South Carolina
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July 30, 2026

Delivered Electronically to rates@santeecooper.com

Chairman Peter M. McCoy, Jr
Santee Cooper, Rates Public Comments (M301)
P.O. Box 2946101
Moncks Corner, SC 29461

RE: Review of the South Carolina Public Service Authority 2026 Request for Rate Adjustment: **South Carolina Department of Consumer Affairs' Comments**

Dear Chairman McCoy:

Please find enclosed the Department of Consumer Affairs' comments regarding Santee Cooper's proposed rate increase, planned to be implemented in February 2027 and 2028. Prior to 2004, the Department was the state designated intervenor to represent consumers in utility matters before the Public Service Commission. The legislature restored the Department's ability to intervene in utility matters to advocate for the "interest of consumers" in 2018 with Act 258. With Act 90 in 2021, the legislature provided a role for the Department in this rate study process, allowing the Department to offer comments directly to the Santee Cooper Board of Directors.

The Department interprets "consumer" in accordance with the Consumer Protections Code: South Carolina residents who purchase utility services primarily for a personal, family, or household use. In other words, residential customers. As you will see from our comments, many of the residential-related rate increase issues identified also impact small commercial customers.

Acadian Consulting Group assisted the Department in this rate review process. Acadian has extensive experience in utility ratemaking matters, having participated in over 300 regulatory proceedings across the United States and abroad. Acadian's review focused on cost of service and rate design and many of its comments were formed based on its experience in other jurisdictions.

Attached to this letter is a presentation regarding the Department's review of Santee Cooper's proposal. The following is a summary of the issues and concerns identified therein.

- The proposed production plant cost allocation relies on methods that are biased and negatively impact low-load factor customers such as residential and small commercial customers.
- The proposed increases in monthly residential customer charges disadvantage low-use low-income customers and do not promote energy efficiency.
- The Department recognizes that "Balanced Demand Billing" is a step in the right direction to mitigate the "one bad day" risk for residential customers; however, the Department has concerns with the proposed increase in the demand charge.
- Demand charges still have the potential to confuse customers.

Based on these findings, the Department recommends:

- Use of a composite classification factor for production plant, such as the use of an Average and Peak ("A&P") cost allocation method, to allocate fixed production plant costs.
- Withdrawal of the proposed increase in RG, RT, and GA customer charges as current customer charges for these rates are already some of the highest in the region.
- Withdrawal of demand charge increase or consideration of further mitigation for customers related to demand charges. The Department recommends omitting weekends and holidays from the monthly demand charge averages related to RG rates.
- Santee Cooper continue to communicate and educate customers regarding demand charges generally and the proposed "Balanced Demand Billing".

Throughout this rate review process, the Department had multiple discussions with Santee Cooper representatives. The Department thanks Santee Cooper for their time and cooperation as it reviewed the proposal. The Department appreciates the opportunity to submit these comments. We look forward to presenting them to the Santee Cooper Board and addressing any questions in August. Please let me know if we can provide any additional information in the meantime.

Regards,

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Santee Cooper 2026 Electric System Cost of Service and Rate Design Review

Prepared on behalf of South Carolina Department of Consumer Affairs ("DCA")

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Acadian Consulting Group

July 30, 2026

Study purpose

The Acadian Consulting Group, LLC ("ACG") has been asked by the Department of Consumer Affairs ("DCA") to review South Carolina Public Service Authority's ("Authority," or "Santee Cooper"), 2026 Electric System Cost of Service and Rate Design published in April 2026.

The purpose of this analysis is to provide the Authority with a consumer-focused opinion of its proposed rate increase. This analysis reviews Santee Cooper's proposed cost and revenue allocation, and the proposed residential and small commercial rate design, including the proposal to implement demand charges for residential and commercial rates.

This analysis finds that:

- **The proposed cost allocation relies on methods that are biased and negatively impact low-load factor customers such as residential and small commercial customers.**
- **The proposed changes to the Residential General Service ("RG") and Small General Service ("GA") could lead to significant bill increases for residential and small commercial customers.**
- **The proposed increases in monthly residential customer charges disadvantages low-income customers.**

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Section 1: Introduction and Summary of Findings

Overview

Santee Cooper is a state-owned utility established in 1934 to provide electricity and water services across the state of South Carolina.

- On April 20, 2026, NewGen Strategies and Solutions, LLC. ("NewGen"), published a report on behalf of Santee Cooper proposing a 3.3 system average percent ($35 million) rate increase effective February 1, 2027, and a 3.1 system average percent ($67 million) rate increase effective February 1, 2028. This includes a 4.7 percent ($15.1 million) residential rate increase in 2027 and a 4.6 percent ($30.2 million) residential rate increase in 2028.
- Santee Cooper's proposed residential rate proposals include:
  1) The implementation of an on-peak average demand charge for the Company's RG and GA tariff;
  2) A $1.00, or 5.0 percent, increase in RG tariff monthly fixed customer charges; and a $5.00, or 25.0 percent, increase in RT tariff monthly fixed customer charges.
- Santee Cooper's proposed rate changes marks a second recent electric service rate increase, with the Authority's last rate increase being in April 2025.

Source: 2026 Electric System Cost of Service and Rate Design Study (April 20, 2026), at pages 1-5.

Revenue requirements for calendar year 2027

For 2027, Santee Cooper proposes an overall $34.9 million, or 3.3 percent, increase in rates. However, distribution customers will see a $22.2 million, or 3.9 percent, increase, including a $15.1 million, or 4.7 percent, increase in residential rates. Meanwhile, industrial customers will see only a $12.7 million, or 2.6 percent, increase in rates.

	Calendar Year 2027			
Service	Existing Rate Revenue	Proposed Rate Revenue	Proposed Revenue Increase	Percent Rate Increase
	($000)	($000)	($000)	
Residential	$ 322,390	$ 337,526	$ 15,136	4.7%
Commercial	222,913	229,435	6,522	2.9%
Lighting	18,215	18,798	583	3.2%
Total Distribution	**$ 563,518**	**$ 585,760**	**$ 22,241**	**3.9%**
Industrial (Firm & Non-Firm)	486,428	499,083	12,654	2.6%
Total Retail System	**$ 1,049,947**	**$ 1,084,843**	**$ 34,896**	**3.3%**

Source: Table ES-2, Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Revenue requirements for calendar year 2028

For 2028, Santee Cooper proposes an overall $67.3 million, or 6.4 percent, increase in rates. However, distribution customers will see a $44.3 million, or 7.9 percent, increase, including a $30.2 million, or 9.3 percent, increase in residential rates. Meanwhile, industrial customers will see a $23.0 million, or 4.7 percent, increase in rates.

Service	Calendar Year 2028 Existing Rate Revenue	Proposed Rate Revenue	Proposed Revenue Increase	Percent Rate Increase
	($000)	($000)	($000)	
Residential	$ 324,471	$ 354,707	$ 30,237	9.3%
Commercial	221,175	234,110	12,936	5.8%
Lighting	18,168	19,303	1,135	6.2%
Total Distribution	**$ 563,813**	**$ 608,120**	**$ 44,307**	**7.9%**
Industrial (Firm & Non-Firm)	489,039	512,055	23,016	4.7%
Total Retail System	**$ 1,052,852**	**$ 1,120,176**	**$ 67,323**	**6.4%**

Source: Table ES-3, Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

DCA findings and residential ratepayer concerns.

DCA's review identifies three residential ratepayer concerns with the Santee Cooper proposed rate increase:

(1) The proposed allocation of costs between customer classes is potentially biased;

(2) The proposed increase in RG tariff customer charges will impact low-income residential customers disproportionately; and

(3) The proposed increase in demand charges for the RG tariff could lead to significant rate increases for low-income and fixed-income customers.

Cost allocation issues.

