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Review of Santee Cooper 2024 Request for Adjustment to Rate Schedule and Tariffs

Prepared for the Board of Directors of the South Carolina Public Service Authority

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The Regulatory Assistance Project (RAP) has been hired by the South Carolina Public Service Authority, commonly known as Santee Cooper, to assist the Board of Directors in its review of the management rate proposal[1] as an independent consultant, pursuant to Act 90 as passed by the South Carolina General Assembly in 2021.[2] This memo represents RAP's initial review of the management filing presented to the board and released to the public on June 10, 2024.[3] Principally, this is a review of two documents:

- The 2024 Request for Adjustment to Rate Schedules and Tariffs (referred to in this memo as the 2024 request filing).[4] That document is structured similarly to an investor-owned utility application for a rate case, with seven sections sponsored by different members of the Santee Cooper management team.

[1] Under Santee Cooper historic governance practices, as codified and amended by statute, the management of the publicly owned utility brings proposals for rates to the board for approval or modification.

[2] S.C. Code Ann. § 58-31-730(E): "The board of directors shall utilize consultants independent from the Authority's management and is authorized to hire independent, outside experts and consultants as necessary to fulfill the board of directors' obligations and duties pursuant to this section." This memo does not constitute legal advice and should not be construed as such. None of its authors is licensed to practice law in South Carolina.

[3] This review is subject to clarification or revision based on further discussions with Santee Cooper management; its consultants, primarily NewGen Strategies and Solutions; and comments filed by the South Carolina Office of Regulatory Staff.

[4] Santee Cooper. (2024a). *2024 request for adjustment to rate schedules and tariffs*. https://www.santeecooper.com/Rates/Rate-Study/_pdfs/Supplement-Santee-Cooper-2024-Rate-Adjustment-Request-05.24.2024.pdf

- The 2024 Electric System Cost of Service and Rate Design Study by the consultant NewGen Strategies and Solutions (the NewGen study).[5] It specifically underpins two sections of the 2024 request filing: (1) Cost-of-Service Report and (2) Rate Design and Proposed Rates Report.

In addition, RAP sent a limited number of clarifying questions that Santee Cooper management and staff answered, transmitted by agreement through outside counsel. RAP also reviewed the comments of the South Carolina Office of Regulatory Staff submitted on September 6, 2024.[6]

RAP's review has three sections:

1. A review of typical rate-making principles and policy goals and how the application of these principles and goals should change in the context of a modernizing electricity system.
2. An overview of key cost allocation issues, with a specific emphasis on the definition and estimation of demand-related costs, and why they matter for rate design.
3. A discussion of rate design reform issues and options, with a focus on the residential and small commercial customer classes.

Overall, we believe the 2024 request filing appears to be a responsible and substantial application for new rates, but there are several issues that could reasonably be discussed and debated.[7]

Our key observations are:

- We appreciate the strong focus on sending improved price signals to shift and manage customer load. This is an important way to take advantage of the investment in advanced metering and billing systems and should be a significant part of creating a cost-effective energy portfolio. Customer behavior is an increasingly vital tool for utility decision-makers to use for public benefit. Improved price signals may bring the utility additional revenue risk, which should be appropriately monitored and managed. If permitted by statute, policies like decoupling can help address revenue uncertainty in a way that is fair for both the utility and customers.

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[5] NewGen Strategies and Solutions. (2024). *2024 electric system cost of service and rate design study*. https://www.santeecooper.com/Rates/Rate-Study/_pdfs/Final_Santee-Cooper-Electric-COS-Study-Report_05.24.24.pdf

[6] South Carolina Office of Regulatory Staff. (2024, September 6). *Review of the South Carolina Public Service Authority 2024 request for rate adjustment*. https://www.santeecooper.com/Rates/Rate-Study/Get-Involved/_pdfs/ORS-Comments-on-Santee-Cooper-2024-Request-for-Rate-Adjustment-REDACTED_Revised.pdf

[7] RAP has not reviewed in detail several sections of the 2024 request filing, including load forecasts, financial planning and budgets, system operation, customer service and workforce issues. Our overall review of these sections is that the work seems to be professional and meets expectations for a utility of this size and governance structure. In addition, the annual budget is set through a separate process overseen by and subject to approval by the board.

- The cost allocation techniques that the NewGen study uses are common nationally but do not necessarily reflect modern best practices. Although traditional cost allocation methods can still be used for many purposes, it is important to understand the limitations of these methods when applied in a new and evolving context. This understanding can inform how we think about rate design reforms as well as future improvements to cost of service studies.
- There is likely a role for residential demand charges in modernized electricity rates, but the type and size are widely debated. For many purposes, a peak demand charge, as proposed in the 2024 request filing, has not been shown to be superior to a similarly structured time-of-use kWh rate. Demand charges in general have additional complexity for small consumers to understand and properly manage compared with most forms of kWh rates, including time-of-use rates.
- Experience with significant adoption of residential demand charges is limited nationally. To our knowledge, only several cooperatives, including some in South Carolina, have implemented default demand charges for a broad residential customer class. However, two major investor-owned utilities — Arizona Public Service and Georgia Power — have residential demand charges that apply to significant numbers of customers. These two utilities have developed messaging and techniques to help customers understand and respond to demand charges. Santee Cooper could improve its current educational materials on peak demand charges based on these examples.
- For all types of rate reforms, customer protection and understanding are important. When implementing rate design changes for a broad customer group, the impacts on bills often are not proportional across all customers. The bill impacts table in Appendix A of the NewGen study indicates that 25% of residential customers could see their bills increase 20% or more when the proposed rates go into effect, although customers could mitigate increases somewhat by adjusting their usage patterns in response to the rate design price signals. Many options are available to minimize the risk of unreasonable customer bill impacts and maximize the benefits of rate design reforms.

We look forward to engaging with the board on these critical issues and appreciate the hard work, time and attention of Santee Cooper management, staff and other stakeholders. We would be happy to answer questions from the board on these topics and others not addressed in this memo and, subject to reasonable scoping and available expertise, revise and extend this memo to additional topics as appropriate.

Regulatory Principles and the Development of the 21st Century Electric System

Although the financing mechanisms and governance structures are different, the management and board of a publicly owned utility typically share the same general policy goals and rate-making principles as investor-owned utilities and the commissions that regulate them. As the electric sector changes, the application of these goals and principles will change as well. Modern technologies enable new opportunities to lower costs and improve reliability. It is important to understand that older analytical methods used in utility regulation were designed around the way the electric grid used to be. As a result, all utilities, regulators and stakeholders should consider how the changes occurring on the electric grid need to be paired with updated analytical and regulatory methods.

Older analytical methods used in utility regulation were designed around the way the grid used to be.

Policy Goals and Rate-Making Principles

The pricing principles the board readopted at its June 10, 2024, meeting are broadly consistent with typical lists of policy goals and rate-making principles used in utility regulation across all jurisdictions. A typical list of policy goals for utility regulation includes:

- **Competition across fuels and within the electric sector.** One of the overarching goals of utility regulation is to ensure efficient choices of energy sources and, relatedly, allocation of resources across sectors. Although the real world never perfectly matches ideal theoretical conditions, the goal that utilities should be governed to mimic efficient market outcomes is a worthy one.
- **Provision of reliable and safe service.** Reliability of electricity service has always been important, but with the advent of distributed energy resources and microgrid capabilities, service can now encompass a broader concept of customer resilience. Safety is important for customers as well as the utility workforce.
- **Affordability and equity.** Historically, policy goals related to equity have focused on affordability and universal access, particularly for publicly owned utilities and cooperatives. In modern times, this concern has also evolved into the goal of equitable distribution of cost across customers through rates and equitable distribution of benefits from public policy programs.

- **Administrative feasibility.** Proposed changes to processes must be workable, and any incremental administrative costs should be justified by proportionate benefits.
- **Employment and economic development.** Many utility decisions affect the broader economy and employment inside and outside the electric sector.
- **Public health and environmental protection.** Compliance with laws and regulations for the protection of public health and the environment is a universal necessity. Many jurisdictions and utility customers have additional goals that can influence aspects of utility operations, programs and rate-making.
- **Gradualism.** Gradualism should not always be considered an end, but a reasonable pace of change is a frequently cited approach to problem-solving and a means to achieve other goals.

