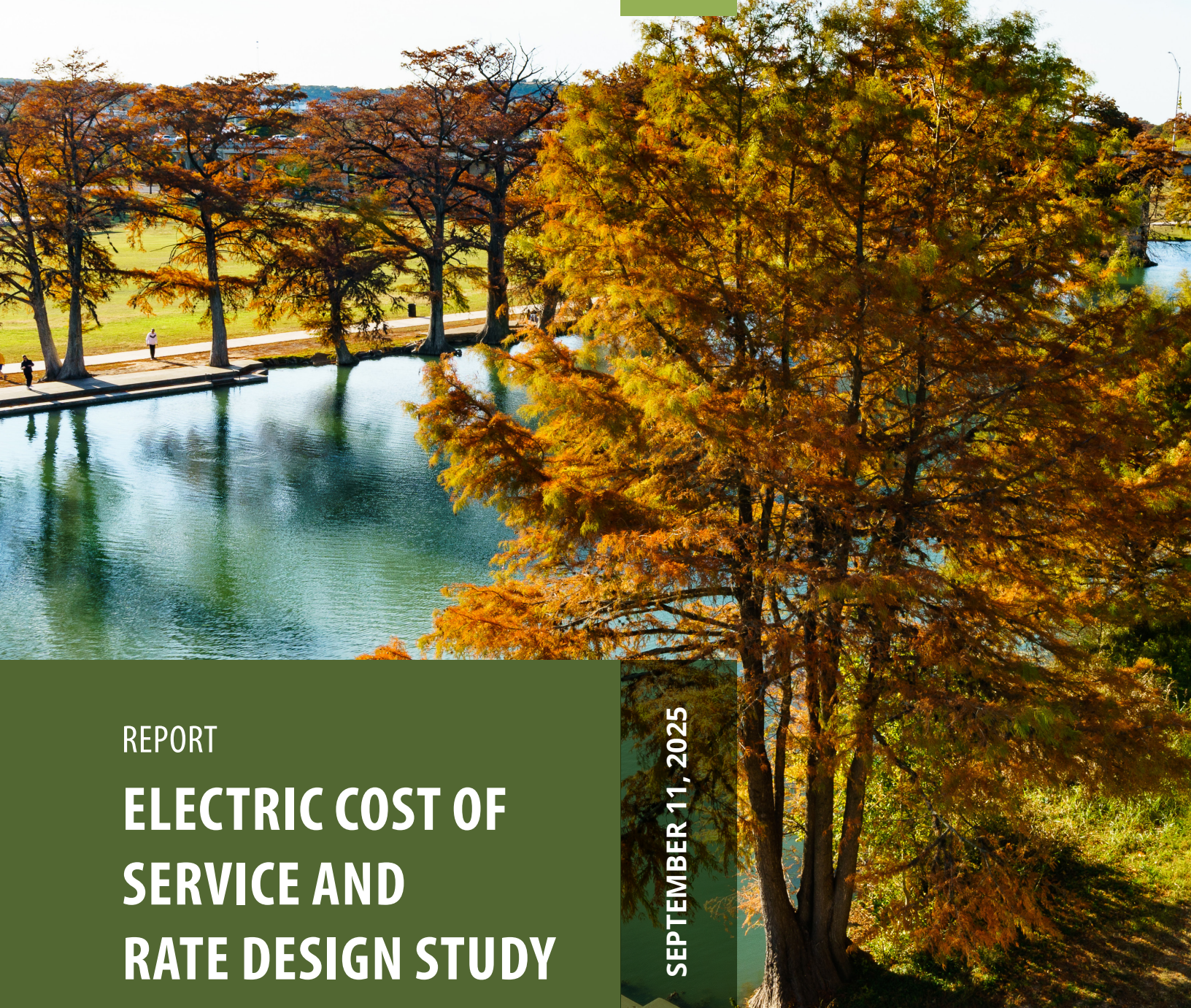




REPORT

ELECTRIC COST OF SERVICE AND RATE DESIGN STUDY

SEPTEMBER 11, 2025



Prepared for:
Kerrville Public Utility Board
2250 Memorial Blvd.
Kerrville, Texas 78028

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EXECUTIVE SUMMARY

Introduction

Kerrville Public Utility Board (KPUB) is a municipally owned electric utility that proudly serves the City of Kerrville, Texas (City) and the surrounding area. Since its establishment in 1987, KPUB has been dedicated to being a responsive and efficient, locally owned provider of safe and reliable utility service at the lowest responsible price.

Cost of Service Study

In this Electric Cost of Service (COS) and Rate Design Study (Study), KPUB examined the costs associated with operating, maintaining, and enhancing its electric utility system. This effort was intended to ensure electric service rates remain fair, equitable, and sufficient to support the utility's ongoing financial sustainability and infrastructure planning. KPUB engaged NewGen Strategies and Solutions, LLC (NewGen) to complete this Study.

The primary goals of the Study were to determine the annual Revenue Requirement needed to operate the electric utility, to evaluate the cost of serving different customer classes, and to develop electric rate structures that support KPUB's mission while meeting legal and policy obligations. The analysis supported rate strategies that promote operational resiliency, financial stability, and equitable cost recovery while maintaining customer acceptance and minimizing administrative burdens.

This Study utilized a "Test Year" approach, beginning with KPUB's Fiscal Year (FY) 2025 budget, and developed rate strategies over a five-year horizon. The objective was to implement rates that allowed for gradual adjustments, where needed, while supporting new generation assets and evolving power supply cost dynamics. The Five-Year Rate Plan (Rate Plan or Plan) developed through this Study serves as a roadmap for KPUB's rate implementation from FY 2026 through FY 2030, facilitating informed decision making for both the KPUB Board and its customers.

Rate Design Objectives/Rate Making Principles

The Study was intended to result in a comprehensive set of proposed rates that define how the utility recovers its Revenue Requirement from each customer class. These rates and charges were designed to ensure that the total revenue needed to operate and maintain the electric system was recovered in an equitable, efficient, and transparent manner, informed by the results of the COS analysis.

Rate design for KPUB considered the utility's existing rate structures, historical practices, and financial goals while also supporting its core values as a community-owned, not-for-profit electric provider. The Study considered KPUB's desire for revenue stability across customer classes, the flexibility to respond to evolving energy demands, and competitiveness with surrounding utility rates. In addition, the process incorporated policy directives from the KPUB Board and the City, where applicable; legal and regulatory requirements (including those related to power cost recovery); and the desire to minimize customer confusion and administrative burden.

Summary of Revenue Needs

The required revenue for KPUB for each year of the Rate Plan is provided in Table ES-1. Additionally, Table ES-1 includes a comparison of the total revenues generated by existing rates (current as of 2025) for the system. The differences between these two values represent the necessary rate adjustments for KPUB to continue providing safe and reliable power to its customers; there is a cumulative shortfall of approximately \$73 million under current rates.

Table ES-1
Revenue Requirement and Revenue for Study Period (\$000)

	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	Total
Revenue Requirement	\$ 58,803	\$ 63,093	\$ 65,041	\$ 67,702	\$ 71,006	\$ 325,645
Revenue from Customers ⁽¹⁾	49,486	49,976	50,471	50,971	51,475	252,379
Difference⁽²⁾	(\$ 9,317)	(\$ 13,116)	(\$ 14,570)	(\$ 16,731)	(\$ 19,531)	(\$ 73,265)

(1) Utilizing existing 2025 rates.

(2) Totals may not add due to rounding.

The Revenue Requirement represents the total annual revenue that KPUB anticipates needing and includes its projections for power production and purchases; ongoing operations and maintenance (O&M) expenses across all of its functions; and projections for debt service, capital funded from cash, and franchise fees. The revenue needed is offset by other miscellaneous revenues, which include other operating revenues, revenues from merchandising, jobbing and contract work, and other non-operating revenue. A summary of the Revenue Requirement for the five-year forecast is provided in Table ES-2.

Table ES-2
Revenue Requirement by Function (\$000)

	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
O&M by Function					
Production	\$ 29,206	\$ 32,287	\$ 32,895	\$ 34,220	\$ 36,097
Transmission	8,138	8,789	9,492	10,252	11,072
Distribution	5,175	5,367	5,562	5,766	5,978
Customer	1,595	1,654	1,714	1,777	1,842
Administrative and General	6,684	6,932	7,185	7,448	7,721
Total O&M	\$ 50,798	\$ 55,029	\$ 56,850	\$ 59,462	\$ 62,709
Capital from Cash	6,425	6,375	6,462	6,450	6,427
Debt Service	531	531	531	531	531
Franchise Fees	1,775	1,901	1,960	2,038	2,136
(Less) Other Operating Revenues	(685)	(702)	(717)	(733)	(749)
(Less) Revenues from Contract Work	(37)	(38)	(40)	(42)	(44)
(Less) Misc. Non-Operating Income	(4)	(4)	(4)	(4)	(4)
Net Revenue Requirement⁽¹⁾	\$ 58,803	\$ 63,093	\$ 65,041	\$ 67,702	\$ 71,006

(1) Numbers may not add due to rounding.

As is typical with most utilities, the production function (generation or purchasing) of electricity is the largest functional element. The debt service listed in Table ES-2 includes only the existing KPUB debt (and does not include the recently issued debt related to the generation investment, which is included within the Production function O&M). The Revenue Requirement offset (reduction) from other revenues, included in Table ES-2, primarily consists of other operating revenues, revenues from contract work, and miscellaneous non-operating income.

Capital Improvement Plan

The Revenue Requirement includes KPUB's levelized five-year CIP. The levelized plan amounts to approximately \$6.4 million per year, which will be funded by cash from rates.

Cost of Service Process

The COS process is an industry-accepted framework that assigns costs to customer classes. This process determines the "cost to serve" each customer class within a utility. Electric utility costs are typically characterized as either fixed or variable; fixed costs are those that do not change with the production of electricity, whereas variable costs are directly related to the amount of electricity produced and/or purchased. Costs are typically further categorized as demand-based, customer-based, or energy-based.

Demand-Based Costs

Demand-based costs for electric utilities are fixed costs that are related to the existing and future investments made to produce, transmit, and deliver power from the generation resources to customers. For KPUB, these costs include debt service on the new generation investment, transmission of electricity by others in Electric Reliability Council of Texas (ERCOT), and most distribution O&M expenses. The labor and materials associated with the O&M and administration of these systems are also demand-based costs as the labor costs are typically fixed in the short-term (budget cycle). In the short-term, fixed costs do not change; the fixed costs represent the ongoing costs to meet the needs of the utility. Fixed costs are allocated primarily to demand in the COS process because they are designed to support the system as a whole. This means that as a result of the COS process, these costs are assigned based on the electric demand (measured in kilowatts [kW]) that a specific customer or customer class places on the system.

Customer-Based Costs

Customer-based costs for electric utilities are fixed costs; these are costs incurred in direct support of the customers served by a utility. For KPUB, this includes the costs associated with the labor, equipment, and investments for customer accounting, billing, and customer assistance. Additionally, a portion of administrative and general (A&G) costs are allocated to the customer-related costs as they are designed to support this function for KPUB. During the COS process, these costs are allocated by the weighted number of customers within a class.

Energy-Based Costs

Energy-based costs for electric utilities are typically variable costs that change with the changes in electric load. The primary examples of energy-related costs for KPUB are its fuel and purchased power costs. During the COS process, these costs are allocated to the customer classes by the amount of energy they are projected to utilize during the Test Year.

Existing Rate Structures and Fixed Cost Recovery

KPUB's existing rate structures vary by the customer class for which they are designed. All major customer classes include a power supply charge (\$/kilowatt-hour [kWh]), a distribution energy component (\$/kWh), and a Customer or Facility Charge (\$/customer-month), as well as a Power Cost Adjustment Factor (PCAF) that is billed on a \$/kWh basis. Some customer classes include a distribution demand component (\$/kW). Residential customers and smaller customers in the Commercial Service customer class do not have a demand charge on their bill; instead, the fixed costs associated with demand-related infrastructure are recovered through the customer charge, power supply charge, and distribution energy charge. The larger customers in the Commercial Service customer class as well as all of the customers in the Large Commercial customer class include a distribution demand charge in their rate structures.

All customers, including Residential customers, place a demand on the system through their use of electricity (electric load). The peak electric load (the highest electricity usage during one hour of the month) is referred to as the peak demand of that customer. Demand is measured in kW and, in terms of how it is billed, it represents a customer's peak usage during a billing period. Currently, only Large Commercial customers and Commercial Service customers who consume more than 2,500 kWh per month are billed directly for demand. Residential customers and Commercial Service customers who consume less than 2,500 kWh per month are not billed based on demand.

The results of this Study for Residential customers are shown in Table ES-3. However, some fixed costs have been converted into a cost per kWh for presentation in the table, as there is no plan to assess Residential customers a demand rate. For the Residential class, the customer-based costs to serve each customer equal \$7.50 per month; however, KPUB's existing rate structure includes a charge of \$15.25 per month as it is capturing other fixed costs that would otherwise be collected in the energy charges. Sufficient fixed cost recovery is an important factor in ensuring the financial stability of the utility.

**Table ES-3
Residential Rates**

Rate Component⁽¹⁾	Current	COS
Customer Charge (\$/month)	\$15.25	\$7.50
Distribution Charges		
Energy (\$/kWh)	\$0.01680	\$0.03670
Demand (\$/kW)	N/A	N/A
Power Supply Charge (\$/kWh)	\$0.04060	\$0.04543

(1) PCAF determined by KPUB is applied to all customer classes but is not included in this table.

Figure ES-1 provides a summary of the fixed and variable cost recovery for the KPUB system. Fixed cost recovery includes revenue from the customer charge and demand charges. Variable cost recovery includes revenue from the distribution energy charge, power supply charge, and PCAF. As shown in the figure, the cost of service is predominantly fixed in nature. Thus, the utility is relying on energy (variable) charges to recover fixed costs. This is not uncommon in the industry, but should be understood as a financial risk to the utility. If energy consumption decreases due to weather or energy efficiency investments (or any other reason), the utility will be faced with decreasing revenues without corresponding decreases in many of its costs.