The proposed class cost of service study (“CCOSS”), and the Authority’s use of this study in allocating costs, employs a method that is biased and negatively impacts low load-factor customers (i.e., residential and small commercial classes) whose electrical use is typically more associated with weather sensitive air conditioning loads relative to larger industrial customers that are less weather sensitive.

A primary methodological flaw with the Authority’s CCOSS is its failure to consider the various joint functions that electric systems perform, particularly with regards to the various roles that production plant assets play. Electric generation units (“EGU”), for instance, serve multiple functions in basic load requirements (called “baseload requirements) and peaking requirements that arise during hot summer hours/days. **This methodological flaw over-emphasizes the importance of the peaking function of Santee Cooper’s generating units while under-emphasizing the role that these units play in supplying basic electricity to customers.**

Source: Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Concerns related to filing – residential rate design

Santee Cooper residential rate design proposals include:

1) The introduction of an on-peak average demand rate under the RG tariff;
2) a $1.00, or 5.0 percent, increase in RG tariff monthly fixed customer charges, and a $5.00, or 25.0 percent, increase in RT tariff monthly fixed customer charges.

- Santee Cooper's proposed changes to the RG and RT tariffs, could lead to significant bill increases for residential customers consistent with the experience of other electric utilities around the country.
- Santee Cooper's proposed increase in monthly fixed residential customer charges disadvantages low-income customers since they typically pay a greater percentage of their monthly bill through the fixed customer charge relative to higher-income customers.

Source: Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Summary of DCA recommendations.

Cost and Revenue Allocation

- DCA recommends the use of a composite classification factor for production plant, such as the use of an Average and Peak ("A&P") cost allocation method, to allocate fixed production plant costs.

Rate Design

- DCA recommends the Authority withdraw its proposal to increase in residential RG and residential RT customer charges as current customer charges for these rates are already some of the highest in the region.
- DCA supports the proposed change to a demand charge based on the average customer use during the customer's four highest hourly on-peak usage during a month, however does not agree with the proposed increase. DCA also recommends the Authority additionally exempt weekends and holidays from determination of demand charges since electric system utilization is lower during these days.
- DCA recommends the Authority continue to find ways to educate customers on demand charges
- The proposed RG demand charges are especially problematic since the proposed $8.75 and $9.50 per kW-month demand charge could potentially increase electric bills for low- and fixed-income households.

Section 2: Cost Allocation

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2.1 Cost of Service Overview

Cost of service methods: overview.

A class cost of service study ("CCOSS") is used to **allocate the total cost of service (revenue requirement) to customer classes**.

Customer classes are determined by **grouping customers with similar cost and usage patterns**. Customers with similar usage characteristics impose similar costs on the utility:

- Size (volume and capacity)
- Type of meter (residential, commercial, industrial)
- Type of usage (space heat, non-space heat)
- Type of load (firm, interruptible)
- Load factor (average usage, peak usage)

Allocation factors are applied and developed by analyzing the relationship (cause and effect) among various cost categories.

Cost of service methods: estimation steps.

Most CCOSS models use a three-part estimation process. This is a process generally followed by Santee Cooper:

Functionalization: The process of dividing the total revenue requirement into functional components as related to utility operations (generation, transmission, distribution).

Classification: The process of separating the functionalized costs into classifications based on the function they serve. Primary cost classification categories:

- Demand-related (capacity-related) – costs that vary with kW of demand
- Energy-related – costs that vary with the kWh of energy
- Customer-related – costs that vary with the number of customers

Allocation: The process of separating the functionalized and classified costs to different customer rate classes.

Allocation factor comparison.

Santee Cooper's proposed CCOSS allocates costs to residential customers in substantially different amounts based on the allocation factor employed.

- **Energy allocation factor** – 30.8 percent of costs allocated to residential customers.
- **Demand allocation factors** – 43.4 – 45.7 percent of costs allocated to residential customers.
- **Customer allocation factors** – 82.6 percent of costs allocated to residential customers.

Santee Cooper's proposed CCOSS relies very heavily on demand and customer allocations, which, as shown above, assigns a greater portion of costs to residential and small commercial customers. This is especially true with regards to allocation of fixed plant costs, which Santee Cooper allocates on the basis of demand allocation factors.

Source: Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Energy allocation factors

Santee Cooper allocated fuel expenses and other variable expenses, such as the energy-related share of purchased power costs, on the basis of the relative electricity use between customer classes.

Customer Class	2027 and 2028 GWh	2027 and 2028 Percent
Residential	2,237	30.8%
Commercial	1,894	26.0%
Lighting	61	0.8%
Total Distribution	**4,192**	**57.6%**
Industrial (Firm & Non-Firm)	3,082	42.4%
Total	**7,274**	**100.0%**

Note: The Test Years are an average of 2027 and 2028.

Source: Table 4-3, Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Demand allocation factors

Most fixed plant costs are allocated by Santee Cooper on the basis of a series of test year demand measured using historical data reported by AMI meters.

- Fixed production and transmission-related costs are allocated based on the average of monthly maximum system coincident peak ("CP") demand;
- Fixed distribution-related costs are allocated based on relative customer class's maximum non-coincident demand ("NCP").

Customer Class	Production 4 CP		Transmission 12 CP		Distribution 12 NCP	
	MW	Percent	MW	Percent	MW	Percent
Residential	592,646	45.7%	517,089	43.4%	494,937	61.0%
Commercial	335,973	25.9%	308,328	25.9%	303,731	37.5%
Lighting	8,409	0.6%	7,140	0.6%	12,355	1.5%
Total Distribution	**937,028**	**72.2%**	**832,556**	**69.9%**	**811,023**	**100.0%**
Industrial (Firm & Non-Firm)	360,387	27.8%	358,147	30.1%	N/A	N/A
Total	**1,297,415**	**100.0%**	**1,190,703**	**100.0%**	**811,023**	**100.0%**

Notes: "Coincident Peak" ("CP") is a measure of each customer class's demand at the time of Santee Cooper's system peak and not the individual customer class peak demand. The 4 CP measure is the average maximum CP for the months of January, February, July, and August. The 12 CP is the average of 12 monthly maximum CP for all 12 months of the test year. "Non-Coincident Peak" ("NCP") is a demand measure of each customer class's highest electrical demand regardless of relationship to system peak demand. The Test Years Demand Allocation Factors are an average of the years 2027 and 2028.

Source: Table 4-2, Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Customer allocation factors

Customer-related costs such as costs associated with meters, service drops, and monthly customer billing is allocated by Santee Cooper on the basis of relative numbers of customers and fixtures, with larger customers weighted greater relative to residential customers.

Customer Class	Rate	Customer Delivery Points	Percent	Weight Factor	Weighted Customer	Percent
Residential	RG	199,339	86%	1.0	199,339	82.6%
Small General Service	GA, TP	27,654	11.9%	1.3	35,950	14.9%
General Service	GB, GV	2,141	0.9%	2.1	4,470	1.9%
Commerical Lg Demand	GL	38	0.02%	2.1	80	0.03%
Commerical Time of Use	GT	24	0.01%	2.1	50	0.02%
Commerical Traffic Light	TL	313	0.1%	1.0	313	0.1%
Lighting	MS, OL	2,328	1.0%	0.5	1,164	0.5%
Total Distribution		**231,838**	**100.0%**		**241,367**	**100%**
Industrial (Firm)		30	0.0%	2.1	62	0.0%
Total Retail System		**231,867**	**100%**		**241,428**	**100%**

Note: The customer allocation factors are an average of the test years (2027 and 2028).

Source: Table 4-4, Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Electric system capital spending

Santee Cooper's demand allocation represents an important concern when reviewing its proposed rate increase because of the Authority's significant recent capital expenditures. Santee Cooper reports a 2027 capital budget of $1,096 million, including proposed generation or production plant spending of $617 million. Production plant represents 56.3 percent of the Authority's overall 2027 capital spending. For 2028, the Authority projects a total capital budget of $1,132 million, with generation spending at $639 million, accounting for 56.4 percent of that year's budget.

