



Santee Cooper

2026 Integrated Resource Plan



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EXECUTIVE SUMMARY

Santee Cooper respectfully submits its 2026 Triennial Integrated Resource Plan (“2026 IRP” or “2026 Triennial IRP”) to the Public Service Commission of South Carolina (“Commission”) for consideration and approval. Santee Cooper developed the 2026 Triennial IRP in collaboration with stakeholders through a comprehensive public engagement process. The 2026 IRP identifies a Preferred Portfolio, that builds on resources under development and reliably meets growing customer needs in a manner that is the most cost-effective and least risk for rate payers. The 2026 Triennial IRP also includes a Short-Term Action Plan for Santee Cooper, which focuses on completing resources under development, identifying and securing near-term resources, and beginning due diligence on a 2035 natural gas combined cycle resource.

Santee Cooper appreciates the input received from stakeholders during preparation of this IRP through an extensive public stakeholder engagement. Santee Cooper has consulted with Central Electric Power Cooperative, Inc. (“Central”), municipal wholesale customers, and retail customers in preparing this IRP. The planning process has benefited from the input received from all interested parties.

INTRODUCTION

The South Carolina General Assembly created Santee Cooper over 90 years ago to provide reliable and affordable electric service to the State of South Carolina. Over those 90 years, our mission has expanded to include providing water service. In June of 2026, employees across Santee Cooper worked together to reflect on who we are today and who we aspire to be tomorrow as an organization. As a result, our Core Values were developed. The values listed below help us drive towards meeting the essential mission of Santee Cooper to benefit the lives of all South Carolinians.



ALWAYS DELIVER

We get the job done. We follow through on all the details. We provide calm in the storm.



TAKE THE LEAD

We act boldly in uncertainty. We own our outcomes. We strive to be better, every day.



POWER WHAT'S NEXT

We take pride in building for the future. We innovate to drive progress. We leave things better than we found.

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Santee Cooper is committed to these values and delivering on our mission, which is to ensure affordable, reliable, and innovative electric and water solutions for the communities we serve. We have multiple projects under construction that will bring additional reliable generation to the Combined Santee Cooper-Central System (“Combined System”). We are committed to delivering these projects on time and on budget. Santee Cooper is proactively seeking ways to serve our customers in an unprecedented period of change within the electric industry, and we are committed to continuing to support economic development across South Carolina and providing the resources required to serve this growth. The 2026 IRP lays out the factors impacting our resource planning and describes our plans for meeting the needs of our customers.

PREFERRED PLAN

The 2026 IRP Preferred Plan provides a diverse mix of resources to serve the growing needs of the Combined System. It includes the following projects described in previous IRPs and approved by the Commission:

- The Canadys Joint Natural Gas Combined Cycle (“Canadys Joint NGCC”), which will add approximately 2,180 MW of reliable generation to the State, of which approximately 1,090 MW will serve the Combined System.
- The conversion project at our Rainey Generating Station, which will add efficient Natural Gas Combined Cycle (“NGCC”) generation to the system and 178 MW of capacity.
- The Winyah turbines which will add 108 MW of peaking resources to the system.

Additionally, Santee Cooper is implementing upgrade projects at the Rainey Generating Station that will add 77 MW of capacity and is procuring the Jefferies battery energy storage system (“BESS”), which will provide a 300 MW resource for the system.

In response to forecasted load growth, the 2026 Triennial IRP identifies the need for additional resources beyond those identified in the 2023 IRP or described above, such as:

- Near-term resources starting in 2027 and growing to provide approximately 350 MW of firm capacity prior to the Canadys Joint NGCC coming online. The 2026 IRP assumes a combination of near-term purchases, BESS, and peaking resources to fill this need; however, the actual resources will be determined by Santee Cooper in conjunction with our partner, Central. The IRP’s Short-Term Action Plan identifies how we will evaluate the options and determine the best mix of resources to reliably and cost-effectively meet this near-term need.
- An NGCC resource in 2035, which is needed to serve growing loads and to assure Winyah Generating Station can be retired as planned by year-end 2034. The 2024 and 2025 IRP Updates identified the need for this resource, and the 2026 IRP confirms the need for an NGCC upon the retirement of Winyah.

In this IRP, Santee Cooper has modeled the offtake proposed by the current agreements related to the restart of the two partially constructed Westinghouse nuclear units at the former VC Summer Nuclear Station site in Fairfield County under the Fairfield Nuclear Project (“Fairfield”). This

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resource, once online, will provide benefit to the State and to customers through reliable, low-cost power.

Finally, the 2026 IRP determines that continued operation of Cross Generating Station benefits customers and assumes the retirement of Winyah Generating Station by year-end 2034. The actual retirement of Winyah will not occur until sufficient resources are available to reliably serve Santee Cooper's growing customer base.

KEY FACTORS IMPACTING PLANNING DECISIONS

Several key factors have impacted the 2026 Triennial IRP; these are discussed below.

CONTINUED LOAD GROWTH

The Combined System continues to see unprecedented load growth. Compared to the 2023 IRP, the 2026 IRP forecasts winter peak demands to be higher by 1,250 MW by the year 2030 and 1,375 MW by the year 2040.

Additionally, for this IRP, Santee Cooper continues to plan and prepare for higher load growth scenarios.

HIGHER PLANNING RESERVE MARGIN

As it did with the 2023 IRP, Santee Cooper retained PowerGEM, LLC ("PowerGEM") (formerly Astrapé Consulting) to perform a planning reserve margin ("PRM") study for the 2026 IRP. The 2026 PRM study identified the need to increase the winter reserve margin from 18% to 20% and increase the summer reserve margin from 15% to 18%, as compared with Santee Cooper's planning since the 2023 IRP.

Santee Cooper is committed to reliably serve our customers, and the 2026 IRP identifies resource additions to meet the new reserve requirements.

CHANGING RESOURCE COSTS

In 2025, tax incentives for renewable resources were effectively eliminated for long-term resource additions through passage of HR1, known as the "One Big Beautiful Bill," ("OB BB"). At the same time, competition for all types of electric generating resources has led to increased costs for both equipment and construction.

The changes in resource costs assumptions impacted which resources Santee Cooper selected in the 2026 IRP, with generally less solar selected than in previous IRPs.

STAKEHOLDER ENGAGEMENT

A robust IRP stakeholder engagement process leads to a more robust resource plan. To support the 2026 Triennial IRP, Santee Cooper facilitated the following stakeholder meetings from April 2024 to August 2026:

- **Twelve stakeholder working group meetings.** The working group is made up of representatives from customers, organizations representing environmental and customer

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stakeholder groups and government entities. The group has a consistent set of members and meets regularly to review and provide feedback on Santee Cooper's planning.

- **Nine technical meetings with members of the stakeholder working group.** These meetings provided the opportunity for discussions of complex technical topics with stakeholders.
- **Four general notice meetings for the public at large.** Santee Cooper provided notice for these meetings through several media outlets and directly to its customers. The meetings covered Santee Cooper resource planning and provided the opportunity for direct feedback from customers and the public.

Throughout the process, stakeholders were engaged and provided valuable feedback. Santee Cooper is committed to continuing the engagement process for future IRPs.

RESOURCE PLAN EVALUATIONS AND RESULTS

For the 2026 IRP and consistent with the 2023 IRP, Santee Cooper evaluated four foundational portfolio options:

- **Economically Optimized Portfolio**, which identifies the most cost-effective portfolio over the 2026 through 2055 period studied herein ("Study Period") under Reference Case assumptions.
- **Future Coal Retirement Portfolio**, which considers the cost impacts and other implications of the retirement of the Cross Generating Station by 2040.
- **Renewable and Storage Portfolio**, which was developed to understand the implications of a build plan considering the addition of only renewable and BESS resources to meet future load growth and resource needs.
- **Net Zero CO₂ by 2050 Portfolio**, which reflects the retirement of all coal resources and the imposition of CO₂ emissions targets over the Study Period designed to achieve net zero CO₂ emissions by 2050.