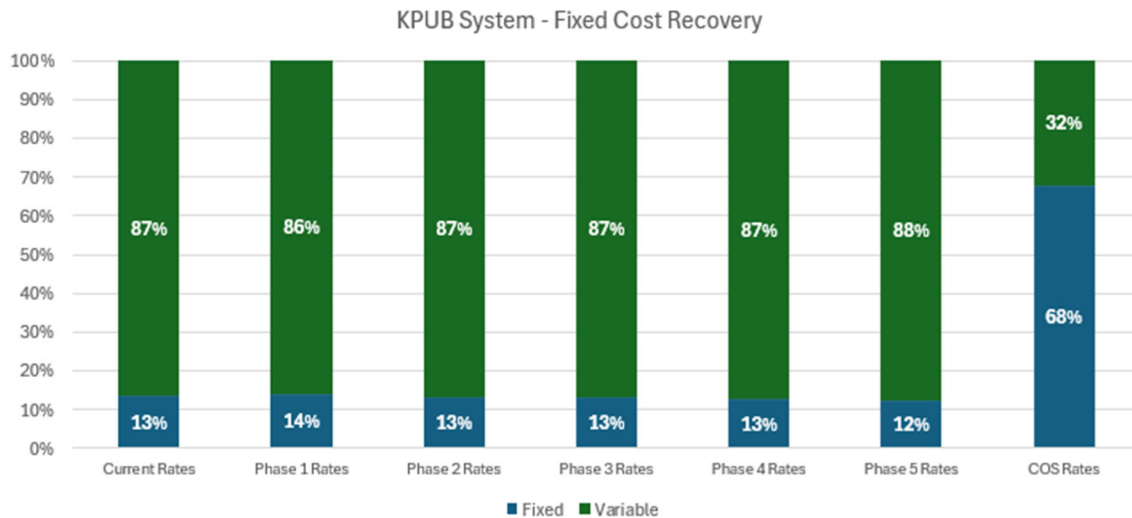


Figure ES-1. Fixed and Variable Cost Recovery for KPUB System

Summary of Proposed Rates

Actual rate increases will vary by customer class and consumption levels, but, on average, the projected rate increases will result in annualized compounded system revenue increases to meet future Revenue

EXECUTIVE SUMMARY

Requirements. The proposed rates are needed because KPUB faces an income shortfall of approximately \$73 million if rates are not increased.

Tables ES-4 through ES-8 provide a summary of the proposed rates by customer class.

It should be noted that KPUB currently has a Commercial Service customer class that has some customers charged demand charges and some customers not charged demand charges. Customers who consume more than 2,500 kWh per month are billed for demand. NewGen has separated this one customer class into two customer classes for the Study. Customers with demands equal to or greater than 25 kW are included in a class called Medium Commercial. Customers with demands less than 25 kW are included in a class called Small Commercial.

Note: The PCAF is not shown in the following tables as this rate will be adjusted periodically based on the cost of purchased power.

Table ES-4
Existing and Proposed Rates – Residential Customers

Rate Component⁽¹⁾	Existing	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Customer Charge (\$/month)	\$15.25	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75
Distribution Charges						
Energy (\$/kWh)	\$0.01680	\$0.02088	\$0.02496	\$0.02905	\$0.03314	\$0.03723
Demand (\$/kW)	N/A	N/A	N/A	N/A	N/A	N/A
Power Supply Charge (\$/kWh)	\$0.04060	\$0.04543	\$0.04543	\$0.04543	\$0.04543	\$0.04543

(1) PCAF is charged to all classes but not shown in this table.

Table ES-5
Existing and Proposed Rates – Small Commercial Customers

Rate Component⁽¹⁾	Existing	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Customer Charge (\$/month)	\$31.50	\$33.00	\$33.00	\$33.00	\$33.00	\$33.00
Distribution Charges						
Energy (\$/kWh)	\$0.01873	\$0.02112	\$0.02351	\$0.02590	\$0.02829	\$0.03068
Demand (\$/kW) ⁽²⁾	N/A ⁽²⁾	N/A	N/A	N/A	N/A	N/A
Power Supply Charge (\$/kWh)	\$0.04228	\$0.04443	\$0.04443	\$0.04443	\$0.04443	\$0.04443

(1) PCAF is charged to all classes but not shown in this table.

(2) Existing Commercial Service customers are billed a demand charge if using greater than 2,500 kWh per month.

Table ES-6
Existing and Proposed Rates – Medium Commercial Customers

Rate Component⁽¹⁾	Existing	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Customer Charge (\$/month)	\$31.50	\$33.00	\$33.00	\$33.00	\$33.00	\$33.00
Distribution Charges						
Energy (\$/kWh)	\$0.01523	\$0.01672	\$0.01821	\$0.01969	\$0.02117	\$0.02265
Demand (\$/kW)	\$1.00	\$1.50	\$2.00	\$2.50	\$3.00	\$3.50
Power Supply Charge (\$/kWh)	\$0.04228	\$0.04443	\$0.04443	\$0.04443	\$0.04443	\$0.04443

(1) PCAF is charged to all classes but not shown in this table.

Table ES-7
Existing and Proposed Rates – Large Commercial Primary Customers

Rate Component⁽¹⁾	Existing	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Customer Charge (\$/month)	\$230.00	\$275.00	\$275.00	\$275.00	\$275.00	\$275.00
Distribution Charges						
Energy (\$/kWh)	\$0.00287	\$0.00501	\$0.00715	\$0.00929	\$0.01143	\$0.01357
Demand (\$/kW)	\$7.50	\$8.00	\$8.50	\$9.00	\$9.50	\$10.00
Power Supply Charge (\$/kWh)	\$0.03030	\$0.03493	\$0.03493	\$0.03493	\$0.03493	\$0.03493

(1) PCAF is charged to all classes but not shown in this table.

Table ES-8
Existing and Proposed Rates – Large Commercial Secondary Customers

Rate Component⁽¹⁾	Existing	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Customer Charge (\$/month)	\$230.00	\$275.00	\$275.00	\$275.00	\$275.00	\$275.00
Distribution Charges						
Energy (\$/kWh)	\$0.00220	\$0.00580	\$0.00940	\$0.01300	\$0.01660	\$0.02020
Demand (\$/kW)	\$7.50	\$8.00	\$8.50	\$9.00	\$9.50	\$10.00
Power Supply Charge (\$/kWh)	\$0.03351	\$0.03643	\$0.03643	\$0.03643	\$0.03643	\$0.03643

(1) PCAF is charged to all classes but not shown in this table.

Further discussion of the proposed rates is provided in Section 6 of this Report. The proposed rates are designed to fully recover KPUB's Revenue Requirement, on average, over the Study period.

Section 1

INTRODUCTION

Kerrville Public Utility Board (KPUB) is a municipally owned electric utility serving the City of Kerrville, Texas (City) and the surrounding area. Since its establishment in 1987, KPUB has provided safe, reliable, and affordable electric service to its residential, commercial, and industrial customers. As a locally controlled, not-for-profit utility, KPUB is committed to delivering high-quality service while supporting community well-being and long-term economic sustainability.

This Electric Cost of Service (COS) and Rate Design Study (Study) is a key component in ensuring the financial sustainability of the utility. The Study was completed to ensure that KPUB's retail electric rates align with the cost to serve each customer class, provide stable and predictable revenues, and reflect best practices in ratemaking. In addition, this Study supported KPUB's ongoing evaluation of rate modernization opportunities, such as demand rate design improvements and updated commercial rate classes, all while maintaining the simplicity and transparency that KPUB's customers expect. KPUB engaged NewGen Strategies and Solutions, LLC (NewGen) to complete this Study.

The financial planning underlying this Study also considered KPUB's recent investments and strategic initiatives. These included the development of a generation plant owned by a Public Facility Corporation (PFC), with KPUB purchasing the majority of the capacity through a power purchase agreement. Planning for the financial impact of this facility, as well as future rate stabilization mechanisms, is key to ensuring long-term affordability.

This Study provided a detailed framework for determining KPUB's annual Revenue Requirement and allocating those costs among customer classes. It also evaluated alternative rate designs suited to KPUB's unique operational, policy, and community goals. By analyzing these elements through a COS approach, the Study resulted in the development of a Five-Year Rate Plan (Rate Plan or Plan) to support sound decision making and financial sustainability for the utility. NewGen completed this Study following the detailed framework below:

1. **Establish the Revenue Requirement:** First, we determined the total revenues the utility must collect over a specified period of time to serve its customers, maintain its debt service obligations, invest in its system, and provide additional funds required by reserve policies, as appropriate. The period of time covered by the Revenue Requirement (as well as the rates) was defined as the Test Year.
2. **Complete Functional Unbundling:** An electric utility can be thought of as four major business units or functions. Functional Unbundling divides the Revenue Requirement into these business units by examining the underlying costs and why they are incurred. These functions include:
 - a. Production
 - b. Transmission
 - c. Distribution
 - d. Customer service
3. **Classify Costs within Functional Area:** Costs were classified based on their underlying nature, or what is driving each cost category, within each functional area. Classes of costs include system demand,

energy consumption, the number of customers being serviced, or costs that are directly attributed (or allocated) to a specific class or customer.

4. **Allocate Costs across Customer Classes:** Based on the customer usage characteristics of the system, NewGen allocated the classified costs to customer classes and determined the COS for the classes.
5. **Design Rates:** Rate design was based on a combination of analysis of the customer class Revenue Requirements (the allocated share of the system costs) and policy decisions.

Schedule

The retail electric rates developed through this Study will be presented conceptually to the KPUB Board and, where applicable, to the Kerrville City Council and relevant community stakeholders for review and feedback. In accordance with KPUB's governance structure, residential rate changes will require final approval by the City Council following KPUB Board recommendation while non-residential rates may be approved solely by the Board.

For the purposes of this Report, NewGen assumed that the proposed series of rate changes will take effect at the beginning of October in each year. Draft rates were completed in June 2025 to support the utility's budget development process and to allow for necessary review, approval, and communication efforts prior to implementation.

KPUB Five-Year Rate Plan

The retail rates proposed in this Study include a Five-Year Rate Plan designed to meet KPUB's financial, operational, and policy objectives through a structured and sustainable implementation of rate adjustments. The Rate Plan period is expected to begin in Fiscal Year (FY) 2026 and extend through FY 2030. This comprehensive, forward-looking plan aims to ensure that KPUB can meet its overall Revenue Requirement while maintaining stability, fairness, and alignment with strategic goals.

The Rate Plan is intended to function as a complete package. Implementing only portions of the plan may prevent KPUB from achieving its long-term objectives, particularly those related to capital investment recovery, customer rate equity, and the financial sustainability of the utility. Proposed rates for KPUB's primary customer classes are detailed within this report. Included in the Study was the segregation of the Commercial Service customer class. Customers in this class that consume more than 2,500 kWh per month are charged demand charges and the rest are not. NewGen has separated this one customer class into two customer classes for the Study. Customers with demands equal to or greater than 25 kW are included in a class called Medium Commercial. Customers with demands less than 25 kW are included in a class called Small Commercial. This provides for more equitable, and appropriate, rate designs for these two groups of customers.

The proposed rates are structured to recover KPUB's overall Revenue Requirement over the five-year planning horizon. This includes anticipated investments in power supply, infrastructure improvements, and operating expenses. The Plan is responsive to the utility's sensitivity to customer affordability and is designed to gradually adjust rates over time, avoiding sudden or disruptive increases in any single year.

The Plan also includes targeted adjustments to fixed cost recovery components, such as customer charges, within each customer class—aiming to improve revenue stability. These changes are progressively introduced to support customer acceptance and allow for operational adjustments.

KPUB Financial Projections

NewGen developed the Revenue Requirement for each of the five years of the Study period as shown in Table 1-1. Additionally, Table 1-1 includes a comparison of the total revenues generated by rates effective on November 1, 2024, for the system. The differences between these two values represent the necessary rate adjustments for KPUB to fund investments, pay operations and maintenance (O&M) costs, and achieve financial policies.

Table 1-1
Revenue Requirement and Revenue for Study Period (\$000)

	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	Total
Revenue Requirement	\$ 58,803	\$ 63,093	\$ 65,041	\$ 67,702	\$ 71,006	\$ 325,645
Revenue from Customers ⁽¹⁾	49,486	49,976	50,471	50,971	51,475	252,379
Difference⁽²⁾	(\$ 9,317)	(\$ 13,116)	(\$ 14,570)	(\$ 16,731)	(\$ 19,531)	(\$ 73,265)

(1) Utilizing existing 2025 rates.

(2) Totals may not add due to rounding.

KPUB Study Test Year

The Test Year for this Study represents the average of the five-year period beginning in Fiscal Year (FY) 2026 and ending in FY 2030. KPUB's Fiscal Year (FY) runs from October 1 through September 30, and, unless otherwise specified, all references in this Report refer to fiscal years. The Test Year framework is used to generate representative average values over the planning horizon, typically centering around the midpoint of the five-year period. However, due to anticipated shifts in customer demand, the actual midpoint may not necessarily align with median values for every revenue or cost component.

The Rate Plan includes a structured series of proposed rate changes and is intended to be evaluated and adopted as a comprehensive package. Reviewing the entirety of the Rate Plan, rather than on a year-by-year basis, is critical to achieving KPUB's long-term financial and policy objectives—including recovery of system costs, enhancement of rate equity, and alignment with infrastructure investment timelines.

KPUB provides electric service to a range of customer classes. In addition, within these customer classes KPUB serves specific public and institutional accounts, such as a locally controlled non-profit hospital and municipal facilities. A summary of the current rate classes, their associated revenues, and the allocation of the Test Year Revenue Requirement is presented in Table 1-2.

Table 1-2
Existing Test Year Rate Revenues vs. Test Year Revenue Requirement
(\$000)

Rate Class	Test Year Existing Rate Revenues⁽¹⁾	Test Year Revenue Requirement	Difference
Residential Service (RS)	\$ 28,857	\$ 37,824	\$ 8,967
Commercial Service (CS)	16,463	20,202	3,739
Large Commercial-Primary (LCS-P)	967	1,417	450
Large Commercial-Secondary (LCS-S)	3,689	5,357	1,668
Lighting ⁽²⁾	501	330	(171)
Total⁽³⁾	\$ 50,476	\$ 65,129	\$ 14,653

(1) Based on existing rates and Test Year (five-year average billing determinants).

(2) Street Lighting includes Outdoor Area Lighting and Street Lighting.

(3) Totals may not add due to rounding.

The value of the difference between the total Test Year Existing Rate Revenue and the Test Year Revenue Requirement represents an “average” year (based on the Test Year concept, as discussed). During the course of the Rate Plan, it is expected that some customers’ load (sales) will increase, as discussed in Section 2. Therefore, the average revenue difference for the Test Year will equal the shortfall identified in Table 1-2 when applied to the changes in customer usage characteristics.

Test Year/Audited Year

As noted, the Test Year for this Study represents the average of the five-year period beginning in FY 2026 and ending in FY 2030 based on projections from KPUB’s internal financial planning efforts and budget assumptions. Starting from the FY 2025 Budget, known and measurable adjustments were applied and then a five-year forecast was developed to reflect expected changes in operating costs, capital expenditures, and system growth. In addition, FY 2024 energy usage and billing data was used to analyze customer load profiles and to estimate class revenues under existing rates. These usage statistics and projected revenues were based on current rate schedules in effect as of the start of FY 2025.

