Electric Rate Study

Stillwater Utilities Authority
Stillwater, Oklahoma
November 3, 2023

LM VEDDER CONSULTING

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Electric Cost of Service and Rate Design Study
2022-23

Stillwater Utilities Authority
City of Stillwater, Oklahoma

November 3, 2023

LM Vedder Consulting
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EXECUTIVE SUMMARY

In 2022, LM Vedder Consulting (LVC) was retained by the City of Stillwater, Oklahoma to update the electric Cost of Service (COS) and Rate Design Study (Study) conducted in 2019 (2019 Study). This report summarizes the results of that effort.

BACKGROUND

At the time of the 2019 Study, over two decades had elapsed since a similar study had been performed. The rate design recommendations were revenue neutral, i.e., designed to collect the same amount of annual revenue. However, changes to the amount of revenues collected from various customer classes were made.

In consideration of the COVID 19 pandemic and emerging events, the Stillwater Utilities Authority (SUA) Trustees postponed implementation of study recommendations. Furthermore, to alleviate economic hardships, the SUA Trustees suspended Consumer Price Index electric rate increases from Fiscal Year (FY) 2019 through 2022.

NOTABLE EVENTS SINCE THE 2019 STUDY

Since the 2019 Study, many notable events have occurred that impact this Study.

- Cost increases
  - Inflation
  - Fuel/wholesale power
  - General fund transfers
  - Labor
  - Health insurance
  - Materials
- Flat electric revenues
- Loss of industrial load
- Supply chain lead time increases
- Need to draw from available fund balance to meet operating costs
- Ratings agency concerns

METHODOLOGY

Under long established principles concerning price setting for public utilities, SUA is allowed to recover the cost to serve each customer plus a reasonable return or margin. A COS study is the accepted industry approach for determining the cost to serve and the basis for setting retail and wholesale rates. The Study included establishing a Test Year Revenue Requirement, performing a five-year financial forecast, projecting electric sales by Customer class over the five-year horizon, allocating costs to customer classes based on COS principles, and designing rates.

RESULTS AND RECOMMENDATIONS

RESULTS

SUA has experienced many changes since the 2019 Study.

- Costs have increased dramatically.
  - ➢ $3 Million for Test Year Revenue Requirement
  - ➢ Average $0.78 Million per year FY 2026 - 2029
- Revenues at current rates are insufficient to meet operating needs.
  - ➢ Fund balance draws have been used to meet operational needs
  - ➢ Forecasted 5-year cumulative deficit of $22 Million.
- Rating agencies have voiced concerns.
  - ➢ Potential for ratings downgrade
  - ➢ Potential for increased financing costs

Action is needed.

RECOMMENDATIONS

Based on the COS Study results and evaluation of the current SUA electric tariff structures, LVC offers the following five recommendations for SUA's consideration.

1. Increase fixed charges to align with cost of service.

2. Eliminate declining block rate billing structures.
   - Structures are archaic and out of alignment with sustainability goals
   - Residential tiers are not working as intended
3. Eliminate seasonal demand charge differentials
   - Not aligned with COS
   - May be distorting summer costs relative to market
4. Align Commercial (General Service) class with peers & COS.

5. Implement new rates January 1, 2024.

INTRODUCTION

LM Vedder Consulting (LVC), is pleased to present the results of the 2022-23 Cost of Service (COS) and Rate Design Study (Study) for the Electric Utility Department of Stillwater Utilities Authority (SUA), Stillwater, Oklahoma (City).

The Study is organized as follows. This section, the Introduction, includes Study Background, Notable Events Since the 2019 Study, and Limitations. Section 2 presents the Methodology. Section 3 provides an Overview of the Electric Utility System. Section 4 contains the Revenue Requirement and Five-year Financial Forecast. Section 5 includes the COS Results. Section 6 covers the Rate Design. Section 7 presents Study Results and Recommendations.

BACKGROUND

In December 2022, the City contracted with LVC to update the Electric COS and Rate Design Study conducted in 2019-20 by Avant Energy, Inc. (2019 Study). Under long established principles concerning price setting for public utilities, SUA is allowed to recover the cost to serve each customer plus a reasonable return or margin. A COS study is the accepted industry approach for determining the cost to serve and the basis for setting retail and wholesale rates.

At the time of the 2019 Study, over two decades had elapsed since a similar study had been performed. The rate design recommendations in the 2019 Study were revenue neutral, i.e., designed to collect the same amount of annual revenue. However, the 2019 Study recommended changes to the amount of revenues collected from various customer classes.

The 2019 Study results were presented in February 2020. By March of that year,

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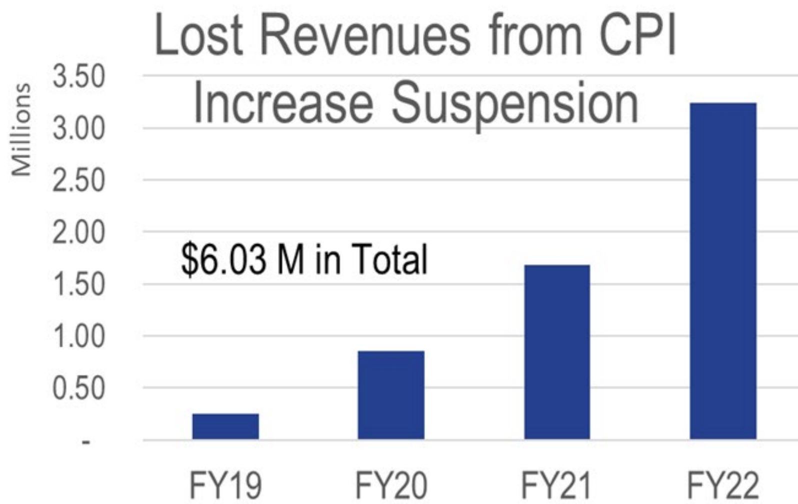
the COVID 19 pandemic had emerged. In consideration of developing events, the SUA Trustees postponed implementation of the study recommendations. Furthermore, to alleviate economic hardships, the SUA Trustees suspended Consumer Price Index (CPI) electric rate increases from Fiscal Year (FY) 2019[1] through 2022. The chart at right illustrates the impact of this moratorium. Over this period the suspension resulted in approximately $6.03 Million in lost revenues to the City.



At the time of this Study, some SUA electric rate designs have remained unchanged for thirty years. Although CPI adjustments have been implemented during this time; these adjustments increase the level of charges but do not alter the structure or design of rates.

NOTABLE EVENTS SINCE THE 2019 STUDY

Since the 2019 Study, many notable events have occurred that impact this Study. The following are discussed in this section:

1) Cost Increases
   - Inflation
   - Fuel/Wholesale Power
   - General Fund (GF) Transfers
   - Labor
   - Health Insurance
   - Materials
2) Flat Revenues
3) Loss of Industrial Load
4) Supply Chain Lead Time Increases
5) Need to Draw from Available Fund Balance
6) Ratings Agency Concerns

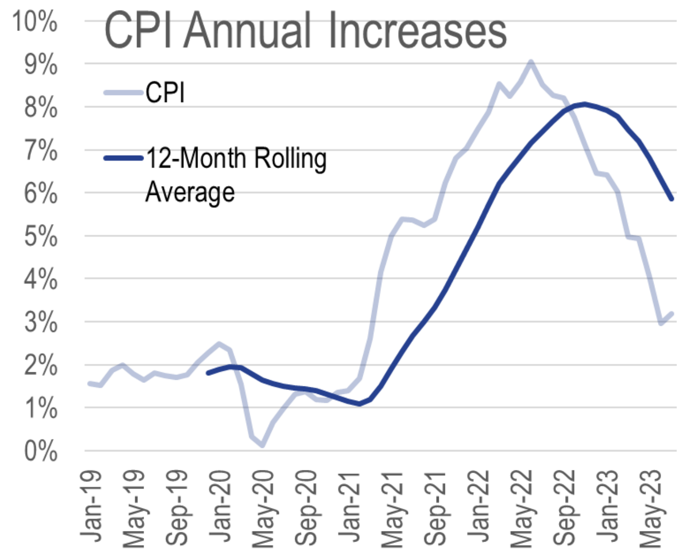
COST INCREASES

Since the 2019 Study the City's Electric Utility has experienced a number of cost increases, many unprecedented. The six categories of cost increases cited above are discussed below.

[1] The City's Fiscal Year runs from July 1 of the prior year to June 30 of the cited year. For example, FY 2019 commenced on July 1, 2018 and ended on June 30, 2019.

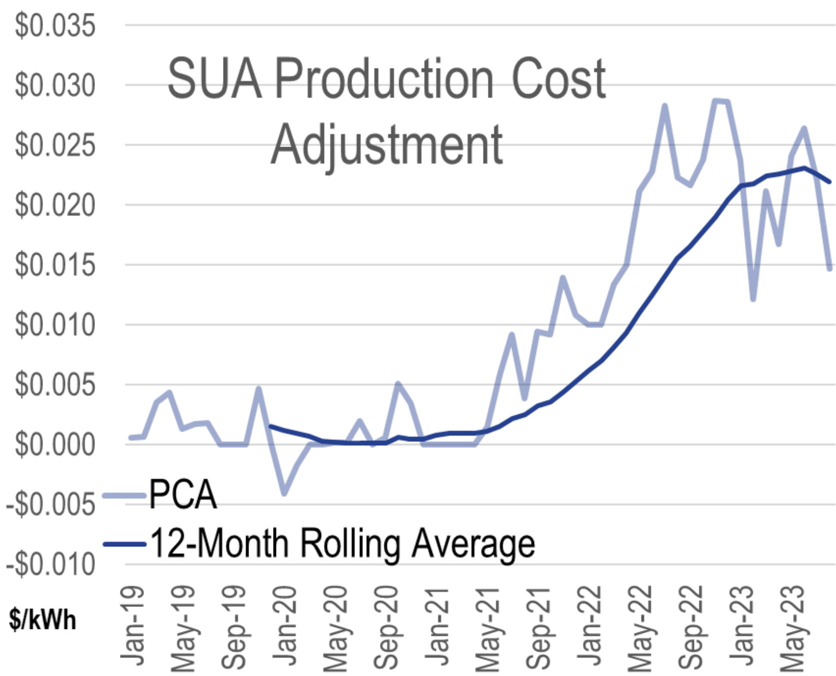
Inflation

As illustrated in the figure at right, since 2021 the Consumer Price Index (CPI) has experienced unprecedented increases.[2] Although as of May 2023 the trend has calmed, inflation is still higher than at the time of the 2019 Study and the impacts are still being felt. The 12-month rolling average indicates how the impact is felt long after the actual index decreases.



Fuel/Wholesale Power

The SUA Production Cost Adjustment (SUA PCA) is a passthrough charge per kilowatt hour (kWh) of energy sold that recovers changes in fuel (primarily natural gas) and wholesale power costs. As can be seen in the graph below, the SUA PCA has experienced unusual growth since the 2019 Study.



The SUA PCA has fluctuated with energy markets, as can be seen from the 12-month rolling average, these variations averaged around zero until an increasing trend commenced in 2021. Similar to the CPI, since 2021 the SUA PCA has experienced steep increases. As discussed later in the Study, funds collected through the SUA PCA are pass-through costs and cannot be used for Electric Utility operations.

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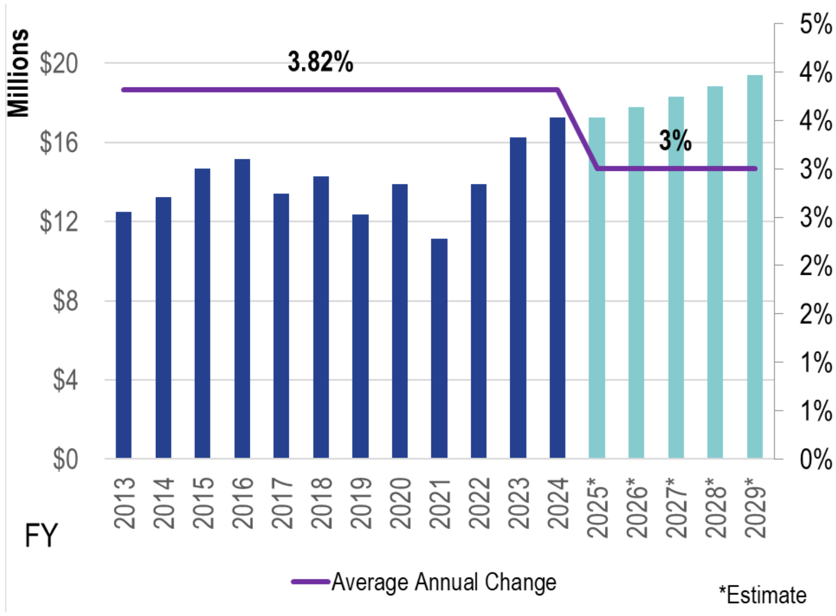
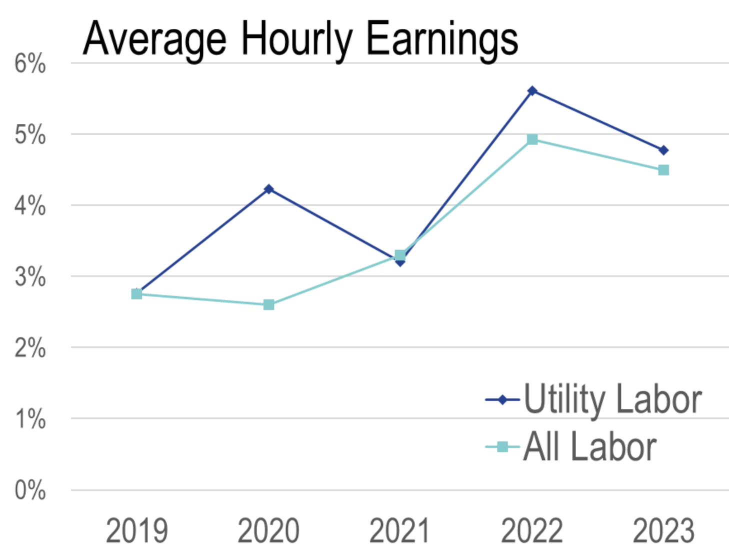
[2] Source: "Consumer Price Index for All Urban Consumers (CPI-U): Indexes and percent changes for selected periods South (1982-84=100 unless otherwise noted) (not seasonally adjusted)," https://data.bls.gov/home.htm

General Fund Transfers

The Electric Department transfers a portion of its revenues to the City's GF annually. The graph at right shows the actual GF transfers from FY 2013 through 2023, the budgeted level for FY 2024, and the estimated levels for FY 2025 to 2029. From FY 2013 to 2024 the average GF increase was 3.82% annually, with transfers ranging from a low of $11.1 Million in FY 2021 to a maximum of $16.3 Million in FY 2023. The FY 2024 budgeted GF Transfer of $17.25 Million represents a 6% increase from FY 2023. From FY 2025 to 2029, the Study period, an annual increase of 3% has been assumed.





Labor

National labor rates have exhibited an increasing trend since 2020 as can be seen in the graph at left.[3] In addition, utility workers tend to be in higher pay brackets. Finally, electric utility workers are among the highest paid of all utility workers, further increasing labor costs.[4]

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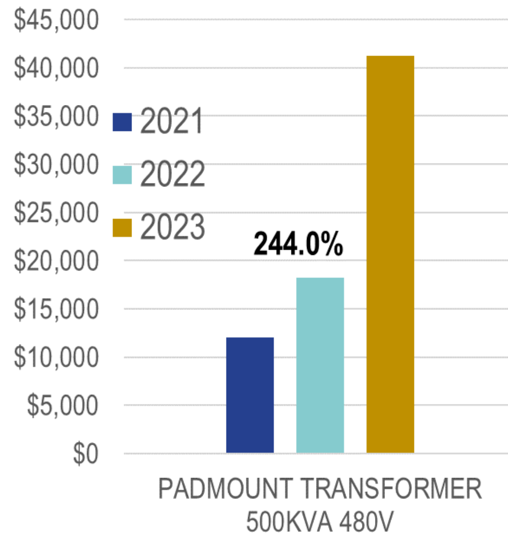
[3] Source: Bureau of Labor Statistics, Series CES4422000003 Average Hourly Earnings of All Employees, Utilities, Seasonally Adjusted versus Series CIU1010000000000A Total Compensation for All Civilian Workers in All Industries and Occupations, 12-Month Percent Change.

[4] Supplement to the 2020 U.S. Energy and Employment Report Wages, Benefits, and Change, USENERGYJOBS.ORG, A Supplemental Report to the Annual U.S. Energy and Employment Report. https://www.usenergyjobs.org/

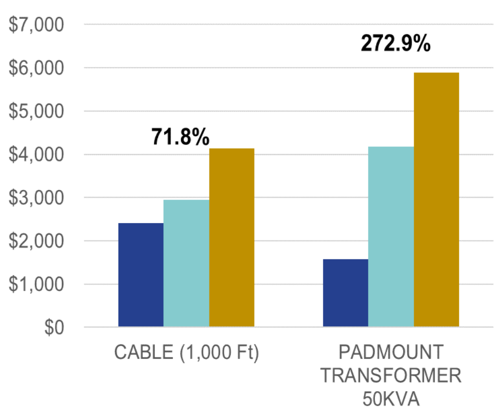
Health Insurance

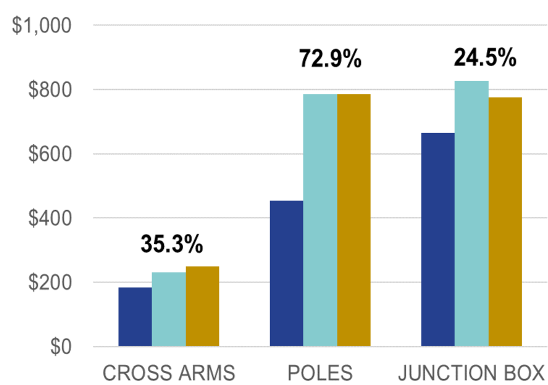
The cost of health insurance has increased dramatically since FY 2017. The City's health insurance costs increased 44% from FY 2017-2023 and 28% from FY 2020-2023. Given the COVID 19 pandemic, the City suspended Cost of Living Adjustments to control costs. Based on this decision, the City chose to absorb health insurance cost increases for employees. This arrangement lasted until July 2023.



Materials

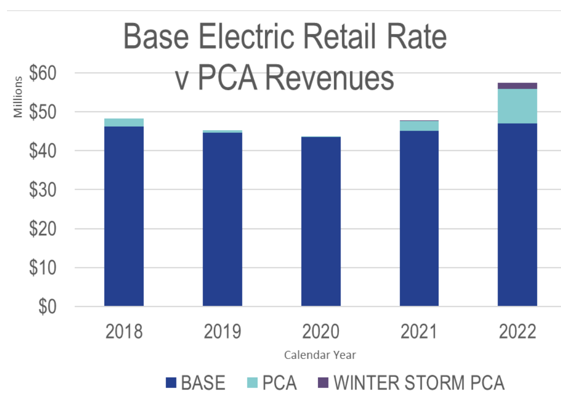
Since 2021 the costs of materials used for distribution electric systems have increased far in excess of inflation. Examples of these cost increases are illustrated in the figures at right and below. These routine items are used to operate, maintain, and expand the electric system.





FLAT REVENUES

Since calendar year (CY) 2018, base electric revenues have remained essentially flat. The figure at right shows actual base revenues from CY 2018 to 2022 in the dark blue bars. Although overall revenues have increased, especially in CY 2022, the increase was driven by the PCA and Winter Storm Uri[5] PCA. These PCA costs are passthrough costs and cannot be used for electric system operations.



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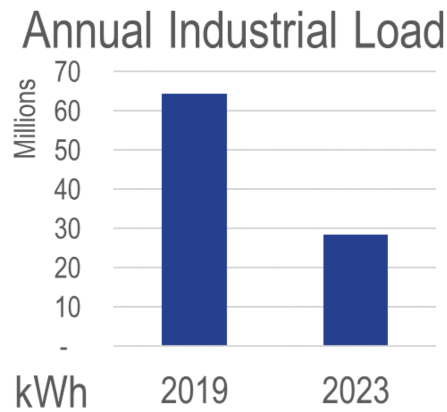
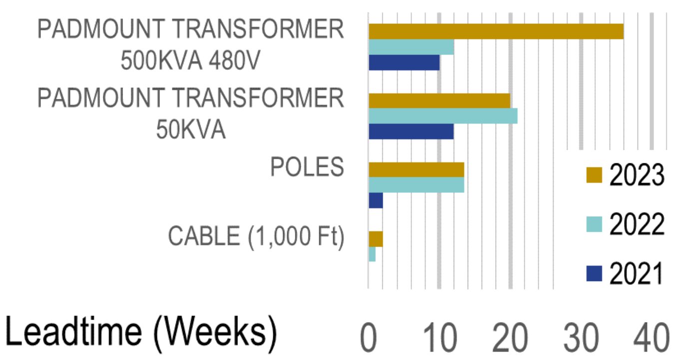
[5] The storm Uri PCA was established by Resolution No. CC-2021-28; SUA 2021-10 adopted September 13, 2021 has been steadily reducing the balance of $3,569,176. The Winter Storm PCA expires in November 2024.

LOSS OF INDUSTRIAL LOAD

Since the last rate study, SUA has lost approximately two-thirds of its Industrial load as can be seen in the figure at right. Industrial customers use large amounts of energy in predictable patterns, making for stable and large revenue streams. In addition, Industrial customers tend to bring jobs and attendant economic benefits to the community. Loss of these customers can have an impact beyond lost revenues. It is anticipated that new Industrial load will come online in the next five years.



