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REPORT

2024 ELECTRIC SYSTEM COST OF SERVICE AND RATE DESIGN STUDY

MAY 24, 2024

santee cooper®

Prepared for:
South Carolina Public Service Authority (Santee Cooper)

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EXECUTIVE SUMMARY

Pursuant to the provisions of an agreement between the South Carolina Public Service Authority (Authority or Santee Cooper) and NewGen Strategies and Solutions, LLC (NewGen or the Firm), and at the direction provided by the management and staff of the Authority, the Firm has completed a 2024 Electric System Cost of Service and Rate Design Study (the Study or 2024 Study) of the Authority's electric rates applicable to all retail customers. This Study does not include ratemaking for the wholesale customer Central Electric Power Cooperative, Inc. (Central) or any other wholesale contract customers served by the Authority, though some of these customers may be impacted by derived rates. The Study addresses the calendar year 2025.

The Firm has summarized the results of the analyses and conclusions in the enclosed report. The report summarizes the basis for the proposed rates for electric service that are necessary to recover the near-term revenue requirements from retail customer classes. The proposed rates were designed to be just and reasonable. This is in accordance with the direction provided by the Authority's management and staff pursuant to S.C. Code Ann Sect. 58-31-55(A), the historic and existing policies of the Authority, and in consideration of guidelines advocated by the Federal Energy Regulatory Commission (FERC).

In preparing the Study, the Firm relied upon historical and projected data for the development of operating revenues, operating expenses, and capital requirements. The Firm obtained historical data from various Authority reports, actual customer billing data, Advanced Meter Infrastructure system information, and discussions with members of the Authority's management and staff. The Firm obtained projected data in part from a Load Forecast conducted in 2023 (LF 23-03), the Authority's forecast of fuel availability and cost, the results of the Authority's production costing analysis, the summarized analysis of customer billing records, and the Authority's current financial assumptions.

Major factors driving the need for rate revisions and for this Study include:

(i) A significant increase in Authority's costs due to compliance with environmental regulations, increased transmission operations and maintenance expenses stemming from regional system constraints, and inflation, and

(ii) A projected shortfall in revenue in 2025.

The projections contained herein were based on numerous assumptions and considerations traditionally used in the rate making process. Thus, the projections are intended to develop unit costs and rates necessary to recover the cost of providing service to the Authority's retail customer classes and any new municipal wholesale customers over time and are not intended to be statements of actual operational performance. Revenues from services provided to Central and other existing wholesale customers are identified herein and only included in the analysis insofar as they impact the rates of Authority retail customers.

The Authority adopted its existing rates for retail customers on December 7, 2015, and implemented these rates on April 1, 2017.

The 2024 Study consists of a summary report and three appendices:

- Appendix A – Bill Comparisons
- Appendix B – Proposed Rate Schedules
- Appendix C – Technical Appendix (available upon request)

Summary of Findings

Section 2 discusses the various assumptions, adjustments, and considerations regarding projected requirements, sales, and customers, and Section 3 addresses the projected revenues and expenditures. Table ES-1 summarizes the total system revenue requirements for the calendar year 2025 and the projected revenues assuming existing rates.

Table ES-1
Total System Costs ($000) (1)

Total System Revenue Requirements	2025
Operations & Maintenance Expenses	
Fuel Expenses	$687,589
Purchased Power	$245,497
Other Production O&M Expenses	$312,698
Total Production Expenses	**$1,245,784**
Transmission Expenses	$73,934
Distribution Expenses	$21,253
Customer Acct. & Information Exp.	$17,772
Sales Expenses	$3,147
Administration & General Expenses	$134,020
Total Operations & Maintenance Expenses	**$1,495,910**
Payment in Lieu of Taxes	$28,368
Debt Service	$505,695
Working Capital Requirement	$13,534
Total Revenue Requirement Before CIF (2)	**$2,043,507**
CIF Requirement	$202,255
Gross Revenue Requirements	**$2,245,762**
Less: Interest and Miscellaneous Income	($4,230)
Less: Other Operating Revenues (3)	($22,292)
Less: Off-System Sales	($38,650)
Total System Revenue Requirements	**$2,180,590**
Less: Wholesale Power Sales (4)	($1,336,977)
Total Cost of Service	**$843,613**
Less: Revenues Under Existing Rates (5)	$803,910
Estimated Revenue Surplus (Deficiency)	**($39,703)**
% Rev. Surplus (Deficiency) Under Current Rates	**(4.9%)**

(1) Numbers may not add due to rounding.
(2) Capital Improvement Fund.
(3) Includes economic development revenues.
(4) Includes Central and Municipal revenues at proposed rates.
(5) Includes industrial non-firm revenue.

Table ES-2 below sets forth the difference between the cost of providing service and the revenue produced by the existing rates by customer class for 2025.

Table ES-2
Retail Cost of Service and Existing Firm Rate Revenue Projections (1)

	Calendar Year 2025 ($000)			
			Difference	
Service	Cost of Service (2)	Existing Rate Revenue	Amount	Percentage
Residential	$266,508	$245,108	$21,400	8.7%
Commercial	$188,875	$181,522	$7,354	4.1%
Lighting	$16,541	$15,756	$785	5.0%
Total Distribution	**$471,934**	**$442,385**	**$29,539**	**6.7%**
Industrial (Firm & Non-Firm)	$371,689	$361,524	$10,164	2.8%
Total	**$843,613**	**$803,910**	**$39,703**	**4.9%**

(1) Numbers may not add due to rounding.

(2) Includes policy adjustments related to cost allocation amongst retail customer classes.

Rate Design

The Firm has prepared proposed electric rates that are designed to reflect, to the extent permitted: (i) the lowest reasonable price consistent with the projected revenue requirement; (ii) the encouragement of economic development, and job attraction and retention; (iii) simple and understandable rate design; (iv) equitable treatment of customer classes and individual customers within classes; (v) an avoidance of undue price fluctuations; (vi) the efficient use of electric service; and (vii) compliance with applicable orders and requirements of local, state, and federal regulatory authorities. The rate change is proposed to become effective for bills rendered on or after April 1, 2025.

The principal effects of adopting the rates proposed herein are:

(i) Rate structures and levels, in general, will continue to be based, in part, on existing allocated embedded cost of service techniques and based, in part, on rate strategy.

(ii) The implementation of an on-peak demand charge for residential customers served by the RG rate, which will result in lower energy rates for this class. The summer on-peak demand period will be from 3:00 p.m. to 6:00 p.m. every day, including weekends and holidays, during the months of April through October. The non-summer on-peak demand period will be from 6:00 a.m. to 9:00 a.m. every day, including weekends and holidays, from November through March.

(iii) The residential time of use (TOU) rate (RT) will be updated to reflect revised daily TOU periods for summer and non-summer. Summer TOU energy periods will occur from April through October from 3:00 p.m. to 7:00 p.m. every day. Non-summer TOU energy periods will occur November through March from 5:00 a.m. to 9:00 a.m. every day.

(iv) The GA class will now have a demand charge and will be mandatory for commercial customers with demands less than 50 kW. The GB class will be mandatory for commercial customers with demands between 50 and 300 kW, and the GL class will be mandatory for distribution voltage commercial customers with demands exceeding 300 kW.

(v) Updated TOU energy rates for commercial customers. Summer TOU on-peak energy periods will occur from April through October from 3:00 p.m. to 7:00 p.m. every day. Non-summer on-peak TOU energy periods will occur November through March from 5:00 a.m. to 9:00 a.m. every day. These new commercial TOU periods will also be applicable to the GT rate class.

(vi) The interruptible service rider to the Large Light and Power rate (L-I) was modified to reflect an updated analysis of the avoided costs of a combustion turbine (CT).

(vii) The Large Light and Power Firm service will include an on-peak energy period during non-summer from 5:00 a.m. to 9:00 a.m. for the months November through February.

(viii) For Economy Power – Optional (EP-O), the trigger for additional on-peak hours is proposed to be tied to price rather than the load forecast.

(ix) Standby Rates for industrial customers will be eliminated.

(x) The lighting tariff will be simplified.

(xi) The experimental REV & EVO electric vehicle rates will be made permanent and will include an on-peak demand charge.

(xii) The experimental lighting contribution rates (OLC/OLDC) will be made permanent and the OLDC rate will become mandatory for developers.

(xiii) A Distributed Generation Rider for industrial customers will be provided.

(xiv) The Fuel Adjustment Clause will be adjusted to include non-shared resources.

Table ES-3 is a comparison of the projected revenues produced by applying the projected billing units to the existing and proposed rates by customer class for 2025.

Table ES-3
Existing and Proposed Firm Rate Revenue Projections (1)

	Calendar Year 2025 ($000)			
	Proposed Rate	Existing Rate	Difference	
Service	Revenue (2)	Revenue	Amount	Percentage
Residential	$266,508	$245,108	$21,400	8.7%
Commercial	$188,875	$181,521	$7,354	4.1%
Lighting	$16,541	$15,756	$785	5.0%
Total Distribution	**$471,924**	**$442,385**	**$29,539**	**6.7%**
Industrial (Firm & Non-Firm)	$371,689	$361,524	$10,164	2.8%
Total	**$843,613**	**$803,910**	**$39,703**	**4.9%**

(1) Numbers may not add due to rounding.
(2) Proposed Rate Revenue adjusted for time lag as discussed herein.

Conclusions

Based on the results of the studies and analyses as summarized in this report, and on the numerous underlying financial and load assumptions and other considerations relied upon in making such analyses and incorporated by reference herein, the Firm is of the opinion that:

1. The existing rates applicable to retail customers produce revenues that under-recover the projected revenue requirements for Test Year 2025.
2. The under-recovery from existing rates for retail customers in 2025 is approximately $39,703,000 or 4.9% of projected revenue requirements.
3. The proposed rates, which will become effective on April 1, 2025, are projected to meet the revenue requirement for 2025. These proposed rates are based on the calculated Test Year revenue requirements as well as an adjustment made to account for a timing lag in revenue recovery resulting from implementing rates in April of the Test Year rather than in January. In the Firm's experience, such an adjustment is an industry-accepted and reasonable approach to rate design.
4. On average, retail customers would experience an incremental annual rate increase of approximately 4.9% in 2025.
5. Based on the results of the cost of service analysis conducted for this Study and the direction provided by Authority management and staff, the proposed rates that will become effective on April 1, 2025, as identified herein, are just and reasonable.
6. To the extent that the assumptions as stated herein regarding future expenses and revenues in 2025 are not substantially realized, the proposed rates as developed herein may not be sufficient to meet revenue requirements within the period identified. Such forecast uncertainty is common in developing electric rates, and the Firm understands that the Authority's management continues to evaluate strategies to mitigate the potential risks of forecast uncertainty in developing rates as part of this Study.

NewGen would like to take this opportunity to express our appreciation for the spirited cooperation and valuable assistance provided by each member of the Authority's management and staff throughout the course of this Study.