Report Outline

The remaining sections of this Report provide a summary of the system and customer class characteristics (Section 2), KPUB’s Revenue Requirement (Section 3), the methods utilized for the cost allocation process (Section 4), the results of the cost allocation (Section 5), and the proposed rate design (Section 6).

Section 2

SYSTEM CHARACTERISTICS

Introduction

KPUB operates as a municipally owned electric utility serving approximately 24,400 customers within a 146 square mile service area in Kerr County, Texas. KPUB is the exclusive electric service provider within its jurisdiction, functioning under the oversight of a five-member Board of Trustees. While KPUB does not currently own generation assets, it is responsible for procuring power through contracts and managing the reliable delivery of electric service through its distribution system and customer service operations.

KPUB's power supply portfolio is diversified across several long-term power purchase agreements, including contracts with CPS Energy, NextEra, the City of Garland (wind projects), Engie, and Concho Bluff (solar projects), as well as a community solar initiative through DG Southwest Solar. These agreements provide a mix of base load, wind, and solar generation resources. Additionally, KPUB has recently created a PFC to support the development of a 122 megawatt (MW) Reciprocating Internal Combustion Engine (RICE)-based peaking generation facility, which is expected to come online in 2027.

The utility maintains well-established infrastructure that includes fully deployed Advanced Metering Infrastructure (AMI) across its customer base. The electric system comprises both overhead and underground distribution lines, a number of substations, and a fully integrated meter data management system metering equipment. KPUB has leveraged these assets to enhance operational efficiency, improve outage response, and support demand-side management programs.

Distribution system reliability and modernization are top priorities for KPUB. The system includes ongoing investments in infrastructure improvements and modernization efforts aimed at enhancing reliability, resilience, and overall service quality. KPUB's operational structure is designed to respond proactively to emerging challenges, including large-scale electric vehicle (EV) charging infrastructure, distributed generation, and the integration of a new generation asset into the Electric Reliability Council of Texas (ERCOT) competitive market.

Demand and Energy Requirements

For the fiscal year ending September 30, 2024, KPUB served a total of 24,387 customers, reflecting continued steady growth in its service area. During this period, KPUB recorded a system peak demand of 172.8 MW, which occurred in January 2024. This represents a modest increase from the prior year's peak of 170.9 MW. Total energy requirements for FY 2024 amounted to 510.9 megawatt-hours (MWh) of electricity delivered to retail customers. This total includes all energy sold across customer classes and accounts for energy losses and company use. Projections for the Test Year (FY 2026–2030) and subsequent years anticipate continued modest growth in both customer count and energy demand, consistent with local economic and population trends. Peak demand is expected to increase gradually, particularly with the anticipated addition of large commercial and EV charging loads discussed in KPUB's planning sessions. While weather normalization adjustments are common in forecasting, KPUB's planning approach currently bases forecasts on historical trends and anticipated system additions. Forecasted system characteristics are summarized in Table 2-1.

Table 2-1
System Usage Characteristics

	FY Ending						
	2024	2025	2026	2027	2028	2029	2030
Total Meters	23,933	24,173	24,587	24,833	25,081	25,332	25,585
Total Energy (MWh) ⁽¹⁾	512,138	512,138	512,138	517,248	522,408	527,620	532,884
Total Demand (MW)	661	668	674	681	688	695	702

(1) Energy and Demand projections for 2025–2030 represent expected retail sales/usage. 2024 represents actual Energy and Demand for FY 2024 (ending September 2024) based on KPUB's billing database.

Demand

Demand is a measurement of energy for a short period of time, typically an hour or a 15-minute interval. Demand is measured in kW or in thousands of kW (1,000 kW) which are reported as MW. A utility must be able to meet the demands of its systems, which represent the total demands of its customers at any given time. To meet these demands, utilities will typically invest in generation facilities that are appropriately sized to meet the peak demand or purchase demand (in the form of capacity contracts) from the power market. Utilities must plan and invest for the system peak capacity, which may go unused during periods of low electrical use. For KPUB, the system typically reaches its peak demand during the winter months, which is unusual in ERCOT (where most systems are summer peaking). KPUB's winter peak is likely related to the absence of natural gas pipelines in the area, which result in the prevalence of electric heating. The Residential customer class, which represents more than half of the system's energy use, is the primary driver of KPUB's system peak demand from a cost causation standpoint.

The peak demand is often referred to as the Coincident Peak (CP) because it is the amount of total load from all customers collectively at the same time (coincident with each other). The 12 Coincident Peak (12CP) allocator refers to the total electric demand recorded during the 12 monthly system peak hours. 12CP is an important tool utilized in allocating costs for a COS Study and is further discussed in Section 4 of this report.

Energy Sales

Energy is the demand that is measured over hourly increments and is measured in kWh. Energy is the product (and service) that most people associate with purchasing from their electric utility. A utility must provide energy to its customers in a reliable, continuous, and safe fashion. Notwithstanding new battery offerings, energy is primarily instantaneously used, meaning that it cannot be effectively stored in large amounts for later use. A utility will use the installed investment in generation (capacity) to produce energy, typically by burning a fossil fuel (e.g., gas or coal) or with renewable resources (e.g., solar or wind). Alternatively, a utility may purchase energy in the power market to meet its customers' load. In ERCOT, all energy produced is sold into the wholesale market and all energy is purchased from the wholesale market. Thus, load serving entities no longer generate to serve their own load. However, ownership of generation or purchase power contracts act as a financial hedge against wholesale market prices.

Figure 2-1 provides a representation of the total energy used by KPUB’s customer classes for FY 2024 based on analysis of its billing database for that period.

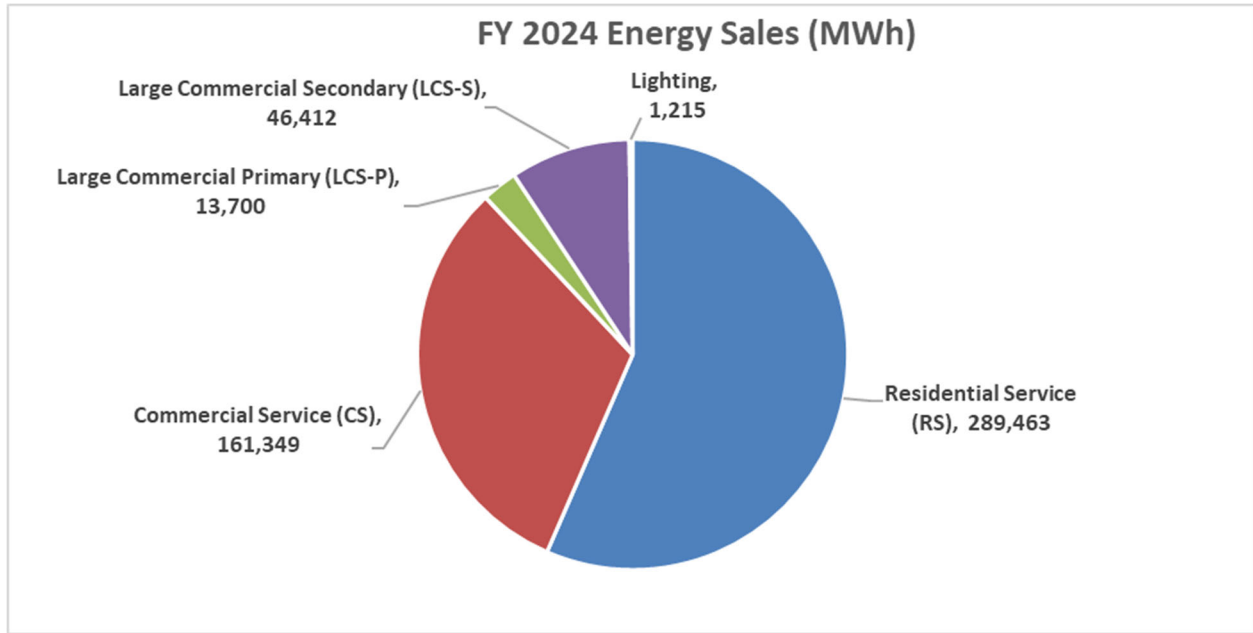


Figure 2-1. Total Energy Consumption by Customer Class for FY 2024 (MWh)

Historical and projected energy sales by customer class are provided in Table 2-2.

Table 2-2
Historical and Projected Energy Sales (MWh)

	FY Ending						
	2024	2025	2026	2027	2028	2029	2030
Residential Service (RS)	289,463	289,463	289,463	292,357	295,281	298,234	301,216
Commercial Service (CS)	161,349	161,349	161,349	162,963	164,592	166,238	167,901
Large Commercial-Primary (LCS-P)	13,700	13,700	13,700	13,836	13,975	14,115	14,256
Large Commercial-Secondary (LCS-S)	46,412	46,412	46,412	46,876	47,345	47,818	48,296
Lighting	1,215	1,215	1,215	1,215	1,215	1,215	1,215
Total System⁽¹⁾	512,138	512,138	512,138	517,248	522,408	527,620	532,884

(1) Total system sales exclude losses. Totals may not add due to rounding.

Average Number of Meters by Customer Class

Table 2-3 presents the average number of meters by customer class for FY 2024 and projected through FY 2030.

Table 2-3
Historical and Projected Meters by Class

	FY Ending						
	2024	2025	2026	2027	2028	2029	2030
Residential Service (RS)	19,937	20,136	20,510	20,715	20,922	21,132	21,343
Commercial Service (CS)	3,974	4,013	4,053	4,094	4,135	4,176	4,218
Large Commercial-Primary (LCS-P)	3	3	3	3	3	3	3
Large Commercial-Secondary (LCS-S)	20	20	20	20	21	21	21
Lighting ⁽¹⁾	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total System^(2,3)	23,933	24,173	24,587	24,833	25,081	25,332	25,585

(1) Lighting is not included because many of the billed devices are unmetered. In FY 2024 there was a total of 3,627 unique devices.

(2) Projected meters are the average monthly projected meters for each FY.

(3) Totals may not add due to rounding.

Customer Statistics

Meter statistics by rate class for FY 2024 are provided in Table 2-4. As shown, the majority of the customers served by KPUB are in the Residential rate class, which also accounts for the largest share of total annual energy sales.

Table 2-4
Actual Customer Usage Statistics for FY 2024

	FY Ending 2024			
	Number of Meters	Percentage of Total	Annual Sales (MWh)	Percentage of Total
Residential Service (RS)	19,937	83.30%	289,463	56.52%
Commercial Service (CS)	3,974	16.60%	161,349	31.51%
Large Commercial-Primary (LCS-P)	3	0.01%	13,700	2.67%
Large Commercial-Secondary (LCS-S)	20	0.08%	46,412	9.06%
Lighting ⁽¹⁾	N/A	N/A	1,215	0.24%
Total System⁽²⁾	23,933		512,138	

(1) Lighting is not included because many of the billed devices are unmetered. In FY 2024 there was a total of 3,627 unique devices.

(2) Totals may not add due to rounding. Based on analysis of KPUB billing database for 2024.

Fixed/Variable Costs and Cost Recovery

The revenues generated from retail sales under KPUB's existing rates for FY 2025 are estimated to be approximately 13% fixed (which includes the customer charge and demand charges, as applicable) and 87% variable, which includes the distribution energy charge, power supply charge, and Power Cost Adjustment Factor (PCAF). Figure 2-2 provides a depiction of the mix between the fixed and variable nature of the system's costs (on the right) and the current revenues for FY 2025 (on the left).

As shown in the figure, the cost of service is predominantly fixed in nature. Thus, the utility is relying on energy (variable) charges to recover fixed costs. This is not uncommon in the industry, but should be understood as a financial risk to the utility. If energy consumption decreases due to weather or energy efficiency investments (or any other reason), the utility will be faced with decreasing revenues without corresponding decreases in many of its costs.

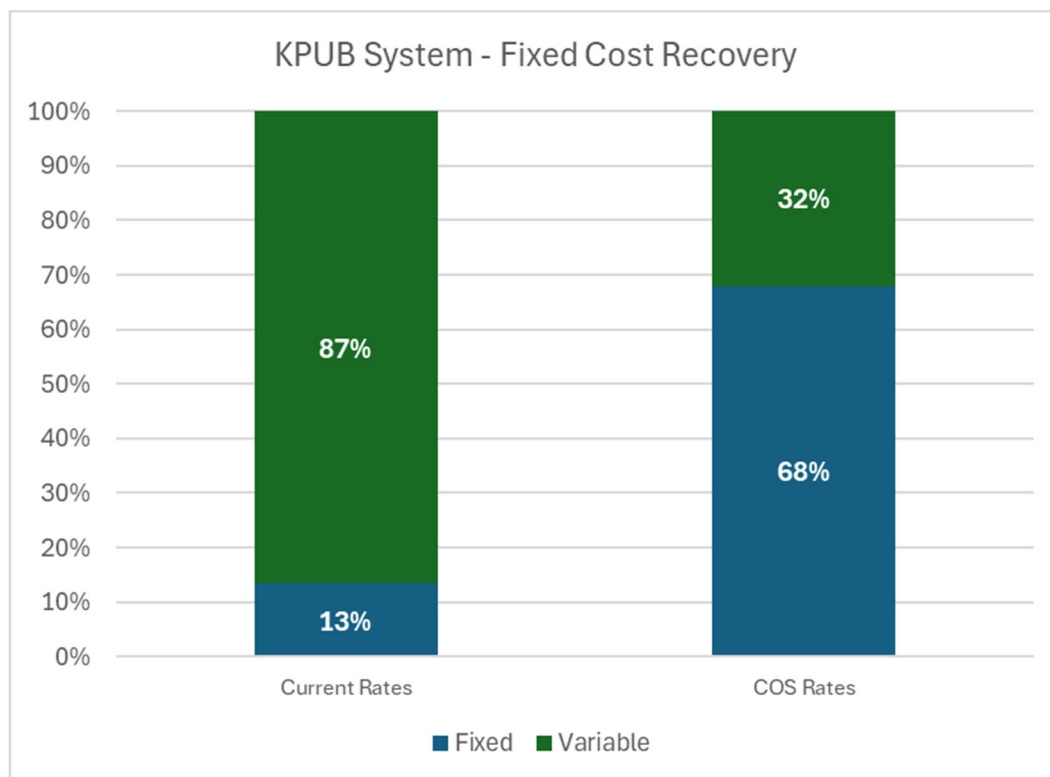


Figure 2-2. Structure of System (COS) Costs vs. Current Revenues

Section 3

REVENUE REQUIREMENT

Summary

The Revenue Requirement refers to the amount of rate-related revenue that a utility is projected to need during the Study period. As indicated earlier, for the purposes of this Study, KPUB utilized a Test Year that represents the average of the five-year period beginning in FY 2026 and ending in FY 2030. KPUB's net Revenue Requirement for the Test Year is \$65,128,962. This value is driven by the specific "known and measurable" changes to the FY 2025 Budget. Because the Test Year is a multiyear representation, this value represents the average annual revenue to be collected by KPUB's retail rates. For the purposes of rate design, provided in Section 6 of this report, revenues collected over the Study period are anticipated to vary by year.