Function	2027 Capital Budget (Million $)	2027 Capital Budget Percent	2028 Capital Budget (Million $)	2028 Capital Budget Percent
Generation	$ 617	56.3%	$ 639	56.4%
Transmission	364	33.2%	389	34.4%
Distribution	63	5.7%	58	5.1%
Customer & Corporate Services	52	4.7%	46	4.1%
Total Capital Budget	**$ 1,096**	**100.0%**	**$ 1,132**	**100.0%**

Source: 1.14a 2027 and 2028 Retail Adj Management Report vF.

Functionalization of revenue requirements

Santee Cooper's significant investment in production plant assets contributes to a significant focus of its overall 2027 and 2028 test year revenue requirements on supporting the generation function. The Authority estimates that of its 2027 test year total revenue requirement of $1,084.8 million, $880.3 million, or 81.1 percent, is associated with the generation function, while for its 2028 test year, of its $1,120.2 million total, $875.7 million, or 78.2 percent, is associated with generation.

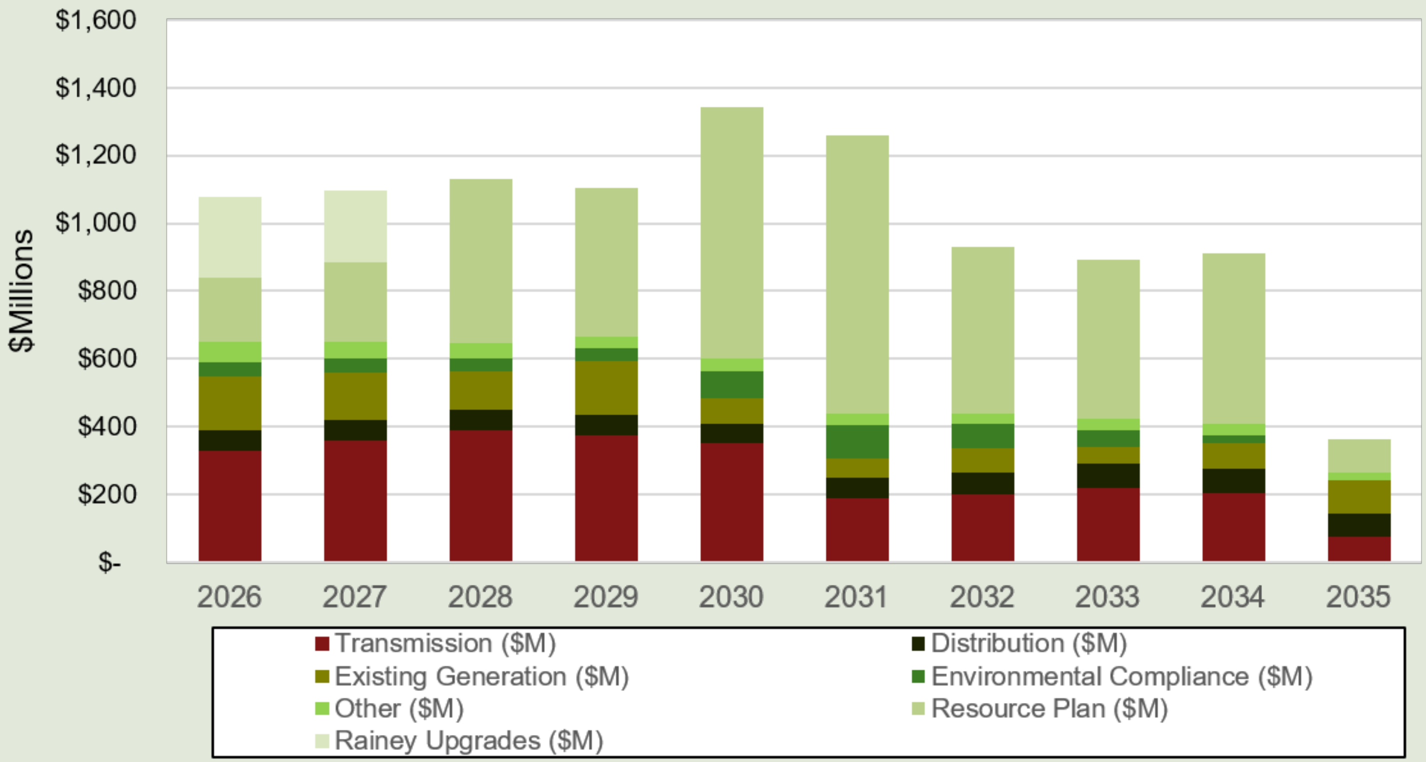
Function	2027 Revenue Requirement (Million $)	2027 Revenue Requirement Percent	2028 Revenue Requirement (Million $)	2028 Revenue Requirement Percent
Generation	$ 880.3	81.1%	$ 875.7	78.2%
Transmission	84.3	7.8%	108.4	9.7%
Distribution	82.1	7.6%	95.3	8.5%
Customer & Corporate Services	38.2	3.5%	40.8	3.6%
Total Retail System	**$ 1,084.8**	**100.0%**	**$ 1,120.2**	**100.0%**

Note: Generation includes Cook Charge.

Source: Table 4-1, Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Electric system 10-year capital plan

Ratebase-related costs for Santee Cooper are only expected to grow over time as the Authority forecasts $10.1 billion in new capital spending over the next decade. New investments covered by the Authority's Resource Plan account for approximately $4.6 billion of this forecasted spending, or approximately 46 percent.



Source: 2-8 Santee Cooper 2024 Rate Adjustment Request 05.24.2024, Attachment B.

2.2 Production Plant Allocation

Inventory of Santee Cooper EGUs

Santee Cooper owns 5.5 GW of electric generation capacity from a variety of generation sources:

- 333 MWs (6.0 percent of total) from a 1/3 ownerships stake in V.C. Summer nuclear generation station;
- 3,495 MWs (63.1 percent of total) from two coal-fired EGUs;
- 1,251 MWs (22.6 percent of total) from natural gas EGUs;
- 200 MWs (3.6 percent of total) from a number of diesel EGUs;
- 226 MWs (4.1 percent of total) from ownership of three hydroelectric dams;
- 30 MWs (0.5 percent of total) from other renewable sources such as landfill gas and solar sources.

Name	In Service Year	Nameplate Capacity (MW)	Percent Total
Nuclear			
V.C. Summer (1/3 Ownership)	**1984**	**333**	**6.0%**
Coal			
Cross	1984-2008	2,345	42.4%
Winyah	1975-1981	1,150	20.8%
Total Coal		**3,495**	**63.1%**
Natural Gas			
Cherokee County Cogeneration	1998	101	1.8%
John S Rainey CC	2001	520	9.4%
Rainey Generating Station CT	2002-2004	630	11.4%
Total Natural Gas		**1,251**	**22.6%**
Diesel			
Hilton Head	1973-1979	100	1.8%
Honea Path	2003	3	0.0%
Myrtle Beach	1962-1976	85	1.5%
Sediver	2003	3	0.0%
Thermal Kem	2003	3	0.0%
Valenite	2003	3	0.0%
Webb Forging	2003	5	0.1%
Total Diesel		**200**	**3.6%**
Hydro			
Jefferies Hydro	1942	140	2.5%
Spillway	1950	2	0.0%
St. Stephen	1985	84	1.5%
Total Hydro		**226**	**4.1%**
Renewables			
Bell Bay Solar Farm	2017	2	0.0%
Berkeley Green Power Project (Landfill Gas)	2011	3	0.1%
Horry County (Landfill Gas)	2001-2003	3	0.1%
Jamison Solar Farm	2019	1	0.0%
Lee County Landfill Combustion Turbine	2009	5	0.1%
Lee County Landfill Internal Combustion	2005	5	0.1%
Richland County Landfill Combustion Turbine	2006	5	0.1%
Richland County Landfill Internal Combustion	2010	3	0.1%
Runway Solar Farm	2019	2	0.0%
Total Renewables		**30**	**0.5%**
Total Generation		**5,535**	**100.0%**

Source: S&P Global.