Section 1
INTRODUCTION

General

South Carolina Public Service Authority (Authority or Santee Cooper) is a body corporate and politic created by Act No. 887 of the Acts of South Carolina for 1934 and acts supplemental thereto and amendatory thereof (the Act), and is codified at S.C. Code Ann. §§ 58-31-10 et seq. The Act, among other things, authorizes the Authority to produce, distribute, and sell electric power and to acquire, treat, transmit, and sell wholesale potable drinking water. The Authority began electric operations in 1942 and the regional water system began operations in 1994.

The Act also grants certain powers to the Authority, including:

> *. . . to fix, alter, charge, and collect tolls and other charges for the use of their facilities of, or for the services rendered by, or for any commodities furnished by, the . . . Authority at rates to be determined by it, these rates to be at least sufficient to provide for payment of all expenses of the Authority, the conservation, maintenance, and operation of its facilities and properties, the payment of principal and interest on its notes, bonds, and other evidences of indebtedness or obligation, and to fulfill the terms and provisions of any agreements made with the purchasers or holders of any such notes, bonds, or other evidences of indebtedness or obligation . . .* [1]

Pursuant to the Act, the Authority is governed by a Board of Directors consisting of up to 14 members (12 voting members and 2 non-voting ex-officio members) appointed by the Governor, screened by the Senate Public Utilities Review Committee, and confirmed by the State Senate. The two non-voting members are from Central Electric Power Cooperative, Inc. (Central). This Board of Directors exercises the Authority's powers.[2] In addition, the Act establishes an Advisory Board consisting of the Governor, the Attorney General, the State Treasurer, the Comptroller General, and the Secretary of State.

Among other things, each Director is required to discharge his or her duties in good faith, with the care of a similarly situated, ordinarily prudent person, in a manner reasonably believed to be in the best interests of the Authority.[3] The "best interests" of the Authority are defined as a balancing of the following factors:

> *(1). . . preservation of the financial integrity of the . . . Authority and its ongoing operations; (2) the interest of [the Authority's] residential, commercial and industrial retail customers, and those wholesale customers served pursuant to contractual arrangements, but excluding joint action agencies and those entities located outside the State, in reliable, adequate, efficient, and safe service, at just and reasonable rates, regardless of customer class; (3) maintenance, preservation, and keeping of [the Authority's] properties… in good repair, working order and condition; (4) the support of economic development and job attraction and retention within [the Authority's] present service area or areas within the State authorized to be served by an electric cooperative or municipally owned electric utility that is a direct or indirect wholesale customer of the Authority;*

[1] S.C. Code Ann. § 58-31-30(13).
[2] S.C. Code Ann. § 58-31-60.
[3] S.C. Code Ann. § 58-31-55(A)(1)-(3).

> *and (5) the exercise of [the statutory powers of the Authority] . . . in accordance with good business practices and [applicable legal requirements].*[4]

Eight executive-level individuals serve as senior management of the Authority. The Board of Directors appoints the President and Chief Executive Officer. The remaining seven members of the executive leadership team are appointed by the President and Chief Executive Officer with the approval of the Board of Directors. The Authority manages approximately 1,600 employees located throughout the State of South Carolina (State).

Electric System

Pursuant to the powers of the Act, the Authority owns, operates, and maintains electric generation, transmission, distribution, and general plant facilities (the Electric System) that provide electric power and energy to three "Sales for Resale" customers: Central and the Cities of Bamberg and Georgetown (these cities are collectively referred to as the Municipal Customers, and with Central are collectively referred to as the Wholesale Customers). The Authority provides wholesale power to other entities as well, known as Off-System Customers. The Authority directly serves approximately 215,000 residential, commercial, industrial, and lighting retail customers including 27 large industrial customers (collectively, the retail customers or direct serve customers).

The Authority's primary business operations are the production, transmission, and distribution of electric power and energy to other electric utility entities and end-use customers, as well as the acquisition, treatment, and distribution of potable drinking water to certain governmental entities for sale to ultimate customers. Consequently, for the purposes of accounting and certain management activities, the Authority operates the Electric System and the Water System as separate entities. Certain common costs are allocated between the Electric System and the Water System. The 2024 Electric System Cost of Service and Rate Design Study does not address the Water System.

Generation

The Authority's reported total summer maximum continuous rating, exclusive of solar and assuming all generating units are available, is 5,158 megawatts (MW), of which 3,465 MW is provided by coal-fueled units; 142 MW by hydroelectric stations; 322 MW by a nuclear-fueled unit; 1,203 MW by oil, gas, or oil/gas-fueled units; and 26 MW by landfill methane gas-fueled units. The reported total non-summer maximum continuous rating, exclusive of solar and assuming all generating units are available, is 5,383 MW, of which 3,480 MW is provided by coal-fueled units; 142 MW by hydroelectric stations; 322 MW by a nuclear-fueled unit; 1,413 MW by oil, gas, or oil/gas-fueled units; and 26 MW by landfill methane gas-fueled units.

Purchased Power

The Authority receives 84 MW of firm supply from the U.S. Army Corps of Engineers (the Corps) and 305 MW of firm hydroelectric power from the Southeastern Power Administration (SEPA). The SEPA allocation consists of 154 MW for wheeling to the SEPA preference customers served by the Authority (Central and the Municipal Customers) and 151 MW purchased by the Authority for its direct serve customers. The Authority also receives 74 MW of biomass-fueled capacity and associated energy under three power

[4] S.C. Code Ann. § 58-31-55(A)(3)(a)-(e).

purchase agreements (the first commenced in September 2010 and the most recent in November 2013, with varying terms from 15 to 30 years). The Authority accepted two purchase power agreements in 2023 to receive 250 MW of winter capacity and 200 MW of summer capacity with optional energy. These agreements took effect on January 1, 2024, with a term of five years.

Solar

The Authority owns three solar photovoltaic (PV) sites with a combined nameplate capacity of approximately 5 MW. There is also an agreement to purchase the output from a 2.5 MW solar PV facility that started producing power in December 2013 and has a 20-year term. The Authority has also entered into four solar Power Purchase Agreements (PPAs) totaling 280 MW, each for five-year terms. Solar units that Santee Cooper either owns or has contracted with to purchase the output are not included in the capacity totals of the Generation and Purchased Power sections above. The effective load carrying capability of those units varies greatly from winter to summer and is also dependent on the amount of total solar on the system.

Transmission

The Authority operates an integrated transmission system which includes lines owned and leased by the Authority as well as those owned by Central. The transmission system includes approximately 5,255 miles of overhead and underground lines primarily rated between 69 kilovolts (kV) and 230 kV. The Authority operates 93 transmission substations and switching stations serving 59 distribution substations and 427 Central members' delivery points. The Authority plans the transmission system to operate during normal and contingency conditions as outlined in electric system reliability standards adopted by the North American Electric Reliability Corporation (NERC) and to maintain system voltages that are consistent with good utility practice.

Interconnections and Interchanges

The Authority's transmission system is interconnected with other major electric utilities in the region. It is directly interconnected with Dominion Energy at twelve locations; with Duke Energy Progress at eight locations; with Southern Company Services, Inc. (Southern Company) at one location; and with Duke Energy Carolinas at two locations. The Authority is also interconnected with Dominion, Duke, Southern Company, and SEPA (Southeastern Power Association) through a five-way interconnection at SEPA's J. Strom Thurmond Hydroelectric Project, and with Southern Company and SEPA through a three-way interconnection at SEPA's R. B. Russell Hydroelectric Project. Through these interconnections, the Authority's transmission system is integrated into the regional transmission system serving the southeastern areas of the United States and the Eastern Interconnection. The Authority has separate interchange agreements with each of these companies which provide for mutual exchanges of power.

The Authority is a party to the Virginia-Carolinas Reliability Agreement (VACAR), which exists for the purpose of safeguarding the reliability of electric service of the parties thereto. The Authority is also a member of the SERC Reliability Corporation (SERC), which is one of six regional entities under the NERC.

Distribution

The Authority owns distribution facilities in two service areas: the Berkeley District and the Horry-Georgetown Division. These service areas include over 3,100 miles of distribution lines.

The electric generation, transmission, and distribution facilities owned by the Authority, as well as certain transmission facilities owned by Central, are operated by the Authority as a fully integrated Electric System.

General Plant

The Authority owns general plant consisting of office facilities, transportation and heavy equipment, computer equipment, and communication equipment necessary to support the Authority's operations. The Authority has one customer service office located in Myrtle Beach and a corporate headquarters located in Moncks Corner, which includes a garage, maintenance facilities, retail office, and warehouse facilities.

Customers

Retail/Direct Serve Customers

The Authority owns distribution facilities and serves customers residing in two non-contiguous areas covering portions of Berkeley, Georgetown, and Horry Counties. Sales to residential, commercial, small industrial, and certain other customers are made pursuant to rate schedules, which include fuel, demand sales, and economic development sales adjustment clauses.

Sales to large industrial customers are made pursuant to long-term contracts and provide for a minimum kilowatt (kW) load for an initial period of not less than five years. All contracts contain rate provisions of the demand and energy type, and include fuel, demand sales, and economic development sales adjustment clauses and other provisions generally used in large industrial power rate schedules.

Wholesale Customers

The Authority supplies all Central's power and energy requirements with the exception of amounts supplied to Central under separate agreements

The amounts of power and energy supplied by the Authority are determined under the terms of an agreement between the Authority and Central (the Central Agreement) which became effective in January 1981. The Authority and Central adopted an amendment to the Central Agreement in January 1988. This amendment included a number of revisions to the cost of service methodology, lowered the cost responsibility and rates to Central, established that the Authority would supply the total power and energy requirements of Central (with some limited exceptions), and extended the contract for an initial term of 35 years ending March 31, 2023.

In May 2013, the Authority and Central adopted an amendment to the Central Agreement (May 2013 Amendment) to better align future interests and formalize the resource planning process among the parties. The May 2013 Amendment further defers rights to terminate the agreement until December 31, 2058. Central has entered into requirements agreements with all 19 of its member cooperatives through December 31, 2058, and obligated its members to pay their share of Central's costs.

In addition to Central, the Authority provides wholesale electric service to the City of Georgetown, SC; the City of Bamberg, SC; the Town of Waynesville, NC; and the City of Seneca, SC pursuant to long-term contracts. The Authority executed a new service agreement in 2013 with the City of Bamberg for 20 years. The Authority executed a 10-year service agreement to provide wholesale electric service to the City of Seneca which began July 1, 2015. The City of Georgetown's agreement began in 2013 and is set to expire on October 31, 2030.

The Authority has a long-term power agreement with Piedmont Municipal Power Agency (PMPA) pursuant to which the Authority will provide PMPA its supplemental electric power and energy requirements (ranging from approximately 200 MW to 300 MW) above PMPA's current resources. The current PMPA agreement is set to expire in 2029.