A summary of the Test Year Revenue Requirement is provided in Table 3-1.

Table 3-1
Revenue Requirement by Function for Test Year (\$000)

Function	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	Test Year Value	Percentage of O&M
Production O&M	\$ 29,206	\$ 32,287	\$ 32,895	\$ 34,220	\$ 36,097	\$ 32,940	58%
Transmission O&M	8,138	8,789	9,492	10,252	11,072	9,549	17%
Distribution O&M	5,175	5,367	5,562	5,766	5,978	5,570	10%
Customer O&M	1,595	1,654	1,714	1,777	1,842	1,717	3%
A&G O&M	6,684	6,932	7,185	7,447	7,720	7,194	13%
Total O&M	\$ 50,798	\$ 55,029	\$ 56,850	\$ 59,462	\$ 62,709	\$ 56,970	
Capital from Cash	6,425	6,375	6,462	6,450	6,427	6,428	
Debt Service	531	531	531	531	531	531	
Franchise	1,775	1,901	1,960	2,038	2,136	1,962	
Contribution to Reserves	-	-	-	-	-	-	
Other Operating Revenues	(685)	(702)	(717)	(733)	(749)	(717)	
Revenues from Merchandising, Jobbing, and Contract Work	(37)	(38)	(40)	(42)	(44)	(40)	
Miscellaneous Non-Operating Income	(4)	(4)	(4)	(4)	(4)	(4)	
Net Revenue Requirement	\$ 58,803	\$ 63,093	\$ 65,041	\$ 67,702	\$ 71,006	\$ 65,129	

Note: Numbers may not add due to rounding.

As shown in Table 3-1 the Production function represents the largest share of KPUB's total O&M costs, accounting for approximately 58% of O&M expenses during the Test Year. This is followed by Transmission O&M (17%), Administrative and General (A&G) (13%), Distribution O&M (10%), and Customer O&M (3%).

Section 3

In addition to O&M expenses, the Revenue Requirement includes several non-O&M costs such as debt service, which reflects principal and interest payments on existing debt. The Franchise line-item includes the 3% transfer to the City embedded in the base rates. Capital from cash denotes investments made directly from rate revenues to fund capital improvements. While no formal contributions to reserves are identified for the Test Year, KPUB expects to make contributions to a Rate Stabilization Fund based on revenues from the new generation project (once in operation).

The calculation of the Net Revenue Requirement also includes deductions for other sources of income, including operating revenues (such as late payment fees and pole rentals); revenues from merchandising, jobbing, and contract work; and other miscellaneous income streams. These items reduce the total amount of revenue that must be collected through base electric rates, ensuring that the Net Revenue Requirement reflects only the retail revenue necessary to fund utility operations and obligations.

Section 4

ALLOCATION OF SYSTEM COSTS

Functionalization and Classification

Allocating costs to a utility's customer classes is achieved through three major processes: 1) functionalization, 2) classification, and 3) allocation. The functionalization and classification of the Test Year Revenue Requirement are discussed in the first part of this section. The development of the allocation factors for the Test Year Revenue Requirement is discussed in the second part of this section.

Functionalization of Test Year Expenditures

Although budgeting and accounting systems generally follow functional groups (e.g., production, transmission, etc.), certain costs—such as A&G expenses—are not typically assigned by accounting and budgetary conventions to a major function. A COS study usually requires the rearrangement of certain expenditures into functional groups for a few reasons: 1) to be more representative of the expenditure causation, 2) to combine costs that have been incurred for a similar purpose, and 3) to facilitate the allocation of cost responsibility. Thus, the functionalization of certain costs is a ratemaking mechanism to apportion such costs to the common utility functions. Table 4-1 provides a categorization of the COS by function.

Table 4-1
Cost of Service by Function

Function	Test Year Value (\$000)	Percent
Production	\$ 34,079	52.3%
Transmission	9,549	14.7%
Distribution	18,226	28.0%
Customer	3,275	5.0%
Total⁽¹⁾	\$ 65,129	

(1) Numbers may not add due to rounding.

Classification of Various Costs

Electric utility costs are generally classified as either: 1) demand-related, 2) energy-related, 3) customer-related, 4) revenue-related, or 5) directly assigned.

Demand (fixed) costs are defined as expenses that are incurred to maintain a “readiness to serve”—an electric system capable of meeting the total combined demands of all customers at all hours, including peak demand. Demand costs are those that are generally fixed in the short-run, do not materially vary directly with the number of kWh generated or sold, and are not defined as customer costs. Demand costs include a portion of the O&M expenses, debt service, renewal and replacements (ongoing capital

improvements and investments), and other costs that are not defined as specifically customer or variable energy costs.

Energy (variable) costs are defined as those expenses that vary substantially or directly with the amount of energy sold (either generated or purchased), including such items as fuel and a portion of the O&M expenses for production facilities (known as variable O&M). However, not all energy procurement contracts are variable. Some contracts have provisions, such as “take or pay,” that require the utility to pay for all energy under contract whether it is used or not.

Customer costs are defined as expenses directly related to the number, type, and size of customers, including customer accounting and bill collection, as well as the costs of meters and services. Also, a portion of the distribution investment and operating costs are classified as customer costs because the size and design of the distribution system is a function of both the number of customers and their load (demand).

Revenue-related costs refer to expenses that vary with the amount of revenue collected by the utility. While municipal utilities like KPUB are not subject to income taxes, they do incur revenue-related obligations—most notably the 3% transfer to the City, which is embedded in base rates. This transfer serves a similar role to taxes in investor-owned utilities.

Another important classification of costs is direct assignment. These costs are not allocated broadly across all customer classes but, instead, are assigned directly to specific classes or customers based on clear cost causation.

Development of Allocation Factors

General

This section discusses the development of the factors utilized to allocate the capacity-related, energy-related, customer-related, and other costs to the various KPUB customer classes. The aforementioned costs are allocated to customer classes based on each class’s specific cost allocation factors developed for the various types of costs.

Demand Allocation Factors

Demand allocation refers to the basis on which capacity and other demand-related costs are distributed or assigned (allocated) among the various customer classes for the purposes of determining the revenues required from each class to recover such costs. The demand allocation factors, as developed and used herein, reflect the cost responsibility for each of the various customer classes in relation to the capacity- or demand-related costs to be allocated. The demand allocation factors were used to apportion the following capacity- or demand-related costs among the various customer classes:

- Debt service on new generation investments (production)
- Fixed transmission and distribution expenses

12 Coincident Peak

For this COS analysis, a 12 CP demand allocator was used to assign demand-related production costs across customer classes. The CP represents the total system demand occurring at the same time across all customers—essentially the moment when the system as a whole is experiencing its peak load. Using

CP allocators ensures that costs are distributed according to how much each customer class contributes to the system peak at those critical times.

The 12 CP methodology allocates costs based on each customer class's contribution to the system peak demand in each month of the year, providing a more balanced and seasonally representative view of system usage. This approach is particularly useful for allocating production-related demand costs as it reflects KPUB's year-round obligation to maintain sufficient generation and purchased capacity to meet peak demands.

To support this methodology, NewGen analyzed historical monthly demand data for each rate class. KPUB's fully deployed AMI allows for detailed tracking of customer load profiles, thereby enhancing the accuracy of the demand allocation. As such, the 12 CP allocator used in this Study reflects both the historical peak characteristics and the most current understanding of class-level demand impacts.

Results from the 12 CP demand cost allocation process are provided in Table 4-2.

Table 4-2
12 CP Cost Allocation

Customer Class	12 CP (MW)	Allocation (%)
Residential Service (RS)	815	61.3%
Commercial Service (CS)	397	29.8%
Large Commercial-Primary (LCS-P)	25	1.9%
Large Commercial-Secondary (LCS-S)	91	6.9%
Lighting	1	0.1%
Total System^(1,2)	1,330	

(1) Based on Test Year projections.

(2) Numbers may not add due to rounding.

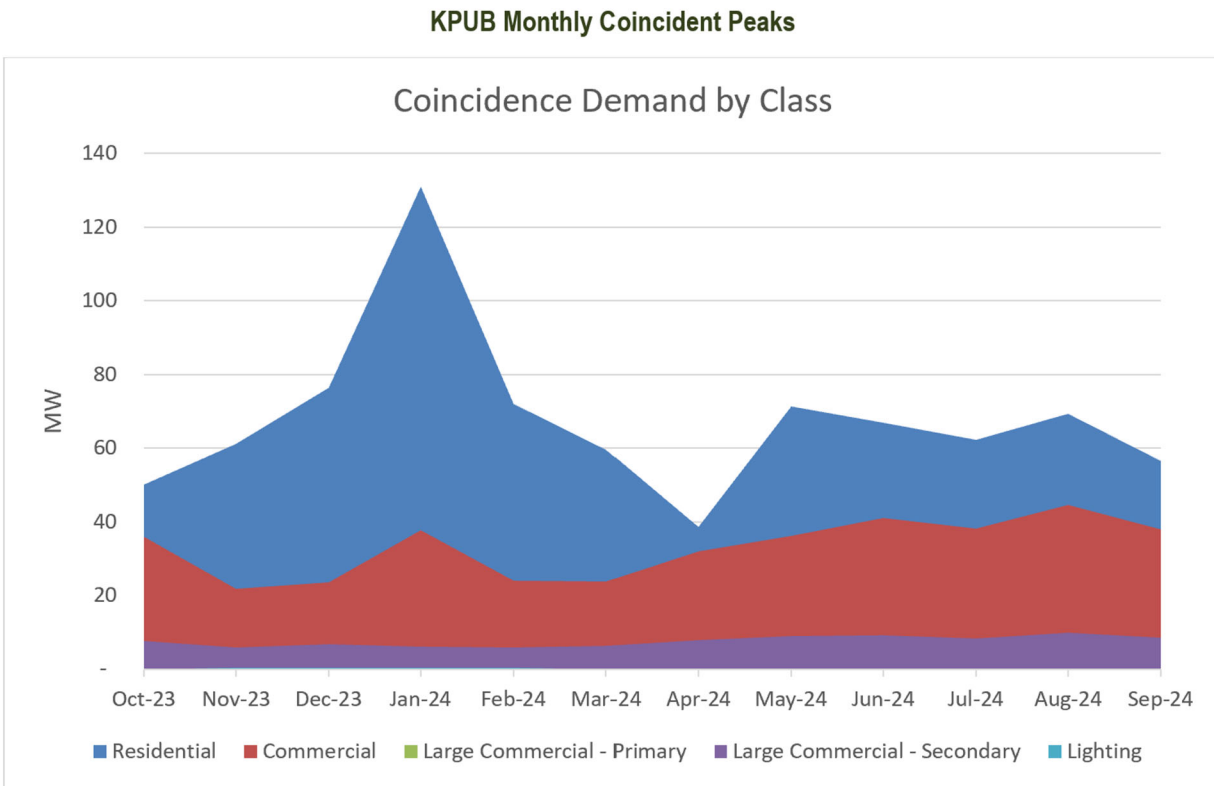


Figure 4-1. 12 CP Demand Cost Allocation

As shown in Figure 4-1, the peak demand months for KPUB occurred in December, January, and February. The peak demand was primarily driven by the increase in electricity usage by the Residential class. The large Residential spike in January 2024 was most likely due to a cold weather event specifically, an unusually low temperature period that caused electric heating systems (such as heat pumps or resistance heaters) to run at full capacity across many homes.

ERCOT 4 Coincident Peak

In ERCOT, the cost of transmission by others is determined based on each load serving entity's contribution to the ERCOT 4 CP. This is based on demands in the months of June, July, August, and September. Thus, for allocation of transmission costs, each customer class's contribution to the ERCOT 4 CP was measured. Table 4-3 shows the ERCOT 4 CP for each customer class.

Table 4-3
ERCOT 4 CP Cost Allocation

Customer Class	ERCOT 4 CP (MW)	Allocation (%)
Residential Service (RS)	199	54.4%
Commercial Service (CS)	127	34.7%
Large Commercial-Primary (LCS-P)	9	2.4%
Large Commercial-Secondary (LCS-S)	31	8.4%
Lighting	0	0.0%
Total System^(1,2)	365	

(1) Based on Test Year projections.

(2) Totals may not add due to rounding.

12 Non-Coincident Peak

The Non-Coincident Peak (NCP) demand allocation method is based on the principle that certain utility costs, particularly those related to distribution infrastructure, are driven by the individual peak demand of each customer class, regardless of whether those peaks occur simultaneously with the systemwide peak. This method recognizes that the sizing and design of distribution facilities must accommodate the maximum demand of each class, even if those peaks occur at different times.

For this Study, NewGen used a 12 NCP methodology to allocate distribution-related demand costs (except for distribution transformers, which were allocated based on sum of maximum demands). This approach captures each class's monthly peak demand over the course of a full year, providing a more comprehensive representation of how each class impacts the system's distribution requirements. The use of 12 monthly values helps smooth out seasonal fluctuations and supports a more accurate allocation of costs associated with substations, feeders, and other localized infrastructure. The results of the 12 NCP demand allocation are shown in Table 4-4.

Table 4-4
12 NCP Cost Allocation

Customer Class	12 NCP (MW)	Allocation (%)
Residential Service (RS)	1,007	63.4%
Commercial Service (CS)	445	28.0%
Large Commercial-Primary (LCS-P)	30	1.9%
Large Commercial-Secondary (LCS-S)	102	6.4%
Lighting	3	0.2%
Total System^(1,2)	1,588	

(3) Based on Test Year projections.

(4) Totals may not add due to rounding.

Sum of Maximum Demands

The Sum of Maximum Demands (SMD) allocation method is based on the principle that certain utility costs, particularly those associated with localized distribution equipment, are driven by the combined maximum demands of all customer classes at the individual facility or asset level. This method captures the sum of each class's highest recorded demand over the study period, regardless of whether those peaks occur simultaneously or during different intervals. By summing these maximum demands, the method ensures that allocation of costs reflects the cumulative capacity that must be designed into localized infrastructure to reliably serve all customer classes.