Based on review of the optimized resource builds across the foundational portfolios and considering the need for flexibility to respond to higher load growth, regulatory uncertainty, and resource implementation risk, Santee Cooper further developed a variation on the Economically Optimized Portfolio, which reflects the addition of a 1x1 NGCC resource in 2035 ("2035 NGCC Resource") and otherwise optimizes for the most cost-effective outcome without further constraints ("Adjusted Economic Portfolio").

Resulting optimized build plans and results for the five portfolios are provided in Table 1 below.

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Table 1. Summary of Optimized Portfolios

	Portfolios				
	Economically Optimized	Coal Retirement	Renewable and Storage	Net Zero	Adjusted Economic
NPV Power Cost (\$B)	\$32.7	\$35.8	\$34.0	\$44.1	\$33.3
Cumulative Capacity Added (MW):					
NGCC	648	1,296	0	0	648
Peaking	909	2,493	142	885	1,040
Nuclear	625	625	625	2,785	625
Solar (Nameplate Capacity)	1,200	850	1,750	2,600	900
Wind (Nameplate Capacity)	150	200	500	1,050	50
BESS (Nameplate Capacity)	550	700	2,030	1,250	600
Total	4,083	6,164	5,047	8,570	3,863
Cross Retirement (MW)	0	2,330	0	2,330	0
CO2 Emissions Profile (2026-2055)					
Total Emissions (millions tons)	552	475	561	331	537
Average Emissions Rate (lbs/MWh)	931	808	944	583	905
Generation Mix by Fuel Type (2026-2055)					
Coal	27%	17%	30%	17%	25%
Natural Gas	47%	58%	41%	28%	50%
Distillate Fuel Oil	1%	0%	0%	0%	0%
Nuclear	19%	19%	19%	42%	19%
Biomass / LFG	1%	1%	1%	1%	1%
Hydro	2%	2%	2%	2%	2%
Solar	3%	3%	4%	8%	3%
Wind	0%	0%	2%	2%	0%
INT/DR	0%	0%	0%	0%	0%

All portfolios reliably meet the needs of the Combined System, but Santee Cooper has identified the Adjusted Economic Portfolio as its Preferred Portfolio for the following reasons:

- Provides flexibility to meet higher than projected load growth and supports economic development.
- Provides a diverse set of dispatchable, on-system resources to meet the requirements of the Combined System.
- Positions Santee Cooper to respond to potential changes in applicable regulations and the potential for requirements to retire coal-fired facilities.
- Positions Santee Cooper to be able to continue to serve system load growth while mitigating resource development risks.
- Provides a set of resources to reliably meet the Combined System needs in a manner that is the most cost-effective and least risk for ratepayers.

While the Economically Optimized Portfolio has the lowest projected net present value (“NPV”) power cost under the Reference Case and scores well across many of the portfolio metrics, the Adjusted Economic Portfolio performs similarly to the Economically Optimized Portfolio across

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most of the portfolio metrics. In addition, the Adjusted Economic Portfolio supports continued load growth and reduces risk related to resource implementation.

SHORT-TERM ACTION PLAN

The table below discusses the key activities Santee Cooper intends to pursue to support the resource additions identified by the Preferred Portfolio.

Category	Activities
Deliver on Resources Under Development	With higher projected load growth compared to previous IRPs, it is important that the resources Santee Cooper currently has under construction are completed on time and on budget. This includes the Canadys Joint NGCC, Rainey Generating Station upgrades, the new turbines at Winyah Generating Station, and the Jefferies BESS project. Santee Cooper will continue to make progress on these vital resources and update the Commission as required.
Identify Near-Term Resources	Ensuring reliable power and meeting load growth is essential for Santee Cooper. The paragraphs below describe how Santee Cooper, working with Central, will evaluate options to meet the near-term need identified by the 2026 IRP. Santee Cooper has issued the 2026 Capacity RFP. Responses to the RFP were received on September 4, 2026, and Santee Cooper intends to shortlist potential projects by early October 2026. Additionally, Santee Cooper is evaluating options including: • Extending current PPAs • Self-build options • Upgrades of existing facilities Santee Cooper may make decisions about which options are most appropriate to pursue during the 2026 IRP proceeding. It will keep the Commission informed of the evaluation and what options it chooses to pursue.

Category	Activities
Begin Due Diligence on the 2035 NGCC Resource	Santee Cooper must begin due diligence on the 2035 NGCC Resource. To date, Santee Cooper has begun the following activities: • Commenced studies for cost, schedule, and transmission assessments, which are ongoing and described below: ○ Engaged Sargent and Lundy to perform a front-end engineering design (“FEED”) study for a 1x1 NGCC. ○ Submitted the resource into Santee Cooper’s Open Access Transmission Tariff (“OATT”) generator interconnection process. • Solicited for alternatives through the 2026 Capacity RFP. Santee Cooper plans to complete the studies described above and the comparison of alternatives in coordination with Central. In addition, Santee Cooper plans to begin environmental assessments at a site owned by Santee Cooper and located in Hampton County, begin fuel procurement planning, and issue an RFP for an owner’s engineer to support the development of the NGCC resource. In future IRPs, Santee Cooper will update the Commission on the status of the 2035 NGCC Resource and associated studies.

INTRODUCTION

Santee Cooper is pleased to submit to the Public Service Commission of South Carolina (“Commission”) this 2026 Triennial IRP as a successor to its triennial 2023 Integrated Resource Plan (“2023 IRP”), which the Commission approved in Order 2024-171 and which Santee Cooper updated with the subsequently-approved 2024 IRP Update (approved by the Commission in Order 2025-244) and the 2025 IRP Update (approved by the Commission in Order 2026-126).

Santee Cooper is required to file with the Commission for approval of an Integrated Resource Plan (“IRP”) every three years and an annual update to an accepted plan in intervening years.¹

In developing the 2026 IRP, Santee Cooper addressed four key items: (i) activities identified in the Short-Term Action Plans of the 2023 IRP, the 2024 IRP Update, and the 2025 IRP Update; (ii) items Santee Cooper was required to address in Order 2024-171, Order 2025-244, and Order 2026-126; (iii) feedback received through the 2024-2026 IRP Stakeholder process; and (iv) trends impacting utility operations and planning, including recent and unprecedented potential growth in load from large customers.

Santee Cooper works with its largest customer, Central, to plan for the near-term needs of the Combined System and to procure resources consistent with its approved IRP. Additionally, Santee Cooper is moving forward with Dominion Energy South Carolina, Inc. (“DESC”) in developing a multi-unit, natural gas-fired, advanced-class combined cycle generation plant, the Canadys Joint NGCC.²

With regard to the 2026 Triennial IRP, Order 2026-126 required Santee Cooper to address the following key items:

- Provide updates regarding its plan for the Cross Generating Station retirement evaluation and associated transmission evaluations
- Monitor and report on potential new large load and the impact these loads have on the load forecast
- Provide an evaluation of new resource additions
- Include information about the Fairfield Nuclear Project as it is available and relevant
- Provide details of the additional NGCC resource under consideration for 2035, including natural gas procurement plans, and providing updates on the on-going activities associated with the joint resource including transmission requirements
- Consider recommendations made by parties in the 2025 IRP Update docket
- Address the recommendations raised by the Office of Regulatory Staff (“ORS”) in the 2025 IRP Update docket

In the 2026 IRP, Santee Cooper provides a status update for each of these items.

¹ S.C. Code Ann. § 58-37-40.

² On June 12, 2026, the Commission issued Order 2026-350 granting Santee Cooper and DESC a Certificate of Environmental Compatibility and Public Convenience and Necessity to construct and operate the Canadys Joint NGCC.