Existing Rates

The Authority's Board of Directors is empowered and required to set rates, as necessary, to provide for expenses of the Authority, including debt service. The Board of Directors adopted the Authority's existing rates and charges for retail customers on December 7, 2015, and these were implemented on April 1, 2017. Rates charged to Central are within the terms and conditions of the Central Agreement, as discussed herein. Similarly, rates charged to Municipal Customers and other wholesale customers are within the terms and conditions of their respective contracts.

The Authority offers non-firm rate options to its direct-served industrial customers to encourage them to reduce their peak demand. As of April 2024, the Authority serves approximately 686 MW of "non-firm power" through contracts with its industrial customers. The Authority's rate schedules include a "fuel adjustment clause" that provides for increases or decreases to the base rates to cover changes in the cost of fuel and purchased power to the extent such costs vary from a predetermined base cost. The Authority's rate schedules also include a "demand sales adjustment clause" that provides for increases or decreases to the base rates to reflect changes in demand-related revenues from non-firm sales (such as interruptible and economy power rate schedules and riders) and off-system sales. Demand-related revenues from non-firm sales are reductions (credits) to customers' rates, to the extent that such credits vary from predetermined base amounts. And finally, the Authority's rate schedules also include an "economic development sales adjustment clause" that provides for increases or decreases to the base rates to reflect changes in demand-related revenues from economic development industrial sales.

In accordance with the Central Agreement, the rates and charges for electric service to Central are determined and adjusted annually pursuant to a cost of service methodology set forth in the Central Agreement. Similarly, in accordance with the contractual provisions, the rates and charges for wholesale electric service to the Municipal Customers are determined pursuant to methodologies set forth in their respective agreements. The cost of service methodology applicable to the Authority's Wholesale Customers is similar to, but different from, the methodology used in determining the rates and charges applicable to the Authority's direct serve residential, commercial, industrial, lighting, and any new municipal customers.

Cook Settlement and 2024 Rate Study

Following suspension of the Summer Nuclear Units 2 and 3 project, a putative class action suit, "Jessica S. Cook et al. v. South Carolina Public Service Authority et al.," was filed on August 22, 2017, and later was transferred to Greenville County (Case No. 2019-CP-23-6675). On March 12, 2020, the Authority's Board approved a settlement (Cook Settlement Agreement) that resolved the case. Pursuant to the terms of the Cook Settlement Agreement, the Authority's Board agreed to hold its rates consistent (the Rate Freeze) with rates (the Settlement Rates) in the Authority's 2019 Reform Plan effective beginning in August 2020 and through all bills rendered on or before January 15, 2025 (the Rate Freeze Period). The Rate Freeze is applicable to all retail customers and Central and other firm wholesale customers.

In practice, this Rate Freeze is implemented for retail customers by (i) "freezing" base rate schedules identified in appendices to the Cook Settlement Agreement such that they may not be modified during the Rate Freeze Period, and (ii) fixing the associated retail rate Fuel Adjustment (FAC-17), Demand Sales Adjustment (DSC-17), and Economic Development Sale Adjustment (EDA-17) clauses to values projected by the Authority in the 2019 Reform Plan. For some wholesale customers with rates based on the ML-17 rate, the Rate Freeze is implemented by fixing the associated retail rate Fuel Adjustment Clause (FAC-17) to the same 2019 Reform Plan values as industrial firm customers.

As part of the Cook Settlement Agreement, the Authority agreed not to defer any costs and expenses incurred or otherwise appropriately attributable to any year during the Rate Freeze Period to any other year or years during or after the Rate Freeze Period. However, the Authority may defer to rates charged in years after the Rate Freeze Period just and reasonable costs and expenses incurred during the Rate Freeze Period directly resulting from the specific circumstances as enumerated in the Agreement (the Cook Rate Freeze Exceptions).

Recovery of the Cook Rate Freeze Exceptions incurred by the Authority during the Rate Freeze Period is anticipated in the Cook Settlement Agreement. However, this cost recovery is not included in the base rates developed from this Study. It is anticipated that such cost recovery will be implemented via a deferred cost recovery adjustment which will be applicable to all retail customer classes and some wholesale customers as described above. Further, as indicated above, upon the cessation of the Rate Freeze Period all customer bills will be subject to the unfrozen FAC, DSC, and EDA, which will operate as before the Rate Freeze.

Act 90 and 2024 Rate Study

In 2021, the S.C. General Assembly passed Act 90 (H.3194, referred to herein as Act 90), which establishes reforms for Santee Cooper by amending the state laws applicable to the Authority. Act 90 established a retail rate process for the Authority requiring the Authority to (i) adopt and publish pricing principles that balance certain factors including, but not limited to, adherence to the Authority's mission to be a low-cost reliable, transparent utility while preserving financial integrity, equity among customer classes, gradualism in adjustments to its pricing and rate schedule type, adequate notice to customers, and relief mechanisms for financially distressed customers, and review of compliance with bond covenants; and (ii) submit to the South Carolina Office of Regulatory Staff for its review and comment any proposed rate adjustments presented to the Board for the Board's approval. Act 90 also formalized a rate adjustment notice and review process and provided for direct appeal of the Board's decisions on rates to the South Carolina Supreme Court, with the only remedy being a change to rates by the Board.

2024 Electric System Cost of Service and Rate Design Study

In July 2023, the Authority retained the Firm to provide consulting services to assist the management and staff of the Authority to prepare an Electric Rate Study and revise rates applicable to retail customers that recover the projected near-term costs for the year 2025, accounting for the cost of service, the goals and policies of the Board of Directors, recognized industry standards, and customer input resulting from periodic meetings with its customers. This engagement excludes rate matters pertaining to the Authority's Wholesale Customers and the respective agreements.

During the course of the assignment, the Firm worked closely with the Authority's management and staff and provided consulting services in the following general ratemaking areas: (i) the development of the near-term (calendar year 2025) annual revenue requirements; (ii) guidance on industry-accepted best practices in rate design; (iii) the development of proposed rates and rate riders for electric service designed to be just and reasonable and equitably recover the near-term cost of service, regardless of customer class; and (iv) the participation in public meetings pertaining to this Study and the proposed rates and charges. The Firm provided independent advice and analysis to support the recommendations proposed by the Authority's management and staff included in this Study. Review and comment of specific strategic decisions made or anticipated to be made by the Authority's management were beyond the responsibility of the Firm.

To meet schedule requirements and to minimize costs, the Firm relied on and used information prepared by, and/or prepared for, the Authority. The Firm believes such information to be reliable but has not verified its accuracy. The Firm has performed a reasonable review of the Authority's cost of service model used to perform this rate Study. To the Firm's knowledge, the summaries presented herein accurately reflect the information obtained from such sources. The results of this Study are based on available assumptions and estimates of future occurrences. As far as such information is different from actual future circumstances, the proposed rates as developed herein may not be sufficient to meet revenue requirements within the period identified. Such forecast uncertainty is common in developing electric rates, and the Firm understands that the Authority's management continues to evaluate strategies to mitigate the potential risks of forecast uncertainty in developing rates as part of this Study.

In the preparation of this Study and the design of proposed rates, the Firm has considered and has utilized, where appropriate, the practices established or advocated by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners (NARUC), as well as the past and present policies of the Authority and the applicable provisions of contracts between the Authority and its customers.

Specific sources utilized and relied on herein include, but are not limited to, the Authority's current forecast of sales (referred to as LF 23-03), the forecast of fuel availability and cost, the results of the Authority's production costing analysis, the summarized analysis of the Authority's customer billing records, and the Authority's current financial assumptions.

Structure of Report

This report provides for the development of revised retail rates for the Authority. The basis for the revised rates includes the projections of customer sales and usage characteristics as provided in Section 2. Section 3 develops the revenues required by the Authority for the Test Year 2025. Section 4 describes the cost of service analysis, which allocates the revenue requirements to the customer classes. Section 5 presents the general rate design by customer class. Section 6 provides the proposed rates and rate comparisons to existing rates. This report is supported by a series of appendices, which include a comparison of customer bill impacts due to the proposed rate changes (Appendix A – Bill Comparisons), the proposed rate schedules (Appendix B – Rate Schedules), and a technical appendix that includes specific schedules and tables from the Authority's cost of service analysis (Appendix C – Technical Appendix). Appendix C is not included as an attachment to this report but is available upon request from the Authority. Across this report and the accompanying appendices, number values provided in tables and text may not always sum or exactly match number values in other tables due to rounding in calculating and conveying this quantitative information.

Section 2
SALES FORECAST

General

The development of a reasonable forecast of future power and energy requirements, sales, customers, and customer usage characteristics is essential in the evaluation of the adequacy of electric rates and rate structures. This section summarizes the various factors considered and utilized in the development of the Authority's Electric System future power and energy requirements for the Test Year ending December 31, 2025. Recognizing the importance of an accurate forecast, the Authority continually reviews and enhances its forecasting models to refine input data and assumptions and to reflect observed changes in customers, usage characteristics, and industry trends.

Sales, customers, and customer usage characteristics for the Test Year were derived from LF 23-03. LF 23-03 was utilized in the determination of the Authority's projected near-term power and energy requirements and was prepared by Santee Cooper, Central, and a consulting firm, GDS Associates, Inc. (GDS). The forecast incorporates updates of the Authority's end-use/econometric models developed by GDS. In addition, the forecast reflects current economic outlooks for the Santee Cooper and Central service areas, projected retail price increases, and normal weather conditions. The forecast includes off-system sales and estimated demand and energy reductions from future Demand Side Management (DSM) and Energy Efficiency (EE) programs to be implemented by Santee Cooper and Central.

Demand and Energy Requirements

The Authority provides retail electric service to residential, commercial, and industrial customers, and wholesale service to Central, other utilities, and the Municipal Customers pursuant to various contracts that provide for the sale and, in some cases, exchange of energy.

Each year, in consultation with Central, the Authority prepares and updates a Load Forecast that sets forth its projected demand and energy requirements, taking into account the projections of the Authority's DSM and EE programs. The estimates of the power and energy requirements of the Authority for the Test Year 2025 have been prepared based upon an analysis of customers and sales by class of service contained in the Load Forecast.

Projection of Electricity Sales to Ultimate Customers

The projections of electric energy sales are based on the results of econometric and end-use analyses of historical growth, usage patterns, appliance stock and efficiencies, housing characteristics, economic conditions, normalized weather, population statistics, and certain economic parameters such as the price of electricity and income. The demand and energy projections also reflect the estimated effects of the conservation and DSM programs that have been proposed, contemplated, or implemented.

Projected Demand

Table 2-1 below sets forth the projected 60-minute integrated coincident peak demands including firm and non-firm loads, losses, and the estimated effects of the various planned conservation programs.