Electric generation unit function

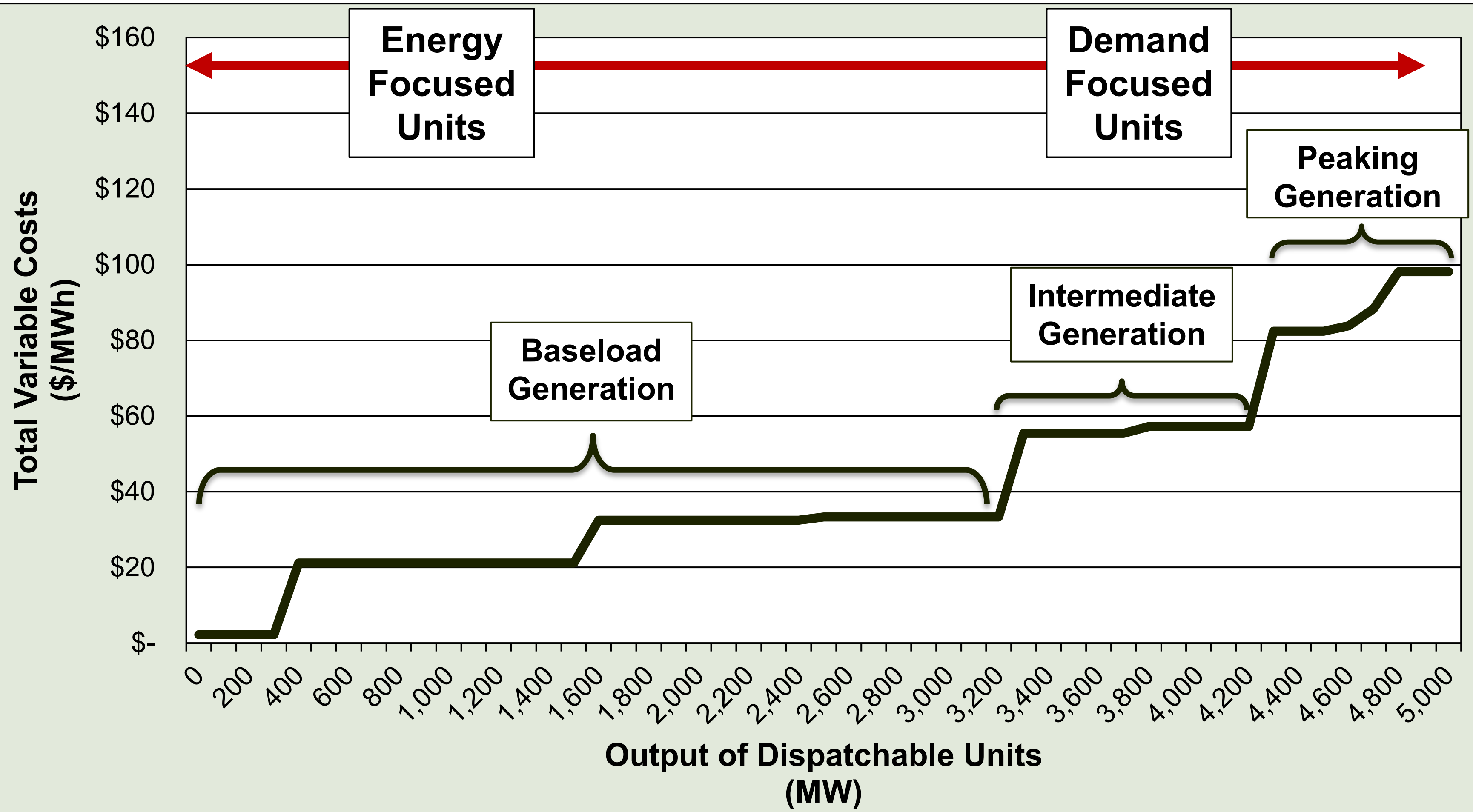
Baseload units: are designed to operate throughout the year to meet a utility's basic generation requirements. These units typically have high installed capital costs, but low operating costs and historically have included nuclear, coal, and hydro-electric units.

Peaking units: are designed to quickly and cost effectively "start-up" to fill temporary shortfalls in generation capabilities. Peaking units are held in reserve and only utilized by a utility during peak, usually weather-driven demand periods when additional generation resources are needed. Natural gas combustion turbines ("CT") typically fulfill these peaking requirements.

Intermediate units: operationally fall between baseload and peaking units that have good cycling capabilities that can ramp up and down or be held in stand-by mode until needed. Intermediate units typically have lower operating costs than peaking units but can have higher capital costs and can include older depreciated former baseload units or natural gas combined cycle ("CC") units.

Utility dispatch curve

EGUs are designed to serve both energy and demand/capacity needs of a utility in a relationship known as a utility's dispatch curve or supply stack.



Source: Author's construct based on Arther Mazer (2007), "Electric Power Planning for Regulated and Deregulated Markets," page 93

Electric generation unit fixed costs

Fixed capital costs associated with large baseload EGUs tend to be much higher than EGUs designed to serve peaking roles despite these units having lower variable operating costs.

For example, a "baseload" nuclear light water reactor, similar to V.C. Summer, is estimated to have fixed capital development costs of $7,782 per kW, while an ultra supercritical ("USC") coal-fired reactor is estimated to have fixed capital development costs of $4,401 per kW.

Alternatively, an industrial frame natural gas CT designed to serve peaking loads is estimated to have far lower capital (development) costs of $801 per kW.

Technology	Region ID SRSE ($/kW)
USC	$ 4,401
USC with 30% CCS	5,511
USC with 90% CCS	7,228
CC—single-shaft	1,235
CC—multi-shaft	1,085
CC with 90% CCS	2,977
ICE	2,200
CT- aeroderivative	1,320
CT- industrial frame	801
Fuel cells	7,271
Nuclear—light water reactor	7,782
Nuclear—small modular reactor	8,164
Distributed generation —base	1,778
Distributed generation—peak	2,126
Battery storage	1,293
Biomass	4,857
Geothermal	NA
Conventional hydropower	5,104
Wind	2,116
Wind offshore	NA
Solar thermal	NA
Solar PV with tracking	1,392
Solar PV with storage	1,781

Source: EIA (AEO 2023), Table 2. Total overnight capital costs of new electricity generating technologies by region.
Notes: Costs are in 2022 dollars per kilowatt. Interest charges are excluded. The costs are shown before investment tax credits are applied. SRSE refers to the Southeast geographic region.

Analysis of 2023 Santee Cooper generation unit capacity factors

Capacity factors are good indicators of EGU roles (baseload, intermediate, peaking). A large share of Santee Cooper's EGUs have high-capacity factors indicating they serve both energy and peak demand requirements. This includes the Company's ownership portion of V.C. Summer, which had a 92.79 percent capacity factor in 2025.

Station Name	Plant Type	Nameplate Capacity (MW)	Net Generation (MWh)	Capacity Factor	Allocation Energy	Allocation Demand
Cross	Steam Turbine	2,345	8,773,860	42.71%	42.71%	57.29%
Hilton Head	Gas Turbine	100	79	0.01%	0.00%	100.00%
Jefferies Hydro	Hydraulic Turbine	140	233,504	19.04%	19.04%	80.96%
John S Rainey CC	Combined Cycle	1,150	3,790,454	37.63%	37.63%	62.37%
Spillway	Hydraulic Turbine	2	4,824	27.53%	27.53%	72.47%
V.C. Summer (1/3)	Nuclear	333	2,704,853	92.79%	92.79%	7.21%
Winyah	Steam Turbine	1,150	4,216,009	41.85%	41.85%	58.15%

The analysis classifies facilities with annual capacity factors less than 10 percent as fully serving the utility's demand requirements, while all other facilities were divided between energy and demand classifications based on the unit's capacity factor.