Introduction

The 2026 IRP was informed by a robust and inclusive stakeholder engagement process, as discussed in the section entitled Stakeholder Engagement Process. Through this process, stakeholders are provided with the opportunity to engage at their desired technical level and to provide feedback that contributes to Santee Cooper’s planning process. Throughout the years, Santee Cooper has received valuable feedback and input from the Stakeholder Working Group (“SWG”) on numerous topics and assumptions, such as load forecast methodology, conventional and renewable resource options, potential portfolio strategies, sensitivity assumptions, coal retirement evaluations, and studies in support of the 2026 Triennial IRP.

Furthermore, the 2026 IRP—and, ultimately, the selection of the Preferred Portfolio—is informed by, and gives Santee Cooper the flexibility to address, trends impacting utility operations and planning, including unprecedented system load growth, increasing costs for new generating resources, environmental regulatory uncertainty, and federal tax implications of renewable resources. Evaluation of these trends is discussed in the Key Considerations and Conclusions section of this report. The remainder of this report provides information regarding the key items above and the data sources, assumptions, methodology, and results of Santee Cooper’s 2026 IRP, including the identification of a preferred portfolio.

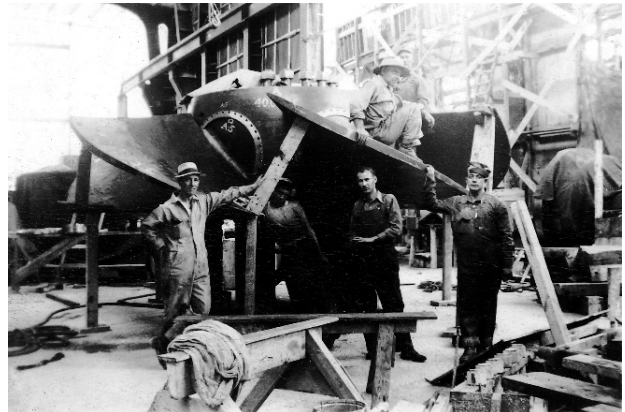
The 2023 IRP and the 2024 and 2025 IRP Updates positioned Santee Cooper well to plan for the resources to meet the needs of its customers in a reliable and cost-effective manner. Those plans produced real progress, including the Canadys Joint NGCC, the RGS conversion and upgrades, the Winyah turbines, and the Jefferies BESS. The 2026 Triennial IRP builds on those plans while recognizing that Santee Cooper faces unprecedented load growth, rising costs for new generating resources, environmental regulatory uncertainty, and a changing federal tax landscape for renewable resources. The 2026 Triennial IRP proposes a Preferred Portfolio that gives Santee Cooper the flexibility to respond to these conditions with a diverse set of dispatchable resources. Santee Cooper is confident that the 2026 Triennial IRP will continue its more than 90-year mission of providing reliable, cost-effective power to South Carolina.

COMPANY OVERVIEW

Santee Cooper is South Carolina's state-owned electric and water utility. Santee Cooper is a not-for-profit entity authorized to produce, distribute, and sell electric power and to acquire, treat, transmit, distribute, and sell wholesale water within various portions of the state. Santee Cooper was created in 1934 as a rural electrification and public works project and first generated electricity in February 1942. Santee Cooper's primary business operation is the production, transmission, and distribution of electrical energy, both at wholesale and retail, to citizens of the State of South Carolina.

Santee Cooper is one of the nation's largest municipal wholesale utilities, directly or indirectly serving approximately two million South Carolinians in all 46 counties of the State.

Santee Cooper owns and operates several large generating facilities, a high voltage transmission network, and over 3,200 miles of distribution lines and associated facilities through which it directly serves approximately 220,000 retail customers in Berkeley, Georgetown, and Horry counties, currently including 27³ large industrial retail customers. Santee Cooper also serves several wholesale municipal customers: the City of Bamberg, the City of Georgetown, the City of Seneca, Piedmont Municipal Power Agency, and the Town of Waynesville, North Carolina.