Such a list of policy goals applies broadly to all utility decision-making, but there are also more specific principles that apply in utility rate-making:

- **Effectiveness in yielding total revenue requirements.** The utility should expect to recover its revenue requirement from customer rates, with a reasonable amount of stability from year to year. In the context of publicly owned utilities, this expectation includes an emphasis on the need to make debt service payments and meet bond covenants, with an appropriate debt service coverage ratio or other forms of security.
- **Customer understanding and acceptance.** Prices should not be so complex or convoluted that customers cannot understand how their bills are determined or how they should respond to manage their bills. Customers and the rest of the public should generally accept that the prices customers are charged for electricity service are fair for the service they are receiving.
- **Equitable allocation of costs and the avoidance of undue discrimination.** The apportionment of total costs of service among the different customers should be done fairly and equitably.
- **Price signals that encourage optimal customer behavior.** On a forward-looking basis, electricity prices should encourage customers to use, conserve, store and generate energy in ways that are most efficient.

There may be trade-offs among these goals and principles. The task of utility management and the board is to strike an overall balance in these objectives.

Key Developments in the 21st Century Electric System

Although the overarching policy goals and rate-making principles are enduring, the implementation should reasonably be updated as technology improves and customer expectations change. Traditional cost allocation and rate design were developed in the mid-20th century, based on certain assumptions that held true then. These included:

- Reliability risks that focused on generation resource adequacy, driven by the highest hours of gross customer usage over the year.
- Little visibility and control within the transmission and distribution systems.
- Customer metering technology that could only handle simple forms of data recording and information storage.
- Little or no capability for customers to manage their usage or export energy onto the grid.

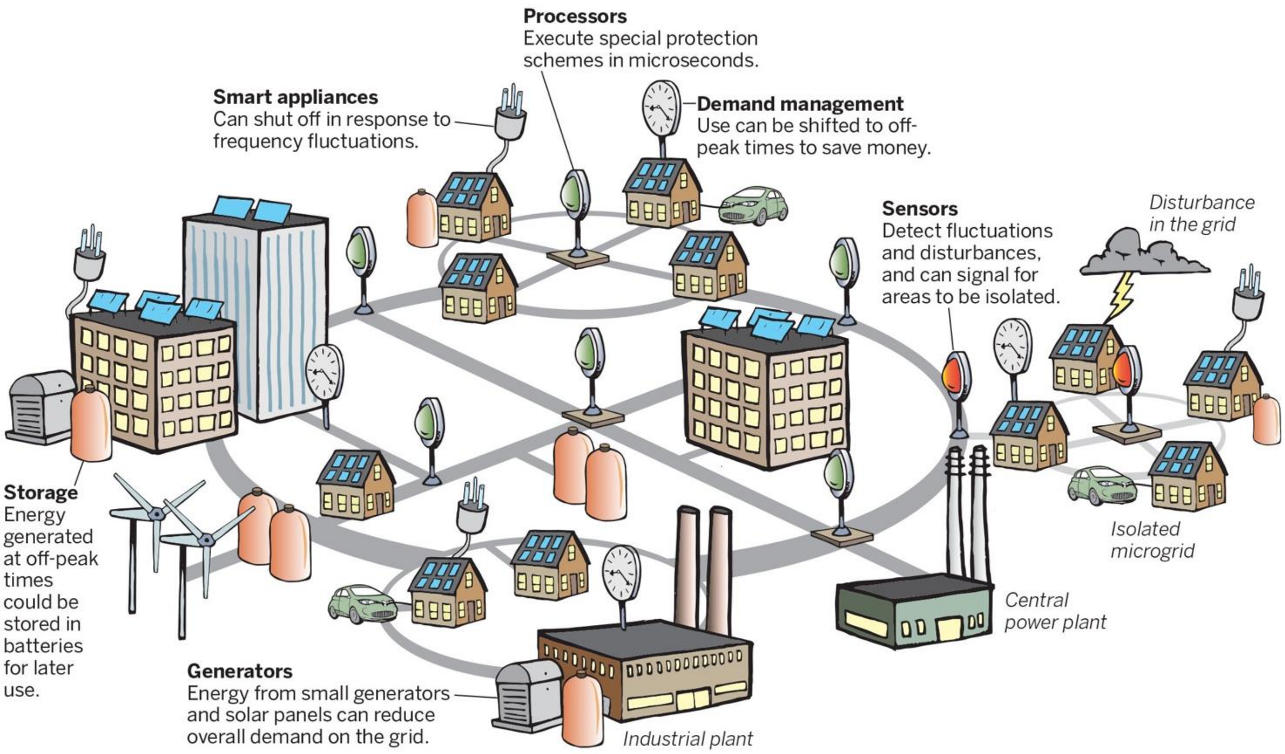
In the 21st century, each of these assumptions is changing, albeit in different ways, at different speeds and in different places. The cost of clean energy and storage technologies has decreased greatly, and there have been breakthroughs in other customer-side technologies. Advanced metering and smarter distribution system technologies provide better data and fine-grained control of the system. Utilities can use this new data in a multitude of ways, including to improve planning and investment criteria — all the way down to more efficient line transformer sizing. In the context of rate design, advanced metering and improved billing systems enable more sophisticated rates for small customers. Furthermore, electrification of transportation and heating poses both challenges and opportunities for the electric sector, particularly when combined with other potential sources of load growth such as data centers and new industrial facilities.[8]

The future electric grid may bear more resemblance to Figure 1 on the next page, with generation and storage at consumer sites, two-directional power flows and more sophisticated control equipment for customers and the grid itself.[9]

[8] Farnsworth, D., Shipley, J., Lazar, J., & Seidman, N. (2018). *Beneficial electrification: Ensuring electrification in the public interest.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/

[9] Adapted from U.S. Department of Energy. (2015). *United States electricity industry primer* (DOE/OE-0017), Figure 30. https://www.energy.gov/sites/default/files/2015/12/f28/united-states-electricity-industry-primer.pdf

Figure 1. Illustrative future electric system



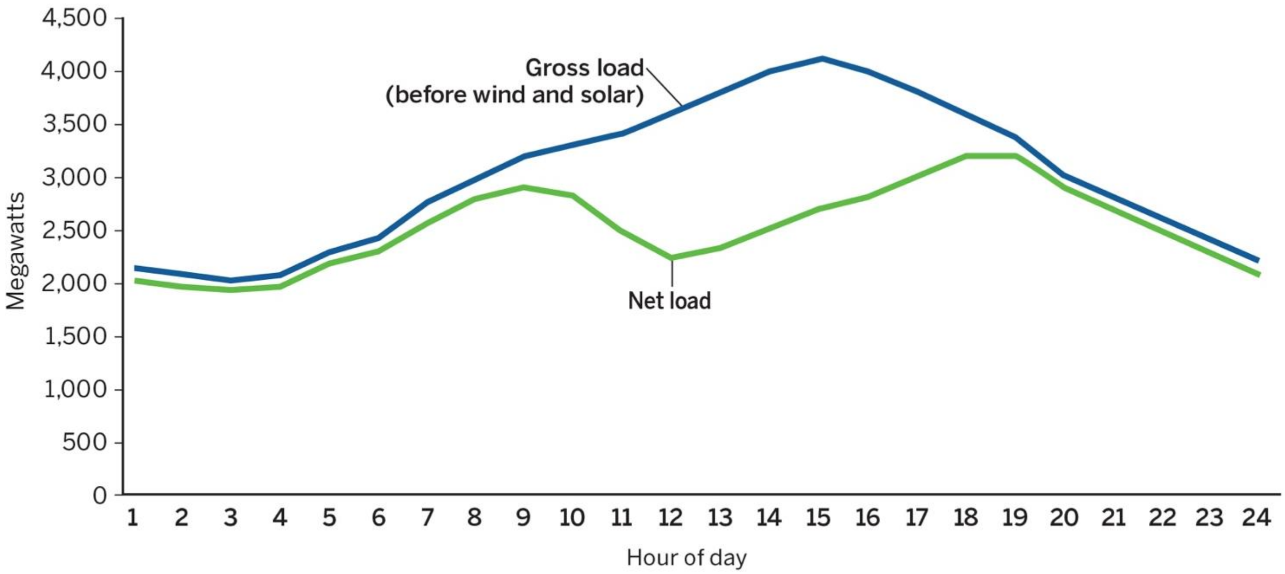
Source: Adapted from U.S. Department of Energy. (2015). *United States Electricity Industry Primer*

Elements of this potential future for the electric system can be sketched out at a high level. Many key uncertainties, however, will be resolved only through observing innovations as they develop, along with policy decisions at every level of government. One important uncertainty is how the generation resource mix will evolve over time, which will be influenced by utility decisions as well as local, state and federal public policies. The Santee Cooper capital plan[10] reflects how the generation mix is starting to change in many jurisdictions with planned investments in solar photovoltaic (PV) generation and battery energy storage systems. With these investments, the dispatch of other generation units likely will start to change, with those other units being used to serve net load — which subtracts out load that is matched with nondispatchable resources. As depicted in Figure 2 on the next page, net load accounts for solar PV and wind but conceptually includes some other resources as well.[11]

[10] Santee Cooper, 2024a, p. 11.