Source: S&P Capital, EIA form 923.

South Carolina electric utility example: Duke Energy Progress production plant.

An analysis of Duke Energy Carolinas (“DEP”) found that a significant 66.0 percent of DEP’s gross plant in service classified as being energy-related, and only 34.0 percent classified as being demand-related.

Station Name	Plant Type	Nameplate Capacity (MW)	2023 Net Generation (MWh)	2023 Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy ($ Millions)	Plant in Service Demand ($ Millions)	Plant in Service Total ($ Millions)
Asheville CC	Combined Cycle	588	3,744,892	72.7%	72.7%	27.3%	$ 774.1	$ 290.6	$ 1,064.7
Asheville Gas Turbine	Gas Turbine	424	134,076	3.6%	0.0%	100.0%	-	116.7	116.7
Asheville Steam	Steam	-	-	-	-	-	-	-	-
Blewett	Gas Turbine	70	27	0.0%	0.0%	100.0%	-	14.0	14.0
Brunswick	Nuclear	2003	15,658,076	89.2%	89.2%	10.8%	3,185.4	384.1	3,569.6
Cape Fear Gas Turbine	Gas Turbine	-	-	-	-	-	-	-	-
Cape Fear Steam	Steam	-	-	-	-	-	-	-	-
Darlington	Gas Turbine	316	22,124	0.8%	0.0%	100.0%	-	92.3	92.3
H.B. Robinson Gas Turbine	Gas Turbine	-	-	-	-	-	-	-	-
H.B. Robinson Nuclear	Nuclear	769	6,694,374	99.4%	99.4%	0.6%	1,671.4	10.5	1,681.9
H.B. Robinson Steam	Steam	-	-	-	-	-	-	-	-
H.F. Lee Gas Turbine	Gas Turbine	1068	6,374,580	68.1%	68.1%	31.9%	484.6	226.6	711.2
H.F. Lee Steam	Steam	-	-	-	-	-	-	-	-
Harris	Nuclear	951	8,609,278	103.3%	103.3%	-3.3%	4,572.3	(147.9)	4,424.4
L.V. Sutton Gas Turbine	Gas Turbine	851	3,890,097	52.2%	52.2%	47.8%	356.4	326.6	683.0
L.V. Sutton Steam	Steam	-	-	-	-	-	-	-	-
Mayo	Steam	763	1,216,965	18.2%	18.2%	81.8%	305.3	1,371.7	1,677.0
Morehead	Gas Turbine	-	-	-	-	-	-	-	-
Roxboro	Steam	2558	4,040,825	18.0%	18.0%	82.0%	584.3	2,656.1	3,240.5
Smith Energy Complex	Gas Turbine	2245	8,597,617	43.7%	43.7%	56.3%	536.2	690.3	1,226.5
W.H. Weatherspoon Gas Turbine	Gas Turbine	40	104	0.0%	0.0%	100.0%	-	28.2	28.2
W.H. Weatherspoon Steam	Steam	-	-	-	-	-	-	-	-
Wayne County	Gas Turbine	980	90,748	1.1%	0.0%	100.0%	-	271.6	271.6
Blewett Hydro	Hydro	25	116,082	53.0%	53.0%	47.0%	58.1	51.5	109.6
Tillery Hydro	Hydro	84	166,394	22.6%	22.6%	77.4%	10.2	35.0	45.3
Walters Hydro	Hydro	108	321,045	33.9%	33.9%	66.1%	32.3	62.9	95.2
Marshall Hydro	Small Hyrdo	5	-364	-0.8%	100.0%	0.0%	16.9	-	16.9
Subtotals:							**$ 12,587.6**	**$ 6,481.0**	**$ 19,068.6**
					Production Plant Classification:		**66.0%**	**34.0%**	**100.0%**

Most expensive units

Source: Docket No. 2025-154-E , Direct Testimony of Michael W. Deupree, Exhibit MWD-3.

2.2 Production Plant Allocation

South Carolina electric utility example: Duke Energy Carolinas production plant.

An analysis of Duke Energy Carolinas ("DEC") found that as much as 47.3 percent, or nearly half, of its gross plant in service was energy-related and 52.7 percent was demand-related.

Station Name	Plant Type	Nameplate Capacity (MW)	2023 Net Generation (MWh)	2023 Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy ($ Millions)	Plant in Service Demand ($ Millions)	Plant in Service Total ($ Millions)
Allen	Steam	435	80,759	2.1%	0.0%	100.0%	$ -	$ 1,488.5	$ 1,488.5
Belews Creek	Steam	2491	8,487,941	38.9%	38.9%	61.1%	1,194.4	1,876.2	3,070.6
Buck	Steam	370	-	0.0%	0.0%	100.0%	-	0.6	0.6
Buck CC	Combined Cycle	698	3,819,959	62.5%	62.5%	37.5%	457.7	274.9	732.6
Buck CT	Combustion Turbine	104	-	0.0%	0.0%	100.0%	-	-	-
Buzzard Roost	Combustion Turbine	198	-	0.0%	0.0%	100.0%	-	-	-
Catawba	Nuclear	2410	3,688,581	17.5%	17.5%	82.5%	147.7	697.8	845.5
Clemson CHP	Combined Heat/Power	0	108,527	0.0%	0.0%	100.0%	-	30.3	30.3
Cliffside	Steam	1531	5,244,807	39.1%	39.1%	60.9%	1,361.4	2,119.8	3,481.2
Dan River	Combustion Turbine	98	-	0.0%	0.0%	100.0%	-	-	-
Dan River CC	Combined Cycle	698	3,728,812	61.0%	61.0%	39.0%	430.3	275.3	705.6
Dan River Steam	Steam	290	-	0.0%	0.0%	100.0%	-	-	-
Lee	Combustion Turbine	108	10,297	1.1%	0.0%	100.0%	-	64.9	64.9
Lee CC	Combined Cycle	847	5,941,449	80.1%	80.1%	19.9%	518.4	129.0	647.4
Lee Steam	Steam	163	-	0.0%	0.0%	100.0%	-	-	-
Lincoln	Combustion Turbine	1754	4,150	0.0%	0.0%	100.0%	-	419.2	419.2
Marshall	Steam	2119	6,899,395	37.2%	37.2%	62.8%	1,042.7	1,762.7	2,805.4
McGuire	Nuclear	2441	18,068,372	84.5%	84.5%	15.5%	2,665.3	489.0	3,154.2
Millcreek	Combustion Turbine	799	38,496	0.6%	0.0%	100.0%	-	264.7	264.7
Oconee	Nuclear	2667	22,246,735	95.2%	95.2%	4.8%	3,795.7	190.4	3,986.1
Riverbend	Combustion Turbine	135	-	0.0%	0.0%	100.0%	-	-	-
Riverbend Steam	Steam	466	-	0.0%	0.0%	100.0%	-	-	-
Rockingham	Combustion Turbine	978	795,794	9.3%	0.0%	100.0%	-	358.9	358.9
Bridgewater	Hydro	28	40,302	16.4%	16.4%	83.6%	51.8	263.2	315.0
Cedar Creek	Hydro	45	138,717	35.2%	35.2%	64.8%	13.4	24.8	38.2
Cowans Ford	Hydro	350	136,244	4.4%	0.0%	100.0%	-	165.4	165.4
Dearborn	Hydro	45	86,857	22.0%	22.0%	78.0%	19.6	69.3	88.9
Fishing Creek	Hydro	42	143,324	39.0%	39.0%	61.0%	30.0	47.0	77.0
Great Falls	Hydro	24	52	0.0%	0.0%	100.0%	-	18.3	18.3
Lookout Shoals	Hydro	26	90,286	39.6%	39.6%	60.4%	32.7	49.8	82.5
Mountain Island	Hydro	60	99,571	18.9%	18.9%	81.1%	11.5	49.4	60.9
Oxford	Hydro	36	87,283	27.7%	27.7%	72.3%	20.0	52.2	72.2
Rhodhiss	Hydro	26	58,640	25.7%	25.7%	74.3%	13.8	39.9	53.7
Rocky Creek	Hydro	0	-	0.0%	0.0%	100.0%	-	0.1	0.1
Wateree	Hydro	91	201,268	25.2%	25.2%	74.8%	20.6	61.0	81.6
Wylie	Hydro	60	128,935	24.5%	24.5%	75.5%	28.2	86.7	114.8
Ninety-Nine Islands	Hydro	18	62,087	39.4%	39.4%	60.6%	11.2	17.2	28.4
Keowee	Hydro	158	43,255	3.1%	0.0%	100.0%	-	269.7	269.7
Thorpe	Hydro	0	55,365	0.0%	0.0%	100.0%	-	16.9	16.9
Nantahala	Hydro	0	186,095	0.0%	0.0%	100.0%	-	31.3	31.3
Tennessee Creek	Hydro	0	24,782	0.0%	0.0%	100.0%	-	27.5	27.5
Jocassee	Pumped Storage	774	1,188	0.0%	0.0%	100.0%	-	204.1	204.1
Bad Creek Outdoor	Pumped Storage	1584	1,776	0.0%	0.0%	100.0%	-	1,114.2	1,114.2
Bear Creek	Small Hydro	9.5	(0)	0.0%	0.0%	100.0%	-	18.7	18.7
Cedar Cliff	Small Hydro	12.8	10	0.0%	0.0%	100.0%	-	128.3	128.3
Queen's Creek	Small Hydro	1.4	4	0.0%	0.0%	100.0%	-	2.3	2.3
Tuckaseegee	Small Hydro	2.5	5	0.0%	0.0%	100.0%	-	5.6	5.6
Subtotals:							**$11,866.4**	**$13,205.0**	**$25,071.4**
						Production Plant Classification:	**47.3%**	**52.7%**	**100.0%**