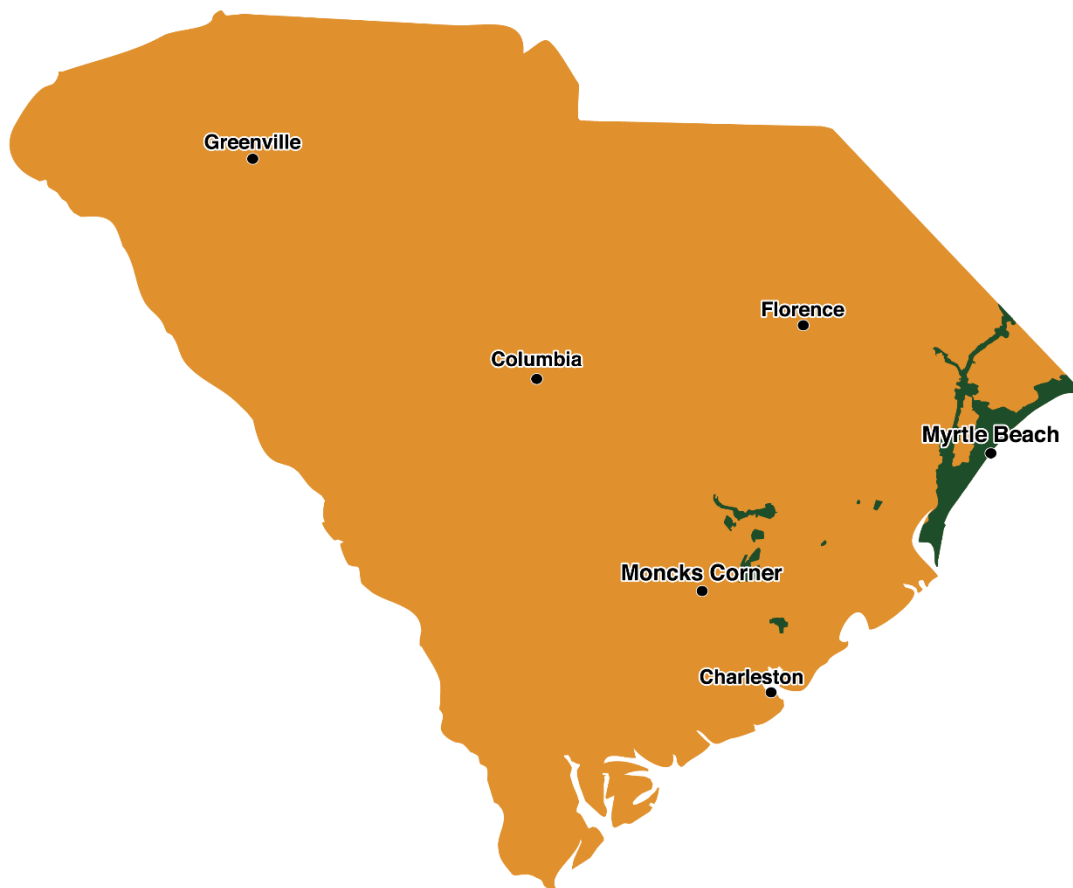


Initial turbine install at Jefferies Hydro Station

SANTEE COOPER AND CENTRAL RETAIL SERVICE AREAS

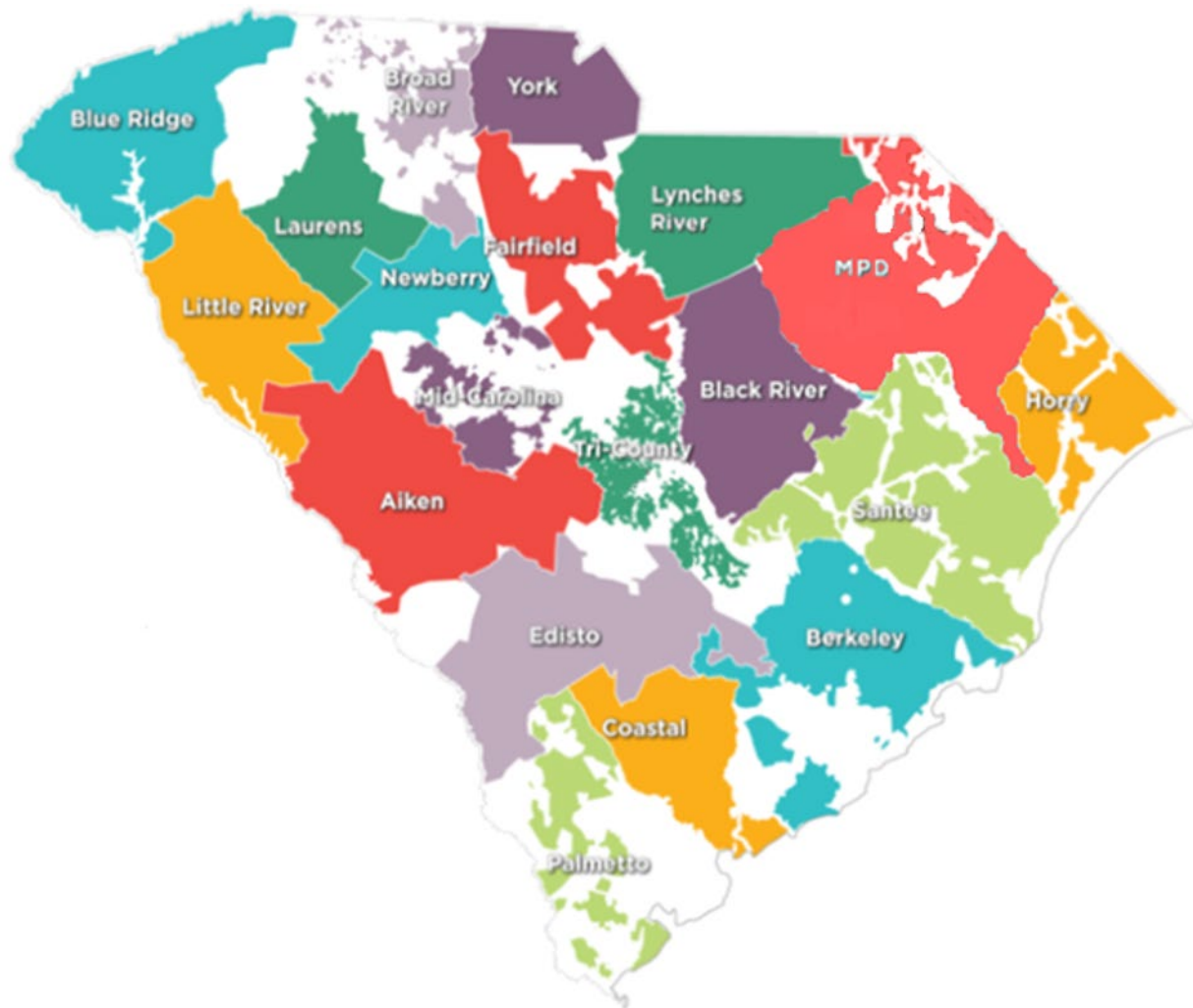
While Santee Cooper serves load throughout most of the state through its wholesale service to Central as described further below, the retail service territory for Santee Cooper consists of two non-contiguous areas covering portions of Berkeley, Georgetown, and Horry counties, as illustrated as the green-colored areas in Figure 1 on the next page.

³ Includes one large industrial retail customer that is ending service in 2026.

Figure 1. Santee Cooper Retail Service Areas

Central is a wholesale electric generation and transmission cooperative headquartered in Columbia, South Carolina. The terms of Central's wholesale purchase of power from Santee Cooper are governed by the Power System Coordination and Integration Agreement, dated December 31, 1980, and most recently amended in 2013 ("Coordination Agreement"). Santee Cooper and Central coordinate resource planning under the terms of this agreement, as discussed in the section titled Central Coordination Agreement.

Central provides power to the state's 19 electric distribution cooperatives ("Central Members") with more than 1.5 million customers in all 46 counties of the state. The cooperatives served by Central are illustrated in Figure 2 on the next page.

Figure 2. Central Retail Cooperative Service Areas

Santee Cooper supplies the total power and energy requirements in the territories served by the fourteen (14) Central Members connected to the Combined System, less any amounts which Central purchases directly from Southeastern Power Administration of the United States Department of Energy (“SEPA”), amounts supplied by Central Non-Shared Resources, and amounts supplied by allowed alternative purchases in accordance with the Coordination Agreement.⁴

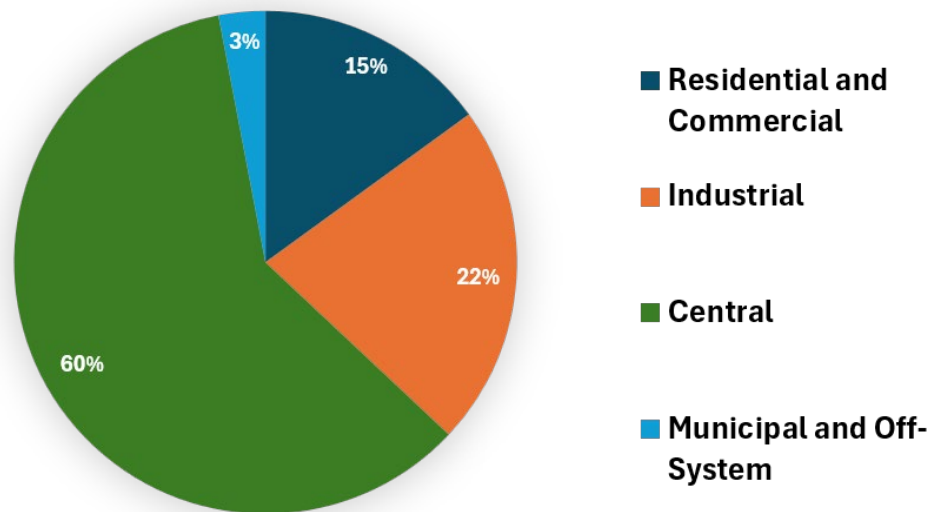
The Central Members primarily serve the rural areas of the state and the suburban areas surrounding the major metropolitan areas, which are served by DEC in the western part of the state and DESC in the eastern part.

⁴ Central purchases from Duke Energy Carolinas, LLC (“DEC”) serve the power and energy requirements of five (5) Central Members—Blue Ridge, Broad River, Laurens, Little River, and York, that are not served under the Coordination Agreement with Santee Cooper and are located in the northwest portion of the state.