[11] For the purposes of generation resource adequacy, all nondispatchable resources are relevant to the calculation of net load, both interconnected at the bulk level and customer-sited resources interconnected to the distribution system.

Figure 2. Illustrative net load curve



However, many other outcomes are possible for the evolution of the generation resource mix. For example, it is possible that a balanced mix of nondispatchable resource development could roughly match the overall system load shape. The overall goal should be a cost-effective portfolio of energy resources, which can be accomplished in different ways given the available resources in a service territory and broader region.

Evolving Considerations for Rate-Making

Although modern technology and better data can update many aspects of utility investment, operations and oversight, there are several new capabilities and considerations specifically in the context of cost allocation[12] and rate design.[13]

Equitable cost allocation across customer classes has always included consideration of fairness and economic efficiency. Many of the basic techniques still used today for cost of service studies of the type NewGen performed — often referred to as allocated cost of service studies or embedded cost of service studies — were developed in the mid-20th century. Many additional techniques have been developed and debated over the past several decades. Today, many utilities have much more complete data — such as customer usage at five-minute intervals — for the system itself and all customers, which can be leveraged for these more modern techniques. In addition, more-sophisticated

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[12] For an extended treatment of modern cost allocation, see generally Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.) (2020). *Electric cost allocation for a new era: A manual*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[13] For an extended treatment of modern rate design, see Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/; and LeBel, M., Shipley, J., Linvill, C., & Kadoch, C. (2021). *Smart rate design for distributed energy resources*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-distributed-energy-resources-2/

economic tools and considerations have been built into modern techniques, although with more complications often comes more controversy and debate. In the context of a rate-making proceeding for an investor-owned utility, it is common for a utility regulator to consider cost of service studies and techniques presented by more than one party and use those studies holistically to come up with a fair and balanced judgment rather than following any one study with great precision.

Rate design typically focuses more on economically efficient individual customer behavior, as well as fairness of cost impacts and bills among individual customers and the need to reasonably recover the revenue requirement. By economic efficiency, we refer to the ideal that through the signals that prices send to customers, rate design can guide choices consistent with least cost service and the public interest. Achieving the ideal depends, of course, on the extent customers have choices about what and when they consume, including their choices about buying and operating equipment — from refrigerators to electric vehicles or industrial pumps.

The technical basis used to design efficient rates is often described as cost causation or marginal costs. In most cases, utilities and regulators use the same economic principles in techniques for rate design as they do for cost allocation. In this way, the analytical choices made with respect to cost allocation can have significant impacts on rate design as well.

In the 21st century, utilities that have invested in advanced metering infrastructure, associated communications equipment and billing system upgrades have much greater flexibility to implement various kinds of rate design than in the past. Improved rate design can motivate an hourly, daily and annual load shape for customers that is less costly for utilities to serve. Modern rate design can also induce more efficient customer choices regarding distributed generation and energy storage.

The expanded array of customer energy choices has important implications for rate design as well. End uses that are inherently flexible — such as smart appliances, smart electric vehicle chargers, smart thermostats and customer-sited battery storage — enable a much greater customer response to many rate designs, such as demand charges or time-varying kWh rates. These resources, increasingly distributed across the Santee Cooper territory at the customer end of the grid, mean the job of the utility to plan for and make electric system investments is changing to account for the evolution of customers that is underway. If a utility ignores the potential for customers as resources, it may invest in too much capital in the electric system. It is important and laudatory that the Santee Cooper 2024 request filing and the NewGen study recognize this with proposed rates for the residential and small commercial customer class with the potential to change customer behavior through pricing. In the modern electric system, this should be an essential part of creating a cost-effective energy portfolio.

Importantly, a transition to a new rate design brings risks to both the utility and customers that should be understood and properly managed. It can be difficult to estimate, both in the short and long term, how customers will respond to rates designed to get a customer response. But revenue erosion is a particular risk from new rates that provide customers with a significant option to save money, unless the level of response is predicted accurately. Later sections of this memo discuss the risks to customers and other options to mitigate the risk of revenue erosion, but it is worth noting that many jurisdictions have implemented a policy known as revenue regulation or decoupling. Revenue regulation is a modest but meaningful variation on traditional rate-making, designed to help ensure that utilities recover their revenue requirement independent of changes in customer behavior or other reasons that sales may deviate from forecasts. After the revenue requirement and rates are established, rates are adjusted periodically (such as yearly) to ensure that the utility is collecting its revenue requirement. For example, if sales decline below the level assumed, rates increase slightly, and vice versa. Decoupling therefore can help ensure stable revenues for the utility while new rate designs send improved price signals to customers about how and when to consume energy more efficiently for the electric system.

Electric Cost Allocation and Its Impacts

The cost allocation methods in the NewGen study are primarily a standard set that many small and medium-sized utilities across the country use. The 2024 request filing and NewGen study in many respects detail the typical process and factors that go into cost allocation for all electric utilities. The methods used for classification and allocation, however, were developed many decades ago, and there are techniques that likely better reflect the economics of the electric system. For several decades, many jurisdictions have split generation capacity investment costs between the demand classification and the energy classification because several types of generation plant investments (e.g., baseload plants) are incurred to reduce fuel costs. Similarly, it is likely more accurate for energy-related costs if cost allocation reflects that fuel costs are higher at peak times because that typically is when the least efficient and most costly plants run to ensure reliability.

Cutting-edge techniques recognize these phenomena more directly and intuitively than the traditional demand and energy classifications, sometimes using more granular data and analytical methods than were available in the mid-20th century. Although these analytical questions matter for cost allocation among customer classes, they often matter for rate design too. The 2024 request filing and NewGen study lean heavily on the concept that demand-related costs should be charged at peak hours, whether through a peak demand charge or a time-varying energy charge. Because of this, the way demand-related costs are calculated is important because it significantly affects the on-peak/off-peak price spread in the proposed rate design.

Overview of Cost Classification Issues

The standard classifications of “customer,” “demand” and “energy” have been used in electric cost allocation for many decades. In 1992, the National Association of Regulatory Utility Commissioners (NARUC) issued a cost allocation manual that featured a lengthy discussion of the different methods for cost classification as well as helpful summaries.[14]

Both the NewGen study and the NARUC manual recognize that the demand-related classification is principally about different types of *peak* demand. Table 1[15] demonstrates that it was common even 32 years ago to partly classify production (generation), transmission and sometimes even distribution as energy-related because not all costs in those functions are incurred to serve peak demand. The exact proportion has always varied across methods and jurisdictions.

Table 1. 1992 NARUC cost allocation manual classification

Cost function	Typical cost classification
Production	Demand-related Energy-related
Transmission	Demand-related Energy-related
Distribution	Demand-related Energy-related Customer-related
Customer service	Customer-related Demand-related

Source: National Association of Regulatory Utility Commissioners. (1992). *Electric Utility Cost Allocation Manual*

The NARUC manual makes clear that the classification as partly energy-related extends to generation capacity investment costs: “capital costs that reduce fuel costs may be classified as energy related rather than demand related.”[16] The clearest example is that baseload plant capacity, which requires a more expensive upfront investment, is built not just to meet peak demand but also because it provides cheaper energy across the entire year, thus reducing fuel costs from more expensive generation units.

[14] National Association of Regulatory Utility Commissioners. (1992). *Electric utility cost allocation manual*. https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

[15] National Association of Regulatory Utility Commissioners, 1992, p. 21.

[16] National Association of Regulatory Utility Commissioners, 1992, p. 21.

More generally, given patterns of customer load, utilities need to invest to meet two primary objectives: (1) ensuring reliability and (2) meeting year-round system load at least cost. Historically, reliability concerns have arisen predominantly at peak system load hours.[17] Achieving these primary objectives in a reasonable way requires detailed economic analysis of the options that meet the engineering criteria, such as when analyzing the optimal mix of generation resources. Additionally, given multiple types of generation technologies, storage and demand response, the optimal mix depends on year-round load patterns. The options have different capabilities and different cost characteristics and should not be lumped together as capacity for system planning, cost allocation or rate design. For example, solar PV capacity does not fit into a framework where all generation capacity investments are treated as demand-related, because its principal benefit is not always meeting peak demand; fuel cost reductions, federal tax credits and requirements or goals for lower emissions are often just as relevant.