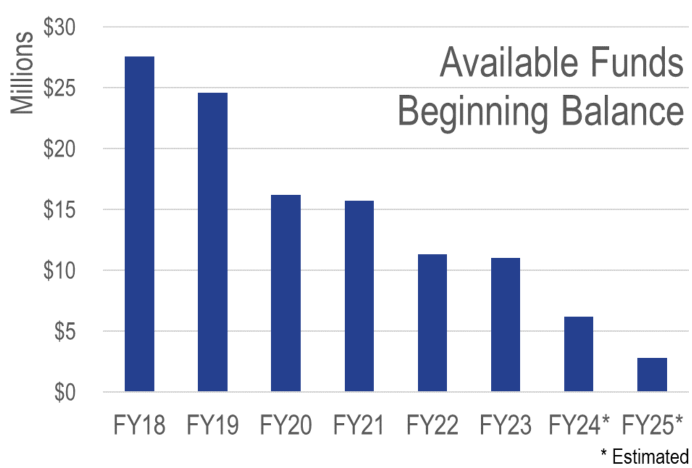
SUPPLY CHAIN LEAD TIME INCREASES



Since 2021, the lead time for distribution system materials has dramatically increased as shown in the figure at left. Delays of this sort contribute to overall cost increases by delaying system upgrades, additions, and operating and maintenance (O&M) projects. Additionally, supply chain delays result in increased use of over-time and other inefficiencies.

NEED TO DRAW FROM AVAILABLE FUND BALANCE

Since FY 2018, the City has made increased draws from its Available Funds Balance. The Available Funds Balance represents unencumbered funds that are eligible to use and do not include any emergency reserve funds. As shown at right, through FY 2023, the available funds balance decreased by 60% or $16.6 Million. Draws in the initial years reflect an initiative of the City Council to put funds to use in the community. However, in recent years draws were necessary to meet current operational needs. The recent trend is not sustainable and, if continued, would reduce available funds to an imprudent level absent action.



RATINGS AGENCY CONCERNS

Standard & Poor's (S&P) conducts annual reviews of City finances. In February 2023, S&P noted a decline in the City's Fixed Charge Coverage ratio (FCC) due to:

- Higher purchased power costs
- Winter storm Uri costs
- High transfers from SUA to the City's GF
- Lack of base rate increases from 2019 to 2022

S&P noted that failure to improve the FCC may result in a downgraded rating for the City. A downgraded rating could result in higher interest costs on future debt.

Fitch completed its review and issued a "Review-No Rating," maintaining the City's AA- with a stable outlook. Fitch noted the same concerns as S&P with the same potential outcomes.

LIMITATIONS

This report has been prepared for the use of the SUA for the specific purposes identified in the report. The conclusions, observations, and recommendations contained herein attributed to LVC constitute the opinions of LVC. To the extent that statements, information, and opinions provided by SUA or others have been used in the preparation of this report, LVC has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. LVC makes no certification and gives no assurances except as explicitly set forth in this report.

METHODOLOGY

The Study was conducted in the three steps in the figure at right. First, the Revenue Requirement was established. Second, the COS analysis was performed, assigning the Revenue Requirement to categories in the three additional tasks listed at right. Based on the results of the first two steps, rate design recommendations were developed in step three.

OVERVIEW

This Section of the report describes the process used to conduct the Study. The first segment discusses Data Gathering and Analysis. The second segment addresses establishing the Revenue Requirement. The third segment explains the COS Analysis. The final segment details the rate design approach.

DATA GATHERING AND ANALYSIS

The Study commenced with data gathering and analysis. LVC reviewed historic data from CY 2018 to 2022 including financial reports, customer consumption and revenue data, wholesale power purchase contracts, and power purchase and sales data. LVC's review included, but was not limited to:

- Historic usage/consumption data by customer class

Step 1 Set Revenue Requirement

Step 2 Perform Cost of Service

Functionally Unbundle
- Power
- Distribution
- Customer

Classify
- Fixed
- Variable

Assign to Customer Classes

Step 3 Design Rates

Overview of Revenue Adequacy Process

- Rate tariffs for all classes
- Customer bills for all classes
- Historic customer revenue data
- Financial statements including budgets, Comprehensive Annual Financial Reports (CAFRs) and Annual Comprehensive Financial Reports (ACFRs), City Books, Trial Balances, and Debt Schedules
- Infrastructure inventory and maps
- Economic, fuels, and labor cost indices and projections
- Strategic plans
- Capital improvement plans

LVC reviewed monthly historic customer consumption data and, in consultation with SUA, created future profiles for the FY 2025-2029 Study period. LVC worked with SUA to identify any significant existing, planned, or terminated commercial, or industrial sales loads to ensure the validity of future usage projections. Similarly, expected growth over the planning horizon by customer class was incorporated into these results. LVC used these estimated consumption projections to calculate Test Year (TY) Billing Determinants by customer class such as customer counts by class, energy usage by month and period (on peak or off peak), demand, etc.

REVENUE REQUIREMENT DEVELOPMENT

The data and analyses from Study initiation were then used to establish the Test Year Revenue Requirement and five-year financial forecast for the Study Period.

Test Year Revenue Requirement Development

As illustrated in the figure at right, the TY Revenue Requirement is equal to SUA's current Capital and Operating Budget adjusted for expected known and measurable changes.

In coordination with SUA, LVC developed the total revenue requirement for the electric system by identifying all costs to be recovered from rates for the projection period or TY. The revenue requirement includes all administrative and general expenses required to operate and maintain the system, transmission costs, purchased power costs, fuel costs, debt service requirements, capital improvements, GF transfers, and other significant utility system costs.

LVC worked with SUA to quantify non-rate revenues, i.e., revenues generated from activities not related to SUA's core business operations, such as pole-attachment fees, real estate rentals, and other miscellaneous revenues. The Test Year Revenue Requirement was reduced by non-rate revenues as well as any interest earnings, transfers or other expense offsets. The resultant net Test Year Revenue Requirement was the basis for setting rates.

Five-Year Financial Projections

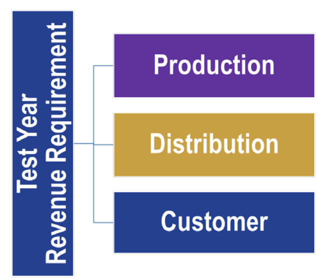
The TY Revenue Requirement was then used to create a five-year financial projection incorporating forecasted changes to the customer base, capital investments, cash reserve policies, economic and market factors, and other long-term financial goals of SUA. The projections also include future capital improvements, renewals, and replacements.

For each of the five Study years the Debt Coverage Ratios and Minimum Cash Reserves were calculated. When revenue projections indicated a failure to meet targeted goals in a future year, LVC worked with SUA to revise rate levels and/or Revenue Requirements to achieve targeted outcomes. Options included increasing rate levels, revising capital and infrastructure investment scheduling, and changing rate mechanisms.

COST OF SERVICE ANALYSIS

The COS Analysis assigned the net TY Revenue Requirement to the various customer rate classes in a manner that reflects the cost of providing electric service to each class. The goal of this effort was to equitably allocate system costs to each customer class based on cost incidence and to align the nature of the cost with the rate mechanism used to recover the cost.

Cost assignment includes three basic activities: functionalization, classification (fixed, variable), and allocation to customer class. Functionalization of costs into unbundled cost categories is illustrated at right.

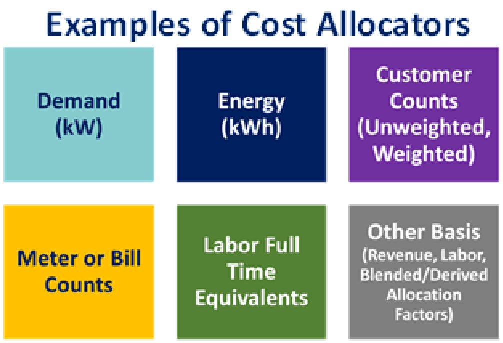


Cost Functionalization

Based on industry precedent, certain costs can either be defined as a functional category or distributed among other functional categories. LVC worked with SUA to determine the preferred treatment of these types of costs, examples of which include:

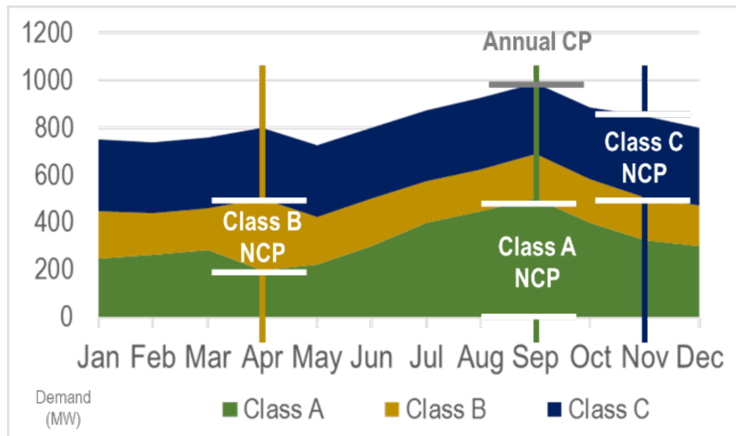
- Metering
- Billing
- General and Administrative
- Shared Overhead

Using various factors, as discussed below, the functionalized costs were then separated into seasonal, and fixed and variable components in the seasonalizing and classification steps. As appropriate, costs may be assigned to on-peak and off-peak periods.

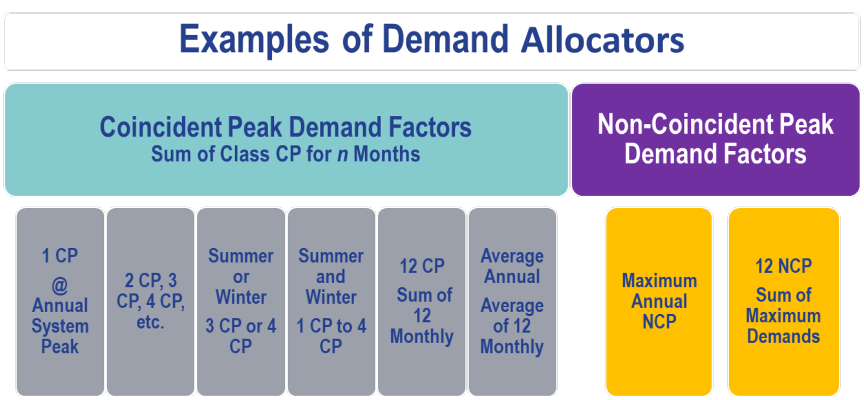


Finally, each category was allocated among customer rate classes. Costs can be allocated to customer classes based on numerous factors including those listed at left.

Demand allocation factors are based on Coincident Peak (CP)—the class demand at system peak, and Non-Coincident Peak (NCP)—class peak demand irrespective of when it occurs. The figure below illustrates CP and NCP using three customer classes. Two classes, Class B and C, experience demand peaks—in April and November, respectively—that do not contribute to the overall System CP in September. Conversely, the NCP of one customer class, Class A, coincides with and exacerbates the System CP in September.



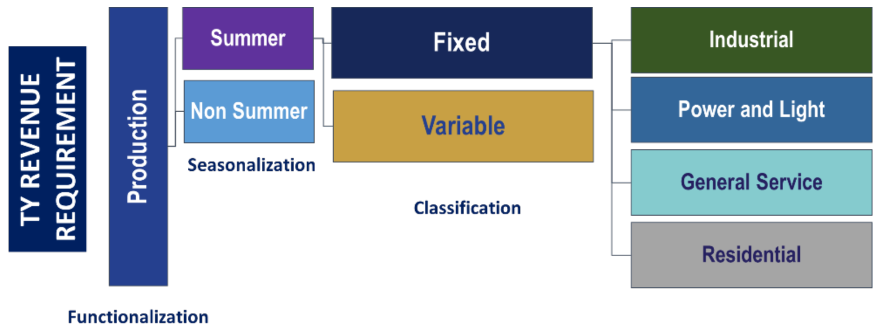
This example demonstrates how peak load impacts the system in different ways and certain costs are more appropriately allocated with different demand factors.



Depending on the type of cost being allocated, system characteristics, and cost recovery goals, different demand allocation factors would be applicable and may include those listed at left.

LVC worked with SUA to determine the best allocation methods that equitably assign costs in light of historic practice and overall goals. Assignments were based on actual data, SUA practice, and industry precedent in the event factors cannot be calculated from available SUA data.

The figure at right illustrates the overall cost assignment process for one functional element: fixed summer production costs for the Industrial Class. Each cost component would be similarly assigned as part of the COS process.



RATE DESIGN

The goal of rate design is to create price signals and rate mechanisms that generate sufficient revenues to adequately fund SUA goals. Public utility rates must conform to long-standing industry rules best explained in the seminal book by James Bonbright.[6] In sum, a public utility like SUA is allowed to charge its Cost to Serve plus a reasonable margin.

Sound rate design must balance competing and often contradictory goals including those in the figure at right.

Revenue Requirements Low Rates Predictability	Equity & Fairness Behavior Modification Ability & Willingness to Pay
Competitiveness Environment Regulations	Simplicity Understandability Accuracy

Bonbright established four functions of public utility rates:

1. Production Motivation/Capital Attraction
   To ensure a supplier is motivated to produce a commodity or provide a service deemed in the public interest
2. Efficiency Incentivizing
   To ensure a supplier produces the optimal amount of a good or service
3. Demand Control/Consumer Rationing
   To discourage over-consumption or moderate demand
4. Income Distribution
   To ensure that ultimate pricing conforms to ability-to-pay standards by imposing a reasonableness criterion[7]

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[6] Bonbright, James C., *Principles of Public Utility Rates*. New York: Columbia University Press, 1961

[7] *Ibid.*, 48-62.

Bonbright also established the eight principles of public utility rates at right.[8]

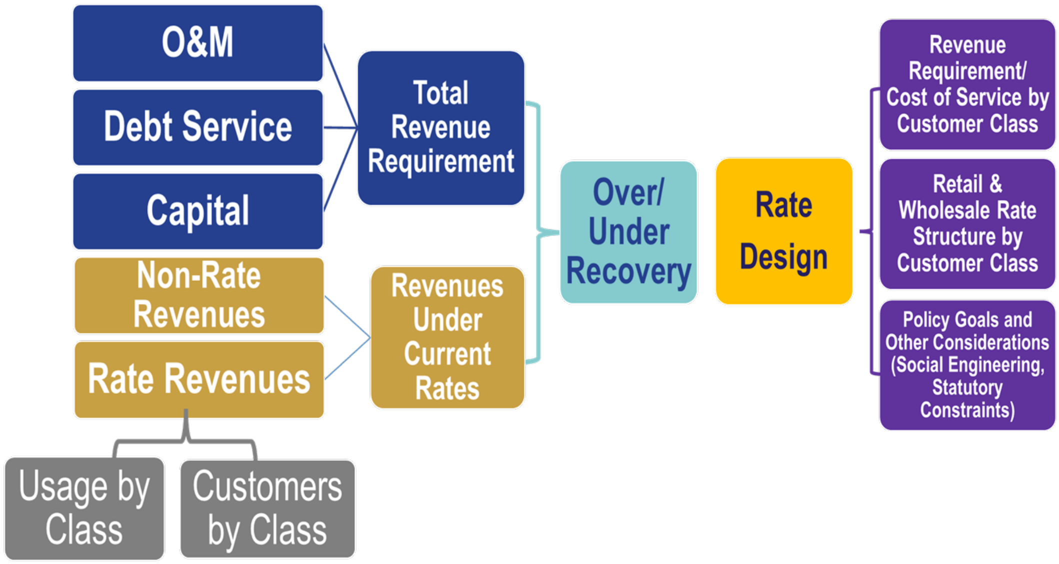
The Study relied upon these 12 concepts for guidance and to inform rate design choices. In particular, when designing rates, LVC incorporated Bonbright's framework by assessing the following factors when making rate design decisions:

- Revenue Adequacy—The ability of expected revenues under proposed rates to meet projected cost obligations.
- Alignment of Rates and Nature of Cost—The level to which current rate designs align with the nature of costs. For example, the extent to which fixed costs (i.e., costs that are generally independent of usage) are recovered with fixed rate mechanisms and variable costs (i.e., costs that vary based on consumption) are recovered with variable rate mechanisms.
- Alignment of Rates and Cost of Service—The extent to which proposed rate designs align with COS.
- Competitiveness with Peer Utility Rates—The relative competitiveness of proposed rates with rates charged by peer utilities.
- Customer Impact—The expected impact of proposed rates on customers within a class.

The figure on the next page illustrates the overall revenue adequacy and rate design process used for this Study. The Revenue Requirement was developed using financial data. The Revenue Requirement was then compared to calculated revenues under current rates based on forecasted usage by customer class. This revenue adequacy test calculated the ability of expected revenues under existing rates to meet cost obligations. This process was repeated for each of the years in the Study forecast, FY 2025 to 2029.

Rates were then designed to meet projected Revenue Requirements, including those arising from social and economic initiatives, statutory requirements, policy goals, and other similar considerations. The goal of rate design is to create price signals and rate mechanisms that generate revenues that adequately fund these goals.

[8] *Ibid.*, 291.

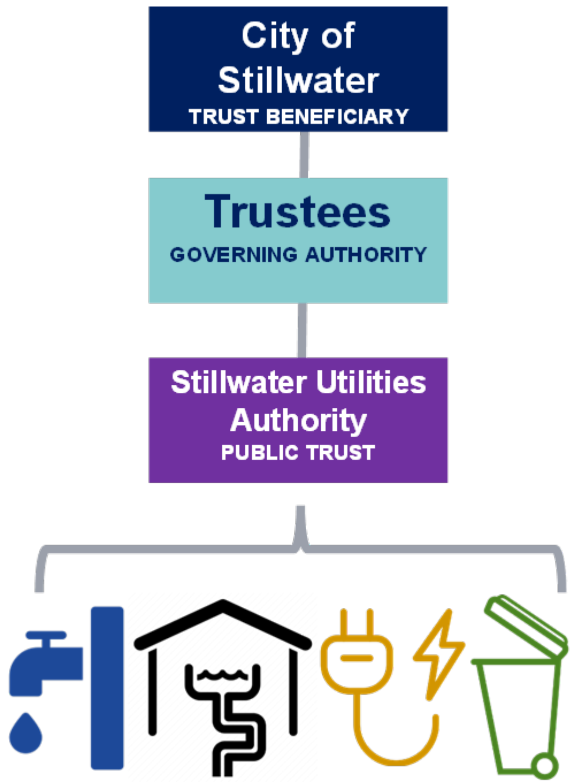


For the electric system and each customer class, LVC prepared a COS and projection of revenue at present rates, showing how existing rates compare with the costs of providing service. LVC calculated the retail rates necessary to reach parity, i.e., rates that fully recover the class COS. These unitized COS-based rates supported rate design recommendations.

LVC worked with SUA to identify the largest users and to develop representative customers at different usage levels for each class to demonstrate the financial effect of proposed rate changes on users at various volumes. Based on this analysis, a customer class profile for the Study period was defined.

ELECTRIC SYSTEM OVERVIEW

Stillwater Utilities Authority was established in 1979 to operate and maintain Stillwater's utilities systems. The Mayor and City Council serve as Trustees. The figure at right illustrates SUA's organization. SUA provides electric, water, wastewater, and solid waste services.



SUA, a public power provider, is the largest municipal generator of electricity and municipal transmission owner in the State of Oklahoma. The approximately 30-square-mile electric service area excludes Oklahoma State University (OSU).

SUA owns and operates the Stillwater Energy Center (SEC). SEC's peaking capacity is 56 Megawatts[9] (MW) generated by natural gas fired reciprocating engine units.

Grand River Dam Authority (GRDA) purchases all SEC capacity and energy production.

SUA owns and operates a fully integrated transmission and distribution system comprised of: eight substations; approximately 24 miles of 69 kilovolt (kV) lines; and 356 miles of 12.47 kV distribution lines.

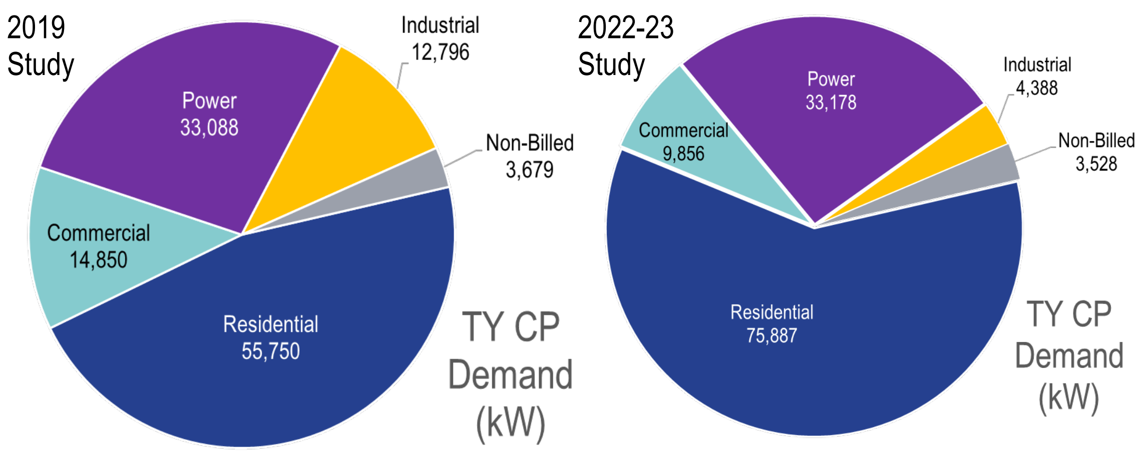
SUA purchases all electric power wholesale from the GRDA. Power is delivered at four 138 kV substations. The Electric Department currently serves approximately 22,000 customers.

[9] 1 MW = 1,000 kW.

COINCIDENT AND NON-COINCIDENT PEAK DEMANDS

Coincident Peak demand reflects the amount of system capacity used by each customer class at the time of the entire system's peak. SUA's average annual demand from Calendar Year (CY) 2015 to 2022 was 121.1 MW; from 2020 through 2022 SUA's CP was 120.9 MW. During this latter period, system losses averaged 7% per year.