Table 2-1
Projected Summer/Non-Summer Demand by Customer Group

	2025 (MW)	
	Non-Summer	Summer
Distribution	927	901
Distribution Losses	28	27
Total Distribution (1)	**955**	**928**
Industrial – Firm	286	295
Industrial – Non-Firm	503	518
Total Industrial	**788**	**813**
Wholesale (2)	3,642	3,193
Total Transmission Deliveries	**5,385**	**4,934**
Transmission Losses	94	87
Total Requirements	**5,479**	**5,021**

(1) Includes residential, commercial, and lighting.
(2) Includes Central and Municipal Customers.

Projected Energy Requirements

Included in the Load Forecast are losses and the projected effects on energy sales from existing and planned conservation programs. Table 2-2 below sets forth the projected energy requirements.

Table 2-2
Projected Energy by Customer Group

	2025 Energy (GWh)
Distribution	4,005
Distribution Losses	120
Total Distribution [(1)]	**4,126**
Industrial – Firm	2,515
Industrial – Non-Firm	4,162
Total Industrial	**6,677**
Wholesale [(2)]	17,235
Total Transmission Deliveries	**28,038**
Transmission Losses	400
Total Requirements	**28,438**

(1) Includes residential, commercial, and lighting.
(2) Includes Central and Municipal Customers.

DSM and Energy Efficiency Programs

Included in the projection of demand and energy requirements in the Load Forecast are estimated reductions associated with DSM and EE programs. DSM and EE programs benefit the Authority's distribution customer classes (and other customers) by reducing their demand and energy. The reduction in demand results in a lower relative contribution to the demand measured at the time of the coincident peak, which effectively lowers their relative class contribution to fixed cost causation (see Section 4). The reduction in demand can also result in lowered billing demand for a specific customer's monthly bill (depending on the customer type). The energy reduction is a direct reduction in energy consumption during the billing month, resulting in lower energy and fuel charges. Table 2-3 summarizes the projected demand and energy reductions during the Test Year.

Table 2-3
Projected Demand and Energy Reductions

2025		
Non-Summer (MW)	**Summer (MW)**	**Energy (GWh)**
55	54	225

Projected Average Number of Customers

As an integral part of its forecasting process, the Authority projects the average number of customers it expects to serve by major customer class. The projected average number of customers based on the load forecast and used as a basis for this Study are provided in Table 2-4 below.

Table 2-4
Projected Average Number of Customers by Customer Group

	2025 Customers
Residential	182,940
Commercial	30,180
Lighting (1)	2,314
Total Distribution	**215,435**
Industrial (Firm & Non-Firm)	31
Wholesale	3
Total Customers	**215,493**

(1) Many lighting customers are also residential or commercial customers.

Sales to and Purchases from Other Entities

The Authority has entered into interchange contracts with other electric utilities and power marketers providing for the purchase and sale of economy energy. It should be noted that economy energy purchases tend to reduce system fuel and energy costs, and these reductions are automatically passed on to the ultimate customer via the Fuel Adjustment Clause, which is an integral component of the Electric Rate Tariffs. Additionally, any operating revenue derived from economy energy or “off-system” sales (or transmission services provided to others) is available to the Authority for the benefit of its customers through adjustment clauses or is recognized as an offset to costs in the development of the revenue requirement.

Summary of Projected Demand and Energy Requirements

Table 2-5 below sets forth the projected summer and non-summer coincident peak demands (adjusted for DSM programs) at the generation level, energy requirements, and system load factors used in this Study.

Table 2-5
Projected Net Demand and Energy Requirements

	2025
Annual 60-Minute Peak Demand (1)	
Non-Summer – MW	5,479
Summer – MW	5,021
Annual Energy Requirements (GWh)	28,440
Annual System Load Factor (2)	**59.25%**

(1) Includes the estimated reduction in sales associated with DSM/EE programs.

(2) Annual Energy Requirements divided by the product of 8,760 hours and the non-summer peak demand.

Power Supply

Power supply to meet the projected demand and energy requirements for the Test Year 2025 was assumed to consist of the following:

- The Authority's existing generation resources aggregate approximately 5,633 MW net summer capability and 5,851 MW of net non-summer capability.
- The purchase of capacity and energy from other utilities.
- The availability of SEPA capacity and energy for Central, the Municipal Customers, and the Authority.
- The generating reserve requirements imposed by NERC and the Public Service Commission.

The expected energy sources have been simulated by the Authority using its computerized economic dispatching model, which takes into account hourly loads, unit availability, maintenance schedules, heat rates, fuel costs, and system operating characteristics.

Customer Service Classes

In general, it is an electric utility practice to classify customers and types of service into homogeneous customer groups. The Authority presently has the following electric rate classifications as provided in Table 2-6 below.

Table 2-6
Existing Rate Schedules (2023)

Type of Service	Existing Rate Schedule	
	Rate Code	Schedule
Residential		
Residential General Service	RG	RG-17
Residential Time of Use	RT	RT-17
Residential Experimental Electric Vehicle Power Schedule	REV	REV-22
Residential Experimental Electric Vehicles Only Power Rider	EVO	RG-22-EVO
Commercial		
Small General Service	GA	GA-17
General Service	GB	GB-17
Seasonal General Service	GV	GV-17
General Service Time of Use	GT	GT-17
Large General Service	GL	GL-17
Temporary Service	TP	TP-17
Lighting		
Traffic Signal Service	TL	TL-17
Municipal Street Lighting	MS	MS-17
Private Outdoor Lighting	OL	OL-17
Experimental Private Outdoor Lighting Contribution Schedule	OLC	OLC-22
Experimental Private Outdoor Lighting Developer Contribution Schedule	OLDC	OLDC-22
Municipal Light and Power	ML	ML-17
Industrial		
Large Light and Power	L	L-17
Interruptible Service	I	L-17-I
Economy Power Service	EP	L-17-EP
Economy Power Optional Energy Charge	EP-O	L-17-EP-O
Economy Power Rider As Used Billing Option	EP-AU	L-17-EP-AU
Demand Response Buy Back	DRB	L-17-DRB
Other		
Fuel Adjustment Clause	FAC	FAC-17
Demand Sales Adjustment Clause	DSC	DSC-17
Economic Development Sales Adjustment Clause	EDA	EDA-17
Distributed Generation Rider	DG	DG-17
Pole Attachment	PA	PA-17

Historical and projected customer statistics by major rate classification are set forth in Appendix C – Technical Appendix (available upon request). The historical data shown has been derived from detailed operating, accounting, and billing data provided by the Authority. The projected average annual number of customers and annual energy sales for the Test Year 2025 have been developed from the Authority's Load Forecast, which incorporates the following considerations:

(i) Continuation of recent historical growth and usage characteristics.

(ii) Continuation of past, present, and projected conservation and DSM programs.

(iii) Continuation of the existing regulatory structure in South Carolina.

Any departure from those assumptions could have a material adverse effect on energy sales and revenues.

The projected Test Year 2025 composition of the Authority's ultimate customers and associated energy sales by rate classification is provided in Table 2-7 below.

Table 2-7
Projected Customers and Energy Reqmts. by Direct Served Customer Group (1)

	Average Number of Customers	Percent of Total	Annual GWh Sales	Percent of Total
Residential	182,940	84.89%	2,071	19.39%
Commercial	30,180	14.01%	1,873	17.54%
Lighting	2,314	1.07%	61	0.57%
Total Distribution	**215,435**	**99.97%**	**4,006**	**37.50%**
Industrial (Firm & Non-Firm) (2)	56	0.03%	6,677	62.50%
Total Customers	**215,490**	**100.00%**	**10,683**	**100.00%**

(1) Direct served customers do not include the Municipal Customers or Central.

(2) The industrial customer count double counts some customers who take service on both firm and non-firm rate schedules.

Billing Determinants

To determine the estimated amount of revenues produced by the existing rates, the existing rates and surcharges were applied to the projected billing determinants for the Test Year period. The projected billing determinants are based on the detailed load forecast and an analysis of historical billing data (see Appendix C – Technical Appendix, available upon request).

Section 3
REVENUE REQUIREMENTS

General

The various components of costs associated with the operation, maintenance, financing of improvements, renewal and replacement of facilities, and assurance of the adequacy and continuity of reliable service to customers are generally referred to as the revenue requirement of a governmentally operated utility. The determination of the revenue requirement as related to the Electric System, and consistent with the methods of other publicly owned utilities utilizing revenue bond financing, includes the various generalized cost components described below.

Operation and Maintenance Expenses: These are ongoing operations and maintenance expenses as defined in the FERC Uniform System of Accounts. These expenses are traditionally separated into the following categories, which relate to the several basic "functions" involved in supplying electricity to the ultimate consumer:

- Production Operation and Maintenance Expenses (including fuel, purchased power, and other power generation expenses).
- Transmission Operation and Maintenance Expenses.
- Distribution Operation and Maintenance Expenses.
- Customer Accounting Expenses.
- Sales Expenses.
- Customer Information Expenses.
- Administrative and General Expenses.

Payment in Lieu of Taxes: As a public body, the Authority is not a taxable entity. However, the Authority is required to pay certain sums in lieu of taxes to certain local authorities and to the State. As with other types of utilities, these costs must ultimately be recovered through rates.

Debt Service: These costs consist of interest and principal payments on the Authority's debt. They are included in the cost of service on an accrual basis. The Authority's debt includes tax-exempt and taxable senior lien revenue bonds and short-term commercial paper and revolving credit agreements.

Allowances for Working Capital, Equity, and Coverage: This category consists of two cost components that provide equity funds and debt service coverage for the Authority. They are:

- An allowance for working capital increases which reflects the additional amounts needed each year to cover timing differences between the payment of expenses and the receipt of revenues from customers. Traditionally, this allowance has been set at one-eighth of the change in operation and maintenance expenses (excluding purchased power and nuclear fuel expenses) from the prior year.
- An allowance for capital improvements in the form of the Capital Improvement Fund (CIF) requirement, which provides a source of capital other than borrowings for renewals, replacements, and improvements to the Authority's system. The CIF requirement provides non-debt funding and thereby generates additional equity capital and debt service coverage which help to maintain the

financial strength of the Authority. The CIF requirement currently included in the cost of service is 9% of gross revenue requirements each year.

Total Annual Net Revenue Requirements: The total of the cost components described above less other income, including investment income on funds invested by the Authority, and other operating revenues is the total annual net revenue requirement and represents the amount of revenues required to be recovered through rates and charges to ultimate customers.

Future Test Year Revenue Requirements

Electric rates should be set at a level such that the revenues produced will be sufficient to meet future revenue requirements. An important objective of a projected test year is to establish rates and rate levels that will also reflect the then-current costs of providing service and market conditions. Thus, it is necessary to estimate or project various cost components over a reasonable period of time to determine the required rate levels. Projections must consider changes in operating practices, new facilities, expected changes in cost, and other factors that may affect the overall cost of operating and maintaining the utility system.

In keeping with industry standards, a forward-looking projected test period or Test Year has been utilized for the determination of the Electric System's projected revenue requirements.