Because of these economic considerations, the kind of capacity built to meet short-term peak needs, as well as to provide reserves on short notice throughout the year, is much different from the capacity needed to generate year-round. Other aspects of Santee Cooper's rates and 2024 request filing recognize the underlying economics. The interruptible credit offered to industrial customers for nonfirm service is calculated as the incremental cost of a simple-cycle combustion turbine unit.[18] This is often a reasonable marginal cost estimate for additional capacity to provide reliability in a limited number of peak hours. Some cost allocation techniques use this exact calculation to classify generation capacity investment costs between demand and energy, sometimes referred to as the equivalent peaker method.

Modern Embedded Cost Allocation Frameworks

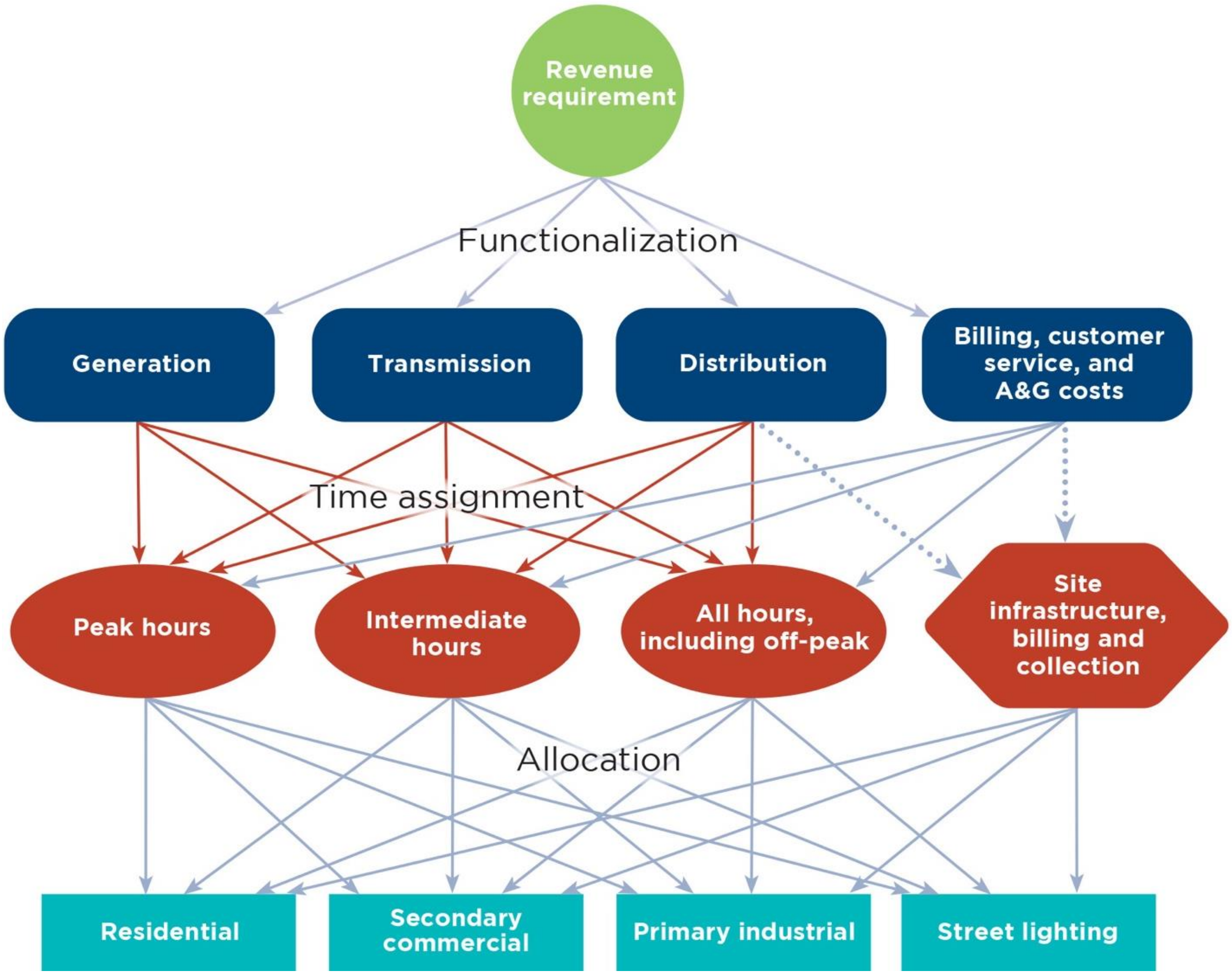
Various cost allocation techniques to account for these underlying electric system economics have been developed and proposed over the years. Some are relatively complex, perhaps using hourly data and one or more sophisticated modeling exercises (e.g., loss of load expectation studies). However, even modest tweaks to traditional methods for classification and allocation can make those methods more flexible, accurate and intuitive. For example, it is possible to do a time-based classification and allocation method that classifies system costs into three categories: peak hours,

[17] Reliability can be thought of as having two dimensions: system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

[18] NewGen Strategies and Solutions, 2024, p. 5-3.

intermediate hours and all hours, including off-peak (see Figure 3).[19] Costs that do not vary by time (e.g., site infrastructure and metering costs for connecting a customer to the grid, as well as billing and collection costs) can be handled separately.

Figure 3. Modern embedded cost of service study flowchart



For generation costs, classification using this method would be intuitive:

- **Peak hours** — combustion turbine plant investment, operations and maintenance (O&M), and fuel costs; investment, O&M and fuel costs for other units with capacity factors under 20%.
- **All hours** — coal plant investment, O&M and fuel costs; nuclear plant investment, O&M and fuel costs; any combined cycle gas plants running with capacity factors over 60%.
- **Intermediate hours** — all other generation costs.

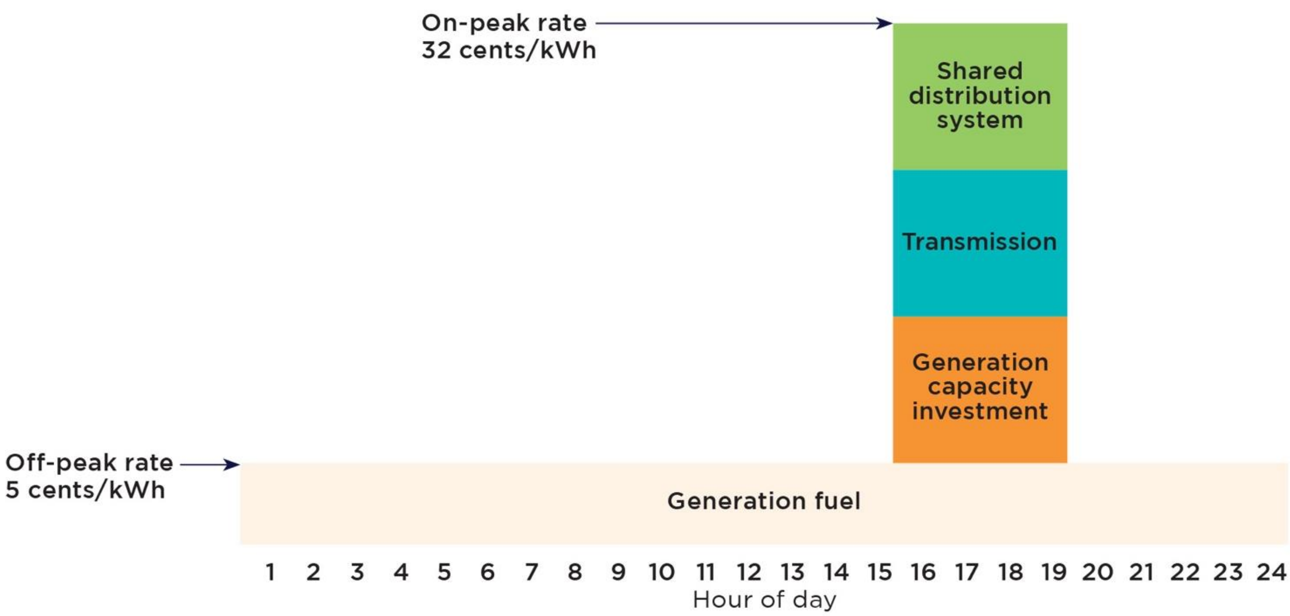
[19] This is an extension of and elaboration on the base-intermediate-peak classification method that some jurisdictions use. Another extension of this framework would allocate solar PV and wind costs to the time periods when they are generating, meaning that solar PV costs would go to sunny hours.