The pie charts below show how the make-up of CP demand has changed since the 2019 Study. The TY CP in 2019 was 120,163 kW and in the current Study, the TY CP was 126,836 kW. Since the 2019 Study, Residential CP has increased while Commercial (General Service) and Industrial CP have decreased. Power (Power & Light Secondary) and Non-Billed Usage have remained fairly constant. Non-Billed usage includes security lights and City use.

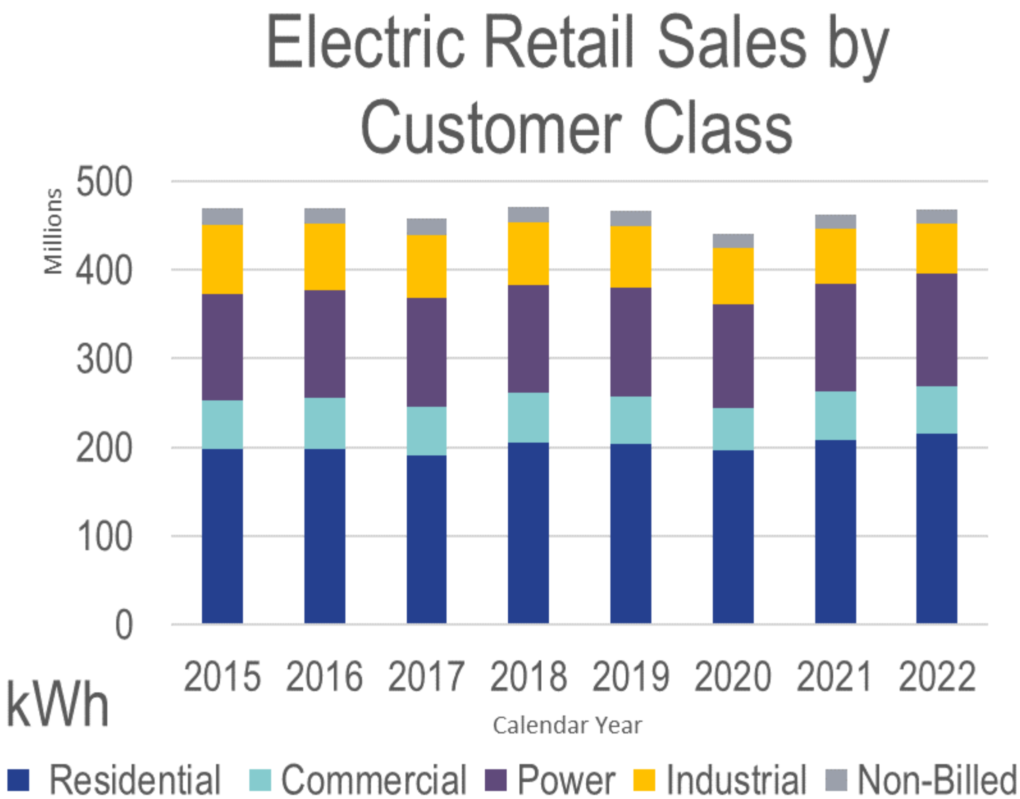


Non-Coincident Peak demand is the peak demand of a customer class whenever it occurs, regardless of system peak. SUA's retail Non-Coincident Peak demand by customer class for the current Study TY was 182,095 kW.

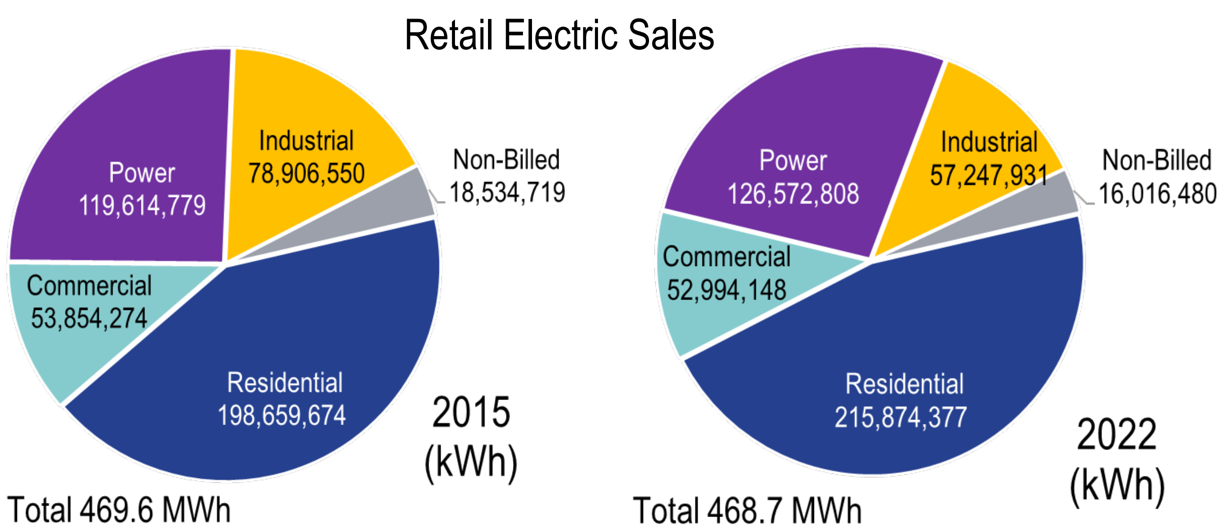
ELECTRIC USAGE BY CUSTOMER CLASS

From CY 2015 to 2022 average annual retail electric sales were relatively flat at 463,400,000 kWh—ranging from a high of 471.7 Gigawatt-hours[10] (GWh) in 2018 to a low of 440.9 GWh in 2020. The bar chart on the following page shows annual retail sales from CY 2015 to 2022 by customer class.

[10] 1 GWh = 1,000,000 kWh; 1 Megawatt-hour (MWh) = 1,000 kWh.

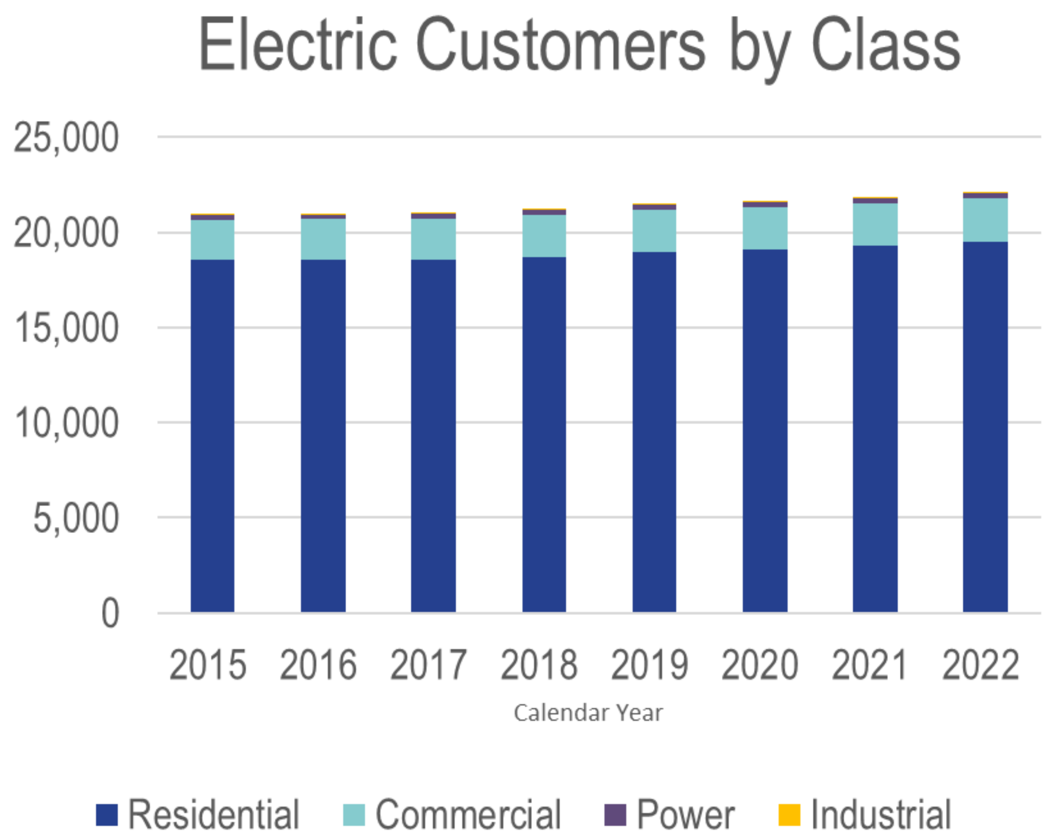


The following pie charts show the relative make-up of retail sales in 2015 and 2022. Over this period, overall sales remained fairly constant, but the mix of sales by class changed. Residential sales increased 3.75% from 42% to 46%; Industrial sales decreased 4.6% from 16.8% to 12.2%; and Power sales increased 1.5% from 25.5% to 27 percent. Commercial sales, along with the sales for the remaining classes experienced changes of less than 1 percent.

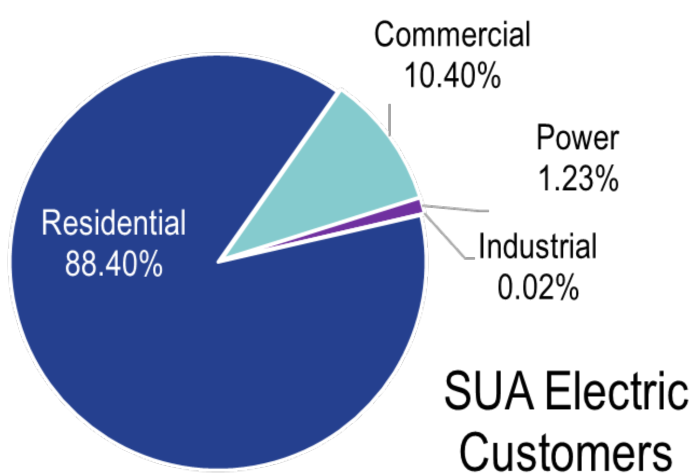


ELECTRIC CUSTOMERS

The following chart shows SUA's electric customer base from CY 2015 to 2022. SUA's number of customers grew 5.4% overall during this period, just over 0.75% per year, to 22,050.



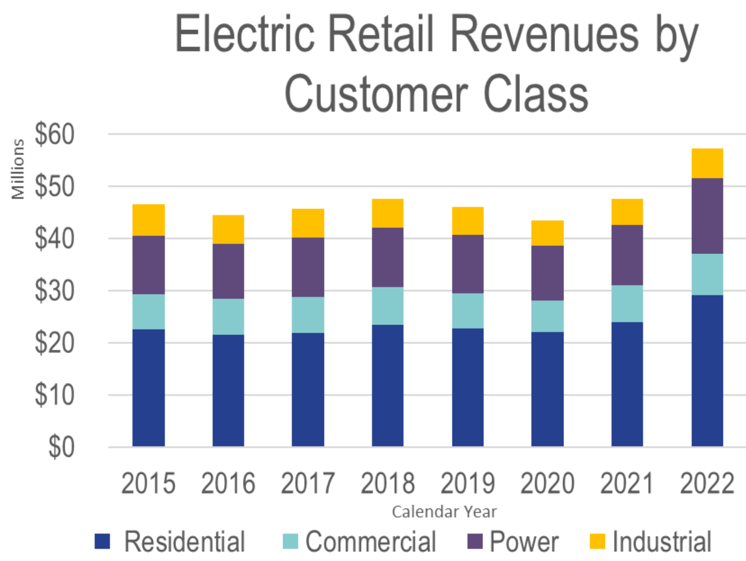
Although the customer count increased from 20,925 to 22,050 from CY 2015 to 2022, as shown in the pie chart at right, the relative proportion of customers remained constant over the same period. The Residential Class comprised around 88.4%, the Commercial Class 10.4%, and the Power Class 1.25 percent. SUA had an average of 5 Industrial Customers over this period, too few to impact relative customer count percentages.

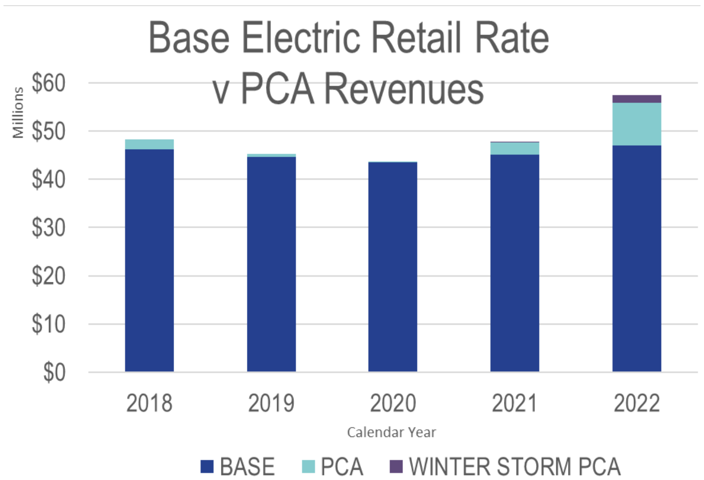


ELECTRIC REVENUES BY CUSTOMER CLASS

From CY 2015 to 2021 SUA electric retail revenues averaged $45.9 Million, as can be seen in the graph at right.

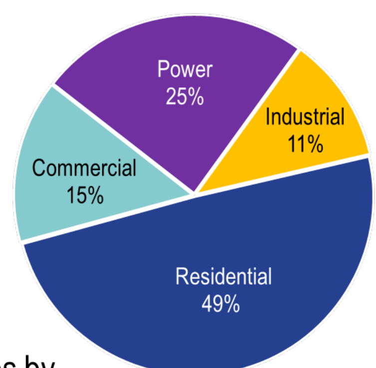
Retail revenues for CY 2022 totaled $57.1 Million, a material increase over the average annual and the CY 2021 total of $47.6 Million. However, $10.5 Million of the CY 2022 increase resulted from an increase in the SUA PCA and Winter Storm PCA related to Storm Uri.[11]





PCA revenues are passed through to third parties to recover costs and are not available to use for operating costs. As can be seen in the chart at left, although base revenues dipped slightly in 2020, when PCA revenues are removed, base revenues were essentially flat from CY 2018 through 2022.

The pie chart at right shows the average portion of revenues by Customer class in CY 2022. Since CY 2015, the Industrial class portion decreased by 3% with the Residential class offsetting that change. The Commercial class portion decreased by 1% over that period with the Power class offsetting that reduction.



Average Portion of Retail Revenues by Customer Class

[11] Refer to Footnote 5.

REVENUE REQUIREMENT & FIVE-YEAR FINANCIAL FORECAST

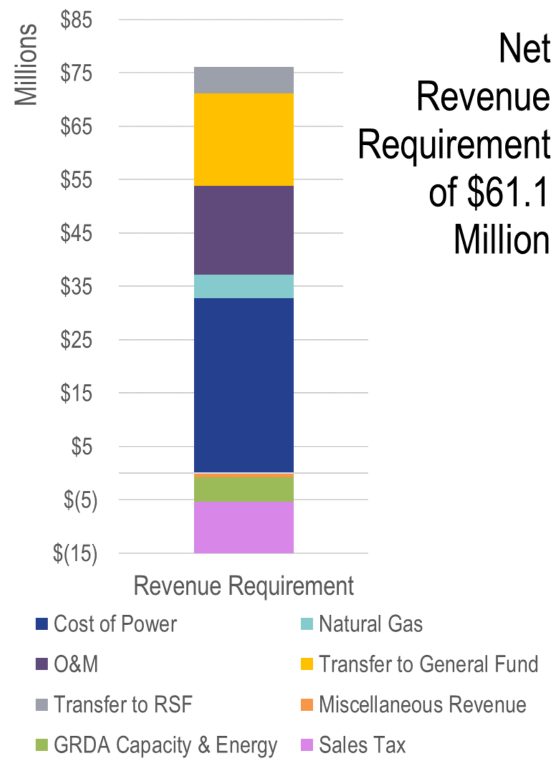
This section presents the TY Revenue Requirement and five-year financial forecast.

NET REVENUE REQUIREMENT

TY REVENUE REQUIREMENT

The Test Year Net Revenue Requirement equals the FY 2024 budget adjusted for known and measurable changes. As shown in the figure at right, total expenses of $76.2 Million were netted against incoming transfers and non-rate revenues of $15 Million to obtain the TY Net Revenue Requirement of $61.1 Million. The Cost of Power is the largest component, comprising 54% of the net Revenue Requirement. The General Fund Transfer and O&M expense were roughly equal and together comprise another 54 percent of this amount.

The table on the following page presents the detailed TY Net Revenue Requirement by line item and projected revenues at current rates. Column (b) contains SUA's net FY 2024 Budget of $58.2 Million—$72.7 Million of expenses less $14.5 Million of incoming transfers and non-rate revenues. Projected rate revenues at current rates of $58 Million include $10 Million of PCA revenues. The projected shortfall is ($159,000).



Column (c) presents net Adjustments to the Budget for known and measurable changes totaling $3 Million. Adjustments include $1.5 Million in net expenses comprised primarily of health and labor expense increases, $1.2 Million, and $0.300 Million of net wholesale power cost increases after natural gas cost reductions of $417, 000 are deducted. Natural gas prices used in the FY 2024 budget were very high given market conditions and are expected to normalize over the Study period. Other adjustments include increases of $2 Million roughly split equally between the GF and Rate Stabilization Fund (RSF) to meet increased Capital Improvement Plan (CIP) and City operating expenses as discussed in the Cost Increases section on Page 2.

Stillwater Utilities Authority — Electric Utility Department
Summary of Projected Revenue Requirements and Existing Rate Revenues
Fiscal Year Ending June 30,

Ln. No.	Description	Proposed Budget 2024	Adjustments	Revenue Requirement 2025
	(a)	(b)	(c)	(d)
	Operating Expenses - Electric Distribution			
1	Cost of Power	$ 32,000,000	$ 725,494	$ 32,725,494
2	Natural Gas	4,950,000	(416,621)	4,533,379
3	Administration	2,022,297	82,500	2,104,797
4	Engineering	1,039,242	144,375	1,183,617
5	Generation O&M	3,384,395	379,500	3,763,895
6	Distribution O&M	6,816,711	523,622	7,340,333
7	Warehouse & Fleet	1,531,411	41,250	1,572,661
8	Customer Service	348,293	-	348,293
9	Metering	337,543	0	337,543
10	*Total Operating Expenses*	*$ 52,429,892*	*$ 1,480,121*	*$ 53,910,013*
	Other Revenue Requirements			
11	Transfer to General Fund	$ 16,256,635	$ 993,365	$ 17,250,000
12	Transfer to RSF	4,000,000	1,000,000	5,000,000
13	Transfer to Replenish RSF	0	0	0
14	*Total Other Revenue Requirements*	*$ 20,256,635*	*$ 1,993,365*	*$ 22,250,000*
15	***Total Expenditures***	**$ 72,686,527**	**$ 3,473,486**	**$ 76,160,013**
	Less Transfers and Other Revenue			
16	Electric Service Connection Fee	$ 108,000	$ 42,000	$ 150,000
17	Utility Pole Attachment	29,000	72,218	101,218
18	Miscellaneous Revenue	50,000	0	50,000
19	SUA Revenue Allocation	525,920	0	525,920
20	GRDA Capacity	165,000	0	165,000
21	GRDA Energy	3,950,000	402,044	4,352,044
22	Sales Tax	9,700,000	0	9,700,000
23	*Total Other Revenue*	*$ 14,527,920*	*$ 516,262*	*$ 15,044,182*
24	**NET REVENUE REQUIREMENTS**	**$ 58,158,607**	**$ 2,957,224**	**$ 61,115,831**
	Projected Revenue From Sales			
25	Existing Base Rate Revenues	$ 48,000,000	$ (127,562)	$ 47,872,438
26	PCA Revenues	10,000,000	365,485	10,365,485
27	Other Revenue	0	0	0
28	**TOTAL REVENUES FROM SALES**	**$ 58,000,000**	**$ 237,924**	**$ 58,237,924**
29	*Revenue Surplus or (Deficiency)*	*$ (158,607)*	*$ (2,719,300)*	*$ (2,877,907)*

Adjustments increase non-rate revenues by $516, 000 primarily due to higher GRDA payments and additional pole attachment fees, as well as inflows from the RSF to cover service extensions.[12] Adjusted TY rate revenues total $58.2 Million resulting in a $2.9 Million deficit.

[12] As of April 4, 2023, SUA covers the cost of infrastructure for new residential connections pursuant to Resolution No. CC-2023-8; SUA 2023-2 adopted April 3, 2023. Previously, these costs were paid by customers, treated as other revenues to the electric department, and offset operating costs. To ensure the electric operating budget still receives this benefit, a transfer from the RSF fund has been added.

RATE STABILIZATION FUND

The table below presents the Rate Stabilization Fund over the Study period. As the name implies, the RSF is a balancing account that insulates customers from cost volatility.