Basis for Test Year Revenue Requirements

It was determined that the revenue requirements for this 2024 Study would be predicated on the projected costs of the Electric System for the fiscal year ending December 31, 2025, designated as the Test Year. The Authority developed the "FF2024 Budget" Financial Forecast for the Electric System. The expenditures contained in the forecasted data were used as a baseline in the development of the projections of the annual revenue requirements for the Test Year.

The 2025 expenditures contained in the financial forecast and utilized as a baseline in the development of the revenue requirements for the Study period are provided in Table 3-1 below, and summarized and discussed as follows.

Table 3-1
Expenditures in Financial Forecast 2025 ($000) (1)

	2025
Fuel and Purchased Power	$933,086
Other Operation and Maintenance	$562,824
Total Operation and Maintenance	**$1,495,910**
Payment in Lieu of Taxes	$28,368
Debt Service and Lease Payments	$505,695
Working Capital	$13,534
CIF Requirement	$202,255
Gross Revenue Requirement	**$2,245,762**

(1) Numbers may not add due to rounding.

Assumptions and Considerations

The development of the projected revenue requirements for the Test Year ending December 31, 2025, required certain assumptions and considerations to reflect certain known or anticipated changes. The analyses, estimates, and projections summarized herein were based upon an understanding of certain contracts, agreements, regulations, statutory requirements, and planned operations. In the preparation of this report, certain assumptions were made with respect to conditions which may occur in the future. While these assumptions are reasonable for the preparation of this Study, they are dependent upon future events, and actual conditions may differ from those assumed. To the extent that actual future conditions differ substantially from those assumed herein or provided to us by others, the actual results may vary from those projected.

The major assumptions and considerations included in the development of the projected annual revenue requirements have been divided into two categories and are listed below.

General

1. All applicable Federal and State environmental laws will continue to be implemented, applied, and enforced.
2. There will be no material change in the taxation of fuel used to produce electricity.
3. There will be no material change in the taxation of governmentally owned or municipally financed electric generation, transmission, and distribution systems.
4. There will be no material change in the level of Federal, State, or local regulation of governmentally owned electric systems.
5. There will be no material change in the Authority’s existing ability to import or export power over the statewide transmission grid.
6. There will be no material change in inflation expectations.
7. The existing form of governance and policies established by the Authority will continue throughout the Study period.
8. The Authority will continue to be the exclusive owner and operator of the Electric System, including its generation, transmission, distribution, and customer care facilities.

Specific

1. Demand and Energy Requirements

Load Forecast LF 23-03 was the basis for the development of the projected energy and demand requirements for the fiscal year ending December 31, 2025. It should be noted that (a) any meaningful variances in the load characteristics of existing or new customers, and/or (b) any differences in expected initiation of service for anticipated new customers, and/or (c) any differences in the expected effectiveness of the various conservation programs initiated and contemplated for the Electric System, and/or (d) any changes in Federal or State legislation that permit customers to select their energy service provider may result in a distortion and/or an over- or under-recovery of revenue requirements for 2025.

2. Operation and Maintenance Expenses

The current projections for non-fuel operation and maintenance expenses for 2025 were included in the 2024 Budget Financial Forecast that was provided to the Board in December 2023, and were utilized as the basis for this Study. The expenses included the Authority's method for determining fixed and variable costs, which aligns cost classifications with the Authority's actual operation and maintenance expenditures.

3. Power Costs

Electric System costs are based on an economic dispatch of Santee Cooper's generating resources, including purchases. The dispatch reflects Santee Cooper's coal contracts, assumed purchased power contracts, and scheduled maintenance. Fuel burned is determined using average heat rate curves.

Power supply costs used herein are predicated in part on (a) the availability of the Electric System's existing generating resources, (b) the purchase of long-term capacity and attendant energy, (c) generation reserve levels being maintained at current levels, and (d) the acquisition of all necessary permits and licenses to continue to operate the existing generating resources and transmission facilities and the planned generating resources at each facility's design capabilities.

Fuel and purchased power energy costs reflect any existing long-term contracts and their applicable annual escalation indexes and productivity adjustments, as well as market purchases. Gas commodity prices are projected from a TEA forecast based on market-forward prices.

Projected purchased power capacity costs include renewable purchases, spot market purchases, short-term energy transactions, and firm purchased power costs assumed to be contracted to meet projected power requirements during the forecast period.

4. Capital

The Authority's two primary sources of funding additions, renewals, replacements, and improvements to the Authority's system are through the issuance of debt and the CIF requirements. The CIF requirement is forecasted at 9% of the gross revenue requirement.

5. Financing Considerations

Table 3-2 below provides interest rates which were assumed for the various types of debt financing.

Table 3-2
Interest Rates Assumed for Debt Financing

	2025
Taxable Commercial Paper/Bond Anticipation Notes	6.05%
Tax-Exempt Commercial Paper/Bond Anticipation Notes/ Float Rate Notes	4.25%
Taxable Revenue Obligation Bonds (30-year)	6.88%
Tax-Exempt Revenue Obligation Bonds (30-year)	5.25%

The Board of Directors has authorized the issuance of variable rate debt not to exceed 20% of the aggregate Authority debt outstanding (including commercial paper notes) at the end of each fiscal year. As of December 31, 2023, 10% of the Authority's outstanding aggregate debt was variable rate. The financial projections reflect debt service (principal and interest) for existing and future debt issuances.

6. Payment to the State

Payment to the State is based on 1% of projected operating revenues (on an accrual basis).

No assumption or provision has been made or included in the projections utilized in the 2024 Study to reflect unforeseen load changes or changes in customer consumption characteristics that may be the result of, but not limited to, deviations from normal weather conditions, modifications to or limitations on existing generation or transmission facilities, generating station or unit failures, or other catastrophic events.

7. Assigned Service Territory

It has been assumed that the Authority will continue to operate and exclusively serve all customers in its assigned service territory. No assumptions have been made to recognize the effects associated with the potential (a) restructuring of the electric utility industry in the state to enable, among other things, customers to choose their supplier; (b) unbundling of traditional services and rates; (c) recovery of stranded investment costs, if any; (d) sale of all or a portion of the Electric System (unless otherwise noted herein); and (e) the passage of federal legislation that would impair the Authority's ability to issue indebtedness.

8. Timing of Rate Adjustments and Calculation of Revenue Requirement

Because annual revenue requirements are calculated on the basis of calendar years and rate adjustments are not effective until April 1 of the Test Year, Santee Cooper adjusted proposed rates to account for the time lag in revenue collection.

Revenue Requirements for Test Year 2025

The revenue requirement for the year ending December 31, 2025, has been developed using the Authority's current financial assumptions as a base. The Electric System retail revenue requirements for the Test Year 2025 are predicated on the previously discussed assumptions and considerations and are summarized in Table 3-3 as follows.

Table 3-3
Projected Net Revenue Requirements Summary ($000) (1)

	2025
Operating Expenses	$1,495,910
Other Revenue Requirements	$749,852
Gross Revenue Requirements	**$2,245,762**
Projected Revenue (Non-Retail)	
Off System & Non-Class Sales	$38,785
Other Operating Revenues (2)	$22,292
Interest and Miscellaneous Inc.	$4,230
Wholesale	$1,336,843
Total Projected Revenue (Non-Retail)	**$1,402,149**
Total Cost of Service	**$843,613**
Existing Rate Revenues	$803,910
(Deficiency) Under Existing Rates	**($39,703)**
Percent of Existing Rate Revenues	**(4.9%)**

(1) Numbers may not add due to rounding.
(2) Includes economic development revenues.

To the extent that electric rates are increased as proposed herein effective April 1, 2025, the deficiencies are projected to be eliminated.

Treatment of Wholesale Revenue

Santee Cooper applied revenues resulting from on-system wholesale contract sales as a credit on a functional basis to the gross revenue requirement of the retail classes. This approach reduced the revenue requirement for each function as applied to the retail class.

In addition to on-system wholesale revenues, the Authority also makes sales to municipal and other wholesale customers that are off-system. Such revenues are allocated to the Authority’s retail customers as a credit to the cost of service, and to the extent that such revenues are not included in base rates, they will be distributed to the retail classes through the Demand Sales Adjustment.

The Firm believes the Authority’s treatment of such wholesale revenues as a credit against the gross revenue requirement is reasonable and aligns with standard industry practice.

Section 4
COST OF SERVICE ANALYSIS

General

There are three major processes in assigning utility costs: functionalization, classification, and allocation. The first part of this section discusses the functionalization and classification of the Test Year revenue requirements. The second half of the section sets forth the development of allocation factors for the Test Year revenue requirements.

The methodology for allocating costs and calculating the proposed rates as a result of this Study remained relatively consistent with that employed as part of Santee Cooper's previous COS studies, with limited changes.

Functionalization of Test Year Expenditures

Although budgeting and accounting systems generally follow functional groups (e.g., production, transmission, etc.), certain costs such as those associated with administrative and general expenses and debt service are not generally assigned by accounting and budgetary convention to a major function. A cost of service analysis usually requires the rearrangement of certain expenditures into functional groups (i) to be more representative of the expenditure causation, (ii) to combine costs that have been incurred for a similar purpose, and (iii) to facilitate the allocation of cost responsibility. Thus, the functionalization of certain costs is merely a ratemaking mechanism to apportion such costs to the common utility function.

Categorization of costs in terms of several basic "functions" involved in the supply of electricity to the consumer is embodied to a large degree in the FERC Uniform System of Accounts:

- Production (the generation of electricity or its purchase at wholesale).
- Transmission (the operation of a high voltage systemwide grid or network for the interconnection of generating facilities and major load centers).
- Distribution (the local distribution of electricity, generally at voltages lower than transmission, within and around load centers to ultimate customers).
- Customer Service (including a variety of customer service, billing, and administrative activities).

The typical functions of the Test Year retail revenue requirements are developed in the retail cost of service analysis and summarized in Table 4-1 below.

Table 4-1
Functionalization of Test Year Retail Revenue Requirements ($000)

	2025
Production – Those costs associated with generating and purchasing power and delivering that power to the utility's bulk transmission system.	$635,351
Transmission – Those costs incurred in connection with the delivery of power over the bulk transmission system to the primary and secondary distribution system.	$103,102
Distribution – Those costs incurred in connection with the delivery of power through the primary and secondary distribution system to the utility's consumers.	$73,166
Customer and Sales Expense – Those costs incurred for billing accounts and providing various services and information for the utility's customers.	$31,994
Total Functionalized Revenue Requirements	$843,613

Classification of Various Costs

Cost of service classification provides the means to distribute Test Year revenue requirements to the various customer classes. The classification of costs below reflects usual regulatory practice, as well as a reasonable and equitable approach.

Demand (Fixed) Costs: Defined as those costs incurred to maintain in readiness-to-serve an electric system capable of meeting the total combined demands of all customer classes. Demand costs are those costs that are generally fixed in the short run and that do not materially vary directly with the number of kilowatt-hours (kWh) generated or sold, and that are not defined as customer costs. Demand costs will include that portion of operation and maintenance expenses, debt service, renewals, replacements and improvements, and other costs which are not designated as specifically customer or variable energy costs.