Most expensive units

Source: Docket No. 2025-172-E, Direct Testimony of Michael W. Deupree, Exhibit MWD-3.

Production Plant Allocation

A significant portion of Santee Cooper's generation fleet is devoted to the provision of baseload power, and thus are functionally energy-related.

The Authority's CCOSS fails to consider the joint functions that EGUs serve in providing basic load requirements (i.e. baseload requirements) and peaking requirements that arise during hot summer hours/days, by fully classifying all production plant assets as 100 percent demand-related.

- Recent analyses of other SC utilities have found that between 47.3 and 66.0 percent of production plant can be appropriately classified as serving the energy function, and not the demand function.

The Authority's methodological flaw over-emphasizes the importance of the peaking function of Santee Cooper's generating units while under-emphasizing the role that these units play in supplying basic electricity to customers.

- This flaw biases CCOSS results against low-load factor customers such as residential and small commercial customers.

Concern Regarding New Large Load Customers

Santee Cooper anticipates spending approximately $4.6 billion over the next decade as part of its resource plan for new generation resources.

This proposed spending is **likely to develop sufficient generation resources to support new large load customers seeking to locate to the Authorities' service territory** as the rapid growth in artificial intelligence, cloud storage, and e-commerce have accelerated the need for new large data centers across to country to support these data requirements.

Data Centers require large investments in base load power since these customers have large generation requirements during off-peak periods **when compared to residential and small commercial customers who use electricity primarily to support air conditioning**.

While Santee Cooper **has implemented a tariff for large load customers which include important ratepayer protections**, **failure to account for the raise in baseload production plant investments may result in residential customers disproportionally paying for new generation resources required to support new large load customers**.

CCOSS methods for classifying production plant investments.

Two common methods can be employed to classify production plant in a more appropriate fashion that reflects the "dual use" (peak demand and energy/electricity production) of production plant/EGUs.

- **Average and Peak ("A&P")** – is a "composite" allocator based on energy and demand. The first component (the "average" component) is measured by each customer class's relative average hourly energy consumption while the second measures each customer class's relative peak demand contribution. A weighted average is used to develop the composite classification factor. The weights can be determined via judgement or through an empirical measure like a utility's system load factor.
- **Average and Excess ("A&E")** – also uses a "composite" method where the first component is based on each customer class's relative average hourly energy consumption while the second component represents only the energy use during peak system conditions that are in excess of the average component, hence the "excess" component. These components are combined through weightings based on a utility's system load factor.

State utility regulatory decisions: Michigan Public Service Commission

The Michigan Public Service Commission ("MPSC") has recognized that energy loads are an important contributing factor of production plant costs and thus classify a portion of production plant costs as energy-related.

The Commission agrees ... that DTE Electric's production system was not designed and built solely for the purpose of providing capacity for four hours a year. Indeed, if that were the case, DTE Electric's generation asset portfolio would be very different and would certainly include far fewer of the large base load units that comprise much of the company's current fleet. ***Instead of building a system to simply meet demand, the company developed its production plant to both deliver energy and provide capacity at the lowest overall cost to all customers who use the system.*** Thus, DTE Electric's generating system includes a mix of base load plants that were significant investments, but that provide abundant, reliable, and low-cost energy to all customers, and peaking plants, with low fixed production costs and typically higher fuel costs than the base load units. These peaking plants are the units that are used to meet peak demand in the summer months.

Source: In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11 (3) et. seq., with regard to DTE Electric Company. Case No. 17689, Opinion and Order, dated June 15, 2015.

Conclusions and DCA recommendations: CCOSS/production plant allocation

Santee Cooper's proposal disproportionately increases rates for low load factor customers like residential and small commercial customers relative to larger industrial customers.

> ***Santee Cooper proposes a system-wide average rate increase of 3.3 percent in 2027 and 6.4 percent in 2028. However, residential rates will be increased by 4.7 percent in 2027 and 9.3 percent in 2028 under the proposal, while industrial rates will receive much smaller increases of 2.6 percent and 4.7 percent, respectively.***

This disproportionate rate increase is driven by the use of a flawed classification methodology that allocates all fixed production plant costs to peak demand factors, without consideration of energy factors associated with these costs.

> ***DCA recommends that the Authority utilize a composite A&P methodology for classifying production plant investments. This method is more appropriate and better reflects the use of production plant and will be less onerous for residential customers.***

Section 3: Rate Design

Overview

Electric utility rates are typically comprised of three basic elements.

- Fixed monthly **customer charges** sometimes referred to as a basic service charge or a basic facility charge.
- **Energy rates** that are volumetric rates applied toward a customer's monthly energy usage during a billing period, often measured in terms of kWh.
- **Demand rates** are surcharges that are assessed based upon a customer's maximum usage during a billing period, commonly measured in terms of kW for those customers that are demand metered.

Historically, some smaller use customer classes, such as **residential and small commercial classes**, are not demand-metered and thus, only face customer and energy charges. Customers with just customer and energy charges have bills that are based upon what is commonly called a **"two-part tariff"** (e.g., energy and customer charge) whereas large demand metered customers face a **"three-part tariff"** (e.g., energy, customer, and demand charges).

3.1 Customer Charges

Survey of customer charges

The Authority's current monthly fixed residential customer charges are the highest in the region. Likewise, the Authority's current monthly fixed small commercial customer charge is the third highest in the region.