RATE STABILIZATION FUND						
Line No.	FY	2025	2026	2027	2028	2029
1	**BEGINNING BALANCE (Net DSR)**	**$ 34,669,091**	**$ 34,948,752**	**$ 32,140,998**	**$ 28,453,434**	**$ 30,335,574**
	RECEIPTS					
2	Transfer In - Electric Revenue	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000
3	GRDA Capacity Payments	4,200,000	4,200,000	4,200,000	4,200,000	4,200,000
4	GRDA Energy Payments (Major Overhaul)	549,996	549,996	549,996	549,996	549,996
5	RSF Replenishment	-	-	0	0	0
6	*TOTAL RECEIPTS*	*$ 10,228,286*	*$ 9,749,996*	*$ 9,749,996*	*$ 9,749,996*	*$ 9,749,996*
	DISBURSEMENTS					
7	Bond Payment-P&I	$ 4,093,625	$ 4,089,750	$ 4,086,500	$ 4,103,675	$ 4,081,975
8	Bond Trustee Fee	5,000	5,000	5,000	5,000	5,000
9	Distribution CIP	4,525,000	8,010,000	8,890,000	3,100,000	3,100,000
10	Production CIP	1,175,000	300,000	300,000	500,000	400,000
11	System Extension to Electric Operating Budget	150,000	153,000	156,060	159,181	162,365
12	*TOTAL DISBURSEMENTS*	*$ 9,948,625*	*$ 12,557,750*	*$ 13,437,560*	*$ 7,867,856*	*$ 7,749,340*
13	**ADJUSTED BALANCE**	**$ 34,948,752**	**$ 32,140,998**	**$ 28,453,434**	**$ 30,335,574**	**$ 32,336,230**
	APPROPRIATIONS					
15	BEGINNING APPROPRIATIONS	$ 29,675,257	$ 30,225,253	$ 30,775,249	$ 31,325,245	$ 31,875,241
16	Current Period Net Changes	549,996	549,996	549,996	549,996	549,996
17	**ENDING APPROPRIATIONS**	**$ 30,225,253**	**$ 30,775,249**	**$ 31,325,245**	**$ 31,875,241**	**$ 32,425,237**
18	*AVAILABLE BALANCE*	*$ 4,723,499*	*$ 1,365,749*	*$ (2,871,811)*	*$ (1,539,667)*	*$ (89,007)*
19	Transfer from/(to) Rate Balancing Account	-	-	591,875	327,795	89,007
20	Excess/(Deficit) Appropriations Balance	4,723,499	1,365,749	(2,279,937)	(1,211,873)	-
17	**ENDING BALANCE (Net DSR)**	**$ 34,948,752**	**$ 32,140,998**	**$ 29,045,309**	**$ 30,663,368**	**$ 32,425,237**
	REVENUE BALANCING ACCOUNT					
18	**BEGINNING BALANCE**	**$ -**	**$ 522,439**	**$ 685,213**	**$ -**	**$ -**
19	NET REVENUES APPLIED TO/(CONTRIBUTED FROM) RATE BALANCING ACCOUNT	522,439	162,774	(93,338)	(264,080)	(235,681)
20	BALANCE BEFORE TRANSFERS	522,439	685,213	591,875	(264,080)	(235,681)
21	Transfer from/(to) RSF	-	-	(591,875)	264,080	238,788
22	*ENDING BALANCE*	*$ 522,439*	*$ 685,213*	*$ -*	*$ -*	*$ 3,107*

The RSF receives transfers of revenues from the Electric Department operating budget (Line #2) to fund CIP projects and other costs. For this Study, given expected upcoming funding requirements, the annual transfer amount was increased by $1 Million to $5 Million. The RSF receives capacity and energy payments related to the SEC (Lines #3 and #4) from GRDA. The RSF is used to pay Debt Service (Lines #7 and #8) and to fund current CIP projects (Lines #9 and #10).

The RSF also pays for electric system extensions (Line #11).[13] Lines #15 through #17

[13] Refer to Footnote 12.

contain current appropriations for future CIP projects. Line #16 shows the net difference between: reductions for current completed CIP, previously encumbered funds expended for current CIP, and new appropriations. Lines #18 through #22 track revenue shortfalls and excesses.

FIVE-YEAR FINANCIAL FORECAST

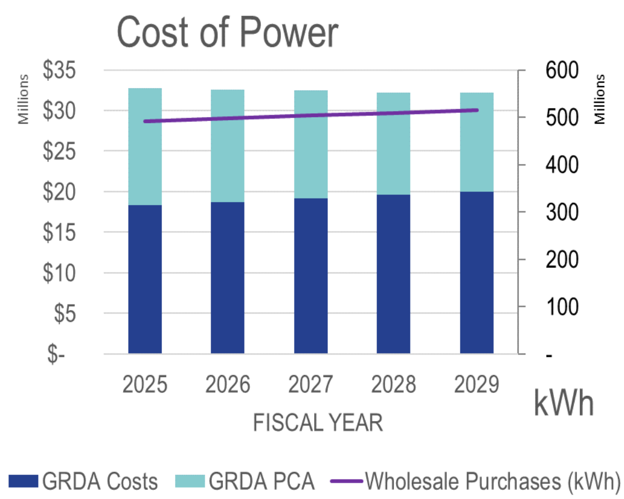
The table below provides the five-year (FY 2025 to 2029) financial forecast of the Revenue Requirement. Over this period, the net Revenue Requirement increases from $61.1 Million to $64.8 Million. Changes to specific categories of costs are discussed in the following pages.

Stillwater Utilities Authority — Electric Utility
Summary of Projected Revenue Requirements and Revenues at Existing Rates
Fiscal Year Ending June 30,

Ln. No.	Description	Revenue Requirement 2025	2026	2027	2028	2029
	(a)	(b)	(c)	(d)	(e)	(f)
	Operating Expenses - Electric Distribution					
1	Cost of Power	$ 32,725,494	$ 32,588,447	$ 32,431,916	$ 32,221,708	$ 32,182,728
2	Natural Gas	4,533,379	4,570,833	4,508,366	4,471,731	4,462,894
3	Administration	2,104,797	2,162,588	2,220,706	2,285,287	2,350,325
4	Engineering	1,183,617	1,234,048	1,281,234	1,330,624	1,376,049
5	Generation O&M	3,763,895	3,862,312	3,962,255	4,074,151	4,188,021
6	Distribution O&M	7,340,333	7,604,988	7,858,712	8,129,945	8,387,913
7	Warehouse & Fleet	1,572,661	1,617,473	1,662,217	1,711,660	1,761,060
8	Customer Service	348,293	361,528	374,116	387,480	400,055
9	Metering	337,543	351,833	365,216	379,234	392,144
10	*Total Operating Expenses*	*$ 53,910,013*	*$ 54,354,051*	*$ 54,664,736*	*$ 54,991,821*	*$ 55,501,188*
	Other Revenue Requirements					
11	Transfer to General Fund	*$ 17,250,000*	*$ 17,767,500*	*$ 18,300,525*	18,849,541	19,415,027
12	Transfer to RSF	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
13	Transfer to Replenish RSF	0	0	0	0	0
14	*Total Other Revenue Requirements*	*$ 22,250,000*	*$ 22,767,500*	*$ 23,300,525*	*23,849,541*	*24,415,027*
15	**Total Expenditures**	**76,160,013**	**77,121,551**	**77,965,261**	**78,841,362**	**79,916,215**
	Less Transfers and Other Revenue					
16	Service Expansion (RSF Transfer)	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365
17	Utility Pole Attachment	101,218	126,853	152,488	178,123	203,758
18	Miscellaneous Revenue	50,000	51,000	52,020	53,060	54,122
19	SUA Revenue Allocation	525,920	539,068	552,545	567,740	583,353
20	GRDA Capacity	165,000	165,000	165,000	165,000	165,000
21	GRDA Energy	4,352,044	4,388,000	4,328,031	4,292,862	4,284,378
22	Sales Tax	9,700,000	9,700,000	9,700,000	9,700,000	9,700,000
23	*Total Other Revenue*	*$ 15,044,182*	*$ 15,122,921*	*$ 15,106,144*	*15,115,966*	*15,152,975*
24	**NET REVENUE REQUIREMENTS**	**$ 61,115,831**	**$ 61,998,631**	**$ 62,859,118**	**$ 63,725,396**	**$ 64,763,241**

COST OF POWER

From FY 2025 to 2029, the Cost of Power is projected to decrease by $500,000, from $32.7 Million to $32.2 Million. This decrease is driven by forecasted reductions in the GRDA PCA charge based on GRDA's projections at the time of the Study.



As shown in the dark blue portion of the bars in the chart at right, SUA's wholesale cost of power, excluding the PCA, is projected to increase, by 9.1% or $1.7 Million, over the five-year period based on information provided by GRDA. SUA wholesale purchases in kWh over this period are expected to increase 4.8%[14] resulting in an effective increase of 4.1% in the per-kWh wholesale cost of power excluding the PCA.

The GRDA PCA is expected to decrease from $0.029/kWh to $0.024/kWh, or by 19% over this period. When applying the 4.8% increase in total kWh purchases, the effective decrease totals 15%, $2.2 Million, over this five-year period.

COST OF NATURAL GAS

The cost of natural gas is based on the generation profile of the SEC in combination with forecasted[15] natural gas costs. After a 7% increase in FY 2026, prices decrease over the next several years resulting in an average overall price increase of 1.7% per year. Taking into account the SEC generation profile, overall, annual natural gas costs hover around $4.5 Million throughout the five-year Study period.

NON-POWER AND NON-FUEL EXPENSES

As discussed in the Cost Increases Section of this report, non-power and non-fuel expenses increased due to various factors including CPI, increases in the cost of labor and benefits, supply chain delays, and other causes. Non-power and non-fuel O&M costs increase from $16.7 Million in FY 2025 to $18.9 Million in FY 2029, 13% overall or an average of 3.1% per year.

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[14] From 490,946,571 to 514,593,093.

[15] Several sources were used including: https://www.eia.gov/opendata/browser/natural and https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html#venue=globex

TRANSFERS TO THE GENERAL FUND AND RSF

As discussed in the Cost Increases section, the General Fund transfer has increased steadily since 2013. The GF Transfer is assumed to increase 3% annually over the Study period from $17.25 Million to $19.415 Million by FY 2029.

The RSF is used to fund CIP and as a balancing account to absorb operating budget fluctuations as needed. Based on increases in the cost of materials, along with extended lead-times, the annual transfer from the Electric Operating Budget to the RSF has been increased by $1 Million to $5 Million for the Study.

INFLOWS AND OTHER NON-RATE REVENUES

Inflows from the RSF to cover service extensions that had formerly been funded by residents (see Footnote 5) increases from $150,000 in FY 2025 to $162,365 in FY 2029. Pole attachment fees more than double, from $101,218 to $203,758, over the five-year period.

The SUA Revenue Allocation consists of interest earned on pooled deposits of SUA funds and miscellaneous revenues generated by the utility billing and collection process. For example, penalty fees on unpaid bills, service connection fees, and disconnection fees. From FY 2025 to 2029 this inflow increases from $525,920 to $583,353 by 10.9 percent.

GRDA capacity payments remain flat at $165,000 over the five-year Study period. GRDA energy payments decrease slightly, from $4.52 Million in FY 2025 to $4.45 Million in FY 2029.

Sales tax inflows are projected to remain flat at $9.7 Million per year over the five-year Study period.

COST OF SERVICE RESULTS

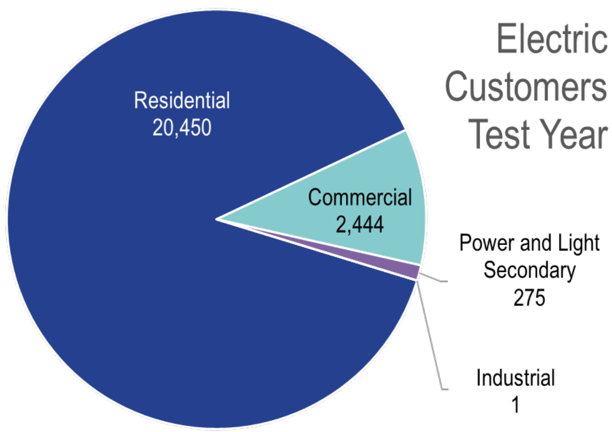
This section of the report presents Study Billing Determinants and COS Analysis.

BILLING DETERMINANTS

Billing Determinants are the basis for electric service revenues and are comprised of items to which rate charges are applied, for example: kWh of monthly consumption. In a COS Study, these values represent an entire customer class rather than an individual customer within a class.

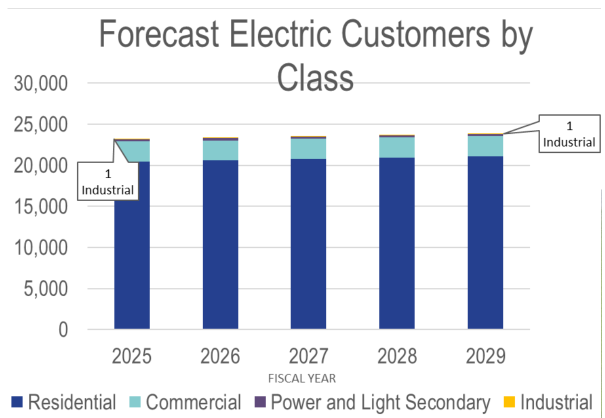
CUSTOMERS

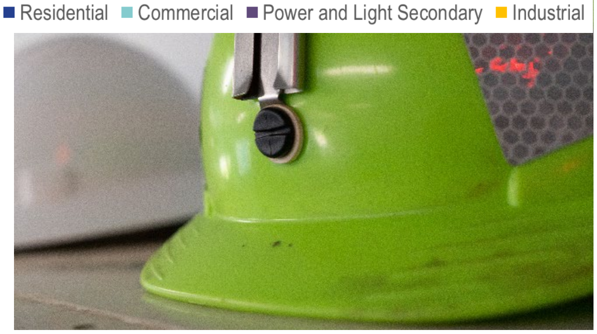
The pie chart below shows TY Customers by Class. The total number of Customers for the TY equaled 23,173.



At the time of the Study, SUA had one electric Industrial Customer, but will most likely acquire additional Industrial Customers over the five-year Study horizon. However, given: the impact this class has on overall outcomes; the unprecedented level of uncertainty and instability in the world at the time of the Study: and the risk of revenue shortfalls had the Study assigned costs to customer loads that never materialize, in consultation with SUA, the decision was made to base Study results assuming no growth in the Industrial Class over the Study period.

The chart below shows Customers by Class from FY 2025 to 2029. Overall, customer growth was assumed to increase approximately 3% over the Study period, with the bulk of growth in the Residential Class. Two new Power and Light Customers, the Hub and the new Convention Center, were included in future customer and load assumptions.





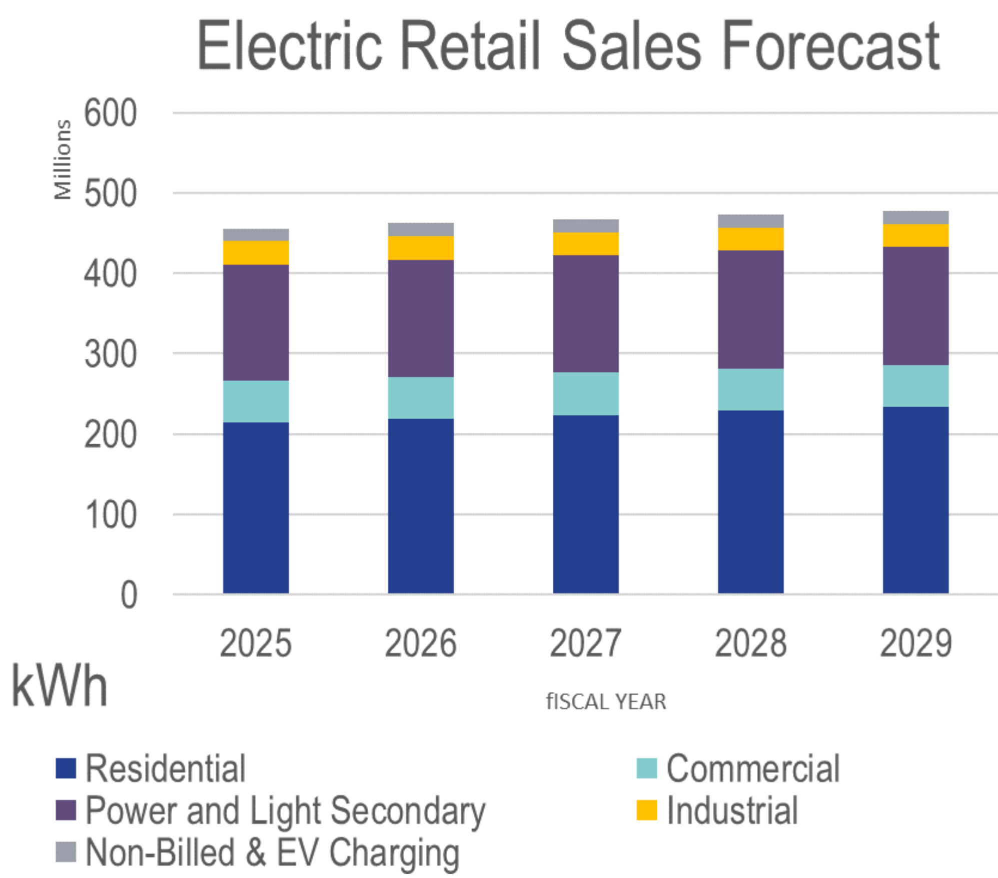
RETAIL ELECTRIC SALES

The table at right shows the electric retail sales forecast and number of Customers by Customer Class for the TY. The Study TY is based on just under 456 GWh of retail energy sales to 23,173 Customers. When accounting for 35 GWh of losses, wholesale purchases from GRDA total slightly less than 491 GWh.

The table below shows electric retail sales by Customer Class for the five-year Study period. Over this timeframe sales increase by 4.8% to 477.9 GWh. Losses would increase wholesale purchases in FY 2029 to 514.6 GWh.

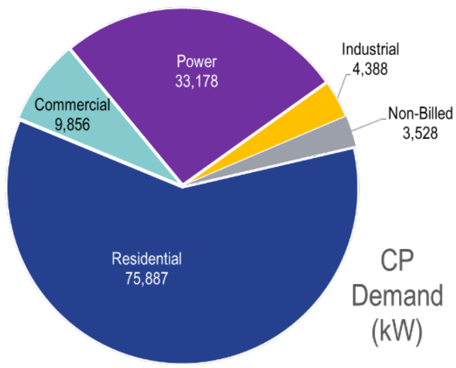
Test Year Customers and Energy Sales

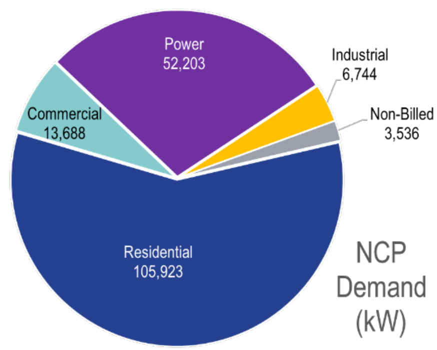
Ln No	Service Class	Number of Customers	Energy Sales (kWh)
	(a)	(c)	(d)
1	Residential	20,450	214,612,889
2	Commercial	2,444	52,263,784
3	Power and Light Secondary	275	144,312,997
4	Industrial	1	28,593,600
5	EV Charging	4	36,125
6	Unbilled		16,157,553
7	**TOTAL SYSTEM**	23,173	455,976,949
8	Losses		34,969,622
9	Total Purchases		490,946,571



COINCIDENT AND NON-COINCIDENT PEAK DEMAND

The pie charts below provide the TY CP demand and NCP demand. Total CP and NCP for the TY are 126,836 kW and 182,095 kW, respectively.





COST OF SERVICE ANALYSIS

COST OF SERVICE BY FUNCTION

The first step in the COS process is functionalization of the TY Revenue Requirement. SUA: provides no wholesale service, purchases all energy wholesale from GRDA, and sells all SEC output to GRDA. The Study therefore modeled SUA as a distribution-only utility and the three functional cost categories used for the COS analysis were:

- Production
- Distribution
- Customer

The table below provides the functionalized TY Revenue Requirement.

Functionalization of Test Year Revenue Requirement		
Ln. No.	***Functional Category***	***Test Year Amount***
1	Production *(Power Purchased from GRDA)*	$45,216,221
2	Transmission *(Included in Power Purchased from GRDA)*	-
3	Distribution	$15,126,100
4	Customer	$773,509
5	**TOTAL REVENUE REQUIREMENT**	**$61,115,831**

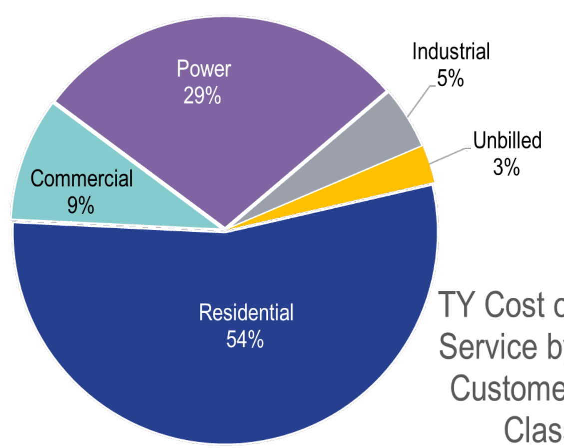
CLASSIFIED COST OF SERVICE

The second step in the COS Analysis is to classify each functional component of the TY Revenue Requirement into fixed and variable components. The Table below provides the classified, functionalized TY Revenue Requirement.

Classification of Test Year Revenue Requirement		
Ln. No.		***Test Year Amount***
	Production *(Power Purchased from GRDA)*	
1	Demand Related	$21,943,508
	Energy Related	
2	On Peak Power	5,530,781
3	Off Peak Power	3,348,374
4	PCA	14,393,558
	Total Energy Related	$23,272,713
5	*Total Production*	*$45,216,221*
	Transmission *(Included in Power Purchased from GRDA)*	-
	Distribution	
6	Demand Related	$9,063,050
7	Customer Related	6,063,050
8	*Total Distribution*	*$15,126,100*
9	**Customer** *(Customer Related)*	*$773,509*
10	**TOTAL REVENUE REQUIREMENT**	**$61,115,831**

TY COST OF SERVICE BY CUSTOMER CLASS

The third step in the COS Analysis is to separate the functionalized, classified TY Revenue Requirement by customer class. The pie chart at right shows that 83% of the COS is assigned to Residential and Power Customers (54% and 29%, respectively). Commercial 9%, Industrial 5%, and Unbilled 3% make up the rest.



TY Cost of Service by Customer Class

The detailed functionalized, classified TY COS by customer class appears in the table below.