SANTEE COOPER SYSTEM

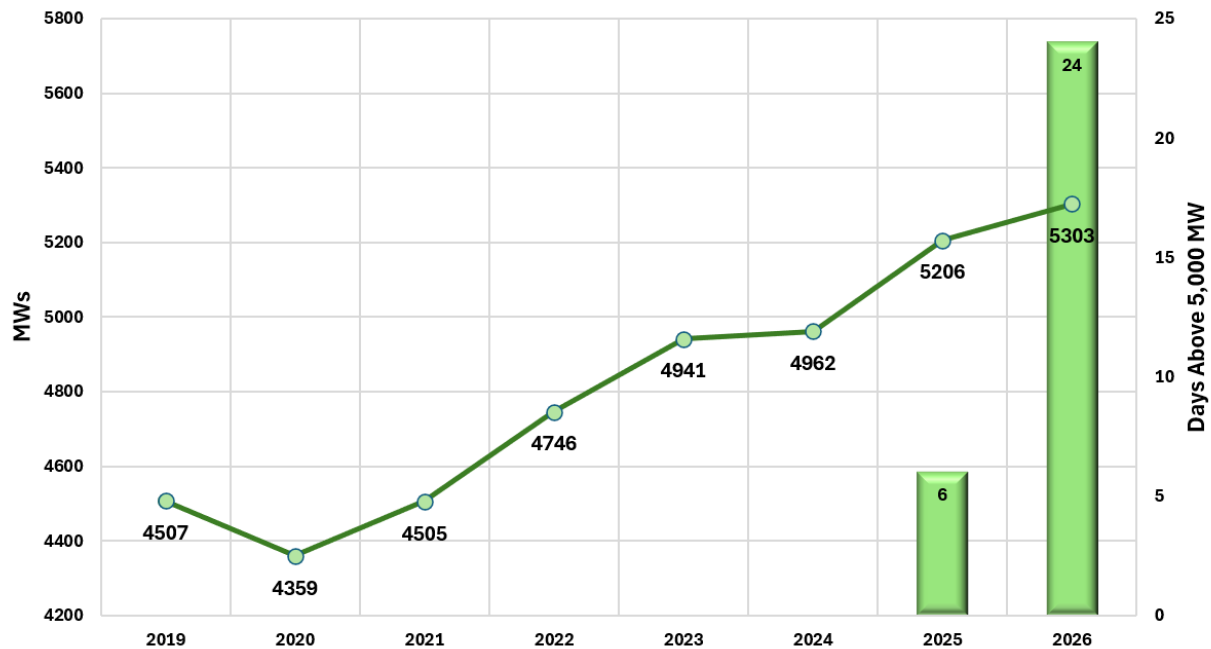
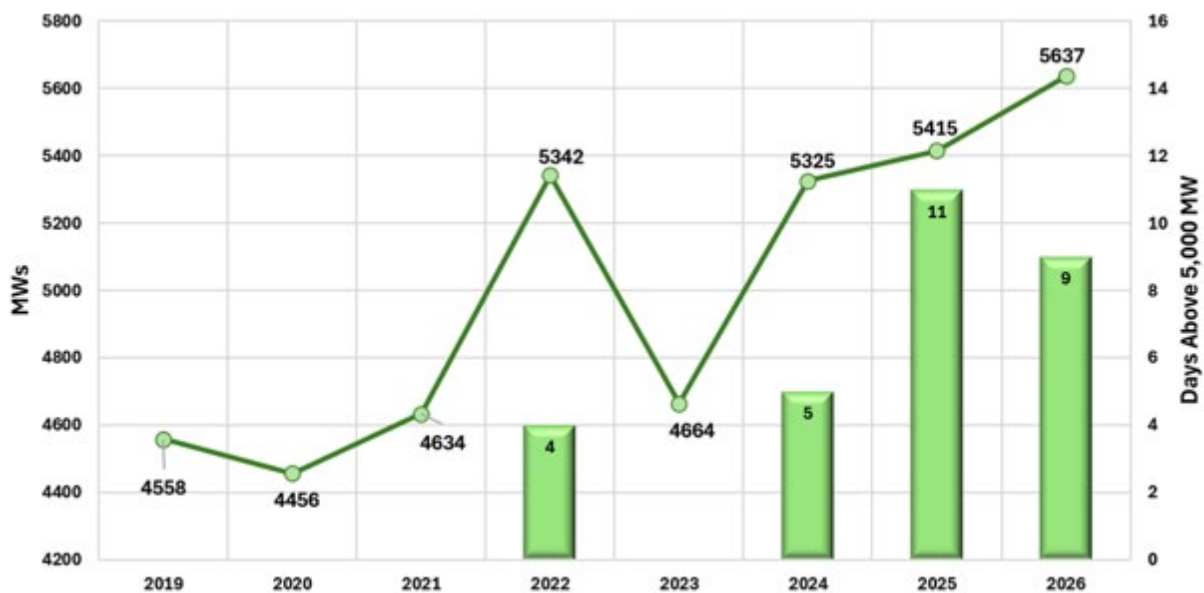
Figure 3 below provides the breakdown of calendar year 2025 electricity sales volume by customer class, reflecting that sales to Central represent well over half of system sales, while sales to residential and commercial customers and to industrial customers represent approximately 15% and 22%, respectively, of the total.

Figure 3. 2025 Electricity Sales Volume by Major Customer Classification



Santee Cooper serves the Combined System load through wholly owned and ownership interests in a variety of coal, natural gas, nuclear, hydro, biomass, landfill, and solar generating units, which total approximately 5,150 MW, based on peak output ratings under summer conditions, and approximately 5,380 MW during the winter. In addition, Santee Cooper and Central have entered into various power purchase arrangements through which they purchase firm capacity and associated energy. The Current Owned Resource Overview section details the generation mix serving the capacity and energy needs of the Combined System. Santee Cooper typically peaks during the winter season.

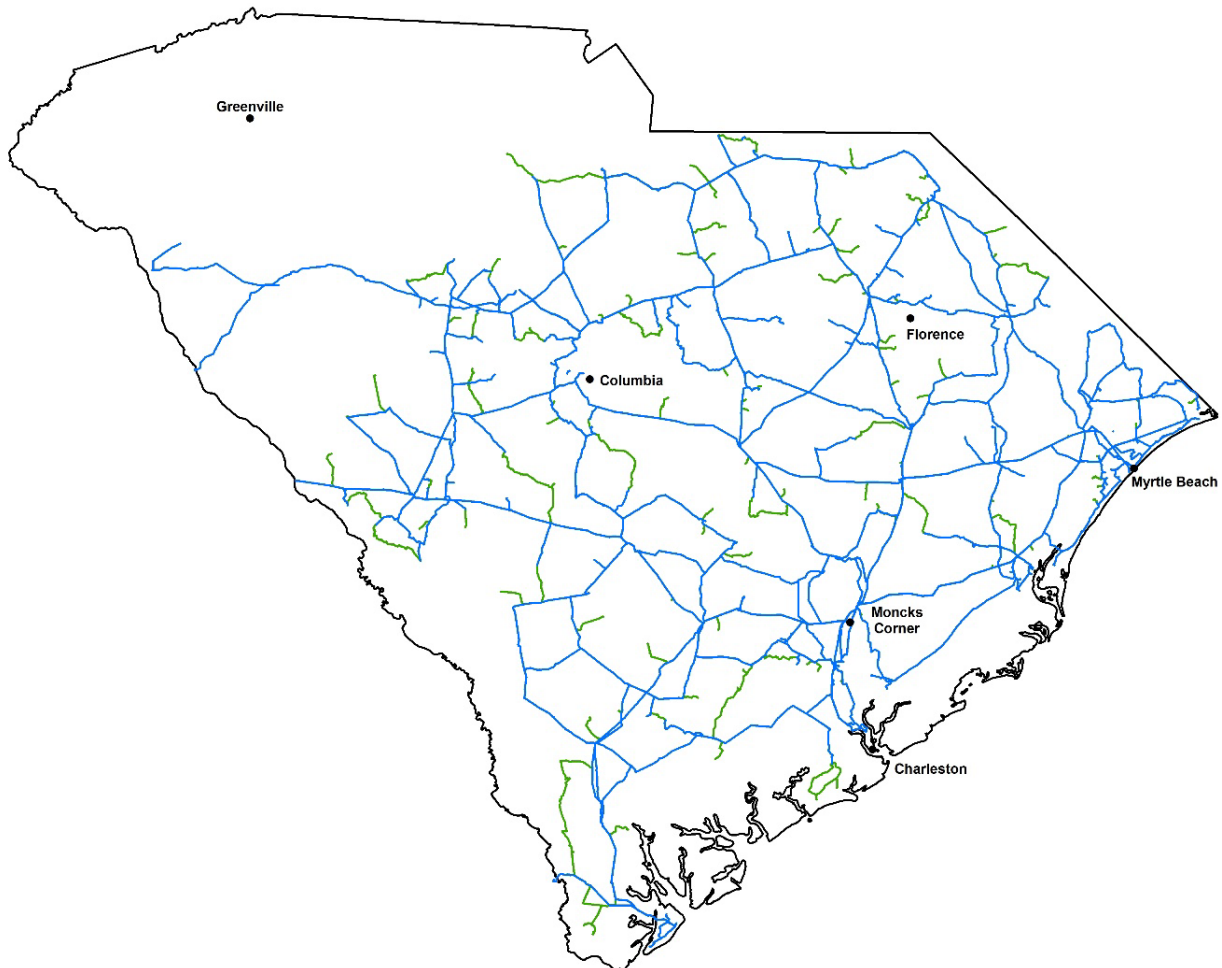
The Santee Cooper Combined System has exhibited strong growth in seasonal peak demand since 2020 and an increase in the frequency of peak load events. Since 2020, Santee Cooper has experienced an increasing summer peak demand nearly every year, with the 2026 summer peak reaching approximately 5,300 MW. Santee Cooper has seen a similar trend with winter peaks since 2020, with the 2026 winter peak reaching over 5,600 MW. In addition, peak load events occur more frequently each year, with 2026 experiencing 33 load events over 5,000 MW as of mid-September. Figure 4 and Figure 5 provide a summary of the recent summer and winter seasonal peaks, respectively.

