1149**

Note: Summer months are May through October. Winter months are November through April.

According to the COS analysis, the Test Year revenues exceed the COS by approximately 26.0% for the TR-1 class. The proposed rates are designed to move this customer class closer to COS levels by decreasing the energy charge and increasing the demand charge. Unlike distribution-level classes, the TR-1 class does not have a seasonal split for its energy charge given the nature of transmission-level service. There is only one customer in the TR-1 class, and they will experience an overall bill decrease of approximately 10.6% in Phase 1, driven primarily by the reduction in the energy charge.

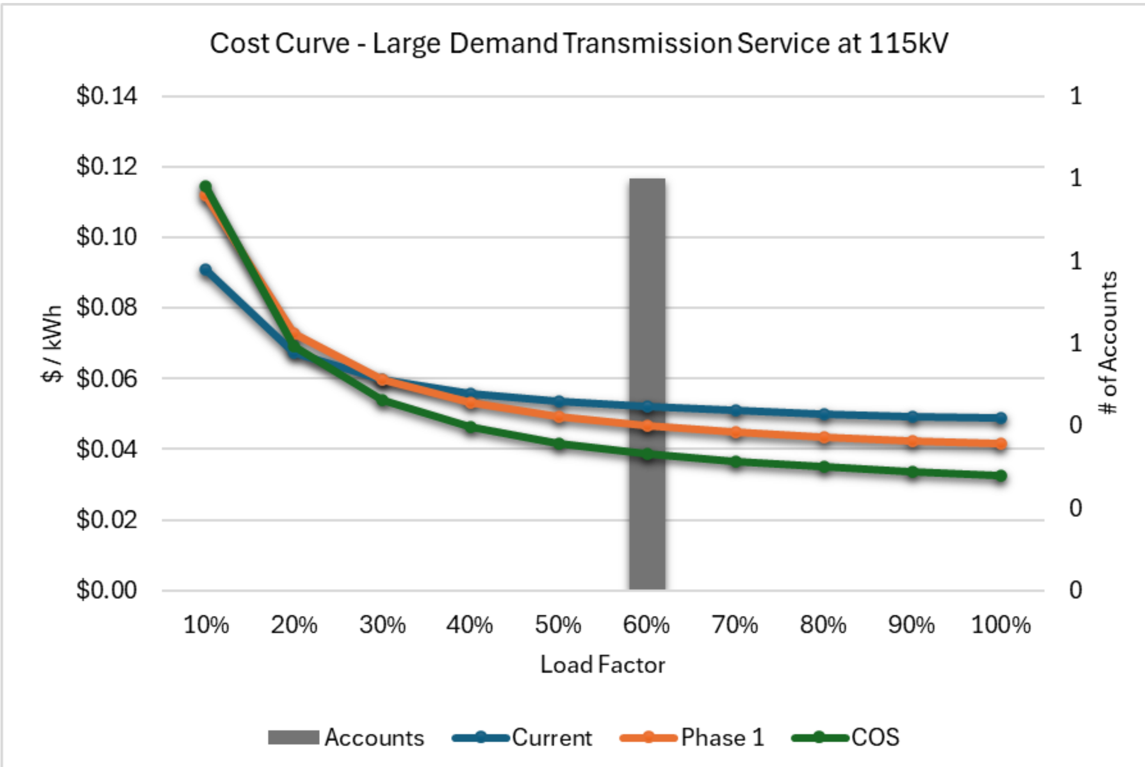

Figure 4-47. Large Demand Transmission Service (TR-1) Cost Curve

Section 5
CONCLUSIONS AND RECOMMENDATIONS

In reliance upon the data received by MID and the analyses described herein, NewGen concludes and recommends the following.

Financial Forecast and Revenue Requirement

- On a systemwide basis, current rates are generating more revenues than needed to meet current costs. The overall COS analysis indicates Test Year revenues exceed the COS by 13.8%.
- MID should implement the rate decreases contained in this report to better align rates with the cost of providing service and to move toward the COS results.
- MID should continue to monitor its revenue requirement on an ongoing basis and perform periodic rate adjustments as needed to maintain alignment between rates and costs.