Test Year Cost of Service by Customer Class ($000)							
Ln.		Production		Distribution	Customer	Cost of Service Requirement	
No.	Service Class	Fixed	Variable	Fixed	Fixed	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Residential						
1	Residential Service	$10,812	$10,061	$4,945	$5,025	$30,844	50%
2	Energy Efficient Residential	20	19	9	8	56	0%
3	Low Usage Residential	213	198	97	723	1,231	2%
4	Residential Heat Pump	305	287	139	118	849	1%
5	Block Billing (kWh)	90	85	41	10	226	0%
6	Total Residential COS	$11,446	$10,656	$5,235	$5,889	$33,227	54%
	Commercial						
7	General Service	$1,476	$2,675	$675	$698	$5,523	9%
8	Ground Source Heat Pump	72	131	33	6	242	0%
9	Total Commercial COS	$1,548	$2,806	$708	$704	$5,765	9%
	Power						
10	Power and Light Primary (PLP)	$614	$792	$213	$4	$1,623	3%
11	PLP, Time of Day (TOD)	-	-	-	-	-	0%
12	Power and Light Secondary (PLS)	6,252	6,367	2,167	234	15,020	25%
13	PLS, TOD	373	328	129	1	830	1%
14	Total Power COS	$7,239	$7,487	$2,509	$239	$17,474	29%
	Industrial						
15	Large Power and Light Level 3 & 4	$1,049	$1,483	$392	$3	$2,928	5%
16	Large Power and Light Level 5	-	-	-	-	-	0%
17	Total Industrial COS	$1,049	$1,483	$392	$3	$2,928	5%
18	Electric Vehicle Charging	$1	$2	$0	$1	$4	0%
	Unbilled						
19	Security Lights	$39	$50	$13	$-	$102	0%
20	City Usage	622	789	205	-	$1,616	3%
21	Total Un-Billed COS	$661	$839	$218	$-	$1,718	3%
22	**TOTAL COS**	**$21,944**	**$23,273**	**$9,063**	**$6,837**	**$61,116**	**100%**

TY COST OF SERVICE v REVENUES AT CURRENT RATES

Comparing the Test Year Cost of Service to projected Revenues by Customer Class at current rates identifies potential cross subsidies between customer classes by identifying which classes are paying more or less than the COS. The table below provides this data by Customer Class. Overall Residential Class TY revenues at current rates are 9.3% below COS. In total, TY revenues at current rates are 4.7% below the required TY COS resulting in a $2.9 Million shortfall.

TY Revenues by Customer Class at Current Rates v COS ($000)

Ln No	Service Class	Current Rates	Cost of Service	Difference Revenues at Current Rates v COS	
	(a)	(b)	(c)	(d)	(e)
	Residential				
1	Residential Service	$28,349	$30,844	$(2,495)	-8.1%
2	Energy Efficient Residential Services	49	56	(7)	-11.7%
3	Low Usage Residential	722	1,231	(509)	-41.4%
4	Residential Heat Pump	740	849	(109)	-12.8%
5	Block Billing (kWh)	239	226	13	5.6%
6	Residential DG-NEM	21	21	0	1.0%
7	Total Residential	$30,121	$33,227	$(3,106)	-9.3%
	Commercial				
8	General Service	$8,018	$5,523	$2,495	45.2%
9	Ground Source Heat Pump	229	242	(13)	-5.4%
10	Total Commercial COS	$8,247	$5,765	$2,482	43.1%
	Power				
11	Power and Light Primary	$1,666	$1,623	$43	2.6%
12	Power and Light Primary, Time of Day	-	-	-	0.0%
13	Power and Light Secondary	14,702	15,020	(319)	-2.1%
14	Power and Light Secondary, TOD	686	830	(145)	-17.4%
15	Total Power COS	$17,053	$17,474	$(421)	-2.4%
	Industrial				
16	Large Power and Light Level 3 & 4	$2,812	$2,928	$(116)	-4.0%
17	Large Power and Light Level 5	-	-	-	0.0%
18	Total Industrial COS	$2,812	$2,928	$(116)	-4.0%
19	Electric Vehicle Charging	$5	$4	$1	29.4%
	Unbilled				
20	Security Lights	-	102.04	(102)	-100.0%
21	City Usage	-	1,616.17	(1,616)	-100.0%
22	Total Un-Billed COS	$-	$1,718	$(1,718)	-100.0%
23	**TOTAL COS**	**$58,238**	**$61,116**	**$(2,878)**	**-4.71%**

RATE DESIGN

This Section discusses SUA's existing electric rate tariffs and structures, and proposed changes. The impact of proposed changes on customers for several rate classes including a comparison with the rates of neighboring utilities is also included.

EXISTING TARIFFS & RATES

SUA has fourteen electric rate tariffs pursuant to which customers can purchase electricity. These tariffs fall within six categories:

1. Residential
2. Commercial
3. Power and Light
4. Industrial
5. Distributed Generation
6. EV Charging

RESIDENTIAL TARIFFS

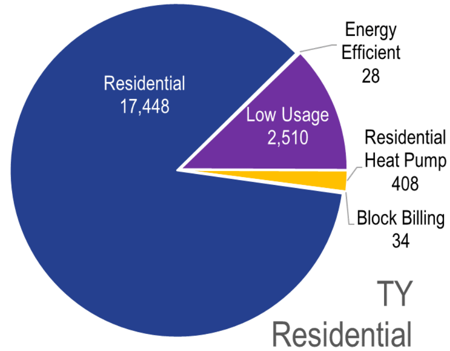
SUA offers electric service to Residential Customers under five tariffs. The table at right provides the current SUA Residential tariffs and rates. Residential Customers that install distributed generation, such as roof top solar, can receive service under SUA's Distributed Generation (DG) Net Energy Metering (NEM) tariff (DG-NEM).

SUA's Residential Service tariff relies on a declining block structure in winter that offers a significant discount on monthly energy use in excess of 600 kWh. Winter months are the seven months from January through April and October through December. Currently, of the 20,450 TY Residential Class Customers, 85% receive service under the Residential Service tariff.

SUA offers a Low Usage Residential tariff to customers with monthly consumption below 500kWh and not greater than 400 kWh for any three

Residential			
Ln. No.	Rate	Unit	Existing Rates
	(a)	(b)	(c)
1	**Residential Service**		
2	Customer Charge	($/month)	$ 10.39
3	Summer (May 1 to September 30)	($/kWh)	$ 0.11446
4	Winter (October 1 to April 30)		
5	0 to 600 kWh per Month	($/kWh)	$ 0.11446
6	> 600 kWh per Month	($/kWh)	$ 0.06693
7	PCA	($/kWh)	Varies
8	**Energy Efficient Residential Services**		
9	Customer Charge	($/month)	$ 10.39
10	Summer (May 1 to September 30)	($/kWh)	$ 0.10978
11	Winter (October 1 to April 30)		
12	0 to 600 kWh per Month	($/kWh)	$ 0.10978
13	> 600 kWh per Month	($/kWh)	$ 0.06225
14	PCA	($/kWh)	Varies
15	**Low Usage Residential**		
16	Customer Charge	($/month)	$ 8.84
17	Energy	($/kWh)	$ 0.09037
18	PCA	($/kWh)	Varies
19	**Residential Heat Pump**		
20	Customer Charge	($/month)	$ 10.39
21	Summer (May 1 to September 30)	($/kWh)	$ 0.11446
22	Winter (October 1 to April 30)		
23	0 to 600 kWh per Month	($/kWh)	$ 0.10600
24	> 600 kWh per Month	($/kWh)	$ 0.06475
25	PCA	($/kWh)	Varies
26	**Block Billing**		
27	Customer Charge	($/month)	$ 10.39
28	Summer (May 1 to September 30)	($/kWh)	$ 0.11446
29	Winter (October 1 to April 30)		
30	0 to 600 kWh per Month	($/kWh)	$ 0.11446
31	> 600 kWh per Month	($/kWh)	$ 0.06693
32	PCA	($/kWh)	Varies

months in a year. The Residential Heat Pump tariff is available to Residential customers who utilize a heat pump for all heating and cooling. SUA offers the Block Billing tariff to multifamily residences with a single shared meter. SUA's Energy Efficient Residential tariff is closed to new customers.



The pie chart at right shows the TY number of Residential Customers by Class. An additional 21 TY Residential customers were assumed to be on the DG-NEM tariff.

COMMERCIAL TARIFFS

SUA has two non-demand Commercial Customer tariffs for non-Residential Customers. The first, General Service (GS), is for Customers whose annual usage divided by the sum of its monthly annual demands is either less than 200; or greater than 200 and its usage for two months is less than or equal to 15,000 kWh. Non-residential customers served by a Ground Source Heat Pump (GSHP) are eligible for service under the second Commercial tariff. The table at right contains these tariffs and current rates.

Commerical Rates

Line No.	Rate	Unit	Existing Rates
	(a)	(b)	(c)
1	**General Service**		
2	Customer Charge	($/month)	$ 19.14
3	Summer (May 1 to September 30)	($/kWh)	$ 0.13679
4	Winter (October 1 to April 30)		
5	0 to 2000 kWh per Month	($/kWh)	$ 0.13679
6	> 2000 kWh per Month	($/kWh)	$ 0.09037
7	PCA	($/kWh)	Varies
8	**Ground Source Heat Pump**		
9	Customer Charge	($/month)	$ 117.22
10	Summer (May 1 to September 30)		
11	0 to 20000 kWh per Month	($/kWh)	$ 0.09112
12	> 20000 kWh per Month	($/kWh)	$ 0.06364
13	Winter (October 1 to April 30)		
14	0 to 20000 kWh per Month	($/kWh)	$ 0.08602
15	> 20000 kWh per Month	($/kWh)	$ 0.05860

Both Commercial tariffs include a declining block energy structure that offers significant savings on energy usage in excess of 2,000 kWh and 20,000 kWh per month for GS and GSHP, respectively. Similar to the Residential tariff, the basic General Service tariff offers this discount in winter only. The Commercial Ground Source Heat Pump tariff offers this discounted structure all year, albeit with higher summer rates. Customers on this tariff are not charged the PCA.

For the TY, total Commercial Class customers were 2,444 of which 2,423 were served as General Service and 21 as Ground Source Heat Pump customers.

POWER AND LIGHT TARIFFS

Larger non-Residential customers whose usage exceeds the General Service tariff limits can be served by one of SUA's four Power and Light (P&L) tariffs: Power and Light Primary (PLP); PLP Time of Day (TOD); PL Secondary (PLS); or PLS TOD. To qualify for service under one of these tariffs, a customer's annual usage divided by summed monthly peak demands must exceed 200, and the customer must have more than two months with usage greater than 15,000 kWh. Primary versus Secondary service is based on the voltage at which customers connect. Secondary voltages apply to connections below 2 kV. SUA offers TOD tariffs for both primary and secondary customers. The table at right summarizes SUA's P&L tariffs and current rates.

All four P&L tariffs include a seasonal demand rate that offers a lower rate in winter. The TOD tariffs include an additional peak summer demand charge.

For the TY, 3 PLP customers and 271 PLS customers were assumed. No customers were included under the PLP TOD tariff; one customer was included under the PLS TOD tariff.

Power Rates			
Line No.	Rate	Unit	Existing Rates
	(a)	(b)	(c)
1	**Power and Light Primary**		
2	Customer Charge	($/month)	$ 429.83
3	Energy	($/kWh)	$ 0.05866
4	Summer Demand	($/kW Month)	$ 11.29
5	Winter Demand	($/kW Month)	$ 9.27
6	PCA	($/kWh)	Varies
7	**Power and Light Primary, Time of Day**		
8	Customer Charge	($/month)	$ 429.83
9	TOU Meter Charge (Summer Mon	($/month)	$ 17.18
10	Energy	($/kWh)	$ 0.05866
11	Summer Demand	($/kW Month)	$ 2.47
12	Summer Peak Demand	($/kW Month)	$ 8.61
13	Winter Demand	($/kW Month)	$ 9.27
14	PCA	($/kWh)	Varies
15	**Power and Light Secondary**		
16	Customer Charge	($/month)	$ 240.70
17	Energy	($/kWh)	$ 0.05866
18	Summer Demand	($/kW Month)	$ 12.06
19	Winter Demand	($/kW Month)	$ 10.11
20	PCA	($/kWh)	Varies
21	**Power and Light Secondary, Time of Day**		
22	Customer Charge	($/month)	$ 240.70
23	TOU Meter Charge (Summer Mon	($/month)	$ 17.18
24	Energy	($/kWh)	$ 0.05866
25	Summer Demand	($/kW Month)	$ 2.53
26	Summer Peak Demand	($/kW Month)	$ 9.24
27	Winter Demand	($/kW Month)	$ 10.11
28	PCA	($/kWh)	Varies

INDUSTRIAL TARIFF

SUA's largest electric customers take service under the Large Power and Light (LPL) tariff. Customers must have a minimum annual usage of 15,000,000 kWh to qualify for this tariff. Rates for service vary based on the voltage at which service is provided. Service levels 3 and 4 are for customers taking service between 2 kV and 50 kV. Service level 5 is for customers taking service at a voltage under 2 kV.

The TY included no Industrial customers on the service level 5 tariff. One customer was assumed to be on the service level 3 and 4 tariff. The table below summarizes the Industrial tariff and current rates.

Industrial							
Line No.	Rate	Unit	Existing Rates	Line No.	Rate	Unit	Existing Rates
	(a)	(b)	(c)		(d)	(e)	(f)
1	**Large Power and Light Service Level 3 & 4**			12	**Large Power and Light Service Level 5**		
2	Customer Charge	($/month)	$ 440.79	13	Customer Charge	($/month)	$ 248.52
3	Summer (May 1 to September 30)			14	Summer (May 1 to September 30)		
4	0 to 2000000 kWh per Month	($/kWh)	$ 0.04932	15	0 to 2000000 kWh per Month	($/kWh)	$ 0.05044
5	> 2000000 kWh per Month	($/kWh)	$ 0.04092	16	> 2000000 kWh per Month	($/kWh)	$ 0.04242
6	Winter (October 1 to April 30)			17	Winter (October 1 to April 30)		
7	0 to 2000000 kWh per Month	($/kWh)	$ 0.04932	18	0 to 2000000 kWh per Month	($/kWh)	$ 0.05044
8	> 2000000 kWh per Month	($/kWh)	$ 0.04092	19	> 2000000 kWh per Month	($/kWh)	$ 0.04242
9	Summer Demand	($/kW Month)	$ 19.50	20	Summer Demand	($/kW Month)	$ 21.26
10	Winter Demand	($/kW Month)	$ 6.97	21	Winter Demand	($/kW Month)	$ 7.60
11	PCA	($/kWh)	Varies	22	PCA	($/kWh)	Varies

DISTRIBUTED GENERATION NET ENERGY METERING TARIFF

Customers receiving service under a Residential, General Service, or Power and Light tariff have the option of installing distributed generation, such as roof-top solar panels, and receiving service under SUA's DG-NEM tariff. Under the terms of this tariff, the customer pays the Customer and Demand Charges associated with the standard tariff and a fixed monthly Service Availability Fee (SAF). The SAF is designed to cover the fixed system costs embedded in the energy charge of the standard tariff.

DG installations are limited to a total maximum installed capacity of 125% of the customer's peak load for the prior calendar year or 100 kW, whichever is less, or a minimum capacity of 2kW.

The customer receives credit at the wholesale energy rate for all energy output returned to the grid and pays the wholesale rate for all energy provided by SUA.

The table at right provides the current SAF for the three DG-NEM tariffs. 21 Residential customers were included on the DG-NEM tariff for the TY.

Net Energy Metering Distributed Generation

Line No.	Rate	Unit	Existing Rates
	(a)	(b)	(c)
1	**Electric Vehicle Charging**		
2	Residential Service Availability Fee	($/month)	$ 44.56
3	General Service Service Availability	($/month)	$ 201.57
4	Power and Light Secondary Servic	($/month)	$ 1,485.26

EV CHARGING TARIFF

SUA offers a wholesale tariff for customers that own EV Charging stations and resell energy to end-use customers. The three-part rate consists of a customer, energy and demand charge. The TY included 5 EV Charging customers.

Electric Vehicle Charging

Line No.	Rate	Unit	Existing Rates
	(a)	(b)	(c)
1	**Electric Vehicle Charging**		
2	Customer Charge	($/month)	$ 37.13
3	Demand Charge	($/kW Month)	$ 10.11
4	Energy	($/kWh)	$ 0.05866
5	PCA	($/kWh)	Varies

RATE DESIGN ANALYSIS AND PROPOSALS

The Rate Design process brings together the elements of the Study covered above. The COS is compared to the annual Revenue Requirements and projected Revenues under the existing rates and tariff structures to assess sufficiency and identify areas for change. This segment of the report presents the rate design analysis and proposals.

CURRENT RATES v COST OF SERVICE

SUA's existing rates were compared to the unit COS to identify the extent to which SUA's current rate structures align with the cost of service. The results are presented in

Proposed Rates v Current and COS Rates on page 40. This analysis informed the proposed rate designs presented in the following sections.

PROJECTED REVENUES AT CURRENT RATES

The revenue sufficiency test compared estimated TY revenues at current rates to the projected Revenue Requirements by year to determine if an over- or under-recovery results. The TY Billing Determinants were applied to SUA's current tariffs and rates to determine the expected revenues for each year in the Study period.

Based on expected customers and consumption patterns, current rates would not generate revenues sufficient to cover forecasted Revenue Requirements. A growing shortfall can be seen in the table below. The TY deficit of $2.9 Million or (4.9%) increases each year to a maximum loss of $5.9 Million or (10%) in FY 2029—a cumulative total of ($21.7 Million).

Summary of Projected Revenue Requirements and Revenues at Existing Rates
Fiscal Year Ending June 30,

Ln. No.	Description	Revenue Requirement 2025	2026	2027	2028	2029
	(a)	(b)	(e)	(f)	(g)	(h)
1	**NET REVENUE REQUIREMENTS**	**$ 61,115,831**	**$ 61,998,631**	**$ 62,859,118**	**$ 63,725,396**	**$ 64,763,241**
	Projected Revenue From Sales					
2	Existing Base Rate Revenues	$ 47,872,438	$ 48,514,737	$ 49,101,597	$ 49,660,251	$ 50,232,441
3	PCA Revenues	10,365,485	9,910,192	9,458,191	8,968,302	8,650,865
4	Other Revenue	0	0	0	0	0
5	**TOTAL REVENUES FROM SALES**	**$ 58,237,924**	**$ 58,424,929**	**$ 58,559,788**	**$ 58,628,553**	**$ 58,883,306**
6	Revenue Surplus or (Deficiency)	$ (2,877,907)	$ (3,573,701)	$ (4,299,330)	$ (5,096,843)	$ (5,879,934)
7	Surplus or (Deficiency) as a Percentage of Existing Rate Revenues	-4.9%	-6.1%	-7.3%	-8.7%	-10.0%

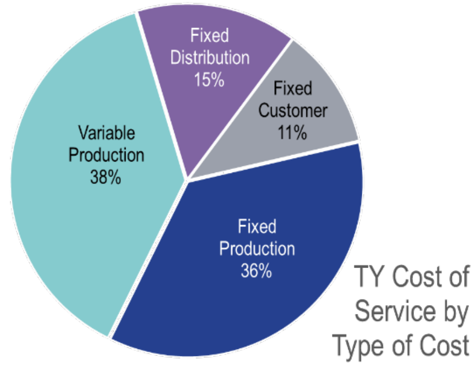
RATE DESIGN RECOMMENDATIONS

Based on the COS and evaluation of the current SUA electric tariff structures, LVC makes the following five recommendations.

1. Increase Fixed Charges to Align with Cost of Service
2. Eliminate Declining Block Rate Billing Structures
3. Eliminate Seasonal Demand Charge Differentials
4. Align Commercial (General Service) Class with Peers & COS
5. Implement New Rates January 1, 2024

Each recommendation is discussed in the following segments.

Increase Fixed Charges to Align with Cost of Service



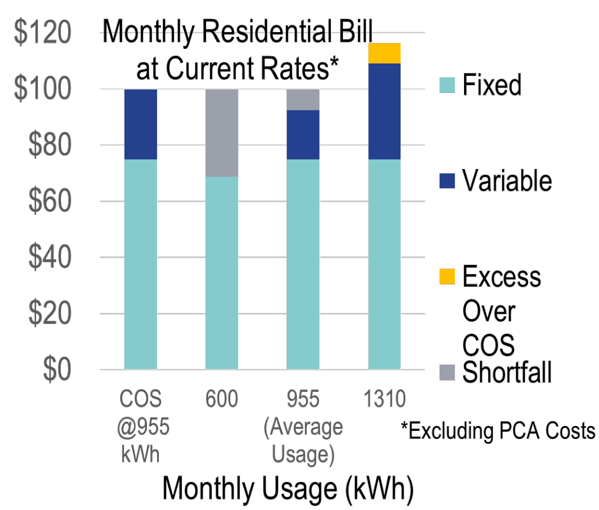
As can be seen in the pie chart at right, 62% of SUA's costs are fixed yet SUA's current rate structures rely on variable or consumption-based rates to recover a large portion of costs. The first proposed rate design recommendation is to align rate structures with COS. In general, this recommendation would result in higher fixed charges.

Eliminate Declining-Block Rate Billing Structures

All but one of SUA's Residential tariffs, both Commercial (General Service) tariffs, and the Industrial tariff use a declining-block structure for energy sales. Under this rate structure, monthly consumption in excess of a specific amount—600 kWh for Residential, 2,000 kWh for GS Commercial, 20,000 for GSHP Commercial, and 2,000,000 kWh for Industrial—receives a heavily discounted rate. The second proposed rate design recommendation is to eliminate the declining block structure.

This rate structure is problematic for several reasons and desirable for at least one reason. First, the structure is archaic and, contrary to City sustainability initiatives, encourages additional energy consumption rather than conservation.[16] Second, in the case of the Residential class the tier is set too low and results in unintended consequences. Third, the rate for the second tier is set below cost which subsidizes excess consumption. Finally, eliminating the second-tier discount is desirable as it reduces the required level of rate increase needed to eliminate the forecasted deficits.