Energy (Variable) Costs: Defined as those costs that vary substantially or directly with the amount of energy sold or generated and purchased, including such items as fuel and a portion of operation and maintenance expense for production facilities.

Customer Costs: Defined as those costs directly related to the number, type, and size of customers, such as customer accounting and collecting, the costs of meters and services, and other distribution-related costs associated with maintaining the minimum distribution system to serve the Authority's customers.

Operation and Maintenance Expenses

A description of how the Authority's functionalized Test Year revenue requirements were classified for the purposes of the cost of service analysis is presented below.

Production Expenses

Fuel expenses represent the single largest operation and maintenance expenditure of the Authority and are, for the most part, classified as energy related because they vary in direct proportion to energy usage. However, a portion of fuel expenses is incurred in startup and to keep certain generating units running at less than full load in order to provide "spinning reserves" (capacity of generating units that are online and operating, but which are not fully loaded so that they may meet anticipated changes in demand and other contingencies). These fuel expenses, therefore, are classified as demand related because they do not vary directly in proportion to energy consumption. Historically, the Authority has estimated the demand-related fuel expenses as 5% of total fuel costs. The Firm is of the opinion that this approach to classifying a small portion of the fuel costs as demand related is appropriate. This percentage is used for the purposes of the 2024 Study as well. Other production expenses (i.e., expenses other than fuel and purchased power) are classified based on an account-by-account analysis of the nature of the costs involved, which differs slightly from those typically employed under FERC Predominance. This system better aligns cost classifications with actual operation and maintenance expenditures. Specifics on the Authority's classification of such expenses is provided in detail in Appendix C – Technical Appendix (available upon request).

Transmission Expenses

Transmission operation and maintenance expenses are classified 100% as demand related because (i) a given transmission system is sized to transmit the load (or demand) placed on that system, and (ii) the expenses incurred to operate and maintain the system do not vary with energy usage.

Distribution Expenses

Distribution expenses represent a combination of costs related to the demand, customer, and direct assignment classifications. The classification of the Authority's distribution expenses is based on an account-by-account analysis of the Authority's historical expenses. In general, meter expenses, customer installation expenses, and certain maintenance expenses are classified as customer related, while load dispatching, station expenses, and line expenses are classified as demand related. Expenses identified as being directly related to providing services to a particular customer or customer class have been directly assigned to that customer or customer class.

Customer Accounts, Service and Informational Expenses, and Sales Expense

Customer accounts, service and informational expenses, and sales expenses by definition are all classified as customer related because they represent costs incurred by the Authority for billing accounts and providing various services and information for its customers. These costs are based on the FERC Uniform System of Accounts.

Administrative and General Expenses

Administrative and general expenses are principally related to personnel matters. Property insurance costs are the one category of administrative and general expenses that are not personnel related. Accordingly, property insurance costs are functionalized and classified on the basis of insured property, while all other administrative and general expenses are functionalized and classified on the basis of functionalized wages and salaries.

Payments in Lieu of Taxes

This cost item generally includes franchise taxes, payments to the State, energy sales tax and generation tax, and other sums in lieu of taxes. Except for a small portion of franchise taxes directly assigned to distribution customers, the Authority's payments in lieu of taxes are classified as demand related because they are regarded as fixed costs related to system facilities.

Debt Service, Capital Improvements Fund Requirements, and Lease Payments

The Authority's two primary sources of funding additions, renewals, replacements, and improvements to the Authority's system are the issuance of debt and the CIF requirements.

The Authority's debt service payments are incurred as a result of infrastructure additions to the system and are therefore allocated in the same manner as the Authority's facilities. The Authority's plant in service is first functionalized and then classified to various cost categories. The resulting classification of plant is used to classify debt service payments to demand-, energy-, or customer-related components. The Authority's CIF requirement is computed as 9% of gross revenue requirements. Because the CIF is often used in lieu of debt to fund capital improvements, it is allocated in the same manner as the Authority's facilities.

Working Capital

The Authority's working capital requirements, which are directly related to operating expenses, are classified to the demand-, energy-, and customer-related components based on the classification of total operation and maintenance expenses other than nuclear fuel and purchased power expenses.

Other Income and Revenues

Other income and operating revenues, such as revenues from invested funds, non-class sales, wheeling, sales of property, and forfeited discounts, among others, are classified as being either demand-, energy-, or customer-related based on an analysis of the particular source of such revenues.

Development of Customer Class Allocation Factors

This section discusses the development of the factors utilized to allocate the demand-, energy-, customer-, and other related costs to the various customer classes. The aforementioned costs are allocated to the customer classes according to the cost allocation factor developed for each class and for each type of cost. As previously discussed, there have been limited changes to the allocation methodology for this Study compared to the Authority's previously completed rate studies.

As one of the factors considered in the development of the proposed rate levels included in this Study, certain analyses common in ratemaking have been employed that provide a reasonable indication of the revenue levels required to recover the full cost of service or revenue requirement of each customer class. Since it is not the practice in utility accounting to maintain a subdivision of accounts that will report the cost of rendering service to each customer class, an allocation of costs must be made on the basis of parameters predicated upon the available classifications of operating expense and utility plant. The allocated cost of service starts with the projected revenue requirements for the Test Year and allocates these requirements to the various customer classes based on the allocation factors discussed in this section.

The development of the allocation factors requires a compilation of data from several different sources including, among others, the Authority's peak demand and energy forecasts, historical billing and other customer information, and data from the Authority's Advanced Metering Infrastructure (AMI) systems. Cost of service allocation factors are developed based on the usage characteristics of the Authority's firm requirements customers and do not take into account non-firm sales. The following is a brief discussion of each type of allocation factor used in this Study.

Demand Allocation Factors

Demand allocation factors are used to allocate that portion of revenue requirements which has been determined to be demand or capacity related. Costs allocated based on the demand allocation factors include:

- Demand-related production expenses.
- Transmission expenses.
- Demand-related distribution expenses.
- Demand-related debt service requirements.
- Capital Improvements.

The demand allocation factors were developed based on historical demand and energy relationships determined by data obtained from the Authority's AMI meters. The demand allocation factors are based on the estimated annual coincident and non-coincident peak demands (the allocation factors are referred to as Coincident Peak or CP, and non-coincident peak or NCP, respectively). Certain costs, such as most production-related costs, are related to the maximum system coincident peak demand while other costs, such as most distribution-related costs, correspond to the maximum non-coincident demand for a particular load.

The Authority utilizes AMI meters for the majority of its customers, so actual billing data by class is imported from all retail customer meters to provide totalized hourly coincident and non-coincident load data by rate code.

Demand allocation factors for production costs were developed based on the four coincident peaks (4 CP) during the months of January, February, July, and August. Historically the 4 CP has been calculated using December, January, July, and August, but in this Study the December component of the 4 CP was replaced with February to better reflect the system peaks experienced in recent years. The Authority's system has two distinct periods of peak load among the summer months and two among the non-summer months. In recent years, the non-summer months have seen peak load in the morning while the summer months have seen peak load in the afternoon. It is necessary for the Authority to plan for sufficient capacity resources to meet both the summer and non-summer peaks.

Demand allocation factors for transmission costs were developed based on the average of the 12 monthly coincident peaks (12 CP). This is congruent with industry standards and is the preferred method used by FERC in developing open access transmission tariffs (OATTs).

Demand allocation factors for distribution costs including line expenses, substation expenses, and load dispatching expenses were developed based on the 12 monthly non-coincident peaks (12 NCP) of each rate class. Industrial customers are not allocated costs associated with the distribution system as they do not take service from the distribution system.

Table 4-2 summarizes the firm demand allocation factors for the Test Year.

Table 4-2
2025 Summary Demand Allocation Factors

	Production 4 CP		Transmission 12 CP		Distribution 12 NCP	
Customer Class	**MW**	**%**	**MW**	**%**	**MW**	**%**
Residential	575,997	47.48%	500,508	44.93%	478,521	60.15%
Commercial	332,756	27.43%	310,830	27.90%	305,148	38.36%
Lighting	7,819	0.64%	6,789	0.61%	11,904	1.50%
Total Distribution	**916,571**	**75.55%**	**818,127**	**73.44%**	**795,574**	**100.00%**
Industrial (Firm)	296,558	24.45%	295,883	26.56%	N/A	N/A
Total	**1,213,129**	**100.00%**	**1,114,010**	**100.00%**	**795,574**	**100.00%**

Energy Allocation Factors

Energy allocation factors are the basis for apportioning those revenue requirements classified as variable or energy related and assumed to vary directly with the level of energy sales or generation. The costs classified herein as variable or energy related include fuel expense, the energy-related portion of purchased power expenses, and the variable portion of other production expenses. The development of the energy allocation factors involves a ratio analysis of total energy consumption for the individual customer class as compared to total system energy requirements, both measured at the production (or generation) level so as to include transmission and distribution losses, as appropriate.

The projected Test Year energy sales data is discussed in Section 2. The resulting energy allocation factors are shown in Table 4-3 below.

Table 4-3
Summary of Energy Allocation Factors

	2025	
Customer Class	**GWh**	**%**
Residential	2,071	31.77%
Commercial	1,873	28.73%
Lighting	61	0.94%
Total Distribution	**4,006**	**61.43%**
Industrial (Firm)	2,515	38.57%
Total	**6,521**	**100.00%**

Customer Allocation Factors

The factors used to allocate customer-related revenue requirements are based on the projected average number of customers or delivery points, and/or service attachments in each customer classification.

Customer-related revenue requirements include meter reading, meter maintenance, customer installations, billing, collecting, and other customer-related accounting, service, and information functions.

In apportioning customer-related costs and revenues to the various customer classifications, customer allocation factors were utilized that recognized weighted and unweighted customers and fixtures. The customer weighting factors were based on an analysis of the Authority's customer-related costs. The customer allocation factors are shown in Table 4-4.

Table 4-4
Summary of Customer Allocation Factors (2025)

Customer Class	Rate	Customer Delivery Points	%	Weight Factor	Weighted Customer	%
Residential	RG	182,940	84.90%	1.00	182,940	80.89%
Small General Service	GA, TP	27,762	12.88%	1.30	36,091	15.96%
General Service	GB, GV	2,050	0.95%	2.09	4,279	1.89%
Commercial Lg Demand	GL	38	0.02%	2.09	80	0.04%
Commercial Time of Use	GT	25	0.01%	2.09	52	0.02%
Commercial Traffic Light	TL	305	0.14%	1.00	305	0.13%
Lighting	MS, OL	2,314	1.07%	0.50	1,157	0.51%
Total Distribution		**215,435**	**99.99%**		**224,905**	**99.44%**
Industrial (Firm)		31	0.01%	40.51	1,256	0.56%
Total Retail System		**215,466**	**100.00%**		**226,160**	**100.00%**

Other Allocation Factors

Administrative and general expenses are allocated based on wage and salary expenses with the exception of property insurance, which is allocated based on net plant in service.