Company	State	Residential Customer Charge ($/month)	Residential Ranking	Small Commercial Customer Charge ($/month)	Commercial Ranking
South Carolina Public Service Authority (Current)	**SC**	**$ 20.00**	**1**	**$ 26.00**	**3**
South Carolina Public Service Authority (Proposed 2027)	**SC**	**$ 21.00**	**1**	**$ 28.00**	**3**
South Carolina Public Service Authority (Proposed 2028)	**SC**	**$ 22.00**	**1**	**$ 30.00**	**3**
Alabama Power Co.	AL	14.50	2	50.00	1
Appalachian Power Co.	VA	7.96	13	9.88	14
Dominion Energy South Carolina, Inc	SC	11.00	11	24.00	4
Duke Energy Carolinas	SC	11.96	9	14.50	11
Duke Energy Carolinas	NC	14.00	5	21.00	7
Duke Energy Florida	FL	14.35	4	18.57	9
Duke Energy Progress	SC	11.78	10	15.00	10
Duke Energy Progress	NC	14.00	5	22.00	6
Florida Power & Light Co.	FL	10.52	12	14.20	12
Georgia Power Co.	GA	14.00	5	36.00	2
Tampa Electric Co.	FL	13.69	8	20.08	8
Virginia Electric & Power Co.	NC	14.40	3	22.97	5
Virginia Electric & Power Co.	VA	7.58	14	13.39	13
Peer Group Average		**$ 12.29**		**$ 21.66**	

Source: Utilities' tariffs.

Residential electric rate comparison

Santee Cooper proposes significant changes to its main residential rate tariffs RG and RT. These include:

1) a 5 percent increase in the fixed monthly customer charge for the RG tariff in 2027, followed by an additional 4.8 percent increase in 2028, resulting in a cumulative 10 percent increase over the two-year period;

2) A 25 percent increase in the fixed monthly customer charge for the RT tariff in 2027;

3) A 9.4 percent increase in demand charges for the RG tariff in 2027, followed by an additional 8.6 percent increase in 2028.

Rate Class	Current	Proposed 2027	Percent Increase	Proposed 2028	Percent Increase	Cummulative Increase
Residential General Service (RG)						
Customer Charge ($/month)	$ 20.00	$ 21.00	5.0%	$ 22.00	4.8%	10.0%
Demand Charge ($/kW month)	8.00	8.75	9.4%	9.50	8.6%	18.8%
Energy Charge ($kWh)	0.0792	0.0899	13.5%	0.0925	2.9%	16.8%
Residential Time-of-Use (RT)						
Customer Charge ($/month)	$ 20.00	$ 25.00	25.0%	$ 26.00	4.0%	30.0%
Energy Charge ($/kWh)						
On-Peak	0.3380	0.2770	-18.0%	0.2969	7.2%	-12.2%
Off-Peak	0.0792	0.0899	13.5%	0.0925	2.9%	16.8%

Source: Table 6-1 and Table 6-2, Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Residential customer charge – Maryland Public Service Commission

Regulatory commissions have recognized the inherently detrimental effect increased fixed charges have on the promotion of energy efficiency, as reduction in electric use will lead to less bill savings for customers.

For example, in a 2013 review of a rate increase by Baltimore Gas and Electric ("BGE"), the Maryland Public Service Commission recognized the need to allow customers the opportunity to control their monthly utility bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.

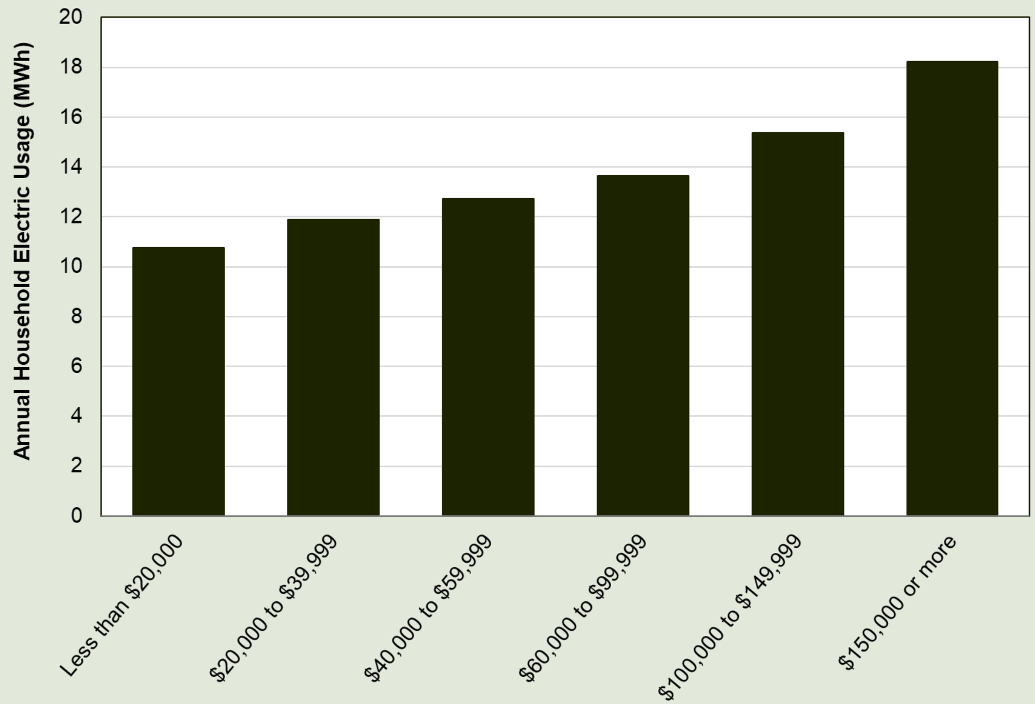
Source: Maryland Public Service Commission Case No. 9299, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (*"Case No. 9299"*). Order No. 85374 at p. 99, rel. February 22, 2013.

High customer charge impacts on lower-income households.

High customer charges discourage energy conservation and shift class revenue recovery responsibilities to lower-use/lower income households.

The Department of Energy reports household usage and income and finds household income is positively correlated with energy consumption in the South region.

For example, households earning less than $20,000 a year consume nearly 41 percent less energy than households earning greater than $150,000 a year.

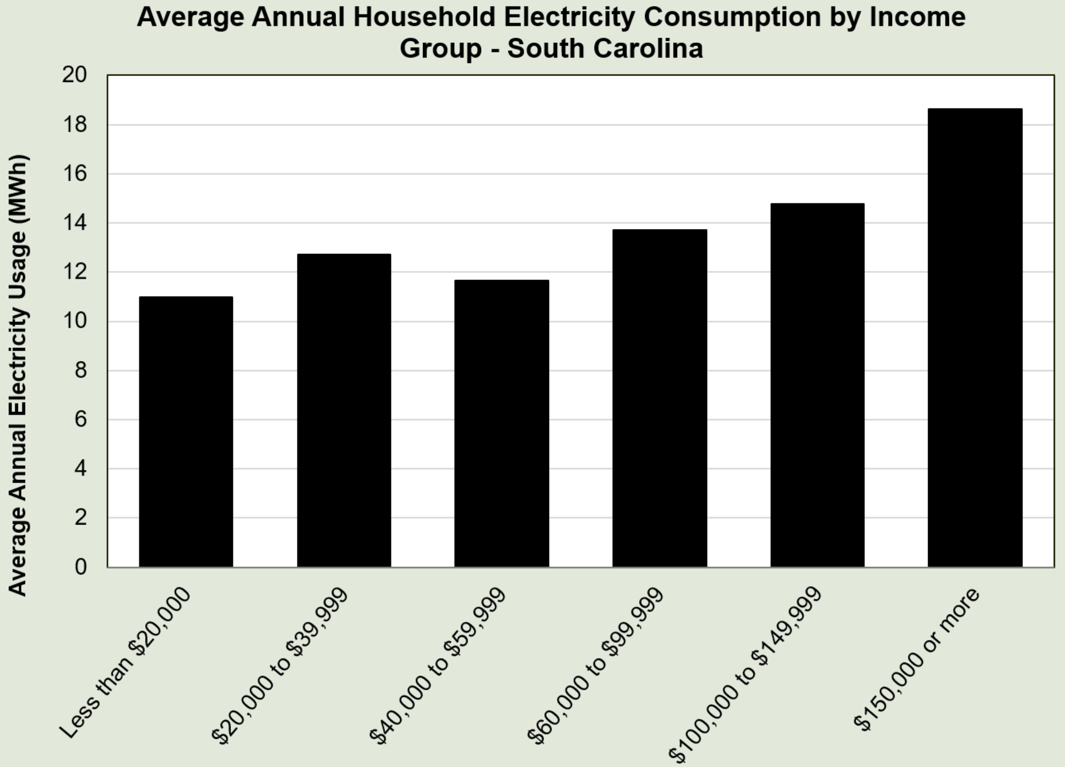


Source: Energy Information Administration, 2020 Residential Energy Consumption Survey.