With regard to the Residential tier, proper rate design would establish the tier level at or above the average level of usage as explained below. The Residential class has an average monthly TY usage of 955 kWh, well above the 600-kWh tier level. Based on 2022 data, 45% to 70% of Customers have usage in the second tier on a given month. This high frequency of second tier activity indicates the tier is set too low. When tier levels are properly set, the first tier should have the majority of activity.

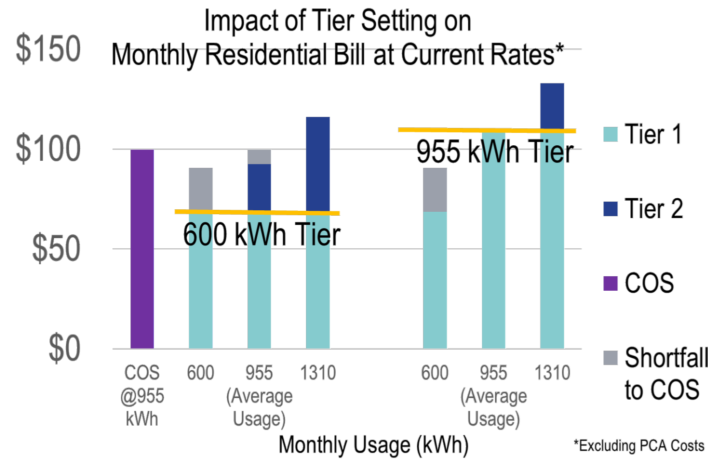


The graph at right illustrates the cost theory behind a declining-block rate structure. The first bar on the left shows that at 955 kWh, SUA's COS is $100, roughly $75 fixed and $25 variable costs.

[16] Conversely, an inclining-block rate structure, aka a conservation rate, imposes a larger cost on the subsequent tiers of usage.

At a consumption of 600 kWh, the second bar, the $68.68 received from the customer covers some of the fixed cost and none of the variable cost. At 955 kWh usage, the SUA shortfall of $7.27 applies to variable costs. At 1310 kWh of consumption, the bar on the far right, SUA actually recovers more than its cost of service. The gold portion of the bar illustrates the excess recovery. Declining block rate structures when properly designed would eliminate this over-recovery.

The figure at right illustrates the impact of setting the tier level at two different levels. The purple bar reflects the COS, $100. The gray portion of the bars shows cost shortfalls. As previously noted, to function properly, the tier level should be set to recover the COS.



Eliminate Seasonal Demand Charge Differentials

SUA's Power and Light and Industrial tariffs include a discount on the winter demand charge. SUA does not pay a reduced demand charge in its wholesale power cost in winter; therefore, this rate mechanism is not consistent with COS. In certain instances the winter discounted rate might be below COS, an additional COS inconsistency. Relative to the winter rate, SUA's summer demand rates are very high and could potentially distort price signals and hinder competition. Finally, eliminating the winter demand discount aligns with the goal of increasing fixed cost recovery. Therefore, the third proposed rate design recommendation is to eliminate the seasonal demand charge discount.

Align Commercial (General Service) Class with Peers & COS

The General Service rates are out of alignment with its COS and the retail prices of peer utilities. This customer class often presents challenges in a Study of this type. Although customers in this class use more energy than those in the Residential class, their demand is not usually metered or charged. This class is usually charged on consumption alone. Absent demand meter data, differentiating this class for COS purposes is challenging. Hence, evaluating the pricing structures of peer utilities provides useful rate design feedback. The fourth proposed rate design recommendation is to align this class with its COS and peer utility rates.

Implement New Rates January 1, 2024

Given the level of shortfalls recently experienced, the future shortfalls projected, and the feedback of rating agencies, proposed rates should be implemented sooner rather than later. Instead of implementing proposed rate designs in FY 2025 (in July 2024) the fifth proposed recommendation is to implement new rates on January 1, 2024.

PROJECTED REVENUES AT FUTURE RATES

The following table shows that revenues at the proposed rates are sufficient to meet the forecasted revenue requirements.

Stillwater Utilities Authority — Electric Utility
Summary of Projected Revenue Requirements and Revenues at Proposed Rates
Fiscal Year Ending June 30,

Ln. No.	Description	Revenue Requirement 2025	2026	2027	2028	2029
	(a)	(b)	(c)	(d)	(e)	(f)
	Operating Expenses - Electric Distribution					
1	Cost of Power	$ 32,725,494	$ 32,588,447	$ 32,431,916	$ 32,221,708	$ 32,182,728
2	Natural Gas	4,533,379	4,570,833	4,508,366	4,471,731	4,462,894
3	Administration	2,104,797	2,162,588	2,220,706	2,285,287	2,350,325
4	Engineering	1,183,617	1,234,048	1,281,234	1,330,624	1,376,049
5	Generation O&M	3,763,895	3,862,312	3,962,255	4,074,151	4,188,021
6	Distribution O&M	7,340,333	7,604,988	7,858,712	8,129,945	8,387,913
7	Warehouse & Fleet	1,572,661	1,617,473	1,662,217	1,711,660	1,761,060
8	Customer Service	348,293	361,528	374,116	387,480	400,055
9	Metering	337,543	351,833	365,216	379,234	392,144
10	*Total Operating Expenses*	*$ 53,910,013*	*$ 54,354,051*	*$ 54,664,736*	*$54,991,821*	*$55,501,188*
	Other Revenue Requirements					
11	Transfer to General Fund	$ 17,250,000	$ 17,767,500	$ 18,300,525	$ 18,849,541	$ 19,415,027
12	Transfer to RSF	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
13	Transfer to Replenish RSF	0	0	0	0	0
14	Deposit to Rate Balancing Account	522,439	162,774	0	0	0
15	*Total Other Revenue Requirements*	*$ 22,772,439*	*$ 22,930,274*	*$ 23,300,525*	*$ 23,849,541*	*$ 24,415,027*
16	**Total Expenditures**	**$ 76,682,451**	**$ 77,284,325**	**$ 77,965,261**	**$ 78,841,362**	***$ 79,916,215***
	Less Transfers and Other Revenue					
17	Service Expansion (RSF Transfer)	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365
18	Utility Pole Attachment	101,218	126,853	152,488	178,123	203,758
19	Miscellaneous Revenue	50,000	51,000	52,020	53,060	54,122
20	SUA Revenue Allocation	525,920	539,068	552,545	567,740	583,353
21	GRDA Capacity	165,000	165,000	165,000	165,000	165,000
22	GRDA Energy	4,352,044	4,388,000	4,328,031	4,292,862	4,284,378
23	Sales Tax	9,700,000	9,700,000	9,700,000	9,700,000	9,700,000
24	*Total Other Revenue*	*$ 15,044,182*	*$ 15,122,921*	*$ 15,106,144*	*$ 15,115,966*	*$ 15,152,975*
25	**NET REVENUE REQUIREMENTS**	**$ 61,638,269**	**$ 62,161,405**	**$ 62,859,118**	**$ 63,725,396**	**$ 64,763,241**
	Projected Revenue From Sales					
26	Existing Base Rate Revenues	$ 51,272,784	$ 52,251,213	$ 53,307,588	$ 54,493,014	$ 55,876,694
27	PCA Revenues	10,365,485	9,910,192	9,458,191	8,968,302	8,650,865
28	Transfer From Rate Balancing Account	0	0	93,338	264,080	235,681
29	**TOTAL REVENUES FROM SALES**	**$ 61,638,269**	**$ 62,161,405**	**$ 62,859,118**	**$ 63,725,396**	**$ 64,763,241**
30	Revenue Surplus or (Deficiency)	$ -	$ -	$ -	$ -	$ -
31	Surplus or (Deficiency) as a Percentage of Existing Rate Revenues	0%	0%	0%	0%	0%

PROPOSED RATES AND CUSTOMER IMPACTS

This section of the report presents proposed TY rates, customer impacts, comparisons with peer utilities, and the five-year proposed rate path. Appendix A presents proposed rates.

PROPOSED RATES v CURRENT AND COS RATES

The table below presents the current, COS, and proposed rates by tariff for the TY.

Summary of Existing Rates, COS Rates, and Test Year Proposed Rates								
Ln No	Tariff	Unit	Exist-ing Rate	COS Rate	Change COS v. Current		New TY Rate	Change New v Existing
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Residential**							
2	**Residential Service**							
3	Customer Charge	($/month)	$10.39	$24.00	$13.61	131%	$12.28	$1.89
4	Summer	($/kWh)	0.11446	0.10390	(0.01056)	-9%	0.11463	0.00017
5	Winter							
6	0 to 600 kWh per Mo	($/kWh)	0.11446	0.10390	(0.01056)	-9%	0.11463	0.00017
7	> 600 kWh per Mo	($/kWh)	0.06693	0.10390	0.03697	55%	0.11463	0.04770
8	PCA	($/kWh)	Varies	0.02352			Varies	
9	**Energy Efficient Residential Services**							
10	Customer Charge	($/month)	$10.39	$24.00	$13.61	131%	$12.28	$1.89
11	Summer	($/kWh)	0.10978	0.10426	(0.00552)	-5%	0.10994	0.00016
12	Winter							
13	0 to 600 kWh per Mo	($/kWh)	0.10978	0.10426	(0.00552)	-5%	0.10994	0.00016
14	> 600 kWh per Mo	($/kWh)	0.06225	0.10426	0.04201	67%	0.10994	0.04769
15	PCA	($/kWh)	Varies	0.02352			Varies	
16	**Low Usage Residential**							
17	Customer Charge	($/month)	$8.84	$24.00	$15.16	171%	$10.45	$1.61
18	Energy	*($/kWh)*	0.09037	0.10405	0.01368	15%	0.09173	0.00136
19	PCA	($/kWh)	Varies	0.02352			Varies	
20	**Residential Heat Pump**							
21	Customer Charge	($/month)	$10.39	$24	$13.61	131%	$12.28	$1.89
22	Summer	($/kWh)	0.11446	0.10309	(0.01137)	-10%	0.10994	(0.00452)
23	Winter							
24	0 to 600 kWh per Mo	($/kWh)	0.10600	0.10309	(0.00291)	-3%	0.10994	0.00394
25	> 600 kWh per Mo	($/kWh)	0.06475	0.10309	0.03834	59%	0.10994	0.04519
26	PCA	($/kWh)	Varies	0.02352			Varies	
27	**Block Billing (kWh)**							
28	Customer Charge	($/month)	$10.39	$24.00	$13.61	131%	$12.28	$1.89
29	Summer	($/kWh)	0.11446	0.10319	(0.01127)	-10%	0.11463	0.00017
30	Winter							
31	0 to 600 kWh per Mo	($/kWh)	0.11446	0.10319	(0.01127)	-10%	0.11463	0.00017
32	> 600 kWh per Mo	($/kWh)	0.06693	0.10319	0.03626	54%	0.11463	0.04770
33	PCA	($/kWh)	Varies	0.02352			Varies	

Summary of Existing Rates, COS Rates, and Test Year Proposed Rates								
Ln No	Tariff	Unit	Existing Rate	COS Rate	Change COS v. Current		New TY Rate	Change New v Existing
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
34	**Commerical**							
35	**General Service**							
36	Customer Charge	($/month)	$19.14	$24.00	$4.86	25%	$19.33	$0.19
37	Summer	($/kWh)	0.13679	0.07333	(0.06346)	-46%	0.12910	(0.00769)
38	Winter							
39	0 to 2000 kWh per Mo	($/kWh)	0.13679	0.07333	(0.06346)	-46%	0.12910	(0.00769)
40	> 2000 kWh per Mo	($/kWh)	0.09037	0.07333	(0.01704)	-19%	0.12910	0.03873
41	PCA	($/kWh)	Varies	0.02352			Varies	
42	**Ground Source Heat Pump**							
43	Customer Charge	($/month)	$117.22	$329.45	$212.23	181%	$121.91	$4.69
44	Summer							
45	0 to 20000 kWh/Mo	($/kWh)	0.09112	0.09671	0.00559	6%	0.08320	(0.00792)
46	> 20000 kWh/Mo	($/kWh)	0.06364	0.09671	0.03307	52%	0.08320	0.01956
47	Winter							
48	0 to 20000 kWh/Mo	($/kWh)	0.08602	0.09671	0.01069	12%	0.08320	(0.00282)
49	> 20000 kWh/Mo	($/kWh)	0.05860	0.09671	0.03811	65%	0.08320	0.02460
50	**Power & Light**							
51	**Power and Light Primary**							
52	Customer Charge	($/month)	$429.83	$120.00	$(309.83)	-72%	$434.13	$4.30
53	Energy	($/kWh)	0.05866	0.026764	(0.03190)	-54%	0.05455	(0.00411)
54	Summer Demand	($/kW Mo)	11.29	24.16	$12.87	114%	13.30	2.01
55	Winter Demand	($/kW Mo)	9.27	24.16	$14.89	161%	13.30	4.03
56	PCA	($/kWh)	Varies	0.02352			Varies	
57	**Power and Light Primary, Time of Day**							
58	Customer Charge	($/month)	$429.83				$434.13	$4.30
59	TOU Meter Charge	($/month)	17.18				17.70	0.030
60	Energy	($/kWh)	0.05866				0.05590	(0.00276)
61	Summer Demand	($/kW Mo)	2.47				2.64	0.17
62	Summer Peak Demand	($/kW Mo)	8.61				9.21	0.60
63	Winter Demand	($/kW Mo)	9.27				9.92	0.65
64	PCA	($/kWh)	Varies				Varies	
65	**Power and Light Secondary**							
66	Customer Charge	($/month)	$240.70	$72.00	$(168.70)	-70%	$243.11	$2.41
67	Energy	($/kWh)	0.05866	0.02855	(0.03011)	-51%	0.05573	(0.00293)
68	Summer Demand	($/kW Mo)	12.06	24.16	$12.10	100%	14.20	2.14
69	Winter Demand	($/kW Mo)	10.11	24.16	$14.05	139%	14.20	4.09
70	PCA	($/kWh)	Varies	0.02352			Varies	

Ln No	Tariff	Unit	Existing Rate	COS Rate	Change COS v. Current		New TY Rate	Change New v Existing
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
71	**Power and Light Secondary, TOD**							
72	Customer Charge	($/month)	$240.70	$72.00	$(168.70)	-70%	$243.11	$2.41
73	TOU Meter Charge	($/month)	17.18	-	$(17.18)	0%	17.70	0.52
74	Energy - On Peak	($/kWh)	0.05866	0.02864	(0.03002)	-51%	0.05749	(0.00117)
75	Energy - Off Peak	($/kWh)	0.05866	0.02864	(0.03002)	-51%	0.05749	(0.00117)
76	Summer Demand	($/kW Mo)	2.53	24.16	$21.63	855%	2.91	0.38
77	Summer Peak Demand	($/kW Mo)	9.24	24.16	$14.92	161%	10.63	1.39
78	Winter Demand	($/kW Mo)	10.11	24.16	$14.05	139%	11.63	1.52
79	PCA	($/kWh)	Varies	0.02352			Varies	
80	**Industrial**							
81	**Large Power and Light Svc Level 3 & 4**							
82	Customer Charge	($/month)	$440.79	$240.00	$(200.79)	-46%	$463.00	$22.21
83	Summer							
84	0 to 2000000 kWh/Mo	($/kWh)	0.04932	0.02836	(0.02096)	-43%	0.04437	(0.00495)
85	> 2000000 kWh/Mo	($/kWh)	0.04092	0.02836	(0.01256)	-31%	0.04437	0.00345
86	Winter							
87	0 to 2000000 kWh/Mo	($/kWh)	0.04932	0.02836		-43%	0.04437	(0.00495)
88	> 2000000 kWh/Mo	($/kWh)	0.04092	0.02836		-31%	0.04437	0.00345
89	Summer Demand	($/kW Mo)	19.50	22.83		17%	13.90	(5.60)
90	Winter Demand	($/kW Mo)	6.97	22.83		228%	13.90	6.93
91	PCA	($/kWh)	Varies	0.02352			Varies	
92	**Large Power and Light Service Level 5**							
93	Customer Charge	($/month)	$248.52				$261.04	$12.52
94	Summer							
95	0 to 2000000 kWh/Mo	($/kWh)	0.05044				0.04537	(0.00507)
96	> 2000000 kWh/Mo	($/kWh)	0.04242				0.04537	0.00295
97	Winter							
98	0 to 2000000 kWh/Mo	($/kWh)	0.05044				0.04537	(0.00507)
99	> 2000000 kWh/Mo	($/kWh)	0.04242				0.04537	0.00295
100	Summer Demand	($/kW Mo)	21.26				13.97	(7.29)
101	Winter Demand	($/kW Mo)	7.60				13.97	6.37
102	PCA	($/kWh)	Varies				Varies	
103	**Electric Vehicle Charging**							
104	**Electric Vehicle Charging**							
105	Customer Charge	($/month)	$37.13	$24.00	$(13.13)	-35%	$39.00	$1.87
106	Demand Charge	($/kW Mo)	10.11	19.81			11.12	1.01
107	Energy	($/kWh)	0.05866	0.02551	(0.03315)	-57%	0.05485	(0.00381)
108	PCA	($/kWh)	Varies	0.02352			Varies	

Ln No	Tariff	Unit	Existing Rate	COS Rate	Change COS v. Current		New TY Rate	Change New v Existing
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
109	**Net Energy Metering Distributed Generation Tariff**							
110	**Net Energy Metering Distributed Generation Tariff**							
111	Residential Service Availability Fee	($/month)	$44.56	$74.27	$29.71	-100%	$51.39	$6.83
112	General Service Availability Fee	($/month)	$201.57				$191.50	(10.07)
113	Power and Light Secondary Service Availability Fee	($/month)	$1,485.26				$1,150.00	$(335.26)

Summary of Existing Rates, COS Rates, and Test Year Proposed Rates

CUSTOMER IMPACTS OF PROPOSED RATES

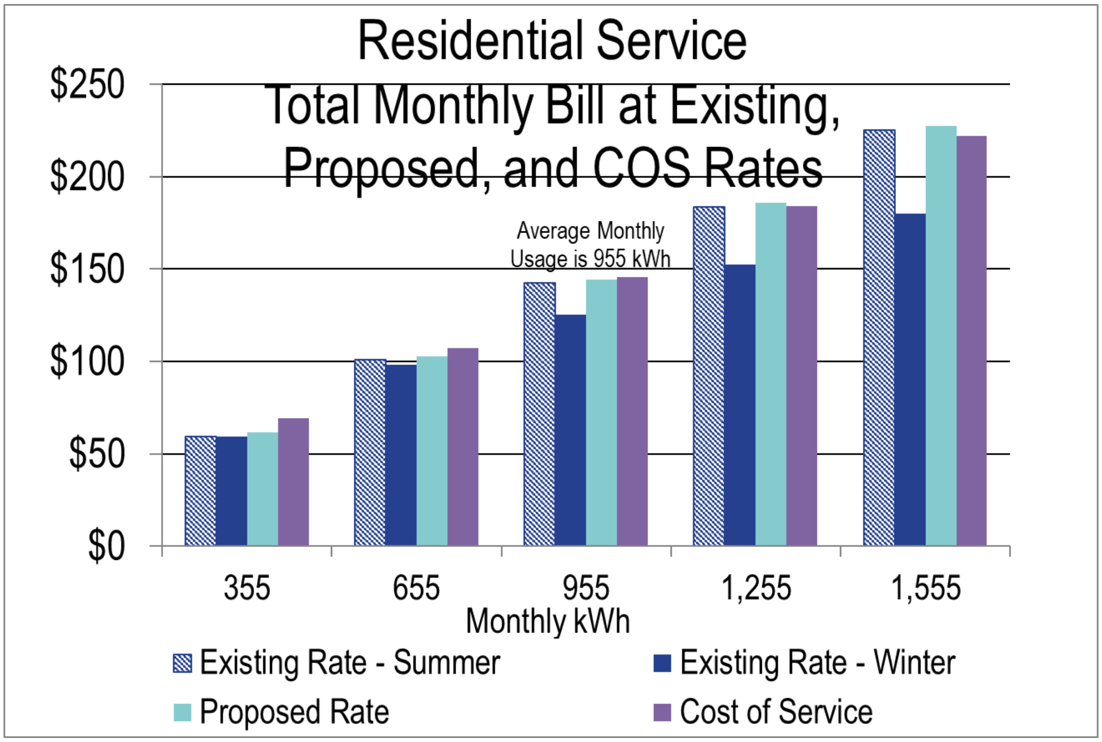
This section provides the impact of proposed TY rates on customers by class, a comparison with peer utilities, and the proposed five-year rate path. Residential Class results are followed by results for the Commercial, Power, and Industrial Classes.