Figure 4. Summer Peak Load Events**Figure 5. Winter Peak Load Events**

Santee Cooper operates an integrated transmission system, illustrated in Figure 6 below, which includes lines owned by Santee Cooper (shown in blue), as well as lines owned by Central and maintained by Santee Cooper (shown in green). The transmission system includes approximately 5,220 miles of overhead and underground lines primarily rated between 69 kV and 230 kV. Additionally, the system includes 93 transmission substations and switching stations, which serve 97 distribution substations owned by Santee Cooper and 427 Central delivery points. Santee

Cooper plans the transmission system to operate during normal and contingency conditions that are described in electric system reliability standards adopted by the North American Electric Reliability Corporation (“NERC”).

Figure 6. Santee Cooper Transmission System



Santee Cooper’s transmission system is interconnected with neighboring electric utilities in the region. It is directly interconnected with DESC at twelve locations (with one additional interconnection currently under construction); with Duke Energy Progress, LLC (“DEP”), at eight locations; with Southern Company Services, Inc. (“Southern Company”) at one location; and with DEC at two locations. Santee Cooper is also interconnected with DESC, DEC, Southern Company, and the SEPA through a five-way interconnection at the SEPA J. Strom Thurmond Hydroelectric Project and with Southern Company and SEPA through a three-way interconnection at the SEPA R. B. Russell Hydroelectric Project. Through these interconnections, the Santee Cooper transmission system is integrated into the regional transmission system serving the Southeastern region of the United States and the Eastern Interconnection (one of the three major electrical grids in the continental U.S. power transmission grid, the others being the Western Interconnection and the Electric Reliability Council of Texas). Santee Cooper has separate

Company Overview

interchange agreements with each of the companies with which it is interconnected to provide for mutual exchanges of power.

The electric generation, transmission, and distribution facilities owned by Santee Cooper, as well as certain transmission facilities owned by Central, are operated and maintained by Santee Cooper as a fully integrated system.

GOVERNANCE

Santee Cooper is governed by a Board of Directors appointed by the Governor of South Carolina with the advice and consent of the Senate. Candidates for appointment to the Board, including the Ex Officio Directors appointed by Central's board, must be screened by the State Regulation of Public Utilities Review Committee ("PURC") and, prior to confirmation by the Senate, must be found qualified by PURC as meeting the minimum requirements described in Santee Cooper's enabling act. An Advisory Board, comprised of the Governor, Attorney General, State Treasurer, Comptroller General and Secretary of State, receives annual reports from the Board. These reports are to be submitted to the General Assembly by the Governor. The South Carolina Legislature's Joint Bond Review Committee approves Santee Cooper's real estate and financing transactions.

Santee Cooper submits annual payments to the state equal to one percent of its projected annual operating revenues. Since the last Triennial IRP, these payments totaled just over \$83 million (from 2023-2026). Santee Cooper also makes payments in lieu of taxes to local governments.

ECONOMIC DEVELOPMENT ACTIVITIES

Santee Cooper's enabling statute requires its Board to consider economic development as part of its mission. To accomplish this mission, Santee Cooper works with many economic development partners, most notably the electric cooperatives and the South Carolina Power Team, to bring jobs and capital investment to South Carolina. Together with the cooperatives, Santee Cooper has helped bring more than \$25 billion in investment and more than 94,000 new jobs to South Carolina since 1988. Notable examples include Volvo, Nucor, Samsung, Redwood Materials, and Century Aluminum.



Camp Hall Hydropillar



Avian Commons at Camp Hall

RECENT ACTIVITIES AND DEVELOPMENTS

This section provides an overview of Santee Cooper's activities related to the Short-Term Action Plans which Santee Cooper presented in the 2023 IRP and 2024 and 2025 IRP Updates and related to compliance with Commission Orders 2024-171, 2025-244, and 2026-126. Additionally, information is provided about recent regulatory developments.

2023 IRP AND 2024 AND 2025 IRP UPDATE SHORT-TERM ACTION PLAN ITEMS

In the 2023 IRP and the 2024 and 2025 IRP Updates, Santee Cooper committed to addressing several items in its Short-Term Action Plans. This section provides a status update for key items.

IMPLEMENTATION OF CANADYS JOINT NATURAL GAS COMBINED CYCLE WITH DESC

Santee Cooper has been advancing the development of the Canadys Joint NGCC, a proposed multi-unit natural gas-fired advanced-class combined cycle generation plant which Santee Cooper will co-own with DESC. The new plant will consist of three advanced-class combined-cycle units with an approximate capacity of 2,180 MW. Santee Cooper will own a 50 percent share of that capacity (1,098 MW). The Canadys Joint NGCC will be located on DESC's former Canadys Station in Colleton County, South Carolina, a brownfield site.

On December 15, 2025, at Docket No. 2025-323-E, Santee Cooper and DESC filed with the Public Service Commission an application for a certificate of environmental compatibility and public convenience and necessity ("CEPCN") under the South Carolina Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-110 et seq., ("Siting Act") for the Canadys Joint NGCC. In Order No. 2026-350, the Commission granted the CEPCN. That Order includes various reporting requirements pursuant to which Santee Cooper and DESC must make quarterly reports⁵ to the Commission and the ORS about progress in permitting, development, construction and operation of the Canadys Joint NGCC project and the FERC jurisdictional pipeline projects that will deliver natural gas to the project's units.

UPGRADES AT THE EXISTING RAINEY GENERATING STATION

On March 4, 2025, the Commission issued Order 2025-136, permitting Santee Cooper to construct and operate a combined-cycle steam turbine generator and associated facilities on existing units at Santee Cooper's Rainey Generating Station (i.e., conversion to combined cycle by installation of heat recovery steam generation units), expected to result in an increase in capacity of 178 MW to plant capacity, as well as a significant improvement in efficiency ("Rainey NGCC Conversion").

Santee Cooper expects this project to be placed in-service during winter 2028 (i.e., December 2027 through February 2028).

Santee Cooper is also moving forward with the Advanced Gas Path⁶ upgrade to Rainey Power Block 1 that will add approximately 56 MW of incremental capacity to the unit. The upgrade work

⁵ These updates will be filed in Docket No. 2025-323-E.

⁶ Advanced Gas Path is a combustion upgrade to 1A and 1B combustion turbines that involves changing some of the combustion and fuel components. GE is providing the parts and labor.

Recent Activities and Developments

has been incorporated into Santee Cooper's planned maintenance outage schedule, with planned completion in 2027. The additional capacity from the upgrades will be available during winter 2028.

Finally, Santee Cooper is moving forward with the Axial Fuel Staging⁷ upgrade on the Rainey Combustion Turbines 3, 4, and 5, which will add a total of approximately 21 MW of incremental capacity to the units in aggregate (7 MW per unit). The upgrade work has been incorporated into Santee Cooper's planned maintenance outage schedule, with planned completion in 2027. The additional capacity from this upgrade will be available during winter 2028.

SOLICITATIONS FOR CAPACITY RESOURCES

In January 2025, Santee Cooper issued a request for proposals ("RFP") to purchase capacity and energy from dispatchable resources for varying durations beginning as early as 2026. As a result of that RFP, Santee Cooper, on February 14, 2025, received 28 different offers from 13 companies. The responses included power purchase offers from existing resources totaling 2,089 MW and 20 proposed new build generating resources totaling 9,478 MW. The offers also included options to acquire new resources. Over 60 percent of the proposals were not available until after 2030. As a result of the evaluation of the proposals received, Santee Cooper secured opportunities for short-term purchases to meet near-term capacity needs for 2027 and 2028. However, the long-term supply proposals Santee Cooper received and evaluated would not be more cost-effective than Santee Cooper-owned resources considered herein.