Debt service payments are related to the existing plant and additions of utility plant on the Authority's system. Therefore, debt service is functionalized on the basis of net plant in service and allocated using the appropriate plant allocation factor.

Direct Assignment

Sales Expenses which can be directly assigned to a customer class have been allocated in this manner. The remaining Sales Expenses were allocated among the customer classes proportionally to each class's energy usage. The Sales Expenses allocation factors are shown in Table 4-5.

Table 4-5
Summary of Sale Expense Allocation Factors

Customer Class	2025 %
Residential	32.85%
Commercial	32.78%
Lighting	0.00%
Total Distribution	**65.62%**
Industrial	34.38%
Total	**100.00%**

DSM and EE costs are assigned directly to residential and commercial classes and are allocated to the customer classes on the basis of the projected demand and energy savings of each of the classes.

Summary of Results

The results of the cost of service analysis are summarized in Table 4-6 as follows.

Table 4-6
Summary of Cost of Service (1,2)

Customer Class	2025 ($000)
Residential	$266,508
Commercial	$188,875
Lighting	$16,541
Total Distribution	**$471,924**
Industrial (Firm & Non-Firm)	$371,689
Total	**$843,613**

(1) Numbers may not add due to rounding.

(2) Includes policy adjustments related to cost allocation amongst customer classes.

Comparison of Allocated Costs to Existing Rate Revenues

The allocated costs by rate class compared to the revenues by class under existing rates are provided in Table 4-7 as follows.

Table 4-7
Comparison of Allocated Costs to Existing Rate Revenues (2025) (1)

	($000)			
Customer Class	**Cost of Service (2)**	**Revenues at Existing Rates**	**Difference**	**%**
Residential	$266,508	$245,108	$21,400	8.7%
Commercial	$188,875	$181,522	$7,354	4.1%
Lighting	$16,541	$15,756	$785	5.0%
Total Distribution	**$471,924**	**$442,385**	**$29,539**	**6.7%**
Industrial (Firm & Non-Firm)	$371,689	$361,524	$10,164	2.8%
Total	**$843,613**	**$803,910**	**$39,703**	**4.9%**

(1) Numbers may not add due to rounding.
(2) Includes policy adjustments related to cost allocation amongst classes.

The detailed cost of service analysis, along with supporting tables, is shown in Appendix C – Technical Appendix, which is available upon request from the Authority.

Section 5
RATE DESIGN

General Rate Design Criteria

Rate design is the culmination of a rate study whereby the rates and charges for each customer classification are established in such a manner that the total revenue requirement of the system will be recovered in an equitable manner consistent with the results of the allocated cost of service study, utility policy objectives, and any applicable orders and/or requirements of local, state, and federal regulatory authorities. To the extent possible, rate design should consider and reflect overall revenue stability, consistency with historical rate forms, conservation considerations, competitiveness with neighboring utility systems, and the policies of those charged with the management and operation of the utility.

The proposed rate levels developed and submitted to the Authority for consideration and adoption will continue to meet the following electric utility rate criteria for service provided by publicly owned utilities:

- Electric rates should be based on a rate policy which calls for low prices consistent with the Authority's other rate design criteria and customer requirements for quality service that is efficiently rendered.
- Electric rates should support economic development, job attraction, and retention.
- Electric rates should be simple and understandable.
- Electric rates should be equitable among classes of customers and individuals within classes, taking into consideration the cost to provide service.
- Electric rates should avoid undue price fluctuations.
- Electric rates should be designed to encourage the most efficient use of the utility plant and discourage unnecessary or wasteful use of service.
- Electric rates should comply with applicable orders and requirements of local, state, and federal regulatory authorities that have jurisdiction.

Additionally, the proposed rate levels developed and submitted to the Authority for consideration and adoption will continue to meet the following criteria set forth in the Authority's Pricing Principles:

- Mission – Limit price increases to less than inflation.
- Equity – Allocate costs to specific customer classes in a reasonable, equitable and defensible manner.
- Efficiency – Design prices so that conservation savings are shared with the customers.
- Adequacy – Provide sufficient revenue to preserve the financial integrity of Santee Cooper.
- Notice – Ensure customer notice and engagement in rate proceedings.
- Protection – Allow reasonable relief mechanisms for financially distressed customers.
- Transparency – Require openness in annual review of compliance with Pricing Principles.

Proposed Rates

Changes to the existing rate design are summarized below, and the proposed rates necessary to recover the revenue requirements are provided in detail in Appendix A – Bill Comparisons and Appendix B – Proposed Rate Schedules. The Firm believes that the proposals offered by the Authority's management and detailed below are reasonable and align with standard industry practice.

For rate classes other than industrial and wholesale, the following structural changes are proposed:

(i) Introduction of demand charges for the RG, REV, EVO, and GA rate codes.

(ii) Revision of the summer months from June–September to April–October, and revision of the non-summer months from October–May to November–March.

(iii) Removal of the seasonal difference in energy rates.

(iv) Implementation of consistent on and off-peak periods for time of use (TOU) rates. A three-hour on-peak period is proposed for classes with on-peak demand windows and a four-hour window is proposed for classes with on-peak energy windows. On-peak energy windows are proposed to be from 3:00–7:00 p.m. in summer months and 5:00–9:00 a.m. in the non-summer months. On-peak demand windows are proposed to be from 3:00–6:00 p.m. in the summer months and 6:00–9:00 a.m. in the non-summer months.

(v) Inclusion of weekends and holidays for TOU windows.

The structural changes detailed above are generally intended to further align customer rates with the Authority's underlying cost structure.

Proposed Residential Rate Designs

As identified in the structural changes detailed at the beginning of this section, the Authority is proposing to implement an on-peak demand charge for rate classes RG, REV, and EVO which will be based on the highest one-hour integrated demand for each customer meter during the on-peak window for each month. This revised rate structure will allow much of the fixed cost recovery previously embedded into the energy rate to be recovered in the on-peak demand charge. As a result, the residential energy rate will decrease. The Firm believes that the recovery of fixed costs through a demand charge allows for a more equitable alignment between cost-causation and cost-recovery.

The proposed on-peak demand window for RG, REV, and EVO is 3:00–6:00 p.m. in the summer months and 6:00–9:00 a.m. in the non-summer months. The proposed on-peak energy window for rate class RT is from 3:00–7:00 p.m. in the summer months and 5:00–9:00 a.m. in the non-summer months.

Proposed Commercial Rate Designs

For the commercial classes, the Authority proposes to implement the changes detailed at the beginning of this section with respect to TOU periods and seasonality.

Additionally, the Authority proposes to introduce a demand charge for the GA class. The proposed demand charge for the GA class will be based on the highest 30-minute integrated demand for each customer.

Under existing rates, customers with less than 50 kW demand have the option to choose between the GA and GB rate classes. Under proposed rates, it will be mandatory for all commercial customers with less than 50 kW of demand to be served on the GA rate schedule. This drives the mandatory transition of approximately 1,500 GB customers to GA.

Additionally, the GB rate schedule will be mandatory for customers with demands between 50–300 kW and the GL rate schedule will be mandatory for distribution voltage customers with demands exceeding 300 kW. All commercial customers may elect the optional seasonal GV or TOU GT rate.

Proposed Lighting Rates

The existing lighting tariff includes over 100 unique rates to reflect the unique costs associated with various fixture and pole combinations. The Authority proposes to simplify this tariff by creating cost segments based on the installation cost of any combination of poles and fixtures.

Proposed Industrial Rates

Services provided under the Authority's industrial rate schedules are offered to customers with demand for electric service of at least 1,000 kW. Service under the industrial rate schedules (Schedule L and various rates, riders, and successors thereto) are governed by General Terms and Conditions of Large Power Electric Service (see "General Terms and Conditions" attached to Schedule L-25).

Under proposed rates, industrial customers will have on-peak energy hours from 1:00–10:00 p.m. during the months of June through August and on-peak energy hours from 5:00–9:00 a.m. during the months of November through February.

Interruptible Service – Combustion Turbine Pricing

Like other utilities, the Authority values Interruptible Service based on the costs for an incremental combustion turbine (CT) generation unit in a simple cycle configuration that are avoided with the Authority's access to interruptible load. This value, or discount to the Firm industrial rate, is identified as the Interruptible Credit.

It was determined that a greenfield site represents the least cost resource for the Credit that provides high reliability in a relative short-term planning horizon. This provides a reasonable and defensible basis for the cost of avoided generation. The Firm reviewed the methodology for developing the CT cost estimate and determined that it was consistent with industry standard practices.

To calculate the Interruptible Credit, Santee Cooper updated the input cost assumptions for the combination of site and generator technology used in the 2015 rate study. The 2015 study included estimated costs for owner's costs and gas/transmission line upgrades to produce a value for total unit costs. Santee Cooper incorporated other indirect costs and contributions to the Authority's CIF. The total summed costs were divided by the Winter rated capacity (in kW) of the CT, which serves as the Interruptible Credit as expressed in terms of dollars per kilowatt-month ($/kW-mo.).

Economy Power

The Authority is proposing to modify the trigger for additional on-peak hours for the Economy Power Optional (EP-O) rate to be tied to an energy price rather than the load forecast.

Economic Development

The Authority is proposing an Economic Development rate to promote development and job creation. The rate will provide for a graduated demand rate discount and extended initial contract period.

Municipal Rate

The Municipal Rate (ML) serves as the basis for negotiated wholesale sales, the terms of which are designed to align with the ML rate offering over time. At this time, the Authority is not proposing to make any changes to its ML rate structure.

Proposed Fuel Adjustment

The Authority has modified the Fuel Adjustment to account for certain resources associated with a wholesale contract. Additionally, the Authority has revised the tariff language to explicitly include gypsum expenses and renewable PPA energy costs as part of fuel costs. Other than these changes, management does not propose any structural changes to its Fuel Adjustment Clause at this time.

The Authority has projected its estimated fuel costs for 2025, and the Fuel Adjustment will be modified to the degree which the actual fuel expenses vary from the projected costs. The Fuel Adjustment unlocks on January 15, 2025, and any adjustments calculated at that time will be included on customer bills.

Demand Sales Adjustment Clause

The Authority has analyzed the Demand Sales Adjustment Clause (DSC), which is related to the manner in which revenues from non-firm energy sales flow through the DSC to customers receiving firm service. At this time, the Authority is not proposing to make any changes to its DSC methodology. The Demand Sales Adjustment unlocks on January 15, 2025, and any adjustments calculated at that time will be included on customer bills.