Residential

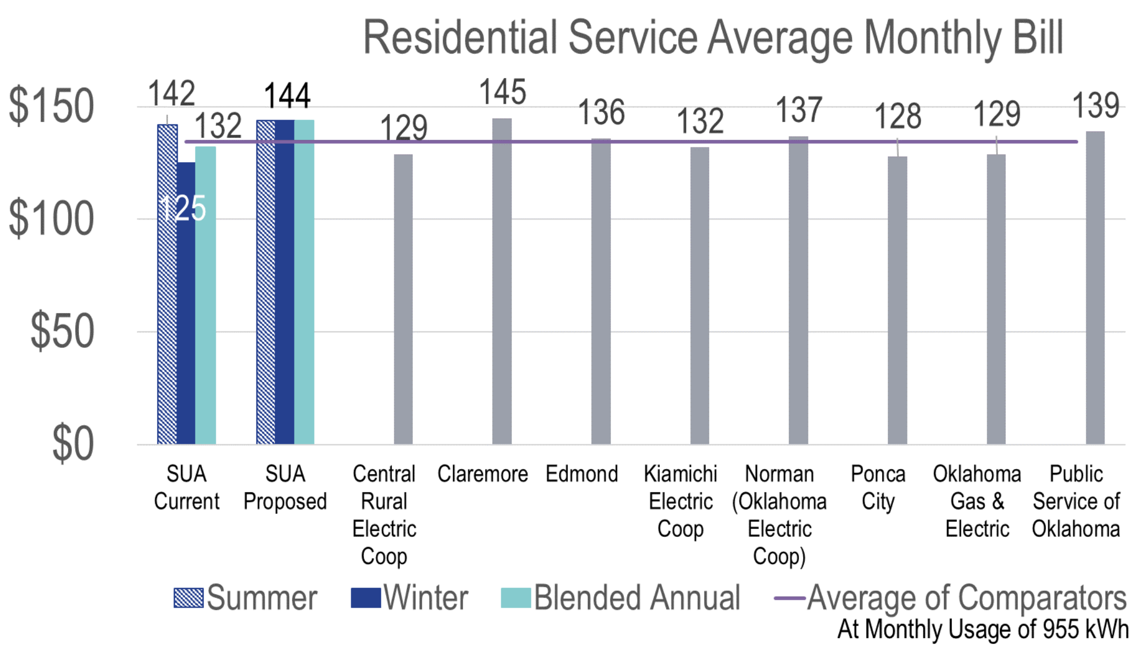
The table below presents the impact of proposed rates on the Residential customer class for the TY. The graph below illustrates rate impacts at different levels of consumption.

Residential Class Summary

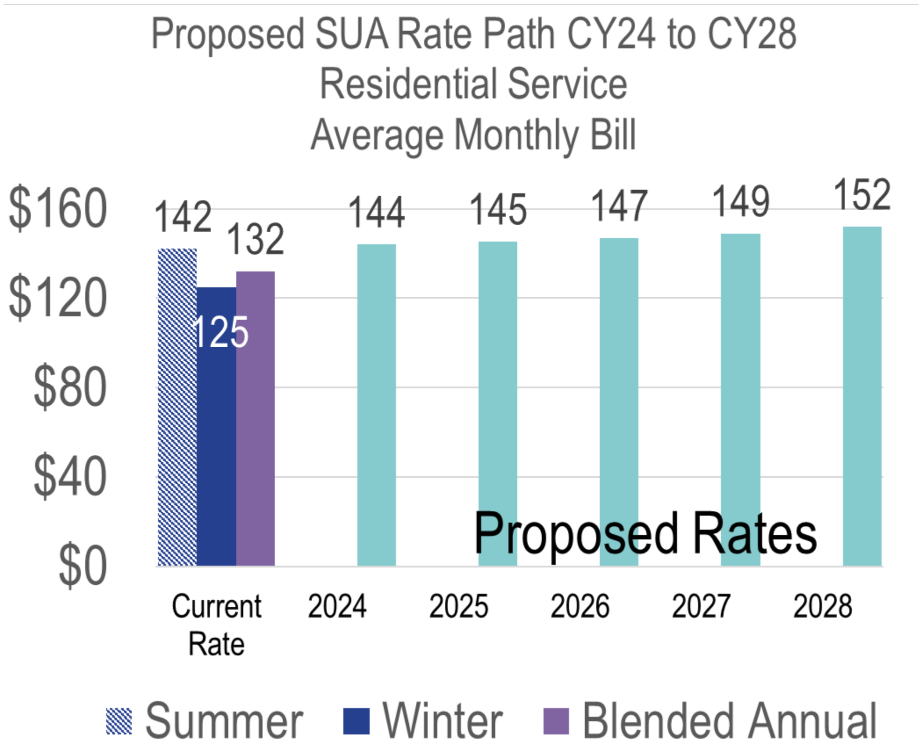
	Existing			COS		Proposed	
Item	Rate	Billing Units	Revenue	Rate	Revenue	Rate	Revenue
Service Charge	$ 10.39	209,377	$ 2,175,432	$ 24.00	$ 5,025,002	$ 12.28	$ 2,571,967
Energy	$ -	-	$ -	$ -	$ -	$ -	$ -
Summer kWh	$ 0.11446	104,030,905	$ 11,907,377	$ 0.09585	$ 9,971,441	$ 0.11463	$ 11,925,238
Winter <= 600 kWh	$ 0.11446	60,081,826	$ 6,876,966	$ 0.09585	$ 5,758,889	$ 0.11463	$ 6,887,281
Winter > 600 kWh	$ 0.06693	38,517,947	$ 2,578,006	$ 0.09585	$ 3,691,974	$ 0.11463	$ 4,415,377
PCA	$ 0.02374	202,630,678	$ 4,811,290	$ 0.03157	$ 6,396,324	$ 0.02374	$ 4,811,290
Total	$ 0.13991	202,630,678	$ 28,349,072	$ 0.15222	$ 30,843,630	$ 0.15107	$ 30,611,154
Change in Revenue ($)					$ 2,494,558		$ 2,262,083
Change in Revenue (%)					8.80%		8.0%



The following table compares an average monthly bill at SUA's current and proposed TY Residential rates to peer utilities. Bills for comparator utilities include fuel and wholesale power cost adjustments based on differing methodologies that in many cases change monthly. Therefore, these values can vary based on the value of the adjustment.



The proposed rate path for the Residential Class appears in the figure below.

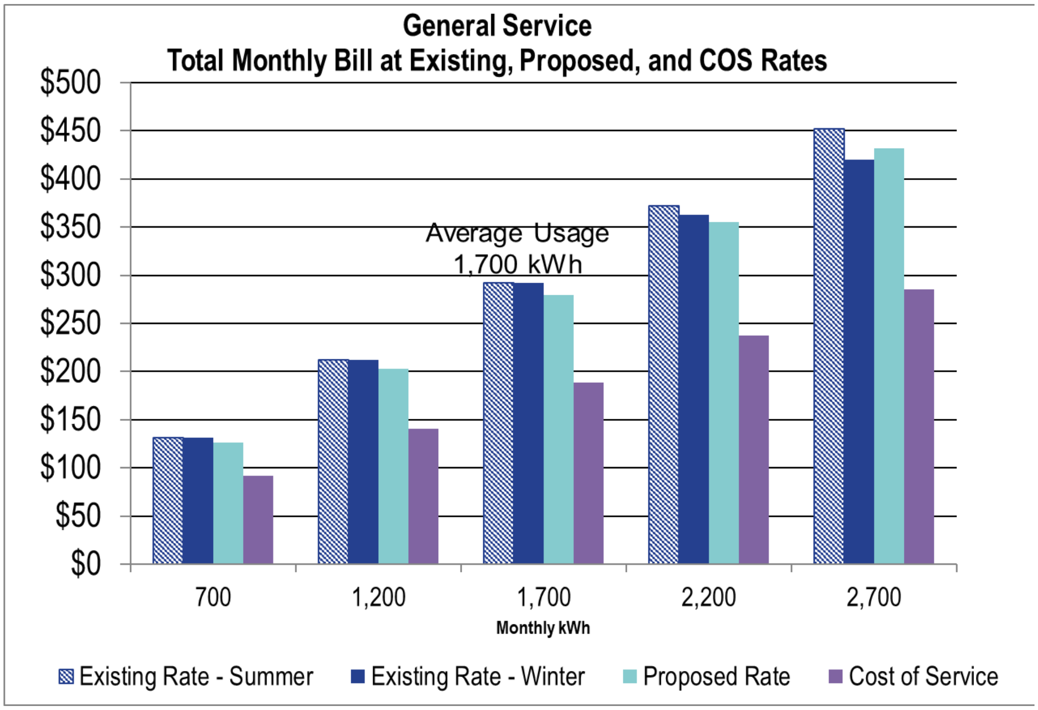


Commercial

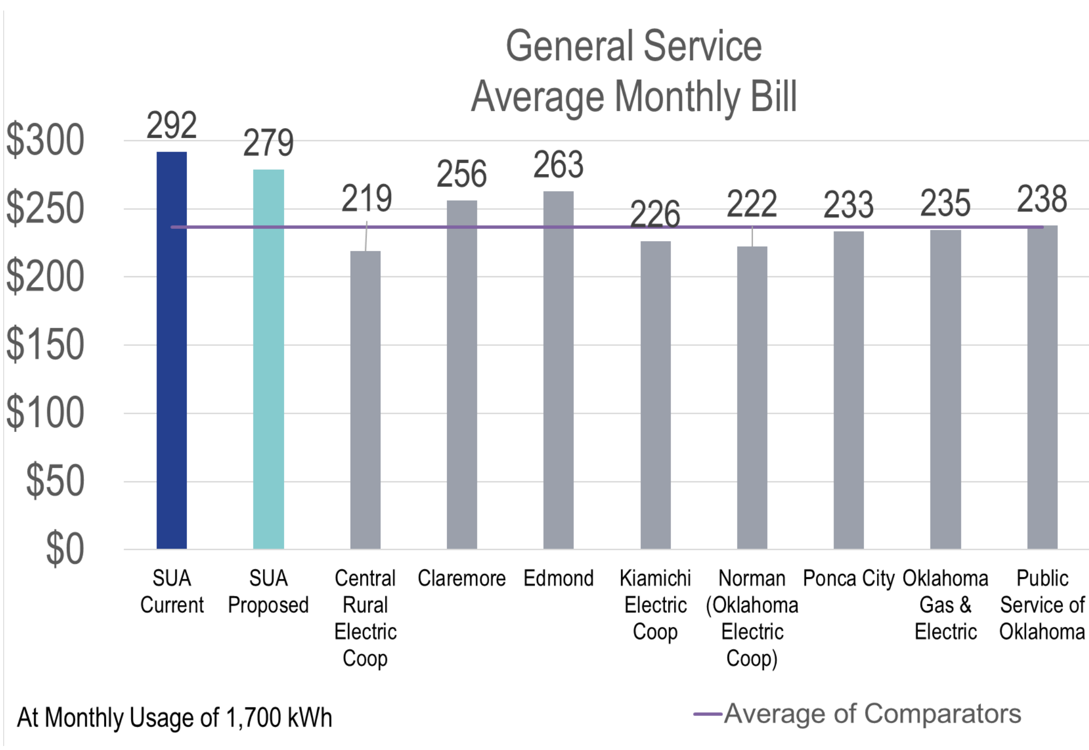
The table below presents the impact of proposed rates on the General Service (Commercial) customer class for the TY.

General Service Class Summary							
	Existing			COS		Proposed	
Item	**Rate**	**Billing Units**	**Revenue**	**Rate**	**Revenue**	**Rate**	**Revenue**
Service Charge	$ 19.14	29,076	$ 556,515	$ 24.00	$ 697,816	$ 19.33	$ 562,080
Energy	$ -	-	$ -	$ -	$ -	$ -	$ -
Summer kWh	$ 0.13679	24,457,645	$ 3,345,561	$ 0.06528	$ 1,596,602	$ 0.12910	$ 3,157,541
Winter <= 2000 kWh	$ 0.13679	13,861,992	$ 1,896,182	$ 0.06528	$ 904,914	$ 0.12910	$ 1,789,616
Winter > 2000 kWh	$ 0.09037	11,505,669	$ 1,039,767	$ 0.06528	$ 751,093	$ 0.12910	$ 1,485,410
PCA	$ 0.02369	49,825,306	$ 1,180,265	$ 0.03157	$ 1,572,806	$ 0.02369	$ 1,180,265
Total	$ 0.16093	49,825,306	$ 8,018,290	$ 0.11085	$ 5,523,232	$ 0.16407	$ 8,174,911
Change in Revenue ($)					$ (2,495,058)		$ 156,621
Change in Revenue (%)					-31.12%		2.0%

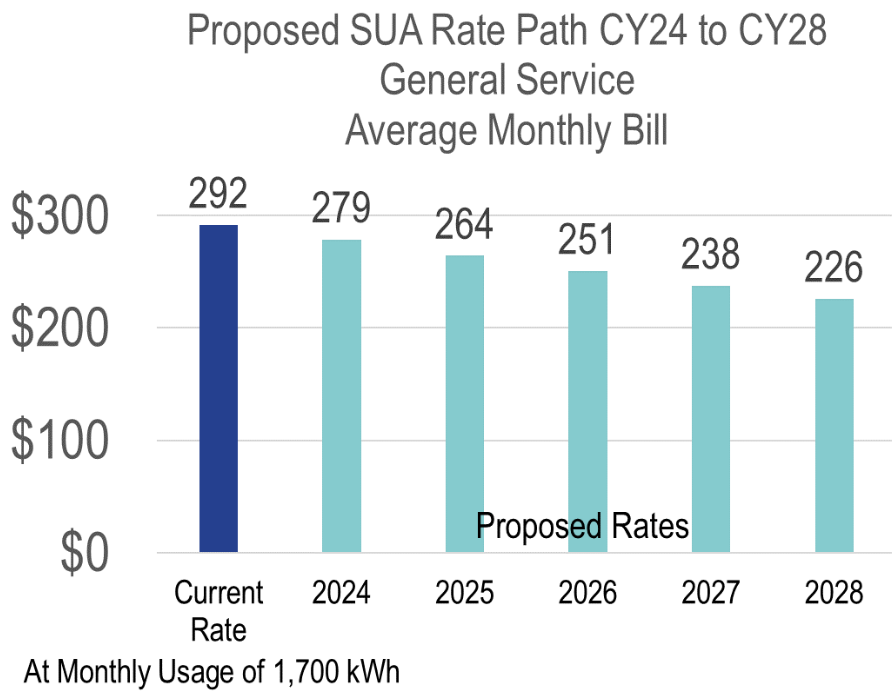
The graph below illustrates rate impacts at different levels of consumption.



The following table compares SUA's current and proposed Commercial (General Service) rates to peer utilities. Bills for comparator utilities include fuel and wholesale power cost adjustments based on differing methodologies that in many cases change monthly. Therefore, these values can vary based on the value of the adjustment.



The proposed rate path for the Commercial (General Service) Class appears in the figure below.

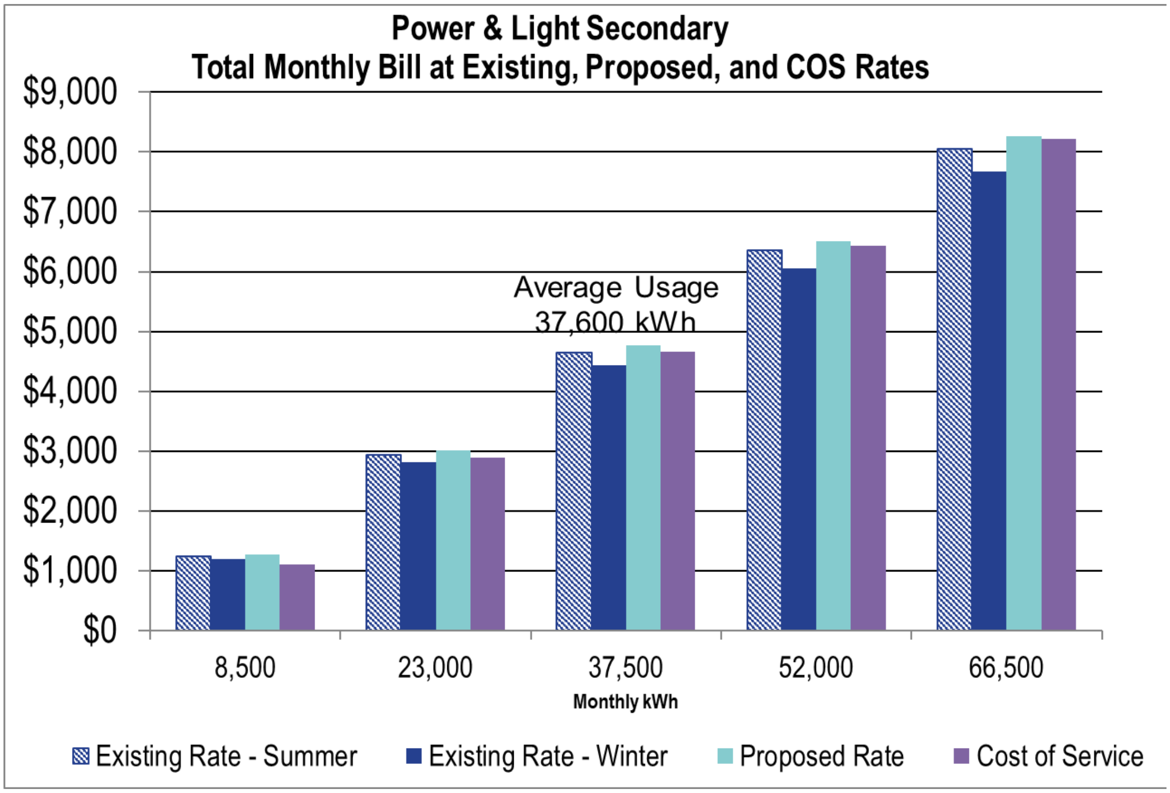


Power and Light

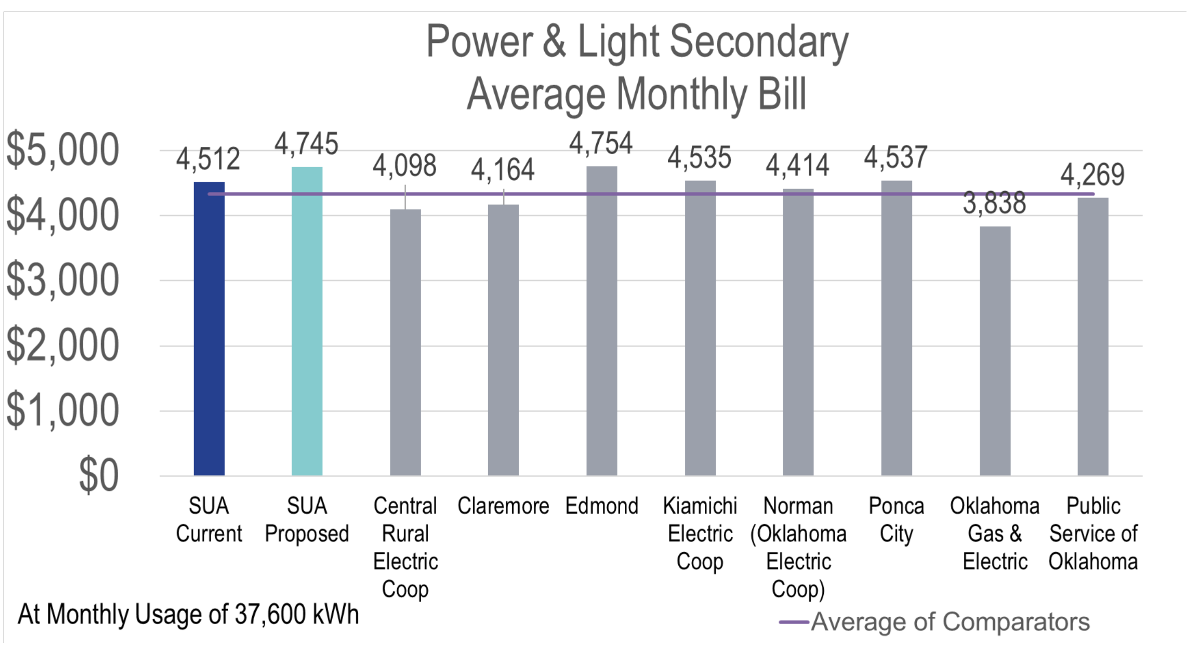
The table below presents the impact of proposed rates on the Power and Light Secondary customer class for the TY.

Power & Light Secondary Class Summary							
	Existing			COS		Proposed	
Item	**Rate**	**Billing Units**	**Revenue**	**Rate**	**Revenue**	**Rate**	**Revenue**
Service Charge	$ 240.70	3,252	$ 782,756	$ 72.00	$ 234,141	$ 243.11	$ 790,584
Energy	$ -	-	$ -	$ -	$ -	$ -	$ -
All kWh	$ 0.05866	122,287,128	$ 7,173,363	$ 0.02855	$ 3,491,259	$ 0.05573	$ 6,814,695
PCA	$ 0.02374	122,287,128	$ 2,902,524	$ 0.02352	$ 2,876,173	$ 0.02374	$ 2,902,524
Demand	$ -	-	$ -	$ -	$ -	$ -	$ -
Summer Demand	$ 12.06	163,908	$ 1,976,728	$ 24.16	$ 3,959,394	$ 14.20	$ 2,327,490
Winter Demand	$ 10.11	184,606	$ 1,866,365	$ 24.16	$ 4,459,381	$ 14.20	$ 2,621,403
Total	$ 0.12022	122,287,128	$ 14,701,736	$ 0.12283	$ 15,020,348	$ 0.12640	$ 15,456,695
Change in Revenue ($)					$ 318,612		$ 754,960
Change in Revenue (%)					2.17%		5.1%

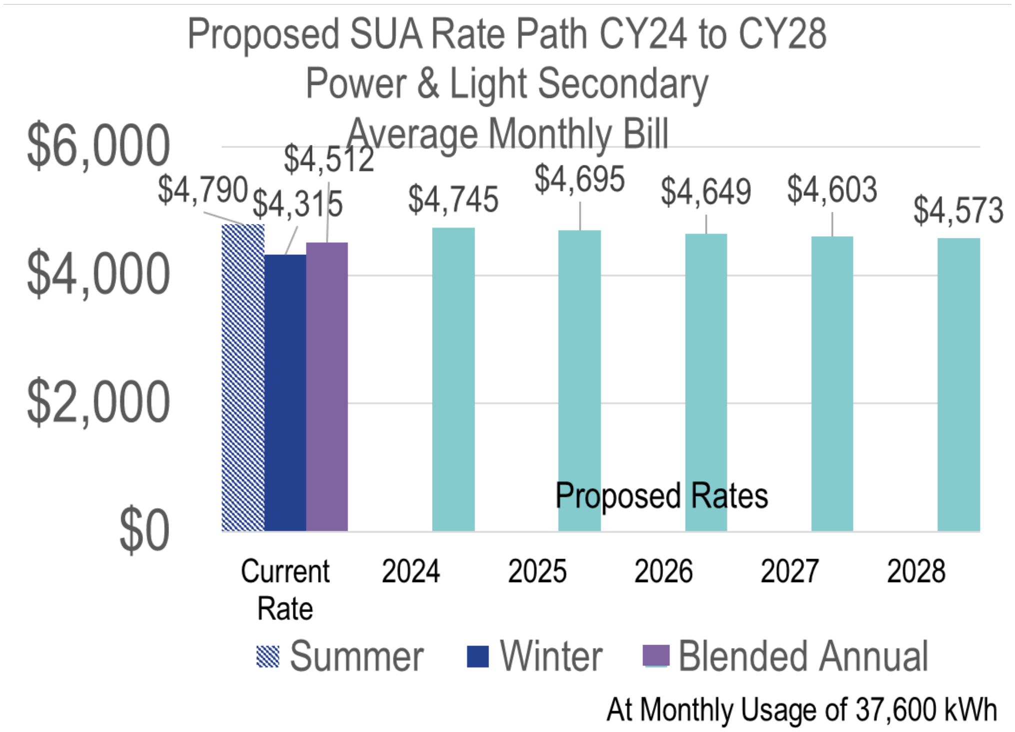
The graph below illustrates rate impacts at different levels of consumption.