The same principles can apply to transmission and distribution, although the proportions may be quite different. Such a method is not perfect, and more sophisticated techniques would likely be even more precise. This time-based method, however, would be an intuitive improvement over many techniques that are used across the country, and it has other virtuous characteristics when applied to rate design as well.

Impact of Cost Allocation Methods on Rate Design

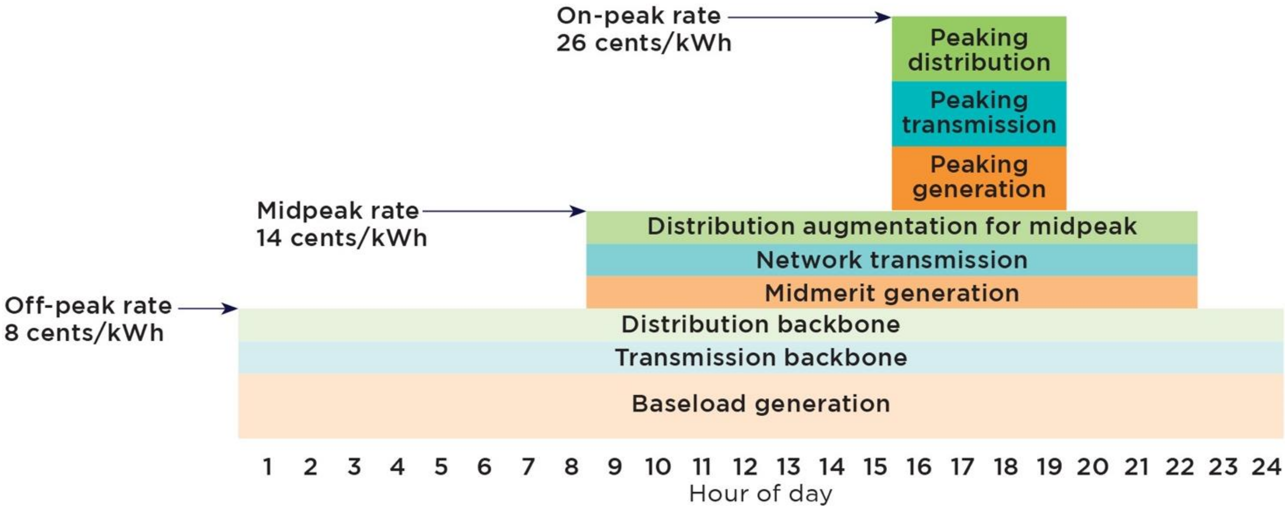
Because both cost allocation and rate design are often based on cost causation or marginal costs, the underlying economic analysis can be relevant for both. As a result, the choice of cost allocation methods influences significant aspects of rate design. Figure 4 shows an illustrative time-of-use kWh rate based on cost allocation methods where all generation, transmission and distribution capital investments are classified as demand-related and thus put into peak hours.

Figure 4. Illustrative summer time-of-use rate using expansive definition of demand-related costs



In contrast, Figure 5 on the next page shows an illustrative time-of-use kWh rate based on a cost allocation method that divides capital investment costs into three periods.

Figure 5. Illustrative summer time-of-use rate using peak, intermediate and all hours method



Many differences between these two alternatives are straightforward, such as a modestly higher off-peak rate and a lower on-peak rate. However, two particular rate design issues are worth special attention. One of the risks of a time-of-use rate or a similarly structured peak demand charge is that the peak will move just outside the hours designated as on-peak, as customers seek to avoid the high-cost time of day. This is a particular risk for a two-period on-peak/off-peak rate with a significant spread or peak demand charge. Moving to a three-period rate helps mitigate this risk. Instead of a large percentage of customers switching on appliances and charging electric vehicles immediately after the on-peak period (e.g., 8:01 p.m.), some customers will wait, particularly if aided by smart technology and timers, until the lowest rate begins (e.g., 11:01 p.m.).

Relatedly, revenue erosion is also a risk from a significant customer response to a two-period on-peak/off-peak rate with a significant spread or peak demand charge. Again, this risk can be mitigated in multiple ways, but the three-period rate does it naturally. If the midpeak rate, encompassing most waking hours, is a price similar to current rates and the off-peak rate includes some capital investment cost recovery, there is a lower chance that a significant customer response leads to a revenue shortfall. The theoretical risk of revenue erosion is present for Santee Cooper, given that its proposed default residential rate presents a potential maximum bill increase for customers that is more than twice that of the optional time-of-use rate. For this reason, the Office of Regulatory Staff recommends that Santee Cooper monitor the potential for rate migration from the default rate to the optional time-of-use rate.

Rate Design Issues for Residential and Small Commercial Customers

The 2024 request filing proposes a significant change to the structure of default rates for residential and small commercial customers. This includes the elimination of the seasonal rate differential and the inclusion of a substantial on-peak demand charge for the default rate for both types of customers, along with more modest changes to the optional residential time-of-use rate. Eliminating the seasonal differential could be reasonable if there are significant generation resource adequacy concerns in both the summer and winter, as the NewGen study indicates.[20]

Demand charges for residential customers have been proposed in jurisdictions across the country and frequently are controversial. Demand charges are more common for small commercial customers, but many electric utilities have a simple kWh energy rate for the smallest category of commercial customers. We are aware that several electric cooperatives that Santee Cooper serves have established on-peak demand charges for residential customers broadly, and at least one other co-op in Colorado has a similar residential rate structure.[21] With respect to larger investor-owned utilities, the availability of optional residential demand charge rates has become more common over time, with Dominion Energy South Carolina being one example.[22] Like most truly voluntary rates, however, they attract few customers.

To our knowledge, only three jurisdictions have approved efforts to apply demand charges to a significant number of residential customers of investor-owned utilities. Georgia Power and Arizona Public Service now have optional rates combining demand charges and time-of-use energy rates that are available for residential customers and adopted by a significant number, to our understanding. Notably, both these utilities still offer customers traditional residential options without a demand charge or time-varying rate.[23] Additionally, the Hawaii Public Utilities Commission has approved a modest demand charge and time-of-use rate for all residential customers of Hawaiian Electric, but implementation is waiting

[20] NewGen Strategies and Solutions, 2024, p. 4-5.

[21] CORE Electric Cooperative in Colorado, formerly known as Intermountain Rural Electric Association, introduced a residential peak demand charge in 2021. CORE Electric Cooperative. (n.d.). *Rate structure*. https://core.coop/my-cooperative/rates-and-regulations/rate-structure/. In addition, a municipal utility in Kentucky implemented coincident peak demand charges for residential customers. French, J. (2016, August 25). *State AG steps into Glasgow EPB rate controversy*. Bowling Green Daily News. https://www.bgdailynews.com/news/state-ag-steps-into-glasgow-epb-rate-controversy/article_67b746ee-6af4-11e6-974a-c7c55e838b5e.html. Other utilities across the country have applied demand charges to subsets of customers that are sometimes described as residential, such as residential customers receiving three-phase power, multifamily master metered residential buildings, or farm and irrigation service.

[22] Dominion Energy South Carolina. (n.d.). *Rate 7 residential service time-of-use demand*. https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/south-carolina/rates-and-tariffs/rate7.pdf?la=en&rev=9569e8338d664215bbc3b2ed80bf1bac&hash=34B6CF59EAB4271072335BDF1F67EE16

[23] Arizona Public Service. (n.d.). *Fixed energy charge plan*. https://www.aps.com/en/Residential/Service-Plans/Compare-Service-Plans/Fixed-Energy-Charge-Plan; Georgia Power. (n.d.). *Residential service*. https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans/residential-service.html

on the rollout of advanced metering and additional study.[24] Regulators across the country have turned down many other investor-owned utility proposals, and some residential demand charges that regulators approved were later overturned by the state legislature[25] or state supreme court.[26]

This background does not mean a residential demand charge is necessarily inappropriate for Santee Cooper, but the board should be aware of the concerns raised across the country and how to potentially avoid or manage them. The first set of concerns is that demand charges do not represent a good cost causation metric except for large industrial customers with high load factors.[27] The second set of concerns revolves around whether residential or small business customers can understand and manage a demand charge. RAP takes these concerns seriously but has frequently presented a modest demand charge for many residential customers when describing modernized electric rates, paired with time-of-use energy rates. In such a scenario, RAP envisions a demand charge of $1 to $2 per kW to cover local customer connection and secondary voltage network costs, while the energy rates cover the remainder of system costs.