For this Study, KPUB/NewGen uses the SMD methodology to allocate the costs of distribution transformers, recognizing that transformer capacity must be sufficient to serve the aggregated maximum demand of all connected classes. This approach ensures a direct link between the sizing of transformer equipment and the total load requirements experienced over time. Using the SMD method provides a more precise allocation for equipment with service areas or capacity constraints driven by aggregated customer demands. The results of the SMD allocation are shown in Table 4-5.

Table 4-5
SMD Cost Allocation

Customer Class	SMD (MW)	Allocation (%)
Residential Service (RS)	1,531	68.4%
Commercial Service (CS)	578	25.8%
Large Commercial-Primary (LCS-P)	26	1.2%
Large Commercial-Secondary (LCS-S)	99	4.4%
Lighting	3	0.1%
Total System^(1,2)	2,237	

(5) Based on Test Year projections.

(6) Totals may not add due to rounding.

Energy Allocation Factors

Energy allocation factors are the basis for apportioning those costs or expenses classified as variable or energy related and assumed to vary directly with the level of kWh sales or generation. The costs classified herein as variable, or energy-related, are all purchased power costs other than transmission and the debt service on the new generation investment.

Total energy sales adjusted for estimated line losses, referred to as net energy for load (NEFL), is used to allocate energy-related costs (see Figure 4-2 and Table 4-6). NEFL can be thought of as the energy necessary at the substation to serve load. In Figure 4-2, the primary Y-axis (the blue bars) represents the allocated costs by major customer class in thousands of dollars. The secondary Y-axis (the red line) represents the total energy (in MWh).

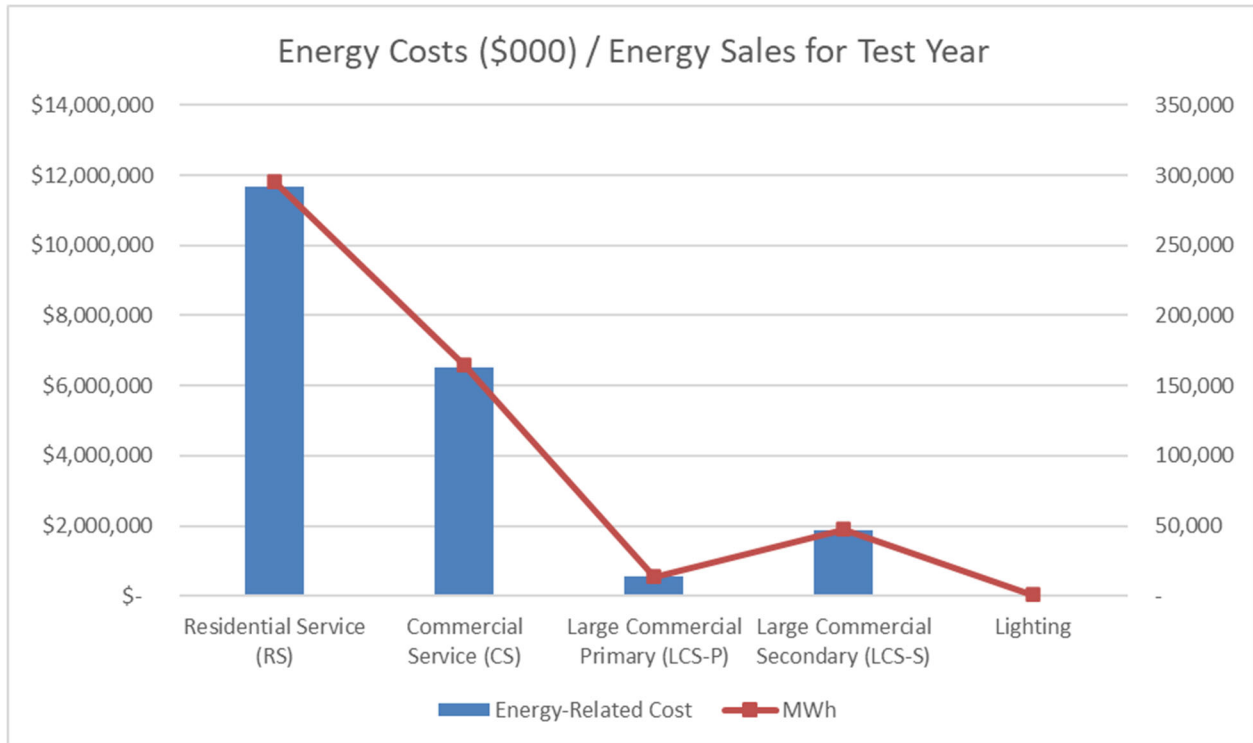


Figure 4-2. Allocation of Energy Costs based on Net Energy for Load

Table 4-6
Energy Cost Allocation

Customer Class	NEFL (MWh)	Allocation (%)
Residential Service (RS)	308,474	56.5%
Commercial Service (CS)	171,982	31.5%
Large Commercial-Primary (LCS-P)	14,608	2.7%
Large Commercial-Secondary (LCS-S)	49,480	9.1%
Lighting	1,215	0.2%
Total^(1,2)	522,310	

(1) Based on Test Year projections..

(2) Totals may not add due to rounding.

Customer Allocation Factors

Customer costs are defined herein as those costs related to the number of customers and the size of service required. Included in the customer-related costs are the costs associated with meter reading, meter maintenance, customer installations, billing, collecting, and other customer-related accounting, service, and information functions. The customer allocation factors developed for this Study were based on the projected average number of customers in each class during the Test Year.

Section 4

In allocating customer-related costs to the various customer classes, NewGen primarily used customer allocation factors that recognized a weighted number of customers by class. The weighted factor is based on the number of customers in a particular class multiplied by a weighting factor. The weighting factors were developed based on the estimated costs associated with serving non-domestic customer classes, recognizing that serving these customer classes is more expensive on a per-customer basis than domestic classes.

Customer Service costs were allocated to customer classes based on a Key Accounts allocator developed specifically to estimate the effort associated with each customer class. This allocator recognizes the larger effort associated with the Large Commercial Services accounts.

Section 5

ALLOCATED COST OF SERVICE

General

As one of the factors considered in the evaluation of KPUB's existing retail rates and rate structures included herein, NewGen employed certain analyses that provide a reasonable indication of the revenue required by KPUB's major customer classes, which include the following:

- Residential Service (RS)
- Commercial Service (CS)
- Large Commercial-Primary (LCS-P)
- Large Commercial-Secondary (LCS-S)
- Lighting

Allocation and Assignment of Cost of Service

The results of the cost allocation analysis are presented in Table 5-1, along with a comparison of the cost recovery currently projected for the Test Year under existing retail rates.

Table 5-1
Existing Test Year Rate Revenues vs. Test Year Revenue Requirement
(\$000)

Customer Class	Test Year Existing Rate Revenue ⁽¹⁾	Test Year Revenue Requirement	Difference
Residential Service (RS)	\$ 28,857	\$ 37,824	\$ 8,967
Commercial Service (CS)	16,463	20,202	3,739
Large Commercial-Primary (LCS-P)	967	1,417	450
Large Commercial-Secondary (LCS-S)	3,689	5,357	1,668
Lighting	501	330	(171)
Total⁽²⁾	\$ 50,476	\$ 65,129	\$ 14,653

(1) Based on existing rates and Test Year (five-year average) billing determinants.

(2) Totals may not add due to rounding.

According to the results of this Study, KPUB's Residential Service (RS), Commercial Service (CS), Large Commercial-Primary (LCS-P), and Large Commercial-Secondary (LCS-S) rates are below the cost KPUB incurs to serve these customers, while Lighting rates are modestly above the COS.

Retail Rate Review

Background information on the existing rate structure of KPUB’s major customer classes is presented below. This includes a comparison of the existing rates to the COS-based rates and a description of the development of cost and rate curves. These elements were considered for the individual customer class rate proposals provided in Section 6 of this report.

Residential Service

Table 5-2 provides a summary of KPUB’s existing RS class rates compared to the COS-based rates developed for this Study. It is extremely important to note that for customer classes that do not have a demand charge, the COS results reflect taking costs assigned to the class, most of which are fixed in nature, and dividing by kWh. Thus, while the COS shown in the following tables indicate costs per kWh, this does not mean the nature of the costs are all variable, as previously discussed.

The existing RS rate includes a monthly customer charge of \$15.25 which is intended to recover costs such as meter reading and billing services. In addition to the fixed charge, customers pay a flat per-kWh energy rate that is broken into two components:

- Distribution Charge: \$0.01680 per kWh
- Power Supply Charge: \$0.04060 per kWh

These rates apply uniformly across all usage levels and seasons; there are no tiered energy blocks. Additionally, the PCAF, which currently captures changes in wholesale power and transmission costs, is an energy charge. This simple, transparent rate design supports consistent billing and reflects KPUB’s approach to maintaining rate stability while recovering actual costs.

Table 5-2
Residential Service (RS) Rates
(Existing and Cost of Service)

Rate Component ⁽¹⁾	Existing	COS
Customer (\$/month)	\$15.25	\$7.50
Distribution (\$/kWh)	\$0.01680	\$0.03670
Power Supply (\$/kWh)	\$0.04060	\$0.04543

(1) Applicable PCAF not shown.

The customer-related COS amount includes the costs for meter reading, billing and collections, customer service, and the allocated portion of distribution infrastructure closely related to customer count (meters and services).

Residential Service Cost Curve

Figure 5-1 provides an illustration of a “cost curve” for KPUB’s RS customer class. A cost curve represents the total costs to serve a customer within a specific rate class over a range of monthly energy usage. The total costs are divided by the total monthly energy usage (in kWh) to calculate an “all-in” cost (\$/kWh) to serve customers. A cost curve is a convenient tool to understand how unit costs (all-in \$/kWh) for fixed cost industries (such as electric utilities) behave. If the customer is only using very small amounts of energy

in a month, the all-in costs per kWh are high because of the high fixed costs. However, if the customer is using large amounts of energy in a month, the fixed costs are spread over more energy, resulting in a lower all-in cost per kWh. This is why the cost curves for KPUB—and, generally speaking, for any utility—exhibit a characteristic shape: a high ‘tail’ on the left, followed by a rapid decline that gradually flattens toward the right. Cost curves are useful in rate design to allow a comparison of rates and rate structures to a utility’s costs.

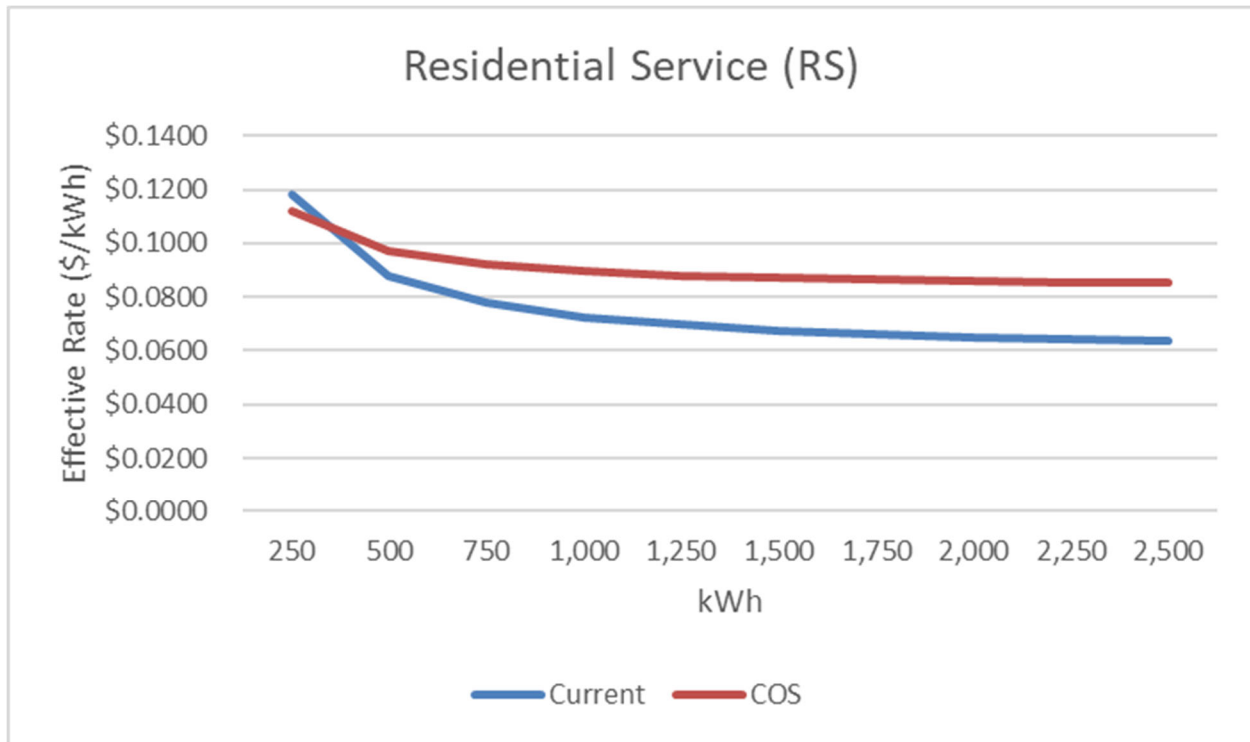


Figure 5-1. Cost and Current Rate Curves for Residential Service

Commercial Service Rate Review

Table 5-3 provides a summary of KPUB’s existing CS class rates compared to the COS-based rates developed in this Study. The existing CS rate includes a fixed monthly customer charge of \$31.50. Beyond this fixed component, energy and demand charges are tiered based on usage and demand levels. The energy component includes both distribution and power supply charges while the demand charge applies to the measured customer demand for customers that use more than 2,500 kWh per month.

Table 5-3
Commercial Service (CS) Rates
(Existing and Cost of Service)

Rate Component ⁽¹⁾	Existing	COS
Customer (\$/month)	\$31.50	\$32.53
Distribution ≤ 2500 kWh (\$/kWh)	\$0.01873	\$0.02891
Distribution >2500 kWh (\$/kWh)	\$0.01523	\$0.02891
Demand >2500 kWh (\$/kW)	\$1.00	\$-
Power Supply (\$/kWh)	\$0.04228	\$0.04443

(1) Applicable PCAF not shown.

The distribution component of the energy rate is binary – it is \$0.01873/kWh for customers that use up to 2,500 kWh per month and it is \$0.01523/kWh for customers that use more than 2,500 kWh per month. The existing CS rate includes a \$1.00/kW demand charge for customers that use over 2,500 kWh per month. While the COS does not show a demand rate, the reality is that the distribution costs are all fixed. These were converted into a rate per kWh for presentation in this table.