EDR Sales Adjustment Clause

The purpose of the Economic Development Sales Adjustment Clause (EDA) is to credit the Authority's firm requirements and interruptible service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority from the sales associated with the EDR to the extent that such sales are not reflected in the effective rates for such customers. The Authority’s management does not propose making any structural changes to its Economic Development Sales Adjustment Clause at this time. The Economic Development Sales Adjustment unlocks on January 15, 2025, and any adjustments calculated at that time will be included on customer bills.

Distributed Generation Rider

In the 2015 Electric Rate Study the Authority created a new rider to govern service to all retail customers that opt to install distributed generation. The Distributed Generation Rider (DG) applies to both residential and non-residential retail customers. Installed systems are capped in size at 20 kW for residential customers, 1,000 kW for commercial customers, or the estimated maximum monthly kW demand of the customer, and the former total system cap on distributed generation of 2% of total distribution class demand has been removed. As part of this rate Study the Authority is offering the DG rider to industrial customers as well, with installed systems limited to 2,000 kW.

For residential customers, the DG Rider will include a modified customer charge. For both residential and commercial customers, the metering fee and standby fee will be eliminated. It is also proposed to remove the seasonality component of the energy credit. For industrial customers, the energy credit will be based on hourly system marginal energy pricing. The Authority’s management does not propose any other changes to the Distributed Generation Rider at this time.

Section 6
PROPOSED RATES

The proposed rates were designed to meet the revenue requirements for Test Year 2025. To test the reasonableness of the proposed rates, an analysis was prepared using the projected billing units. Table 6-6 provides the projected rate revenue by customer class using the proposed rates effective April 1, 2025.

Residential Service

The proposed residential rates have been designed to produce approximately $266,508,000 in 2025. The existing and proposed monthly rates for residential service are provided in Table 6-1 below.

Table 6-1
Existing and Proposed Residential Rates

Description	Sch.	Existing	Proposed 2025
Residential General Service	**RG**		
Customer Charge ($/month)		$19.50	$20.00
Demand Charge ($/kW month)		N/A	$10.03
Energy Charge ($/kWh)		$0.1197 (Summer) $0.0997 (Non-Summer)	$0.0684
Residential Time-of-Use	**RT**		
Customer Charge ($/month)		$28.00	$20.00
Energy Charge ($/kWh)			
On-Peak		$0.3438 (Summer) $0.3094 (Non-Summer)	$0.3139
Off-Peak		$0.0613	$0.0684
Electric Vehicle Power (REV)	**REV**		
Customer Charge ($/month)		$19.50	$20.00
Demand Charge ($/kW month)		N/A	$10.03
Energy Charge ($/kWh)			
On-Peak		$0.2463	$0.0745
Off-Peak		$0.0860	N/A
Super Off-Peak		$0.0418	$0.0418
Electric Vehicle Power Only (EVO)	**EVO**		
Customer Charge ($/month)		$5.00	$5.00
Demand Charge ($/kW month)		N/A	$10.03

Table 6-1
Existing and Proposed Residential Rates

Description	Sch.	Existing	Proposed 2025
Energy Charge ($/kWh)			
On-Peak		$0.3376	$0.1000
Off-Peak		$0.0860	N/A
Super Off-Peak		$0.0418	$0.0418

Commercial Service

The proposed commercial rates have been designed to produce approximately $188,875,000 in 2025. The existing and proposed monthly rates for commercial service are provided in Table 6-2 below.

Table 6-2
Existing and Proposed Commercial Rates

Description	Sch.	Existing	Proposed 2025
Small General Service	**GA**		
Customer Charge ($/month)		$25.00	$26.00
Demand Charge ($/kW month)		N/A	$17.08
Energy Charge ($/kWh)			
Summer (Existing) | On-Peak (Proposed)		$0.1126	$0.0481
Non-Summer (Existing) | Off-Peak (Proposed)		$0.0926	$0.0381
General Service	**GB**		
Customer Charge ($/month)		$26.00	$28.00
Demand Charge ($/kW month)		$23.42	$24.95
Energy Charge ($/kWh)			
Summer (Existing) | On-Peak (Proposed)		$0.0475	$0.0501
Non-Summer (Existing) | Off-Peak (Proposed)		$0.0375	$0.0401
Seasonal General Service	**GV**		
Customer Charge ($/month)		$26.00	$28.00
Demand Charge ($/kW month)		$25.04	$26.23
Energy Charge ($/kWh)			
Summer (Existing) | On-Peak (Proposed)		$0.0475	$0.0476
Non-Summer (Existing) | Off-Peak (Proposed)		$0.0375	$0.0376

Table 6-2
Existing and Proposed Commercial Rates

Description	Sch.	Existing	Proposed 2025
Gen. Service Time-of-Use	**GT**		
Customer Charge ($/month)		$31.00	$33.00
On-Peak Demand Charge ($/kW month)		$25.76	$27.42
Off-Peak Demand Charge ($/kW month)		$13.94	$14.92
Energy Charge ($/kWh)			
Summer On-Peak		$0.0475	$0.0501
Non-Summer On-Peak		$0.0475	$0.0501
Off-Peak Hours		$0.0375	$0.0401
Large General Service	**GL**		
Customer Charge ($/month)		$26.00	$28.00
Demand Charge ($/kW month)		$23.60	$25.73
Energy Charge ($/kWh)			
Summer (Existing) | On-Peak (Proposed)		$0.0465	$0.0481
Non-Summer (Existing) | Off-Peak (Proposed)		$0.0365	$0.0381
Temporary Service	**TP**		
Customer Charge ($/month)		$22.00	$26.00
Energy Charge ($/kWh)			
Summer (Existing) | On-Peak (Proposed)		$0.1412	$0.1478
Non-Summer (Existing) | Off-Peak (Proposed)		$0.1212	$0.1378

Lighting Service

The proposed lighting rates have been designed to produce approximately $16,541,000 in 2025. The existing and proposed monthly rates for lighting service are provided in Table 6-3 below.

Table 6-3
Existing and Proposed Lighting Rates

Description	Sch.	Existing	Proposed 2025
Traffic Signal Service	**TL**		
Customer Charge ($/month)		$25.00	$26.00
Base Energy Charge ($/kWh)		$0.1010	$0.1113
Energy Charge			

Table 6-3
Existing and Proposed Lighting Rates

Description	Sch.	Existing	Proposed 2025
Per Lamp 25 W or less		$1.60	$1.75
Per Lamp 26 to 70 W		$2.21	$2.45
Per Lamp >70 W		$3.00	$3.36
Municipal Street Lighting (see Appendix B)	**MS**		
Pole & Fixture Rental Charges (See Appendix B)		$17.64	$19.02
Energy Charge ($/kWh)		$0.0661	$0.0649
Private Outdoor Lighting	**OL**		
Pole & Fixture Rental Charges (See Appendix B)		$14.01	$15.17
Energy Charge ($/kWh)		$0.0661	$0.0649
Pole Attachment	**PA**		
Annual Charge		$14.60	$19.10

Industrial Service

The proposed Industrial rates for both firm and non-firm service have been designed to produce approximately $371,689,000 in 2025 (Table 6-4).

Table 6-4
Existing and Proposed Industrial Rates

Description	Sch.	Existing	Proposed 2025
Large Light & Power	**L**		
Customer Charge ($/month)		$3,400	$3,605
Base Demand First 300 kW ($/month)		$7,511	$8,223
Additional kW Demand ($/kW month)		$19.26	$21.08
Transformation Discount ($/kW month)		$0.60	$0.70
Excess Demand Charge ($/kW month)		$12.00	$13.00
Excess Reactive Demand ($/kVAr month)		$0.82	$0.93
On-Peak Energy Charge ($/kWh)		$0.0575	$0.0497
Off-Peak Energy Charge ($/kWh)		$0.0375	$0.0375
Off-Peak Demand Provision ($/kWh)		$0.02104	$0.02287

Table 6-4
Existing and Proposed Industrial Rates

Description	Sch.	Existing	Proposed 2025
Interruptible Service	**L-I**		
Demand Charge ($/kW month)		$10.31	$10.44
On-Peak Energy Charge ($/kWh)		$0.0575	$0.0497
Off-Peak Energy Charge ($/kWh)		$0.0375	$0.0375
Economy Power Service	**L-EP**		
Customer Charge ($/month)		$1,000	$1,000
Reservation Charge ($/kW month)		$1.81	$3.24
Generation Related Expenses ($/MWh)		$8.31	$7.47
Markup %		12.92%	12.92%
EP Optional Energy Charge	**L-EP-O**		
Reservation Charge ($/kW month)		$3.66	$4.89
Off-Peak Energy Charge ($/kWh)		$0.0375	$0.0375
EP As Used	**AU**		
Hourly Energy Charge ($/kWh)		$0.02104	$0.02287
Demand Response Buy Back	**DRB**		
Monthly Credit ($/kW month)		$490	$418
Event Credit ($/kW month)		$588	$502

The proposed Distributed Generation rider is provided in Table 6-5 below.

Table 6-5
Existing and Proposed Distribution Generation Rider

Description	Sch.	Existing	Proposed 2025
Distributed Generation Rider	**DG**		
Incremental Customer Charge – Residential ($/month)		N/A	$10.00
Metering Charge ($/month)		$2.00	N/A
Standby Fee – Residential		$4.40	N/A
Standby Fee – Comm.		$4.70	N/A
Summer Credit ($/kWh)		$0.0416	$0.0415
Non-Summer Credit ($/kWh)		$0.0384	$0.0415

Summary

Table 6-6 below provides a comparison of the Test Year projected revenues produced by applying the projected billing determinants to the existing rates and the proposed rates for each classification.

Table 6-6
Summary of Proposed Revenues

Type of Service	Rate Code	Proposed Revenues ($000) 2025
Residential		
Residential General Service	RG	$266,508
Total Residential Revenues		**$266,508**
Commercial		
General Service	GA	$60,294
General Service Demand	GB	$109,904
Seasonal General Service	GV	$1,738
Large General Service	GL	$11,023
General Service Time of Use	GT	$1,096
Temporary Service	TP	$4,627
Traffic Signal Service	TL, TL-M	$192
Total Commercial Revenues		**$188,875**
Lighting		
Municipal Street Lighting	MS	$4,280
Private Outdoor Lighting	OL	$12,261
Total Lighting Revenues		**$16,541**
Industrial		
Large Light and Power	L	$160,909
Non-Firm Industrial	I, EP, EP-O	$210,779
Total Large Light and Power		**$371,689**
Total Proposed Revenues		**$843,613**

Percent Increase in Revenue Recovery

Table 6-7 below provides a summary of the percent increase in firm revenue recovery for major rate classifications. Appendix A shows the calculation of monthly bills using the existing and proposed rates at a variety of energy/demand usages.

Table 6-7
Incremental Percent Increase in Revenue Under Proposed Rates

Service	Proposed Revenue Increase [1] 2025
Residential	8.7%
Commercial	4.1%
Lighting	5.0%
Industrial (Firm & Non-Firm)	2.8%
Total	**4.9%**

(1) Revenue increase in 2025 under proposed rates versus under existing rates.

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