The following table compares SUA's current and proposed Power & Light Secondary rates to peer utilities. Bills for comparator utilities include fuel and wholesale power cost adjustments based on differing methodologies that in many cases change monthly. Therefore, these values can vary based on the value of the adjustment.



The proposed rate path for the Power & Light Secondary Class appears in the figure below.

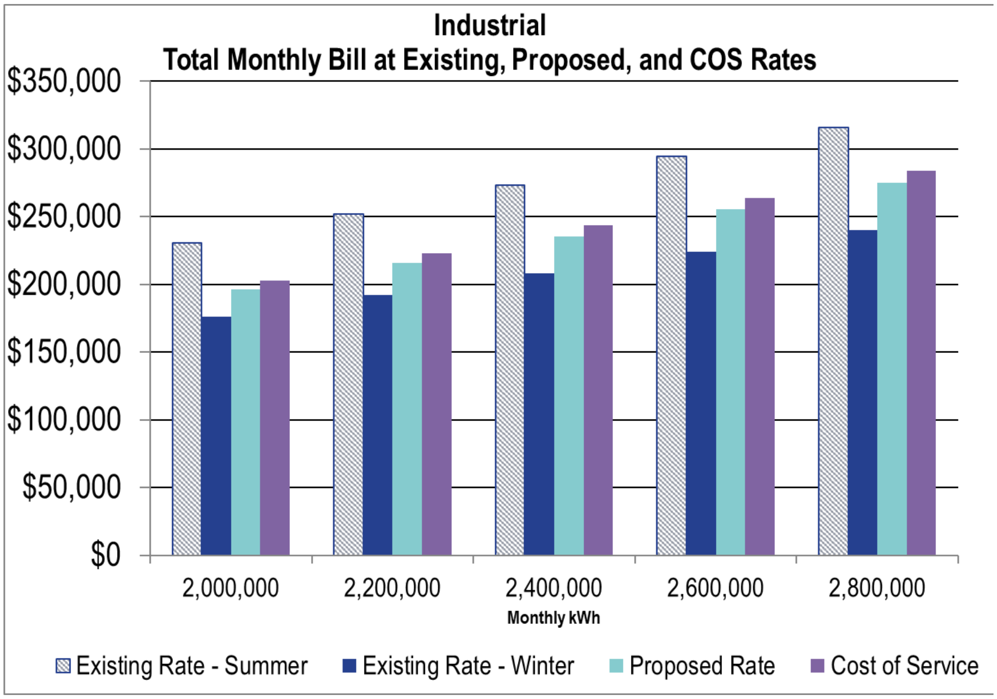


Large Power and Light

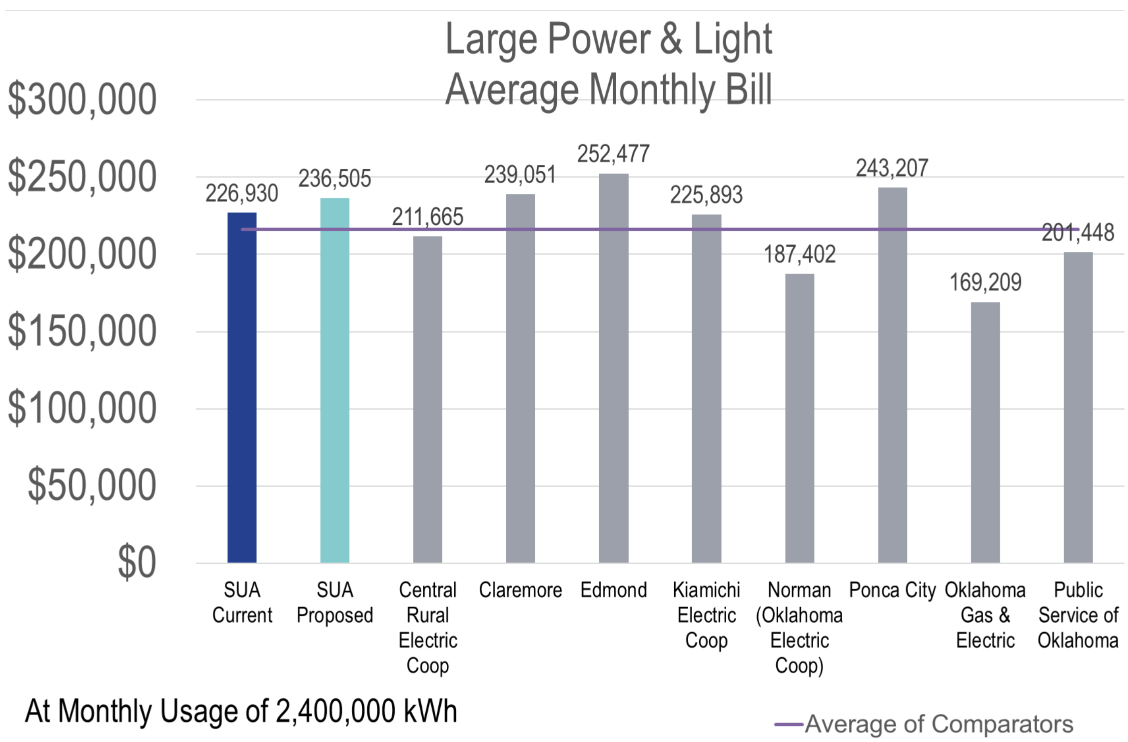
The table below presents the impact of proposed rates on the Large Power and Light Service Level 3 & 4 customer class for the TY.

Large Power and Light Service Level 3 & 4 Class Summary							
	Existing			COS		Proposed	
Item	**Rate**	**Billing Units**	**Revenue**	**Rate**	**Revenue**	**Rate**	**Revenue**
Service Charge	$ 440.79	12	$ 5,289	$ 240.00	$ 2,880	$ 463.00	$ 5,556
Energy							
Summer kWh		12,014,400		$ 0.02836	$ 340,713	$ 0.04437	$ 533,046
Summer <= 2000000 kWh	$ 0.04932	10,000,000	$ 493,200				
Summer > 2000000 kWh	$ 0.04092	2,014,400	$ 82,429				
Winter kWh		16,579,200		$ 0.02836	$ 470,165	$ 0.04437	$ 735,574
Winter <= 2000000 kWh	$ 0.04932	14,000,000	$ 690,480				
Winter > 2000000 kWh	$ 0.04092	2,579,200	$ 105,541				
PCA	$ 0.02356	28,593,600	$ 673,538	$ 0.02352	$ 672,517	$ 0.02352	$ 672,517
Demand							
Summer Demand	$ 19.50	25,639	$ 499,963	$ 22.83	$ 585,457	$ 13.90	$ 356,384.22
Winter Demand	$ 6.97	37,480	$ 261,236	$ 22.83	$ 855,838	$ 13.90	$ 520,972.89
Total	$ 0.09833	28,593,600	$ 2,811,678	$ 0.10239	$ 2,927,570	$ 0.09877	$ 2,824,050
Change in Revenue ($)					$ 115,892		$ 12,372
Change in Revenue (%)					4.12%		0.4%

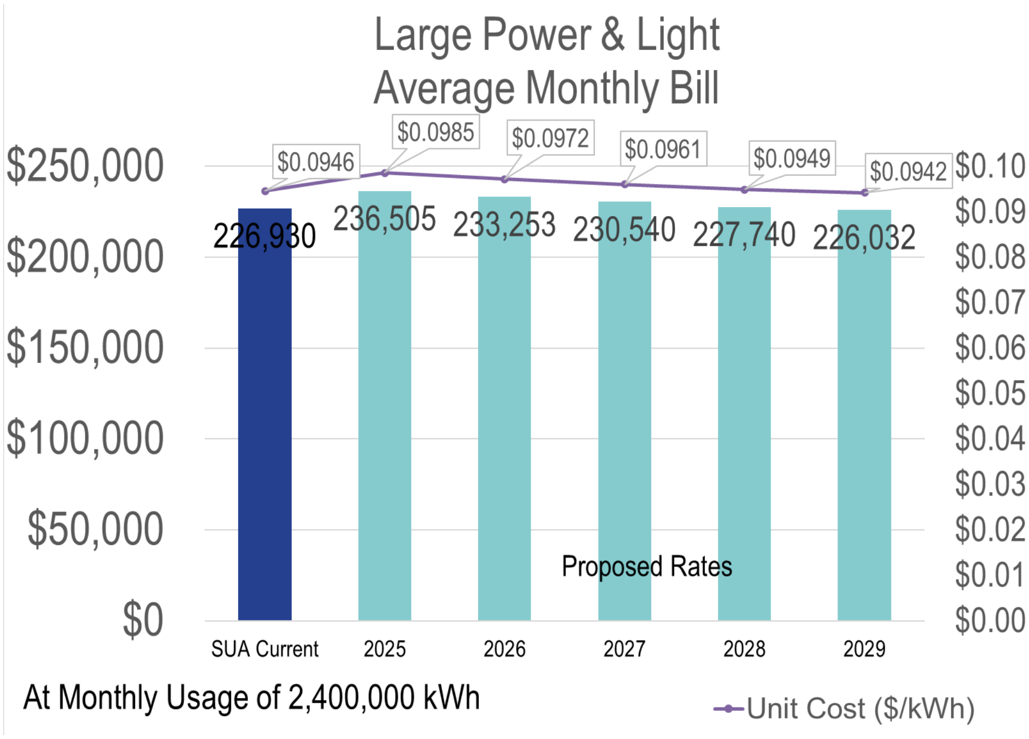
The graph below illustrates rate impacts at different levels of consumption.



The following table compares SUA's current and proposed Large Power and Light Service Level 3 & 4 rates to peer utilities. Bills for comparator utilities include fuel and wholesale power cost adjustments based on differing methodologies that in many cases change monthly. Therefore, these values can vary based on the value of the adjustment.



The proposed rate path for the Large Power and Light Service Level 3 & 4 Class appears in the figure below.



RESULTS & RECOMMENDATIONS

RESULTS

SUA has experienced many changes since the 2019 Study.

- Costs have increased dramatically.
    - $3 Million for Test Year Revenue Requirement
    - Average $0.78 Million per year FY 2026 - 2029
- Revenues at current rates are insufficient to meet operating needs.
    - Fund balance draws have been used to meet operational needs
    - Forecasted 5-year deficit of $22 Million
- Rating agencies have voiced concerns.
    - Potential for ratings downgrade
    - Potential for increased financing costs

Action is needed.

RECOMMENDATIONS

Based on the COS Study results and evaluation of the current SUA electric tariff structures, LVC offers the following five recommendations for SUA's consideration.

1. Increase fixed charges to align with cost of service.
2. Eliminate declining-block rate billing structures.
    - Archaic and out of alignment with sustainability goals
    - Residential tiers are not working as intended
3. Eliminate seasonal demand charge differentials.
    - Not aligned with COS
    - May be distorting summer costs relative to market
4. Align Commercial (General Service) class with peers & COS.
5. Implement new rates January 1, 2024.

APPENDIX A. PROPOSED RATES BY TARIFF

The following table presents the proposed rates by tariff.

Line No.	Rate (a)	Current (b)	2024 (c)	2025 (d)	2026 (e)	2027 (f)	2028 (g)
	Proposed Electric Rates CY2024 - CY2028						
1	**Residential**						
2	**Residential Service**						
3	Customer Charge ($/Month)	$10.39	$12.28	$14.52	$17.17	$20.30	$24.00
4	ENERGY CHARGE ($/kWh)						
5	Summer (May 1 to September 30)	0.11446	0.11463	0.11480	0.11498	0.11515	0.11532
6	Winter (October 1 to April 30)						
7	0 to 600 kWh per Month	0.11446	0.11463	0.11480	0.11498	0.11515	0.11532
8	> 600 kWh per Month	0.06693	0.11463	0.11480	0.11498	0.11515	0.11532
9	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
10	**Energy Efficient Residential**						
11	Customer Charge ($/Month)	10.39	12.28	14.52	17.17	20.30	24.00
12	ENERGY CHARGE ($/kWh)						
13	Summer (May 1 to September 30)	0.10978	0.10994	0.11011	0.11027	0.11044	0.11061
14	Winter (October 1 to April 30)						
15	0 to 600 kWh per Month	0.10978	0.10994	0.11011	0.11027	0.11044	0.11061
16	> 600 kWh per Month	0.06225	0.10994	0.11011	0.11027	0.11044	0.11061
17	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
18	**Low Usage Residential**						
19	Customer Charge ($/Month)	8.84	10.45	12.36	14.61	17.27	20.42
20	Energy ($/kWh)	0.09037	0.09173	0.09310	0.09450	0.09592	0.09735
21	PCA ($/kWh)	*Varies*	*Varies*	*Varies*	Varies	Varies	Varies
22	**Residential Heat Pump**						
23	Customer Charge ($/Month)	10.39	12.28	14.52	17.17	20.30	24.00
24	ENERGY CHARGE ($/kWh)						
25	Summer (May 1 to September 30)	0.11446	0.10994	0.11011	0.11027	0.11044	0.11061
26	Winter (October 1 to April 30)						
27	0 to 600 kWh per Month	0.10600	0.10994	0.11011	0.11027	0.11044	0.11061
28	> 600 kWh per Month	0.06475	0.10994	0.11011	0.11027	0.11044	0.11061
29	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
30	**Block Billing**						
31	Customer Charge ($/Month)	10.39	12.28	14.52	17.17	20.30	24.00
32	ENERGY CHARGE ($/kWh)						
33	Summer (May 1 to September 30)	0.11446	0.11463	0.11480	0.11498	0.11515	0.11532
34	Winter (October 1 to April 30)						
35	0 to 600 kWh per Month	0.11446	0.11463	0.11480	0.11498	0.11515	0.11532
36	> 600 kWh per Month	0.06693	0.11463	0.11480	0.11498	0.11515	0.11532
37	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies

Line No.	Rate (a)	Current (b)	2024 (c)	2025 (d)	2026 (e)	2027 (f)	2028 (g)
	Proposed Electric Rates CY2024 - CY2028						
38	**Commercial**						
39	**General Service**						
40	Customer Charge ($/Month)	19.14	19.33	19.52	19.72	19.92	20.12
41	ENERGY CHARGE ($/kWh)						
42	Summer (May 1 to September 30)	0.13679	0.12910	0.12185	0.11500	0.10854	0.10244
43	Winter (October 1 to April 30)						
44	0 to 2,000 kWh per Month	0.13679	0.12910	0.12185	0.11500	0.10854	0.10244
45	> 2,000 kWh per Month	0.09037	0.12910	0.12185	0.11500	0.10854	0.10244
46	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
47	**Ground Source Heat Pump**						
48	Customer Charge ($/Month)	117.22	121.91	126.79	131.86	137.13	142.62
49	ENERGY CHARGE ($/kWh)						
50	Summer (May 1 to September 30)						
51	0 to 20,000 kWh per Month	0.09112	0.08320	0.08653	0.08999	0.09359	0.09733
52	> 20,000 kWh per Month	0.06364	0.08320	0.08653	0.08999	0.09359	0.09733
53	Winter (October 1 to April 30)						
54	0 to 20,000 kWh per Month	0.08602	0.08320	0.08653	0.08999	0.09359	0.09733
55	> 20,000 kWh per Month	0.05860	0.08320	0.08653	0.08999	0.09359	0.09733
56	**Power**						
57	**Power and Light Primary**						
58	Customer Charge ($/Month)	429.83	434.13	438	442.85	447.28	451.76
59	Energy ($/kWh)	0.05866	0.05455	0.05450	0.05446	0.05441	0.05436
60	Summer Demand ($/kW)	11.29	13.30	13.43	13.57	13.70	13.84
61	Winter Demand ($/kW)	9.27	13.30	13.43	13.57	13.70	13.84
62	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
63	**Power and Light Primary, TOD**						
64	Customer Charge ($/Month)	429.83	434.13	438.47	442.85	447.28	451.76
65	TOU Meter Charge (Summer $/Mo)	17.18	17.70	18.14	18.59	19.06	19.58
66	Energy ON PEAK ($/kWh)	0.05866	0.05749	0.05634	0.05521	0.05411	0.05302
67	Energy OFF PEAK ($/kWh)	0.05866	0.05749	0.05634	0.05521	0.05411	0.05302
68	Summer Demand ($/kW)	2.47	2.84	3.27	3.76	4.32	4.97
69	Summer Peak Demand ($/kW)	8.61	9.90	11.39	13.09	15.06	17.32
70	Winter Demand ($/kW)	9.27	10.66	12.26	14.10	16.21	18.65
71	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
72	**Power and Light Secondary**						
73	Customer Charge ($/Month)	240.70	243.11	245.54	247.99	250.47	252.98
74	Energy ($/kWh)	0.05866	0.05573	0.05545	0.05517	0.05490	0.05462
75	Summer Demand ($/kW)	12.06	14.20	14.30	14.40	14.50	14.60
76	Winter Demand ($/kW)	10.11	14.20	14.30	14.40	14.50	14.60
77	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies

Line No.	Rate (a)	Current (b)	2024 (c)	2025 (d)	2026 (e)	2027 (f)	2028 (g)
	Proposed Electric Rates CY2024 - CY2028						
78	**Power and Light Secondary, TOD**						
79	Customer Charge ($/Month)	240.70	243.11	245.54	247.99	250.47	252.98
80	TOU Meter Charge (Summer $/Mo)	17.18	17.70	18.14	18.59	19.06	19.58
81	Energy ON PEAK ($/kWh)	0.05866	0.05749	0.05634	0.05521	0.05411	0.05302
82	Energy OFF PEAK ($/kWh)	0.05866	0.05749	0.05634	0.05521	0.05411	0.05302
83	Summer Demand ($/kW)	2.53	2.91	3.35	3.85	4.42	5.09
84	Summer Peak Demand ($/kW)	9.24	10.63	12.22	14.05	16.16	18.58
85	Winter Demand ($/kW)	10.11	11.63	13.37	15.38	17.68	20.33
86	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
87	**Industrial**						
88	**Large Power & Light Svc Level 3&4**						
89	Customer Charge ($/Month)	440.79	463.00	486.15	510.50	536.03	562.83
90	ENERGY CHARGE ($/kWh)						
91	Summer (May 1 to September 30)						
92	0 to 2,000,000 kWh per Month	0.04932	0.04437	0.04428	0.04419	0.04410	0.04401
93	> 2,000,000 kWh per Month	0.04092	0.04437	0.04428	0.04419	0.04410	0.04401
94	Winter (October 1 to April 30)						
95	0 to 2,000,000 kWh per Month	0.04932	0.04437	0.04428	0.04419	0.04410	0.04401
96	> 2,000,000 kWh per Month	0.04092	0.04437	0.04428	0.04419	0.04410	0.04401
97	Summer Demand ($/kW)	19.50	13.90	14.00	14.11	14.22	14.32
98	Winter Demand ($/kW)	6.97	13.90	14.00	14.11	14.22	14.32
99	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
100	**Large Power & Light Svc Level 5**						
101	Customer Charge ($/Month)	248.52	260.95	273.99	287.69	302.08	317.18
102	Summer (May 1 to September 30)						
103	0 to 2,000,000 kWh per Month	0.05044	0.04537	0.04528	0.04519	0.04510	0.04501
104	> 2,000,000 kWh per Month	0.04242	0.04537	0.04528	0.04519	0.04510	0.04501
105	Winter (October 1 to April 30)						
106	0 to 2,000,000 kWh per Month	0.05044	0.04537	0.04528	0.04519	0.04510	0.04501
107	> 2,000,000 kWh per Month	0.04242	0.04537	0.04528	0.04519	0.04510	0.04501
108	Summer Demand ($/kW)	21.26	13.97	14.11	14.25	14.39	14.54
109	Winter Demand ($/kW)	7.60	13.97	14.11	14.25	14.39	14.54
110	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
111	**Electric Vehicle Charging**						
112	**Electric Vehicle Charging**						
113	Customer Charge ($/Month)	$37.13	$39.00	$40.95	$41.97	$43.02	$44.10
114	Demand Charge ($/kW)	10.11	11.12	12.23	13.46	14.80	16.28
115	Energy ($/kWh)	0.05866	0.05485	0.05128	0.04795	0.04483	0.04192
116	PCA ($/kWh)	Varies	Varies	Varies	Varies	Varies	Varies
117	**Net Energy Metering Distributed Generation Tariff**						
118	**DG-NEM Tariff**						
119	Residential Service Avail Fee	$44.56	$51.39	$58.22	$65.04	$71.87	$78.70
120	General Service Avail Fee	$201.57	$191.50	$182.00	$173.00	$164.00	$156.00
121	Power & Light Secondary SAF	$1,485.26	$1,150.00	$1,150.00	$1,150.00	$1,150.00	$1,150.00