Cost of Service

- MID should continue to perform a comprehensive COS study every three to five years, or when aligned with a major change in operations, such as a new power supply contract, a significant change in system operations, or a major shift in the customer mix.
- The AG-2 and MD-3 classes are currently under recovering their COS. All other rate classes are currently collecting revenues above their COS requirements. Please note, both the AG-2 agricultural processes and customers and MD-3 customers with behind the meter rooftop solar are impacting those classes COS results thus influencing the rate design for conventional customers.
- The proposed rate decreases move each class closer to its COS.

Rate Design

- Based on the COS results, MID implemented a system average rate decrease of 9%, with varying decreases in each customer class.
- The COS results support rate design changes that better align revenues with the fixed and variable costs of providing service to each customer class.
- All customer classes should continue to move closer to their COS. MID should continue to minimize subsidization across customer classes.
- Rate changes have been implemented as a single phase in FY 2027.
- MID’s rate structure should continue to be evaluated to improve fixed cost recovery. Customer and demand charges could continue to move toward COS results over time.
- MID should continue to utilize the PCA and EC adjustment as designed, allowing them to reconcile actual power supply and environmental costs with projected costs on a regular basis. Timely semi-annual and annual reviews of these adjustments reduce financial risk, ensure accurate cost recovery, and improve fiscal performance.

Appendix A
COMMERCIAL NEM 2.0 RATE SCHEDULES

Table A-1
Proposed NEM 2.0 Electric Rates:
Large Demand General Service (ED-1P) NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$1,100.00
Energy Charge ($/kWh)	
Summer	$0.0721
Winter	$0.0721
Demand Charge ($/kW)	
Summer	$32.75
Winter	$32.75
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-2
Proposed NEM 2.0 Electric Rates:
ED-2 NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$1,100.00
Energy Charge ($/kWh)	
Summer	$0.0733
Winter	$0.0733
Demand Charge ($/kW)	
Summer	$33.12
Winter	$33.12
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-3
Proposed NEM 2.0 Electric Rates:
ED-2P NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$1,535.00
Energy Charge ($/kWh)	
Summer	$0.0737
Winter	$0.0737
Demand Charge ($/kW)	
Summer	$33.12
Winter	$33.12
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-4
Proposed NEM 2.0 Electric Rates:
ED-3 NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$350.00
Energy Charge ($/kWh)	
Summer	$0.0706
Winter	$0.0706
Demand Charge ($/kW)	
Summer	$30.64
Winter	$30.64
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-5
Proposed NEM 2.0 Electric Rates:
ED-3V NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$200.00
Energy Charge ($/kWh)	
Summer	$0.0824
Winter	$0.0824
Demand Charge ($/kW)	
Summer	$34.74
Winter	$34.74
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-6
Proposed NEM 2.0 Electric Rates:
ED-4 NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$130.00
Energy Charge ($/kWh)	
Summer	$0.0705
Winter	$0.0705
Demand Charge ($/kW)	
Summer	$28.82
Winter	$28.82
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-7
Proposed NEM 2.0 Electric Rates:
EGS-2 NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge – Single Phase ($/Month)	$55.00
Customer Charge – Three Phase ($/Month)	$82.50
Energy Charge ($/kWh)	
Summer	$0.0733
Winter	$0.0733
Demand Charge ($/kW)	
Summer	$25.02
Winter	$25.02
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-8
Proposed NEM 2.0 Electric Rates:
MD-3 NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$350.00
Energy Charge ($/kWh)	
Summer	$0.0733
Winter	$0.0733
Demand Charge ($/kW)	
Summer	$35.27
Winter	$35.27
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

Table A-9
Proposed NEM 2.0 Electric Rates:
MD-4 NEM 2.0

Rate Unit	NEM 2.0 Rate
Customer Charge ($/Month)	$130.00
Energy Charge ($/kWh)	
Summer	$0.0733
Winter	$0.0733
Demand Charge ($/kW)	
Summer	$25.20
Winter	$25.20
EC Adjustment ($/kWh)	$0.0041
PCA Adjustment ($/kWh)	$0.0100
Excess Generation Credit ($/kWh)	$0.0495

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