In August of 2026, Santee Cooper issued an RFP for capacity and energy purchases from dispatchable resources beginning as early as 2028, and responses were received in early September 2026. Santee Cooper and Central will jointly evaluate the proposals and select options to serve the capacity and energy needs of the Combined System.

UPDATE ON PEAKING RESOURCES AT WINYAH GENERATING STATION

In Order 2026-74 issued February 6, 2026, the Commission authorized Santee Cooper to construct and operate two dual fuel aeroderivative combustion turbine generators (GE Vernona LM6000s) and associated facilities at the Winyah site ("Winyah Turbines"). These resources will provide dispatchable peaking capacity, and the quick start capability will support system operating reserves.

Construction on this project began in the first quarter of 2026, and the project is on track to be completed by the fourth quarter of 2027.

PROCUREMENT OF SOLAR RESOURCES

On January 3, 2024, and pursuant to Order No. 2024-2, the Commission approved Santee Cooper's Competitive Procurement Program. As part of this approval, Santee Cooper is required to publish a public report after each solar solicitation that summarizes the proposals received and the awards made, including details such as project size, location, pricing, and term length.

⁷ Axial Fuel Staging is a combustion upgrade to the existing units 3, 4, and 5 that involves changing some of the combustion and fuel components. GE is providing the parts and labor.

Recent Activities and Developments

Under the program guidelines, Santee Cooper issued the 2024 Solar RFP on June 10, 2024, inviting solar developers to submit competitive bids. The process was facilitated by The Energy Authority (“TEA”) through its online platform. As a result of this RFP process, Santee Cooper and Central jointly contracted for the 42 MW Magnolia solar project, which is scheduled to enter commercial operation in 2028.

As part of its commitment to regularly test the market for renewable resources, on May 11, 2026, Santee Cooper issued its 2026 Solar RFP with a July 6, 2026, deadline to submit proposals. Santee Cooper and Central will jointly evaluate the proposals and will select solar projects if they benefit the Combined System. Quarterly reports for the 2026 Solar RFP are filed under Docket No. 2022- 351-E.

Central has also contracted for approximately 224 MW of solar projects⁸ which will be online by 2028.

IMPLEMENTATION OF BATTERY ENERGY STORAGE SYSTEM RESOURCES

Santee Cooper initiated a competitive procurement process in March 2025 for up to 300 MW of 4-hour battery energy storage system (“BESS”) to be located at the Jefferies Generation Station site, formerly home to retired coal and oil generation units. Interest in the solicitation was robust, with 30 firms submitting 88 offers. Santee Cooper evaluated proposals with assistance from Sargent & Lundy. Aypa Power, a leading battery storage developer and independent power producer, was the successful bidder. In the Fall of 2025, Santee Cooper and Aypa Power entered into a battery energy storage system service agreement for 300 MW of 4-hour duration storage (“Jefferies BESS Project”). The Jefferies BESS Project issued notice to proceed to the construction contractor in September 2026. The project has an expected commercial online date of December 1, 2027.

Central has also contracted for approximately 150 MW of BESS projects, which are anticipated to be online by year-end 2029.⁹

CROSS GENERATION STATION RETIREMENT EVALUATIONS

Since the 2023 IRP, Santee Cooper has worked with stakeholders to develop and refine the analytical process utilized to study the retirement of coal units at Cross Generating Station. Appendix H: Coal Retirement Study, discusses the stakeholder interactions, analytical approach, and results of the evaluation. Conclusions of the retirement evaluation for Cross are incorporated in the 2026 Triennial IRP analyses.

FAIRFIELD NUCLEAR PROJECT

Santee Cooper, with the support of state leaders, initiated a competitive bidding process in January 2025 to market the two partially constructed Westinghouse AP1000 nuclear units located at the former VC Summer Nuclear Station, Units 2 and 3 site, in Fairfield County. The response reflected strong interest in developing two AP 1000 reactors on this site. After review of proposals

⁸ These solar projects are Central Non-Shared Resources.

⁹ These BESS projects are Central Non-Shared Resources.

Recent Activities and Developments

from global leaders in the nuclear power industry, Santee Cooper's Board of Directors, on October 24, 2025, entered into a letter of intent with Brookfield Asset Management ("Brookfield") to begin feasibility talks about resuming development of the two AP1000 nuclear reactors. On December 8, 2025, Santee Cooper's Board approved a Memorandum of Understanding ("MOU") with Brookfield that established a formal feasibility period regarding completing the two units. On June 26, 2026, Brookfield completed all initial milestones for the Fairfield Nuclear Project, as set out in its MOU. The Phase 1 due diligence activities described in the MOU are complete, and the project has moved to Phase 2 of due diligence through the execution of the first amendment to the MOU ("Amendment") on June 26, 2026. Schedule 1 of the Amendment establishes the next phase of project due diligence milestones, including the Final Investment Decision date for Brookfield of March 31, 2028. The non-binding terms of the MOU contemplate \$2.7 billion in cash to Santee Cooper should the parties reach a final investment decision and commit to constructing the units plus a targeted 25% tenancy-in-common interest ("TIC") share for Santee Cooper, with proportional capacity, once the units begin commercial operation. The ownership benefits could be adjusted depending on the final cost of completing the units.

Santee Cooper maintains a public website that provides key updates and project information for the Fairfield Nuclear Project.¹⁰

In addition to the MOU and Amendment, Brookfield submitted the Fairfield units into Santee Cooper's Open Access Transmission Tariff Generator Interconnection Process.

WIND RESOURCE STUDY

Santee Cooper engaged DNV, an industry leading firm with extensive wind energy experience, to evaluate the technical feasibility of developing onshore wind resources in South Carolina. DNV identified several sites with potential for development, with an average potential capacity of approximately 190 MW per site and modeled wind speeds ranging from 5.4 to 6.2 meters per second. The assessment considered land-use characteristics, environmental sensitivities, hurricane risk, proximity to military installations and airspace systems, and it used a scoring methodology that can be adjusted to reflect Santee Cooper's planning priorities.

The study determined that onshore wind is technically feasible in South Carolina and validated key wind resource modeling assumptions and development timelines used in the 2026 IRP analyses. The study also developed representative production profiles and identified areas that may be favorable for future wind research and development activities. Additionally, the study found development of an onshore wind project would take more than seven years including siting, required studies, permitting, and construction. This timeline aligns with the first-year available assumption for onshore wind resources assumed for the 2026 IRP.

Santee Cooper will continue to evaluate onshore wind as a resource option in future IRPs and monitor advancements in wind technology. If future IRP analyses identify onshore wind as an appropriate resource for development, Santee Cooper may pursue site-specific wind data

¹⁰ The website can be accessed via: <https://www.scnuclear.com/>.

Recent Activities and Developments

collection and additional evaluations to further refine resource potential, costs, and development feasibility.

NUCLEAR LICENSE EXTENSION

In 2004, the Nuclear Regulatory Commission (“NRC”) extended the operating license for Summer Nuclear Unit 1 an additional twenty years to August 6, 2042. On June 30, 2025, the NRC granted a second 20-year renewal of the operating license extending the expiration date from August 2042 to August 2062.

ENVIRONMENTAL REGULATORY DEVELOPMENTS

EPA GREENHOUSE GAS RULE

In 2024, the U.S. Environmental Protection Agency (“EPA”) regulated the emission of GHGs from new gas-fired combustion turbines and existing coal, oil, and gas-fired steam generating units (the “EPA GHG 2024 Rule”).