Types of Demand Charges

Many kinds of demand charges have been implemented over the decades. For each, there is an integration period — the length of time for which maximum demand is measured — or another rule for calculating measured demand. A longer integration period is more forgiving for customers and in many cases leads to a lower customer demand measurement. The 2024 request filing recognizes this by applying a 60-minute integration period for residential customers, which is double the 30-minute period for general service customers. Although typically integration periods are 15, 30 or 60 minutes, the measurement could be done in many other ways, particularly with advanced metering. A two- or three-hour integration period is possible, as well as averaging two or more peaks across the billing period.

Several different basic demand charge structures are in use across the country and globe.

- **Monthly noncoincident peak (NCP) demand charge:** A rate is applied to the highest measured demand anytime within the monthly billing period.
- **Peak or peak window demand charge:** A rate is applied to the highest measured demand within designated hours during the monthly billing period, akin to the same

[24] Hawaii Public Utilities Commission, Order No. 38680 on October 31, 2022. https://puc.hawaii.gov/energy/der/ard/

[25] Spector, J. (2018, August 1). *Mass. lawmakers set storage target, raise RPS, overturn rooftop solar demand charge*. GreentechMedia. https://www.greentechmedia.com/articles/read/massachusetts-lawmakers-set-storage-target-raise-rps-overturn-rooftop-solar

[26] Hanley, S. (n.d.). *Kansas Supreme Court invalidates demand charges for residential solar customers.* CleanTechnica. https://cleantechnica.com/2020/04/06/kansas-supreme-court-invalidates-demand-charges-for-residential-solar-customers/

[27] For an in-depth discussion of demand charges and cost causation, see LeBel, M., Weston, F., & Sandoval, R. (2020). *Demand charges: What are they good for?* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/demand-charges-what-are-they-good-for/

hours designated as on-peak for a time-of-use energy rate. This is the type of demand charge proposed in the 2024 request filing.

- **True coincident peak demand charge:** A rate is applied to the customer's measured demand during the actual system peak or other designated peak hour.
- **Daily-as-used demand charge:** A demand measurement is taken every day, and a rate is applied to each day's demand measurement.
- **Ratcheted demand charge:** The customer pays the higher of the monthly demand measurement or a percentage of the highest value in the previous 12 months (typically between 85% and 100%).

The theoretical cost causation basis for each of these types of demand charges varies. The most traditional industrial demand charge is a monthly NCP demand charge, often with an annual ratchet. This type of charge is justified conceptually by the idea that high-load-factor industrial customers have largely the same demand year-round and that it remains a proxy for their contribution to the annual system peak. Importantly, the metering that enabled a broad customer NCP demand charge has been available for well over a century and was comparatively easy to implement for large customers. The logic underpinning a traditional monthly NCP demand charge has never applied to smaller customers because they typically do not have high load factors and their usage and maximum demand tends to be more idiosyncratic — a quality known as diversity of load. However, RAP has considered the most local infrastructure that connects a customer directly to the grid — notably service lines, secondary voltage networks and line transformers — as having a more direct relationship to individual customer NCP demand and thus potentially being more appropriate for a monthly NCP demand charge or a demand-based subscription for residential customers.

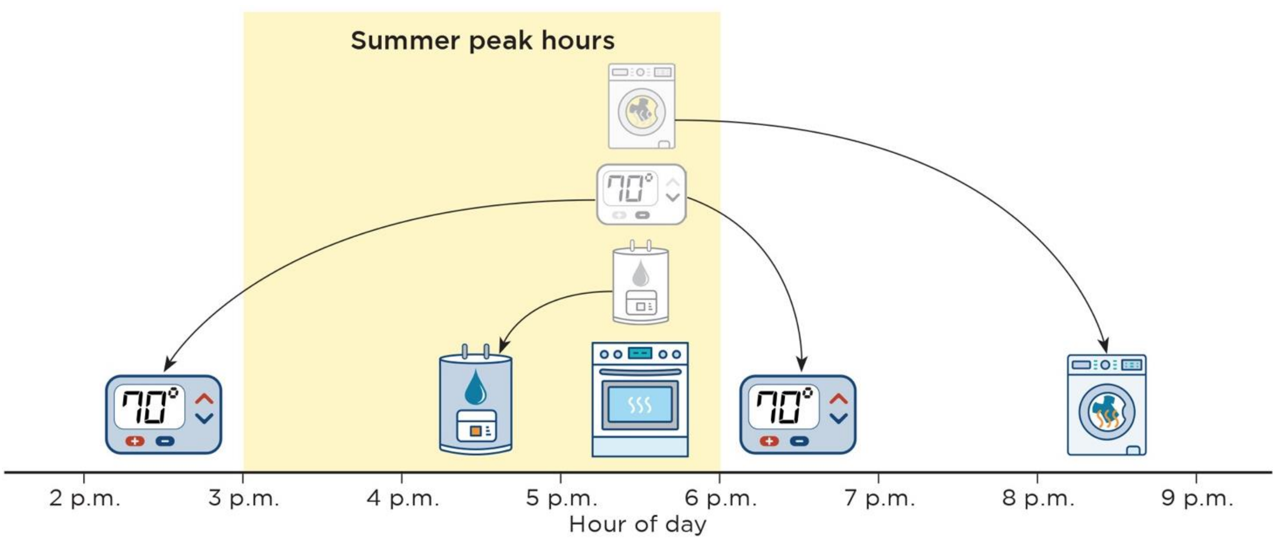
The theoretical cost causation basis for the type of peak demand charge proposed in the 2024 request filing is different, focusing on directly managing costs in the chosen peak hour windows. A comparison between a peak demand charge and time-of-use rates is helpful in this context. The primary customer response to a peak demand charge may be close to their response to a similarly structured time-of-use rate. If the peak hours are 3 to 6 p.m., customers would like to shift usage to other hours as much as possible — regardless of whether we are discussing a peak demand charge or a two-period time-of-use rate. However, a peak demand charge contains an additional layer of complexity for customers to understand and manage. For example, if a customer sets a high demand early in a billing period (accidentally or on purpose), there is less of an incentive to reduce usage in peak hours for the rest of that billing period. More generally, the peak demand charge structure encourages customers to levelize usage within the peak period and reduce variability. Any benefits of such customer levelization within the peak hours have not been studied in detail, to our knowledge.

Understanding and Managing Residential Demand Charges

One of the criticisms of demand charges for small customers is that they are a trap for the unwary or uninformed. This is particularly true for demand charges with shorter integration periods. For shorter periods, it is easy to accidentally have major appliance usage overlap during a month without the time to realize and react, particularly since many appliances cycle on and off automatically (e.g., electric water heaters). This risk is mitigated by a longer integration period, of course, but still represents a challenge for many residential customers to understand and manage.

Arizona Public Service and Georgia Power both have developed messaging and other measures to help residential customers with demand charges. The Georgia Power rate pairs a simple on-peak/off-peak time-of-use energy charge with a significant monthly NCP demand charge.[28] Arizona Public Service has a moderately more complex time-of-use rate in combination with a peak demand charge.[29] Both utilities use a 60-minute integration period to calculate demand. Importantly, both utilities have settled on a message of “Don’t stack usage, stagger usage” to help customers understand how to manage a demand charge. Figure 6 illustrates this concept.

Figure 6. Managing a summer residential peak demand charge: “Don't stack, stagger”



[28] Georgia Power. (n.d.). *Electric service tariff: Time of use – residential demand schedule: “TOU-RD-10.”* https://www.georgiapower.com/content/dam/georgia-power/pdfs/residential-pdfs/tariffs/2024/tou-rd-10.pdf

[29] Arizona Public Service. (n.d.). *Rate schedule R-3 residential service time-of-use 4PM to 7PM weekdays with demand charge*. https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Service-Plans/Time-of-Use4pm-7pmWithDemandChargeR-3.pdf?la=en&hash=E107CA3AC17204BB6BE3D8AF619C9E70

In addition, the websites for both utilities link to a PDF with the typical demand for residential end uses.[30] Such information will need to be kept up to date and would ideally provide customers with a comprehensive list of end uses. For example, the electric Ford F-150 Lightning has an optional charger available that offers the ability to power a home during an outage and provides "[u]p to 80 amps on demand" for faster home charging,[31] which is equivalent to more than 19 kW.

Santee Cooper has provided online educational materials to help inform residential customers about the proposed rate changes, including a rate proposal webpage,[32] a two-page educational PDF[33] and a 2.5-minute video.[34] These efforts are a useful starting point. The key message about how customers can manage the *demand* aspect of the demand charge is referenced once in the educational video[35] but not in the other materials. The two-page educational PDF provides sample demands for five types of appliances. Santee Cooper could improve these materials based on the examples from Georgia Power and Arizona Public Service.