South Carolina households show a similar relationship between income and electricity usage.

The Department of Energy's Residential Energy Consumption Survey data show that the South Carolina results generally align with the pattern observed in the South Region: average household electricity consumption tends to increase with income.

The lowest-income households use approximately 41 percent less electricity than the highest-income households. A higher fixed customer charge would represent a larger charge per unit of electricity consumed for these lower-use households.



Source: Energy Information Administration, 2020 Residential Energy Consumption Survey.

Residential customer charge – conclusion

The Authority should withdraw its proposal to increase its residential RG monthly customer charges from $20.00 to $21.00 per month in 2027 and to $22.00 per month in 2028, and its proposed increase in its residential RT customer charges from $20.00 to $25.00 per month in 2027 and to $26.00 per month in 2028.

- Increased customer charges have been shown to disincentivize energy efficiency efforts by reducing the ability of customers to save money on monthly utility bills by reducing electrical usage.
- Increased customer charges have also been shown to disproportionately impact lower income households whose monthly customer charge comprises a greater percentage of monthly utility bills.

Santee Cooper's current residential and small commercial customer charge are among some of the highest in the region, with the Authority's residential customer charge being the highest and its small commercial customer charge being the third highest. The proposed increases will further this disparity between the Authority's rates and that of other regional electric utilities.

3.2 Residential and Commercial Rate Changes

Authority's proposed residential demand charges.

Demand charges are designed to recover the costs associated with providing electric service during peak periods and are typically assessed on a customer's highest level of electricity usage.

- Santee Cooper proposes to change current on-peak demand charges for the RG and GA rate classes.
- This new demand charge will be based on the average four highest daily one-hour integrated demand periods for each customer meter during the on-peak window for each billing cycle.

Santee Cooper states that this approach is **prudent to reduce the financial impact on customers** of a single peak period during the month, **while continuing to align rates with cost causation** and encourage customers to "defeat the peak" by reducing their usage during peak periods.

The change to an average on-peak demand charge **will likely reduce the customer use subject to the demand charge.** However, the **Authority pairs this with a cumulative 18.8 percent increase in residential demand rates over a two year period**. This may negatively harm residential ratepayers.

Source: Santee-Cooper-Electric-COS-Study-Report_04.20.26-With-Appendices-A-and-B.

Authority proposed increase to Demand changes.

Authority has proposed to increase its current residential RG demand charge from the current $8.00 per kW-month to $8.75 per kW-month in 2027, which will increase again to $9.50 per kW-month in 2028. Combined, this results in a 18.8 percent increase in the residential RG demand charges over a two-year period.

Similarly, the Authority proposes to increase the small general service GA demand charge from the current $12.21 per kW-month to $13.00 per kW-month in 2027, which will increase again to $14.00 per kW-month in 2028. Combined, this results in a 14.7 percent increase in small commercial GA demand charges over a two-year period.

Santee Cooper expressed to DCA that the Authority **expects the proposed change in RG and GA demand charges to have limited impact on customers due to the accompanying proposal to average on-peak demand across four hours for purposes of the demand charge**. However, DCA recommends continuing to find ways to educate customers on demand charges and seeking additional mitigation methods, like excluding weekends and holidays from the demand window.

Example of utility demand charge proposals: Arizona Public Service Company

Arizona Public Service Company ("APS") in a 2017 rate case proposed implementation of mandatory time-of-use or residential demand charges, along with a $5 million education plan to educate customers on the new rates.

- In its education plan, APS promised to notify customers through a variety of channels, including bill messages, web portal, text messages, social media posts, and formal TV and newspaper media.
- A critical aspect of APS' education plan was a focus on potential customer "savings," but did not include specific messages or education content to explain how demand rates worked or how the customer would be affected by the move to demand rates.
- APS's education materials failed to identify if the customer was on the "best plan" based on historical usage.
    - Indeed, after the fact reviews found that 36 percent of APS's residential customer base were moved to rates that were not the most economical rate plan for the customer.

Source: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return thereon, to Approve Rate Schedules Designed to Develop such Return, Docket No. E-01345A-19-0236, Staff Report dated May 19, 2020.

Differing residential load curves

A detailed analysis by APS prior to its implementation of residential demand charges found that **there exists significant heterogeneity in the consumption patterns of residential customers**.

- APS identified **five separate load curves** associated with its residential customers, including **typical weekday evening peakers** (i.e. those customers who have peak demand during evening hours returning from work); **customers with greater daytime peak demand** (i.e. retirees and customers who worked from home); and **twin peakers with significant morning and evening peak demands**.
- APS found that the typical weekday evening peakers **represented only approximately 58 percent** of its residential customers, with **approximately 42 percent of customers** not meeting this typical framework.
- APS also **found less diversity** on holidays and weekends, with most residential customers exhibiting greater daytime peak demand during these periods.

It is important to analyze the impact the proposed implementation of demand charges will have on customers whose load profile differ from typical residential profiles.

- **It is likely that the proposed demand charges will negatively impact customers who rely on electric heating during winter months and thus have high morning energy demands.**
- **It is also possible that the proposed demand charges will negatively impact low-income and fixed-income retirees who have higher daytime loads.**

Source: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return thereon, to Approve Rate Schedules Designed to Develop such Return, Docket No. E-01345A-19-0236, Direct Testimony of David E. Dismukes at 17:6-18.

Residential and Small Commercial rate change conclusions

DCA recommends the Authority withdraw or consider additional mitigation related to its proposed changes in the current residential RG and GA tariffs.

- The Authority should also recognize the significance of its **proposed $8.75 and $9.50 per kW-month demand charge for residential customers**, which could potentially increase utility bills for low-load factor residential customers such as senior citizens living on fixed incomes.
- The Authority should continue to find ways to educate customers on demand charges and seek additional mitigation methods, like excluding weekends and holidays from the demand window.

Section 4: Conclusions

Summary of findings.

Cost and Revenue Allocation

- DCA recommends the use of a composite classification factor for production plant, such as the use of an Average and Peak ("A&P") cost allocation method, to allocate fixed production plant costs.

Rate Design

- DCA recommends the Authority withdraw its proposal to increase in residential RG and residential RT customer charges as current customer charges for these rates are already some of the highest in the region.
- DCA supports the proposed change to a demand charge based on the average customer use during the customer's four highest hourly on-peak usage during a month, but opposes the increase in the demand charge's cost. DCA also recommends the Authority additionally exempt weekends and holidays from determination of demand charges since electric system utilization is lower during these days.
- The proposed RG demand charges are especially problematic since the proposed \$8.75 and \$9.50 per kW-month demand charge could potentially increase electric bills for low- and fixed-income households.
- The Authority should continue to find ways to educate customers on demand charges

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