As part of this Study, NewGen has recommended that KPUB introduced a new Medium Commercial (CM) service class to better differentiate between small and medium commercial customer loads. Customers with billing demands exceeding 25 kW will be reassigned to the CM class, which incorporates a dedicated demand charge that more accurately reflects their cost to serve. The remaining customers in the CS class will be part of a Small Commercial class, which will have no demand charge. This reassignment of customers in the existing CS class will simplify the rate structure (as the rates charged will no longer be different within the same class depending on how much energy is used in any particular month).

The existing power supply charge of \$0.04228 per kWh is slightly below the COS-derived rate of \$0.04443 per kWh. As with the RS class, energy charges under the CS class rate remain subject to the PCAF.

Commercial Service Cost Curve

Similar to the analysis conducted for the RS class, Figure 5-2 presents a cost curve comparison for the CS class, illustrating the relationship between existing rates and COS-based revenue recovery across a wide range of monthly usage levels. The curve highlights how current rates under-recover costs across most usage levels compared to COS-based rates.

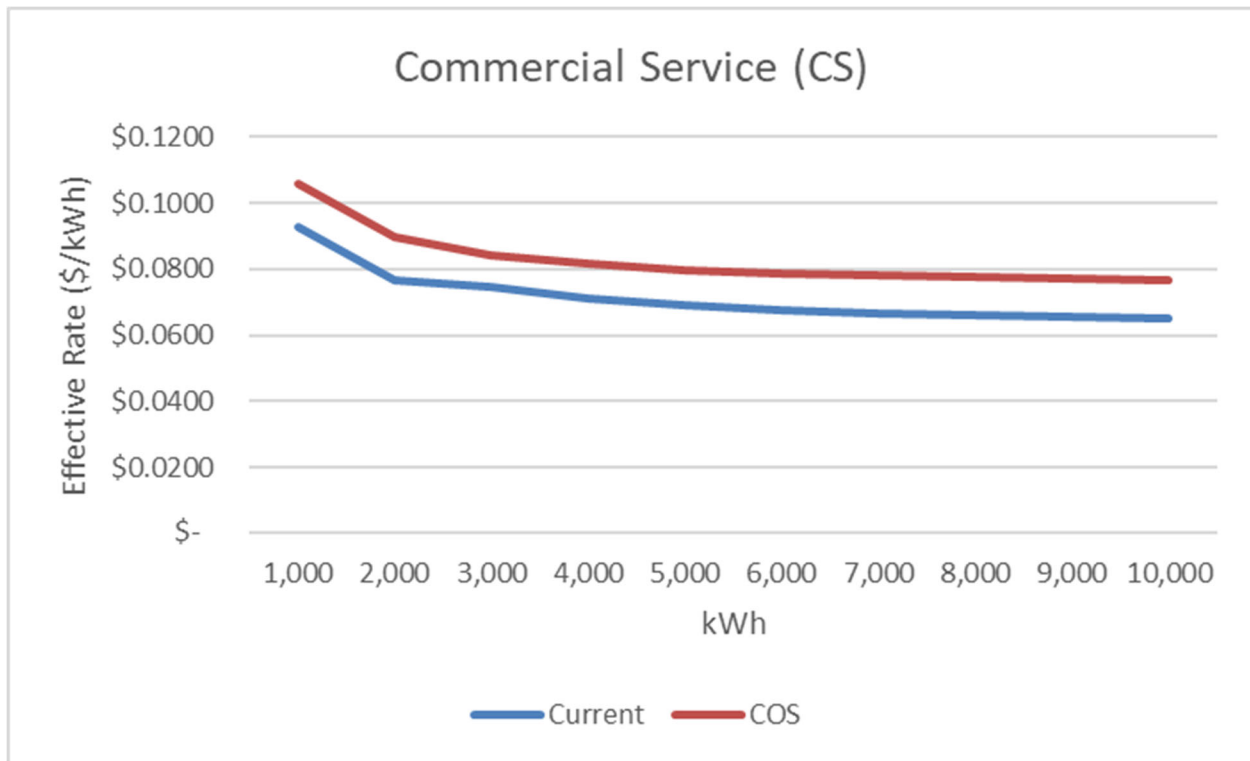


Figure 5-2. Cost and Current Rate Curves for Commercial Service

Large Commercial-Primary Rate Review

The LCS-P class is designed to serve KPUB's largest commercial and industrial customers who receive service at the primary distribution voltage level and exhibit high and consistent demand profiles. These customers typically include manufacturing plants, institutional campuses, and large-scale commercial operations with significant peak demand and energy requirements.

Table 5-4 provides a summary of KPUB's existing rates for the LCS-P class alongside those derived from the COS analysis. Under the current rate structure, the customer charge is set at \$230.00 per month, which is significantly below the COS-based customer charge of \$2,729.28. This COS-based figure reflects the full cost of serving large customers at the primary voltage level, including investment in metering, infrastructure, billing, account management, and other fixed costs that are not based on usage.

The existing distribution rate is \$0.00287 per kWh. Note that there is no COS-derived energy rate for distribution because these costs are all fixed and this customer class can be assessed demand charges. The demand charge is used to recover fixed capacity costs associated with production, transmission, and the demand-related portion of the distribution systems. The current demand charge is \$7.50 per kW compared to a COS-derived rate of \$10.54 per kW. The COS more closely aligns with the true cost of maintaining and operating the infrastructure required to meet these customers' peak demands in a reliable manner. The power supply charge under the existing rate is \$0.03030 per kWh, which is slightly lower than the COS-derived rate of \$0.03493 per kWh. Like other customer classes, the LSC-P customers are subject to the PCAF.

Table 5-4
Large Commercial-Primary Service Rates
(Existing and Cost of Service)

Rate Component ⁽¹⁾	Existing	COS
Customer (\$/month)	\$230.00	\$2,729.28
Distribution (\$/kWh)	\$0.00287	\$-
Demand (\$/kW)	\$7.50	\$10.54
Power Supply (\$/kWh)	\$0.03030	\$0.03493

(1) Applicable PCAF not shown.

Large Commercial-Primary Cost Curve

Figure 5-3 illustrates the cost curve comparison for KPUB's LCS-P class, showing the relationship between existing effective rates and those derived from the COS analysis across a wide range of monthly usage levels. The effective rate expressed in \$/kWh is calculated by combining customer-, demand-, distribution-, and energy-related charges based on varying monthly kWh consumption.

As seen in the chart, the COS curve is consistently above the existing rate curve, particularly at lower usage levels. This gap highlights a significant under-recovery of costs under the current rate structure. As usage increases, the effective rate stabilizes as fixed costs are spread over a greater volume of kWh. But, even at high consumption levels, the existing rates remain below the COS.

This comparison underscores the need to realign the LCS-P rate structure with cost causation principles. The COS results support a substantial increase in the monthly customer charge and upward adjustments to the demand and distribution rates to better reflect the infrastructure investment, service level, and capacity needs of this large customer class. Such changes would ensure that cost recovery is equitable and that cross-subsidization from other classes is minimized.

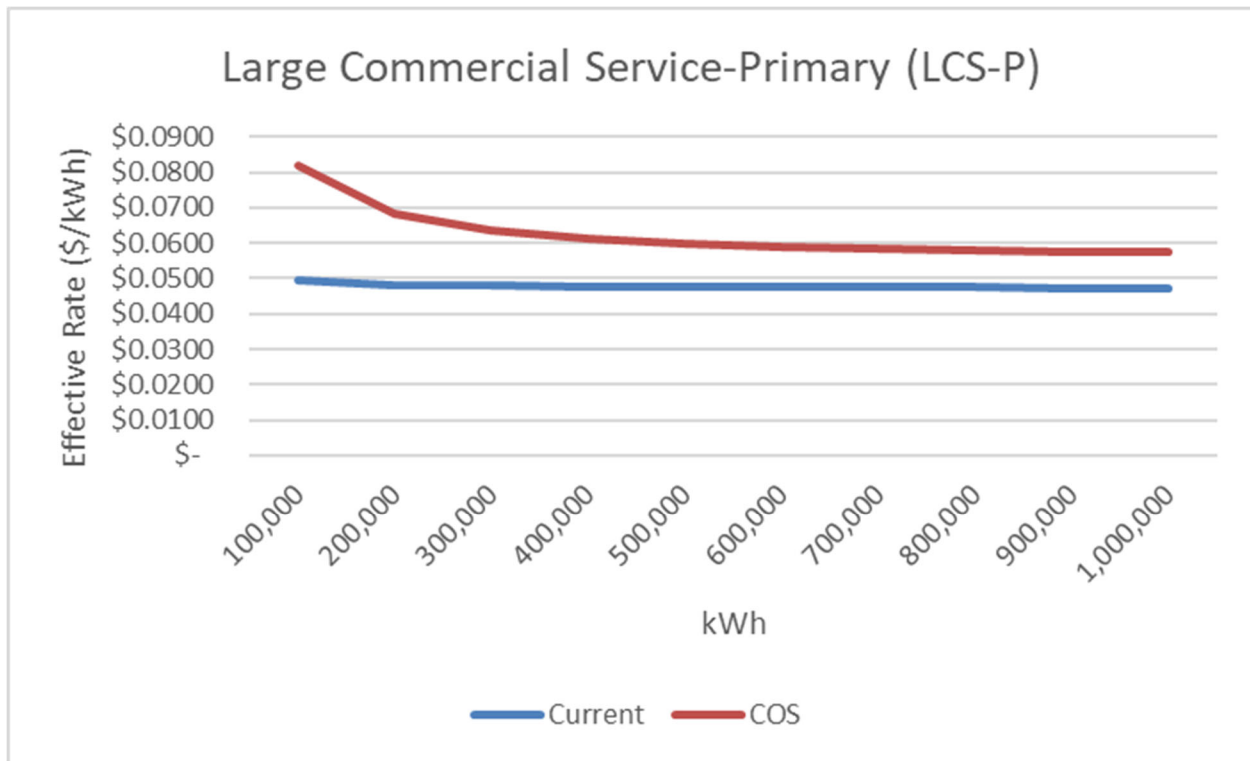


Figure 5-3. Cost and Current Rate Curves for Large Commercial-Primary

Large Commercial-Secondary Rate Review

The LCS-S class serves KPUB's large commercial customers who receive service at secondary voltage level and maintain consistently high demand and energy usage. These customers often include large retail centers, hospitals, schools, and manufacturing facilities that require substantial load but are not configured for primary voltage delivery.

Table 5-5 presents a comparison of existing LCS-S rates with those derived from the COS analysis. The current monthly customer charge is \$230.00, and the COS-based figure is \$2,729.28. This reflects the full scope of fixed costs associated with serving this customer class, including metering, account management, customer service, and infrastructure that is not sensitive to usage. The existing rate includes a distribution charge of \$0.00287 per kWh. As with LSC-P, there is no COS-based on energy charge for distribution. The demand charge is currently \$7.50 per kW compared with a COS-derived value of \$10.88 per kW. This rate captures the cost of capacity-related investments in production, transmission, and the demand-allocated share of the distribution system. This class exhibits relatively stable, high peak demands that drive long-term system planning and investment. The current power supply charge of \$0.03351 per kWh is slightly below the COS-based amount of \$0.03643 per kWh. As with all customer classes, the LCS-S class is subject to the PCAF.

Table 5-5
Large Commercial-Secondary Service Rates
(Existing and Cost of Service)

Rate Component ⁽¹⁾	Existing	COS
Customer (\$/month)	\$230.00	\$2,729.28
Distribution (\$/kWh)	\$0.00287	\$-
Demand (\$/kW)	\$7.50	\$10.88
Power Supply (\$/kWh)	\$0.03351	\$0.03643

(1) Applicable PCAF not shown.

Large Commercial-Secondary Cost Curve

Figure 5-4 illustrates the cost curve comparison for KPUB's LCS-S class, highlighting the relationship between existing effective rates and those derived from the COS analysis across a range of monthly energy consumption levels. The effective rate expressed in \$/kWh includes customer-, demand-, and energy-related charges applied to varying levels of monthly usage.

As shown in the figure, the COS-based curve is notably higher than the existing rate curve across all consumption levels, particularly at the lower end of the usage spectrum. This disparity reflects significant under-recovery of fixed costs, especially customer- and demand-related costs, under the current rate design.

The cost curve reinforces the need for adjustments to the current rate design for LCS-S customers. The COS results support a substantial increase in the monthly customer charge and demand rate to more accurately recover the cost to serve this class. These changes are intended to reduce cross-subsidization from other rate classes and improve alignment with cost causation principles.

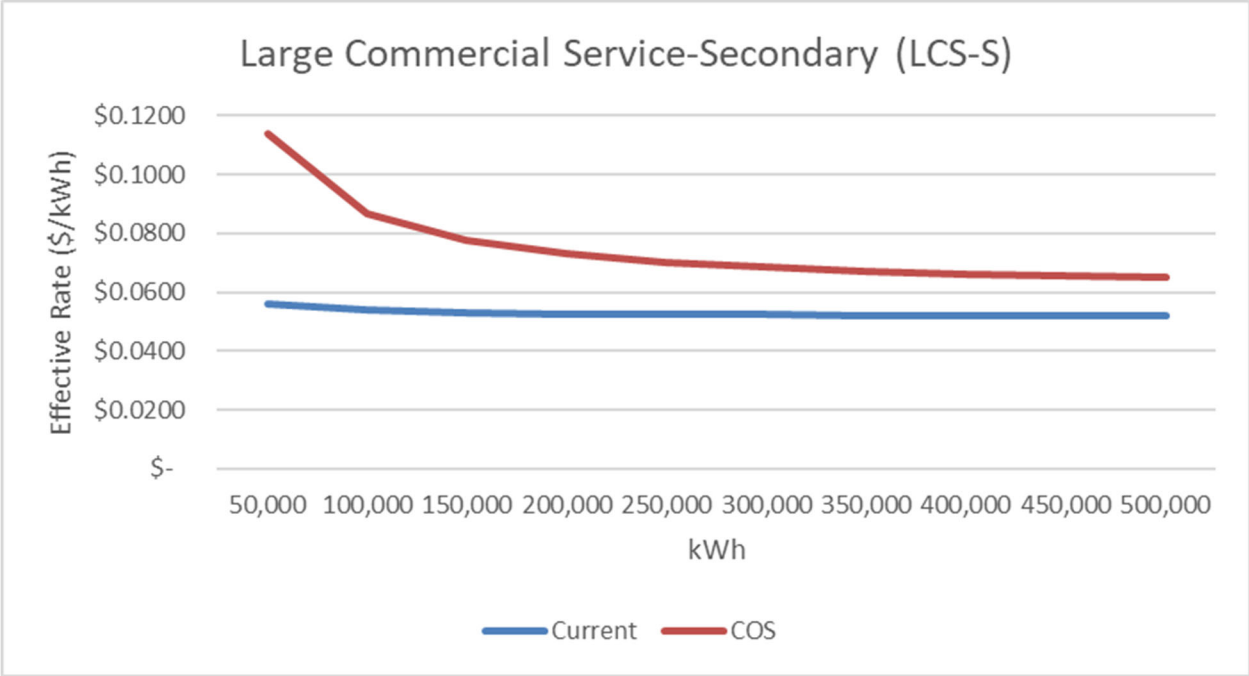


Figure 5-4. Cost and Current Rate Curves for Large Commercial-Secondary

Section 6

PROPOSED RATES

General

As previously noted, rate design is the final step in a COS study and establishes the cost recovery mechanisms (rates and charges) for each customer class. Rates and charges are set for each customer class to collectively meet KPUB's average annual Revenue Requirement as well as to address specific policy goals and objectives, as determined by KPUB. For the purposes of this Study, NewGen considered the following rate design objectives during the rate design process, which are inclusive of the following ratemaking principles established in concert with KPUB:

- Achieve full recovery of costs.
- Equitably allocate costs across and within customer classes.
- Encourage efficient use of electricity.
- Provide rate stability.
- Maintain rate competitiveness in the region.
- Ensure ease of management with rates that are easy to understand and communicate to customers.