Automation, smart appliances and other technological advances may provide additional opportunities for some customers to manage their demand. At least one company offers residential demand controllers for this purpose.[36] More generally, battery storage is a powerful tool for demand charge management and typically can be automated with the appropriate software. As recommended by the Office of Regulatory Staff, Santee Cooper could consider providing additional outreach and education to its customers so they may understand the implications of demand charges and how to adjust their energy use patterns to minimize bill impacts.[37]

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[30] Georgia Power. (n.d.). *Approximate demand for regular household items*. https://www.georgiapower.com/content/dam/georgia-power/pdfs/residential-pdfs/Approximate_Demand_for_Appliances.pdf; Arizona Public Service. (n.d.). *How do I estimate my demand?* https://www.aps.com/-/media/APS/APSCOM-PDFs/Residential/Save-Money-and-Energy/Demand/APSDemandEstimator.pdf?la=en&hash=E8A923A2805D0458C5BCEAEA1651E728

[31] Ford Motor Company. (n.d.). *Ford Charge Station Pro*. https://chargers.ford.com/ford-charge-station-pro?fmccmp=fv-homecharging-cta2-fcg-stationPro

[32] Santee Cooper. (n.d.). *Residential customers*. https://www.santeecooper.com/rates/rate-study/residential/

[33] Santee Cooper. (n.d.). *Powering a reliable and sustainable future for South Carolina*. https://www.santeecooper.com/Rates/Rate-Study/_pdfs/Final-2024Rates_onepager_04.pdf

[34] Santee Cooper. (2024b, April 16). *Electricity demand whiteboard* [Video]. YouTube. https://www.youtube.com/watch?v=esU6SLAm0CA

[35] "Stagger your use of major appliances, like washer, dryer and oven" is a recommendation at 1:56 in the educational video. Santee Cooper, 2024b.

[36] Energy Sentry. (n.d.). *Residential demand controllers*. https://energysentry.com/PP-residential-controllers.php

[37] South Carolina Office of Regulatory Staff, 2024, p. 20.

Options for Time-Varying Rates for Small Customers

Time-varying energy rates have just as many potential variations as demand charges, if not more. Time-of-use rates, in which prices vary according to a set hourly schedule, are one of the simplest forms of time-varying rates but themselves have simpler and more complex versions. Optional time-of-use rates for residential customers have been common across the country for many years. Santee Cooper currently offers one and proposes to continue it in a modified form. In the past decade, several jurisdictions have moved to default time-of-use rates for residential customers as one way to take advantage of investment in advanced metering, yielding benefits for responding customers and the electric system.

In this subsection, we highlight four approaches to default time-of-use rates, including the mildest in Missouri and a more sophisticated approach taken by Xcel Energy in Colorado. The default time-of-use rates in Michigan are in between, and the municipal utility in Fort Collins, Colorado, has a default time-of-use structure similar to the optional time-of-use rate proposed in the 2024 request filing. In addition, many other types of time-varying rates are possible for residential customers. We highlight three rates later in this subsection: (1) optional critical peak pricing offered by Duke Energy in South Carolina, (2) optional variable peak pricing in Oklahoma and Arkansas, and (3) peak-time rebates in Maryland.

Default Time-of-Use Rates: Four Examples

After consideration of a large on-peak/off-peak differential as an initial approach, Missouri electric utilities are now introducing a very mild time-of-day rate as the default residential rate. For Evergy, one of two major Missouri investor-owned electric utilities, this means a 1 cent per kWh credit for usage between midnight and 6 a.m., along with a 1 cent per kWh adder for peak usage during the summer.[38] This is a way to gently introduce the concepts and incentives of time-varying rates to customers.

In Michigan, the two major electric utilities have introduced time-of-use rates by default for all residential customers. For example, the default residential rate for DTE Energy currently has a modest 1.3-cent differential between off-peak and on-peak rates most of the year but has a more substantial 5.6-cent differential for its on-peak summer rate from 3 to 7 p.m. on nonholiday weekdays.[39] The Michigan Public Service Commission has chosen a formula-based method for setting these on-peak differentials, based on the percentage difference in wholesale market locational marginal prices during on-peak and off-peak hours. This

[38] Evergy. (n.d.). *Default time based plan*. https://www.evergy.com/manage-account/rate-information-link/plan-options/default-time-based-plan

[39] DTE Energy. (n.d.). *Time of day 3 p.m. – 7 p.m.* https://solutions.dteenergy.com/dte/en/Products/Time-of-Day-3-p-m---7-p-m-/p/TOD-3-7

percentage difference is then applied to the power supply portion of the rate, and the distribution kWh rate is flat.[40]

Colorado has two noteworthy examples of residential time-of-use rates. Xcel Energy provides an excellent example of modern three-period time-of-day rates, which is now the default for its residential customers with advanced metering.[41] From October through May, the three time periods have modest differentials: 12 cents per kWh off-peak, 16 cents midpeak and 19 cents on-peak. In summer, the off-peak rate is still 12 cents, but the midpeak rate is 22 cents and the on-peak rate is 32 cents. The municipal utility in Fort Collins has had default residential time-of-use rates for several years. In 2024, the off-peak rate is approximately 8 cents year-round, with a peak rate of 28.5 cents in the summer and 26 cents in other months.[42]

Three Other Types of Time-Varying Rates

Critical peak pricing, which often is layered on top of time-of-use rates, is one way to offer more accurate price signals than a typical time-of-use rate. Under a critical peak pricing structure, the utility identifies days and times that are likely to have resource adequacy concerns and then notifies customers that a higher price will apply during a certain period. The notification may be an email, text message, phone call or alert in a mobile application or some combination of these. The Duke Energy offering in South Carolina is a typical example of this type of pricing,[43] where the utility can call up to 20 critical peak days per calendar year. Charging a higher price during the on-peak period of a critical peak day allows for more accurate marginal cost pricing signals and thus better customer responses.

Another variation on this theme is known as variable peak pricing. Instead of a predetermined peak period price, the utility uses objective criteria to decide what the peak period price will be for the following day. Oklahoma Gas & Electric (OG&E) has a variable peak pricing rate option available for residential customers in its Oklahoma and Arkansas territories, as well as a more traditional time-of-use rate.[44] During the summer, OG&E

[40] Michigan Public Service Commission, Case No. U-20836, Order on November 18, 2022, pp. 399-400. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000058iIbAAI

[41] Xcel Energy. (n.d.). *Residential rates: Time of use*. https://co.my.xcelenergy.com/s/billing-payment/residential-rates/time-of-use-pricing

[42] City of Fort Collins. (2023, December 13). *2024 City of Fort Collins utilities electric rates*. https://www.fcgov.com/utilities/img/site_specific/uploads/2024-electric-rates.pdf?1704238780

[43] Duke Energy Carolinas. (n.d.). *Schedule RSTC residential service: Time of use with critical peak pricing*. https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/electric-sc/scschedulerstc.pdf?rev=a3394406860f479ea532e9279f50fad6

[44] Oklahoma Gas & Electric. (n.d.). *Pricing options: SmartHours*. https://www.oge.com/wps/portal/ord/residential/pricing-options/smart-hours/!ut/p/z1/lZDNDoIwEISfhSfo0NaKxxqQVk1KjRTsxXAiJIoejM9vryD-sLdNvtnZGeJJTXzfPLu2eXS3vrmE_eTFmapUqG0Ok5gDh13HjG5SxYyOSTUEjJMZLOPJstgfAQjiZ-lzu1sEPTLpOGcA-0-PDyMx0_8d8N_PV8SPLJxMQwlhjF4VFDIeAxMVDYGJDn59cb-WZVmj020UvQDYS5Sq/dz/d5/L2dBISEvZ0FBIS9nQSEh/

notifies customers on the variable peak pricing rate whether the following day will have a low, standard, high or “critical” price. Notification can take place by phone, text or email and is on a dedicated website. OG&E also has a program to integrate smart thermostats with its pricing systems.[45]

Lastly, peak-time rebates are a gradual way to provide more specific incentives to all customers using advanced metering capabilities without any risk of unexpected bill increases. Under this program structure, customers receive bill credits for reducing their usage on designated peak savings days so it’s below their measured baseline, and no customer is penalized for usage above their baseline. This structure has principally been adopted in Maryland as a “peak energy savings credit.”[46] Customers receive notifications of peak savings days by phone, text or email. Peak-time rebates can also be used to structure additional demand response programs, such as smart thermostat incentives.

Customer Protection and Transition Options

When introducing rate reforms for large customer groups, it is appropriate to consider how to help customers manage the new rate and find the best options, to minimize the risk of backlash from a substantial number of customer complaints. When changing the structure of rates, the use of averages can conceal significant variations. This would likely be the case with residential peak demand charges as shown in bill comparisons in Appendix A of the NewGen study. While the overall residential customer class is slated for an 8.7% increase, many residential customers would see their bills increase significantly more. With a static analysis, 25% of residential customers would see their bills increase more than 20%, and 10% of residential customers would see an increase of more than 30%. If customers can respond effectively to the incentives from the new peak demand charge, any increase would be mitigated, but it is unlikely that all customers will be able to do so.

One simple method that can be used to address several issues is to phase in new rates or rate elements over multiple years. This allows a customer to learn the incentives built into a new rate design with lower stakes and less risk of significant bill impacts from being unaware or misunderstanding, while still allowing the utility to earn its revenue requirement. By the time the rate is fully phased in, customers would have multiple years of experience with the rate structure or element. One utility using this practice is the Sacramento

[45] IFTTT. (n.d.). *OG&E SmartHours integrations*. https://ifttt.com/oge

[46] PEPCO. (n.d.). *About peak energy savings credit*. https://www.pepco.com/ways-to-save/for-your-home/maryland/peak-energy-savings-credit/about-peak-energy-savings-credit

Municipal Utility District, which approves rate changes to take place over time within a single proceeding. These rates are then laid out in each tariff sheet, with separate effective dates for each step of the evolution.[47]

When a utility provides multiple rate options for customers within a class, various measures can help customers navigate their options. The utility can use the billing data for that customer to advise them on the best rate option. On the bill itself, the utility can show what a customer's bill would be if they adopted a different rate option. This practice is known as shadow billing because the customer sees their actual bill as well as their potential bill from the alternative rate. A customer could also be billed based on whichever of two rate options leads to the lowest bill — a practice known as "best bill" or "hold harmless." These options can be instituted permanently but are more common as a transition measure. In addition, when implementing a rate that benefits from customer response, programmatic assistance can be appropriate. For example, OG&E provides a rebate for smart thermostats to encourage efficient responses to the utility's variable peak pricing rates.[48]

Several options for customer protection are specific to demand charges. As mentioned previously, a longer integration period can be helpful. As recommended by the Office of Regulatory Staff, Santee Cooper may want to monitor the demand charge's impact on customers' monthly bills and consider bill impact mitigation.[49] There are other ways to construct demand charges that may be appropriate for residential customers, such as the average of the two highest hours. Arizona Public Service offers two additional features for residential demand charges. There is an automatic floor for the customer load factor that mitigates the risk of extraordinarily high bill increases. If a customer's load factor drops below 15%, the demand charge is capped, as long as it happens only three or fewer times a year. In addition, the company provides a demand charge credit up to once a year if a customer feels they had an unfairly high bill. That customer can call the utility customer service line and receive a credit on their next bill if the demand measurement was abnormally high.[50]

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[47] Sacramento Municipal Utility District. (n.d.). *Residential time-of-day service rate schedule R-TOD*. https://www.smud.org/-/media/Documents/Rate-Information/Rates/1-R-TOD.ashx

[48] Oklahoma Gas & Electric. (n.d.). *Pricing options FAQS: What kind of thermostat can I use with SmartHours?* https://www.oge.com/wps/portal/ord-hidden/faqs/pricingoptions-faqs/!ut/p/z1/04_Sj9CPykssy0xPLMnMz0vMAfIjo8zijQw83D0sLYwMLUO8nA3MvA1D3ENNzAwswoz1w_EqcDPWjyJKv4eLmYeXu4G_e0iooUGgMRA6m5gaGRgYEaffAAdwNCDSftwKovAbH64fhdcKUAhAFODxIiFLCnJDQ0MjDDI9HRUVAdxOs6g!/dz/d5/L2dBISEvZ0FBIS9nQSEh/

[49] South Carolina Office of Regulatory Staff, 2024, p. 20.

[50] Arizona Public Service. (n.d.). *Time-of-use 4pm-7pm weekdays with demand charge*. https://www.aps.com/en/Residential/Service-Plans/Compare-Service-Plans/Time-of-Use-4pm-7pm-Weekdays-with-Demand-Charge

Bringing Equity Into Rates

Although the NewGen study and 2024 request filing discuss equity, rightly, in the context of cost allocation, more could be done to advance the pricing principle “allow reasonable relief mechanisms for financially distressed customers” in the context of rates and rate design.[51]

First, some jurisdictions have identified cost-based distinctions that help some low-income or fixed-income households that often have trouble making ends meet. One of these distinctions is that multifamily dwellings are typically cheaper to serve than single-family homes, for reasons that include shared service lines and diversity of heating and cooling needs. As a result, NV Energy in Nevada has separate single-family and multifamily customer classes, where the multifamily customers receive a lower monthly customer charge and a modestly lower kWh rate.[52] Similarly, the municipal utility in Burbank, California, has a tiered monthly customer charge that is modestly lower for multifamily residential customers.[53] The low-use residential rate that Dominion Energy South Carolina offers may fit in this category as well.[54]

It is also common for utilities to offer bill discounts or percentage of income payment plans (PIPPs). Bill discounts can be simple, such as the Georgia Power income-qualified discount, which provides a flat monthly bill reduction for three categories of customers: (1) those over 65 years old with income less than 200% of the federal poverty level, (2) those who receive Social Security Disability Income or Supplemental Security Income and (3) those receiving federal housing choice vouchers.[55] Other jurisdictions provide bill discounts more generally based on income thresholds of different kinds, which are often based on eligibility for other state and federal programs. States such as Ohio[56] and Virginia[57] offer PIPPs, which provide bill assistance for customers whose income is below certain thresholds. PIPPs are often contingent on customers’ continuing to make their reduced payments in full and on time.

One significant challenge in implementing programs for low- to moderate-income customers is identifying those who qualify. Traditionally, location-based census tract data

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[51] Importantly, Santee Cooper offers payment plans and budget billing for customers in need. In addition, South Carolina by statute requires Santee Cooper to establish procedures to restrict termination of power (shut-offs) during extremely hot or cold weather and for customers with special medical needs. S.C. Code Ann. § 58-31-520.

[52] NV Energy. (n.d.). *Nevada Power Company d/b/a NV Energy electric rate schedules for residential customers.* https://www.nvenergy.com/publish/content/dam/nvenergy/bill_inserts/2023/04_apr/np_res_rate_1_29.pdf

[53] City of Burbank Water and Power. (n.d.). *Electric rates.* https://www.burbankwaterandpower.com/electric/rates-and-charges

[54] Dominion Energy South Carolina. (n.d.). *Rate 2 low use residential service*. https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/south-carolina/rates-and-tariffs/rate2.pdf?la=en&rev=c85893b24e974cb0a374c885949f37dd&hash=06201EF9EB4C687C61D54431B9C10C18

[55] Georgia Power. (n.d.). *Electric service tariff: Income qualified discount service rider schedule: “IQD-1.”* https://www.georgiapower.com/content/dam/georgia-power/pdfs/electric-service-tariff-pdfs/IQD-1.pdf

[56] Ohio Department of Development. (n.d.). *Percentage of income payment plan (PIPP)*. https://development.ohio.gov/individual/energy-assistance/2-percentage-of-income-payment-plan-plus

[57] Virginia Department of Social Services. (n.d.). *Percentage of income payment program (PIPP)*. https://www.dss.virginia.gov/benefit/PIPP/index.cgi

was used, but now with more geographic migration, utilities are using data analysis based on electricity usage patterns to help identify these customers. Current tools available include location, housing and food cost data from various third-party sources and more to ensure a truly equitable approach.[58] A holistic review of Santee Cooper's customer base and the application of programs already offered at the state and federal levels would enable the creation of a robust, transparent approach to supporting customers through this rate change.

Conclusion

Many of the suggestions and observations in this memo have different time horizons for implementation, with some being appropriate to consider for this rate proceeding and others being more appropriate for future rate proceedings. RAP looks forward to continuing to engage with the Santee Cooper board on these critical issues and appreciates the hard work, time and attention of Santee Cooper management, staff and other stakeholders. We want to reiterate our willingness to answer questions from the board on topics in this memo as well as issues not addressed and to revise and extend this memo, subject to reasonable scoping and available expertise, for additional detail and topics as appropriate.

[58] Energy Equity Project. (2022). *Energy equity framework: Combining data and qualitative approaches to ensure equity in the energy transition*. University of Michigan, School for Environment and Sustainability. https://energyequityproject.com/wp-content/uploads/2022/08/220174_EEP_Report_8302022.pdf