Achieving the Revenue Requirement is a primary goal of the rate design. This requires aligning rate components (e.g., energy, demand, and customer charges) with projected billing determinants to generate sufficient revenue for fund operations and capital investments.

KPUB also needs to ensure sufficient recovery of fixed costs through fixed charges – recognizing that a significant portion of fixed costs will be recovered in energy charges. Greater reliance on customer and demand charges helps ensure financial stability.

Current Rate Classifications

At the time of this Study, KPUB has six rate schedules in effect. A summary of the current rate schedules and their customer classes is provided in Table 6-1.

Table 6-1
Current Rate Schedules and Customer Class

Rate Schedule	Rate Code	Customer Class
Residential Service	Rate Schedule-RS	Individually metered single-family homes (non-shared, non-commercial).
Commercial Service	Rate Schedule-CS	Non-residential services with maximum monthly demand < 400 kW.
Large Commercial Service-Primary	Rate Schedule-LCS-P	Non-residential services with monthly demand ≥ 400 kW. Primary voltage.
Large Commercial Service-Secondary	Rate Schedule-LCS-S	Non-residential services with monthly demand ≥ 400 kW. Secondary voltage.
Outdoor Area Lighting	Rate Schedule-OAL	Unmetered outdoor lighting (excludes street, shared, or resale).
Street Lighting	Rate Schedule-SL	Lighting for public roads using KPUB's distribution system.

Proposed Rate Design

This section of the report provides a summary of the proposed rate design for each year of the Rate Plan for each major rate class. Included in this summary is an analysis of the proposed rates, including rate impacts for the selected customer types.

Residential Service Rates and Bill Comparison Analysis

Table 6-2 provides a summary of the proposed rate adjustments for the RS rate class for each year of the Rate Plan and a comparison of the rate components to the existing rate structure.

Table 6-2
Residential Rates
(Existing and Proposed)

Rate Component ⁽¹⁾	Existing	Proposed Effective October 1 st				
		2025	2026	2027	2028	2029
Customer Charge (\$/month)	\$15.25	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75
Distribution Charge						
Energy (\$/kWh)	\$0.01680	\$0.02088	\$0.02496	\$0.02905	\$0.03314	\$0.03723
Demand (\$/kW)	N/A	N/A	N/A	N/A	N/A	N/A
Power Supply Charge (\$/kWh)	\$0.04060	\$0.04543	\$0.04543	\$0.04543	\$0.04543	\$0.04543

(1) Applicable PCAF not shown.

The proposed customer charge is \$16.75 for the entire five-year period. This increase in the customer charge allows for more fixed cost recovery of demand-related costs, as this class does not have a demand rate. The proposed power supply charge is designed to recover the fixed costs associated with the debt service on the new generation investment and transmission by others. For the RS rate class, the proposed

power supply charge is \$0.04543 per kWh for the entire five-year period. The proposed energy rates for the RS rate class are set to generally recover the balance of the revenue requirement allocated to this customer class but allow for a phase-in over the five-year period.

Distribution of Bill Impacts – Residential Service Customers

Figure 6-1 presents an analysis of bill impacts across KPUB’s existing RS customer class based on actual billing data. The graph illustrates the change in customer bills from current rates to proposed rates for FY 2026, showing that most customers will experience a 7%–8% increase in their monthly bill.

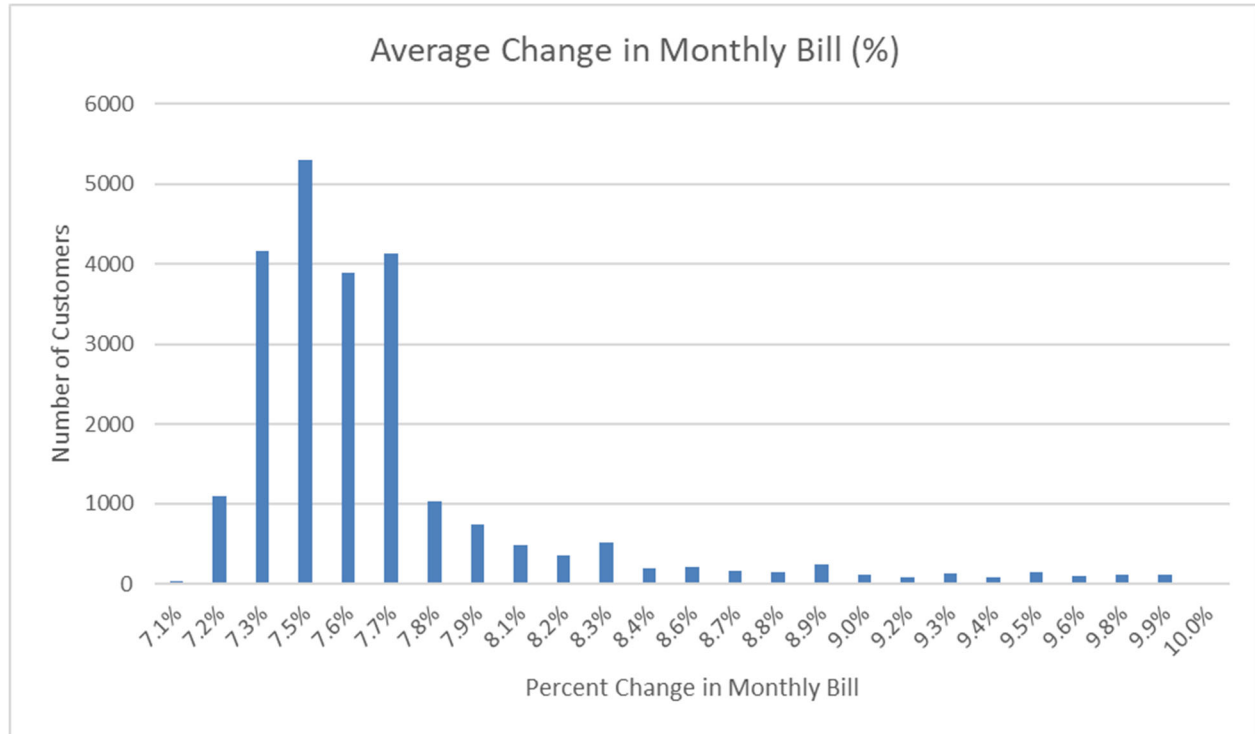


Figure 6-1. Distribution of KPUB Residential Customers’ Bill Change

Small Commercial Service Rates and Bill Comparison Analysis

Table 6-3 provides a summary of the proposed rate adjustments for the CS rate class, specifically for those customers that were not assessed a demand charge under the current rate design and which will be in the proposed Small Commercial customer class.

Table 6-3
Commercial Service Rates (Small Commercial)
(Existing and Proposed)

Rate Component ⁽¹⁾	Existing	Proposed Effective October 1 st				
		2025	2026	2027	2028	2029
Customer Charge (\$/month)	\$31.50	\$33.00	\$33.00	\$33.00	\$33.00	\$33.00
Distribution Charge						
Energy (\$/kWh)	\$0.01873	\$0.02112	\$0.02351	\$0.02590	\$0.02829	\$0.03068
Demand (\$/kW)	\$-	\$-	\$-	\$-	\$-	\$-
Power Supply Charge (\$/kWh)	\$0.04228	\$0.04443	\$0.04443	\$0.04443	\$0.04443	\$0.04443

(1) Applicable PCAF not shown.

The proposed customer charge is \$33.00 for the entire five-year period. This increase in the customer charge allows for greater recovery of fixed costs, including a portion of demand-related costs, while maintaining rate stability over time. The proposed power supply charge is designed to recover the fixed costs associated with the debt service on the new generation investment and transmission by others. For the CS rate class, the proposed power supply charge is \$0.04443 per kWh for the entire five-year period. The proposed energy rates for the proposed Small Commercial rate class are set to generally recover the balance of the revenue requirement allocated to this customer class but allow for a phase-in over the five-year period.

Distribution of Bill Impacts – Small Commercial Service Customers

Figure 6-2 presents an analysis of bill impacts across KPUB's Small Commercial customer class based on actual billing data. The graph illustrates the change in customer bills from current rates to proposed rates for FY 2026, showing that most customers will experience a 1.2%–3.1% increase in their monthly bill.

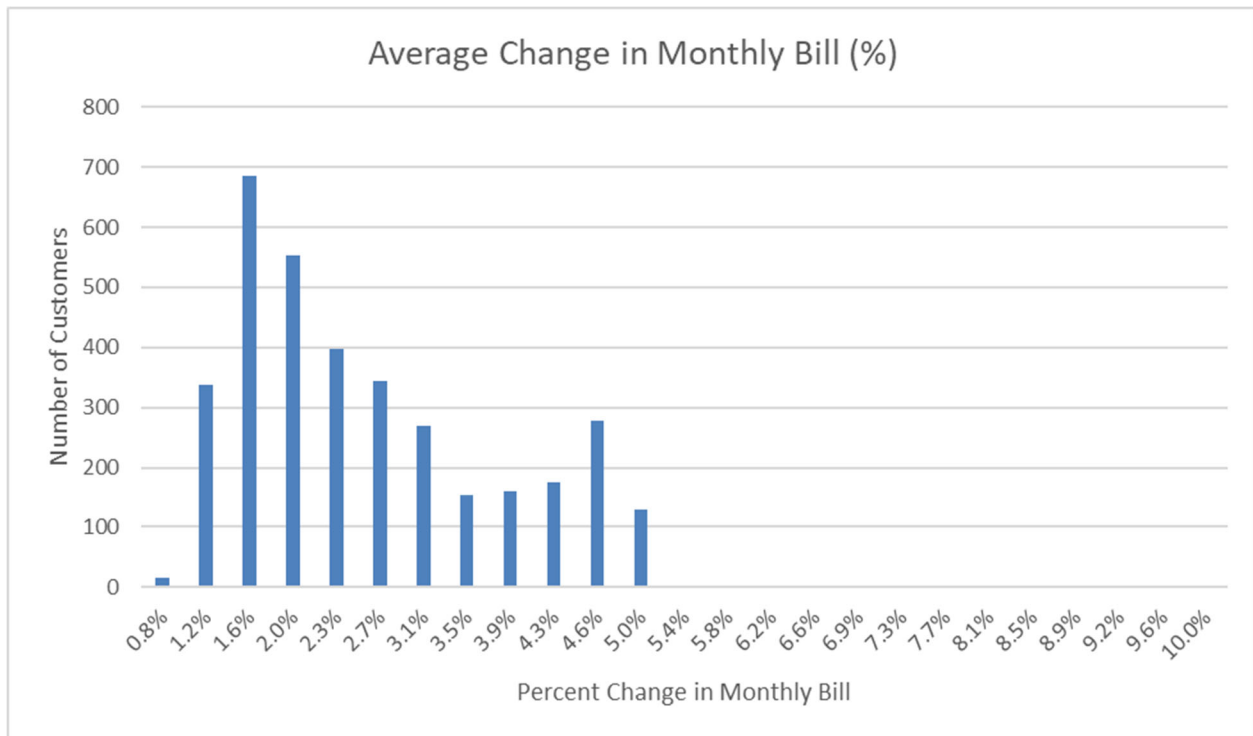


Figure 6-2. Distribution of KPUB Small Commercial Customers' Bill Change

Medium Commercial Service Rates and Bill Comparison Analysis

Table 6-4 provides a summary of the proposed rate adjustments for the CS rate class, specifically for those customers that were assessed a demand charge under the current rate design and which will be in the proposed Medium Commercial customer class. Under the proposed rate structure, a demand charge is applied to all commercial customers with loads exceeding 25 kW (but less than 400 kW). These customers would be in the proposed Medium Commercial customer class. By refining the class structure, the proposed rate design promotes fairness in cost allocation and supports more efficient energy usage among commercial customers.

Table 6-4
Commercial Service Rates (Medium Commercial)
(Existing and Proposed)

Rate Component ⁽¹⁾	Existing	Proposed Effective October 1 st				
		2025	2026	2027	2028	2029
Customer Charge (\$/month)	\$31.50	\$33.00	\$33.00	\$33.00	\$33.00	\$33.00
Distribution Charge						
Energy (\$/kWh)	\$0.01523	\$0.01672	\$0.01821	\$0.01969	\$0.02117	\$0.02265
Demand (\$/kW)	\$1.00	\$1.50	\$2.00	\$2.50	\$3.00	\$3.50
Power Supply Charge (\$/kWh)	\$0.04228	\$0.04443	\$0.04443	\$0.04443	\$0.04443	\$0.04443

(1) Applicable PCAF not shown.

The proposed customer charge is \$33.00 for the entire five-year period. The demand charge is proposed to increase by \$0.50 per year over the five-year period. These increases in the customer charge and demand charge allow for greater recovery of fixed costs while allowing a phase-in over the five-year period. The proposed power supply charge is designed to recover the fixed costs associated with the debt service on the new generation investment and transmission by others. For the CS rate class, the proposed power supply charge is \$0.04443 per kWh for the entire five-year period. The proposed energy rates for the proposed Medium Commercial rate class are set to generally recover the balance of the revenue requirement allocated to this customer class but allow for a phase-in over the five-year period.

Distribution of Bill Impacts – Medium Commercial Service Customers

Figure 6-3 presents an analysis of bill impacts across KPUB's Medium Commercial customer class based on actual billing data. The graph illustrates the change in customer bills from current rates to proposed rates for FY 2026, showing that most customers will experience a 1.8%–4.3% increase in their monthly bill.

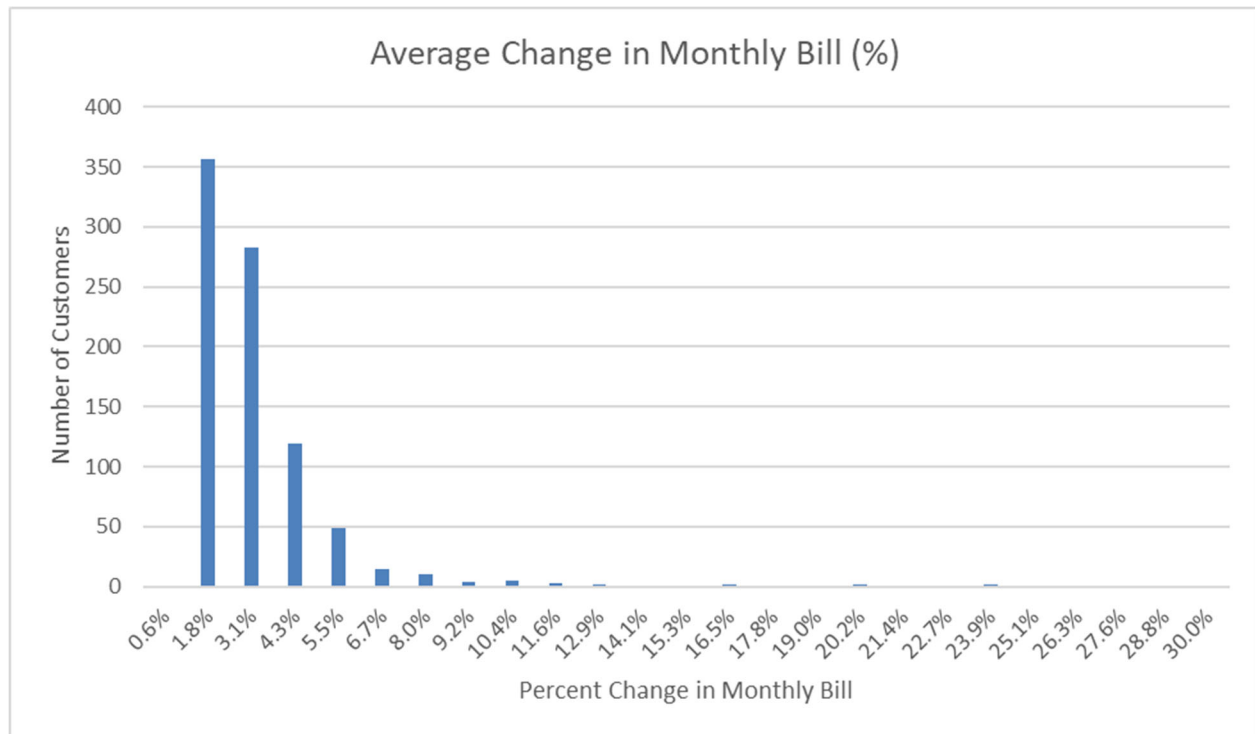


Figure 6-3. Distribution of KPUB Medium Commercial Customers' Bill Change

Large Commercial Service-Primary Rates and Bill Comparison Analysis

Table 6-5 provides a summary of the proposed rate adjustments for the LCS-P rate class for each year of the Rate Plan and a comparison of the rate components to the existing rate structure.

Table 6-5
Large Commercial Service-Primary Rates
(Existing and Proposed)

Rate Component ⁽¹⁾	Existing	Proposed Effective October 1 st				
		2025	2026	2027	2028	2029
Customer Charge (\$/month)	\$230.00	\$275.00	\$275.00	\$275.00	\$275.00	\$275.00
Distribution Charge						
Energy (\$/kWh)	\$0.00287	\$0.00501	\$0.00715	\$0.00929	\$0.01143	\$0.01357
Demand (\$/kW)	\$7.50	\$8.00	\$8.50	\$9.00	\$9.50	\$10.00
Power Supply Charge (\$/kWh)	\$0.03030	\$0.03493	\$0.03493	\$0.03493	\$0.03493	\$0.03493

(1) Applicable PCAF not shown.

The proposed customer charge is \$275.00 for the entire five-year period. The demand charge is proposed to increase by \$0.50 per year over the five-year period. These increases in the customer charge and demand charge allow for greater recovery of fixed costs while allowing a phase-in over the five-year period. The proposed power supply charge is designed to recover the fixed costs associated with the debt

service on the new generation investment and transmission by others. For the LCS-P rate class, the proposed power supply charge is \$0.03493 per kWh for the entire five-year period. The proposed energy rates for the proposed LCS-P rate class are set to generally recover the balance of the revenue requirement allocated to this customer class but allow for a phase-in over the five-year period.

Distribution of Bill Impacts – Large Commercial Service-Primary Customers

Figure 6-4 presents an analysis of bill impacts across KPUB’s existing LCS-P customer class based on actual billing data. The graph illustrates the change in customer bills from current rates to proposed rates for FY 2026, showing that customers will experience a 17.3%–19.7% increase in their monthly bill.

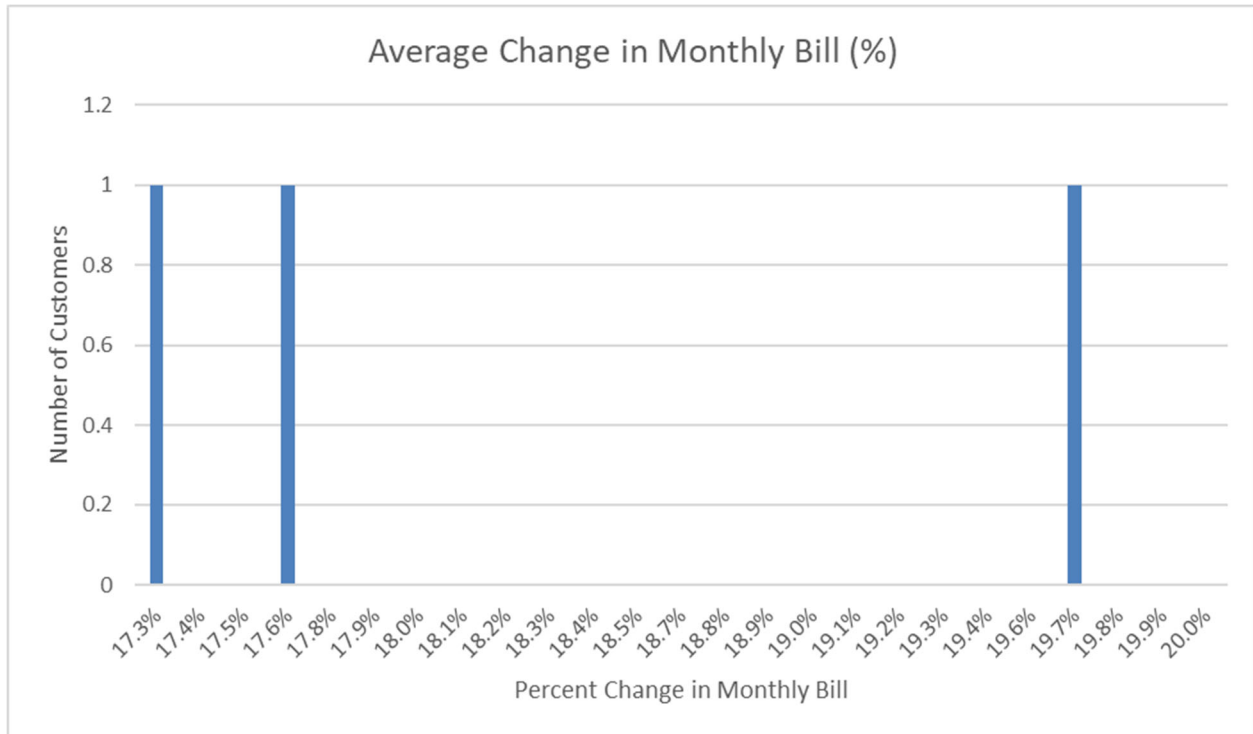


Figure 6-4. Distribution of KPUB Large Commercial-Primary Customers’ Bill Change

Large Commercial Service-Secondary Rates and Bill Comparison Analysis

Table 6-6 provides a summary of the proposed rate adjustments for the LCS-S rate class for each year of the Rate Plan and a comparison of the rate components to the existing rate structure.

Table 6-6
Large Commercial Service-Secondary Rates
(Existing and Proposed)

Rate Component ⁽¹⁾	Existing	Proposed Effective October 1 st				
		2025	2026	2027	2028	2029
Customer Charge (\$/month)	\$230.00	\$275.00	\$275.00	\$275.00	\$275.00	\$275.00
Distribution Charge						
Energy (\$/kWh)	\$0.00220	\$0.00580	\$0.00940	\$0.01300	\$0.01660	\$0.02020
Demand (\$/kW)	\$7.50	\$8.00	\$8.50	\$9.00	\$9.50	\$10.00
Power Supply Charge (\$/kWh)	\$0.03351	\$0.03643	\$0.03643	\$0.03643	\$0.03643	\$0.03643

(1) Applicable PCAF not shown.

The proposed customer charge is \$275.00 for the entire five-year period. The demand charge is proposed to increase by \$0.50 per year over the five-year period. These increases in the customer charge and demand charge allow for greater recovery of fixed costs while allowing a phase-in over the five-year period. The proposed power supply charge is designed to recover the fixed costs associated with the debt service on the new generation investment and transmission by others. For the LCS-S rate class, the proposed power supply charge is \$0.03643 per kWh for the entire five-year period. The proposed energy rates for the proposed LCS-S rate class are set to generally recover the balance of the revenue requirement allocated to this customer class but allow for a phase-in over the five-year period.

Distribution of Bill Impacts – Large Commercial Service-Secondary Customers

Figure 6-5 presents an analysis of bill impacts across KPUB's existing LCS-S customer class based on actual billing data. The graph illustrates the change in customer bills from current rates to proposed rates for FY 2026, showing that most customers will experience a 13.5%–14.1% increase in their monthly bill.

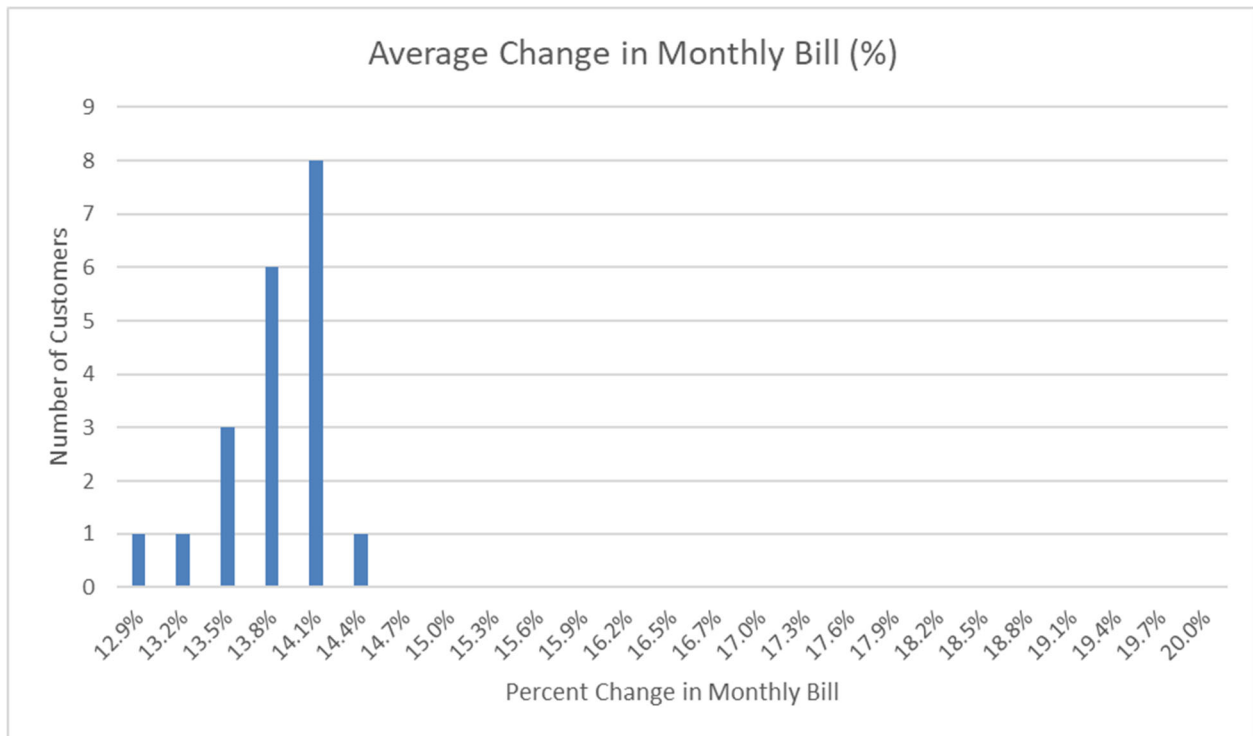


Figure 6-5. Distribution of KPUB Large Commercial-Secondary Customers' Bill Change

Lighting Rates

The analysis and discussion with KPUB indicates that a change to the existing lighting rates is not warranted at this time.

Conclusions

Based on the results of the Electric COS and Rate Design Study, NewGen makes the following conclusions:

- The analysis conducted for the Five-Year Rate Plan reveals that KPUB's current electric rates are not sufficient to generate the revenue required to meet projected financial obligations and sustain ongoing utility operations.
- The proposed rate structures have been designed to support cost-reflective pricing while balancing affordability and stability. These structures gradually increase fixed charges and introduce demand-based charges where appropriate, improving alignment with cost causation principles and mitigating cross-subsidization among classes.

Recommendations

Based on the conclusions and supporting analyses presented herein, NewGen makes the following recommendations:

- Adopt the Proposed Five-Year Rate Plan:

- The rates and charges developed in this Study provide a balanced approach to meeting KPUB's Revenue Requirement while addressing policy goals such as equity, simplicity, and stability. The full implementation of the Five-Year Rate Plan is recommended to avoid exacerbating revenue shortfalls and to support capital investment recovery.
- **Maintain Infrastructure Investment and Operational Readiness:**
 - KPUB should proceed with its planned Capital Improvement Plans (CIP), system modernization efforts, and investment in generation resources. These measures are critical to ensuring reliable service delivery and accommodating future load growth and power supply changes.
- **Reassess Rate Strategies Regularly:**
 - It is recommended that KPUB revisit its rate structures and COS at regular intervals, particularly as new generation assets come online and system characteristics evolve. This will ensure that rates remain fair, financially sustainable, and responsive to customer needs.



THANK YOU!



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