However, on September 17, 2026, the EPA partially repealed the GHG 2024 Rule. It did so by publishing a final rule, Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units (“EGUs”), which repeals most of the CO₂ performance standards applicable to affected EGUs under the 2024 GHG Rule (“EPA GHG 2026 Rule”). Most importantly, EPA repealed:

- i. The emission guidelines prescribing CO₂ emission standards of performance for all existing coal-fired steam generating units;
- ii. The performance standards based on carbon capture and sequestration (“CCS”) for existing coal-fired steam generating units undertaking a large modification; and
- iii. The CCS-based Phase 2 standards for new baseload natural-gas fired stationary combustion turbines.

Remaining in place from the EPA GHG 2024 Rule are the efficiency-based standards for new natural gas-fired combustion turbines and combined cycle (“NGCT” and “NGCC,” respectively) electric generating units. These standards are based on expected capacity factor and compliance can occur via one of the three potential compliance pathways described below:

- i. Base load units (i.e., units operating at greater than 40 percent annual capacity factor) were to meet CO₂ emission standards for highly efficient combined cycle generation upon startup. (CO₂ emissions rate of less than 800 lbs/MWh for units 2,000 MMBtu/hr or greater).
- ii. Intermediate load units (i.e., units operating at annual capacity factors between 20 percent and 40 percent) were to meet CO₂ emission standards for highly efficient simple cycle generation (CO₂ emissions rate of less than 1,170 lbs/MWh).
- iii. Low load units (i.e., units operating at annual capacity factors less than 20 percent) were to utilize low-emitting fuels (CO₂ emission rate of less than 160 lbs/MMBtu).

Existing combustion turbines (whether operated as simple cycle or combined cycle units) are not addressed in the EPA GHG 2026 Rule or the EPA GHG 2024 Rule.

Recent Activities and Developments

Concurrently with the EPA GHG 2026 Rule, EPA published a supplemental proposed rule, which contends that section 111 of the Clean Air Act (“CAA”) does not authorize regulation of CO₂ and other GHG emissions from fossil fuel-fired power plants. If finalized, this proposed rule would rescind all remaining CO₂ emission standards applicable to fossil fuel-fired EGUs, including the efficiency based CO₂ performance standards in the EPA GHG 2024 Rule along with the CO₂ performance standards in the 2015 Rule.

Santee Cooper will continue to monitor changes in GHG regulations and incorporate revised requirements into future IRPs and analyses.

EPA EFFLUENT LIMIT GUIDELINES RULE

Current Steam Electric Effluent Limitation Guidelines Regulations

Winyah and Cross plants have completed construction of physical chemical and biological treatment systems for Flue Gas Desulfurization (“FGD”) wastewater and have been in compliance with the 2020 ELG Best Available Technology (“BAT”) Standard since December 31, 2025. As the rule currently stands, both plants must either cease coal combustion or install Zero Liquid Effluent Discharge (“ZLD”) membrane treatment no later than December 31, 2034, to remain in compliance beyond 2034. EPA provides flexibility in the existing regulations that facilities may request alternate compliance dates for cessation or ZLD when unexpected circumstances occur, such as major market shifts, unforeseen demand changes, or supply chain delays, which prevent cessation or achieving ZLD by December 31, 2034.

The 2024 Effluent Limit Guideline (“ELG”) rule and subsequent rule updates provide the following potential pathways for compliance.

- 1) Cease Coal Combustion Operation Options
 - a. Cease coal combustion operations by December 31, 2034, in addition to continued compliance with the 2020 BAT standards.
- 2) Continue Operation Options
 - a. BAT Option – Comply by December 31, 2034, with the 2024 ELG rule¹¹ BAT standards requiring zero discharge of FGD, Combustion Residual Leachate (“CRL”) and Bottom Ash Transport Water (“BATW”). This will require installation of membrane treatment and elimination of BATW discharge. The BAT compliance is in addition to continued compliance with the 2020 ELG BAT standards.

ELG Regulatory Changes

The EPA has undertaken revising the 2024 ELG rule in three phases. The first phase, Deadline Extensions for ELG, is final and was effective on March 2, 2026. This extended the deadline to submit the Notification of Planned Participation (“NOPP”) for cessation from the end of 2025 to the end of 2031. It also extended the compliance for ZLD from the end of 2029 to the end of 2034. The second phase, Proposed Revisions to Unmanaged CRL, is a proposed rule that was published in the Federal Register on May 18, 2026, and comments were provided by Santee

¹¹ The rule retains most of 2020 ELG rule requirements and adds to the 40 CFR 423 Steam Electric ELG.

Recent Activities and Developments

Cooper. The third phase Proposed Rule is expected to address ZLD technologies with alternate flexibilities for FGD and CRL and be published late 2026 or early 2027. Santee Cooper will continue to monitor developments regarding ELG rule regulation to be incorporated into future IRPs.

CHANGES IN FEDERAL LAW

On July 4, 2025, HR1, known as the “One Big Beautiful Bill,” (“OBBB”) was signed into law. Among many other impacts, the OBBB significantly modifies the tax incentives introduced through the IRA. As a result of the OBBB, solar and wind resources are not eligible for tax credits unless they begin construction within 12 months of OBBB enactment or are placed into service before 2028. This requirement considerably compresses the timeline for tax credit eligibility (and therefore pricing) for future solar and wind resources. For other renewable and BESS resources, the OBBB alters the “applicable year” for purposes of the phase-out of tax credits to fix the applicable year at 2032 rather than having it dependent on the extent of reductions in U.S. electricity sector greenhouse gas emissions. This restatement of the applicable year implies that the phase-out of the tax credits for qualified facilities will effectively start for facilities that begin construction in 2034.

Additionally, in August 2025, the U.S. Treasury released revised guidance related to identifying the start of construction for eligibility for clean electricity tax credits, in most cases essentially removing the previous 5% expenditure test for safe harboring equipment in favor of requirements related to physical work at the project site or manufacturing of equipment. The guidance explicitly excludes such preliminary activities as planning, designing, and securing financing from the definition of “physical work of a significant nature.”

On August 26, 2026, Executive Order 14420 declared a national emergency to secure the United States bulk power system from foreign-made equipment that may pose national security risks. Given the recent declaration of the Executive Order and uncertainty regarding implementation, Santee Cooper has not reflected the impact of the order in its 2026 IRP analysis. Santee Cooper is and will continue to evaluate how this order affects projects currently under construction and proposed projects.

REQUIREMENTS FROM COMMISSION ORDERS AND ORS RECOMMENDATIONS

In Order 2024-171, the Commission directed Santee Cooper to address the following issues in the 2024 IRP Update and future IRPs:

- Consider other approaches to load forecasting and resource portfolio analysis to plan for future industrial load growth due to economic development and provide updates to the Commission in future IRP filings
- Incorporate actual solar additions and any updates to future planned solar additions in its annual IRP updates
- Continue to evaluate the NGCC shared resource in the analyses conducted for future IRPs and IRP updates
- Review and address the recommendations of the ORS witnesses to discuss seven issues with stakeholders no later than the 2026 Triennial IRP

Recent Activities and Developments

The above-referenced ORS recommendations regarding discussions with stakeholders included the following topics:

- Commodity price forecasts for natural gas, coal, and CO₂ and if the forecasts sufficiently consider variation and risk
- Higher penetration of renewable resources and Effective Load Carrying Capability (“ELCC”) studies
- Integration costs and associated modeling methodologies, including modeling operating reserves
- Impacts of EPA GHG regulations and the need for a sensitivity scenario to evaluate the rules impacts
- Scope for further studies to analyze any potential cost savings that might accrue to ratepayers from retirement of additional coal units
- Development of a quantitative reliability metric
- Methodology to study and evaluate transmission investment costs associated with the retirement of Cross coal-fired generating facility

In Order 2025-244, the Commission directed Santee Cooper to address the following issues in the 2025 IRP Update and future IRPs:

- Continue to engage with stakeholders as outlined in the processes described in the Santee Cooper 2024 IRP Update
- Provide updates to the Commission about the activities of the group and Santee Cooper's plans to incorporate lessons learned into future IRP filings
- Continue to provide updates regarding its plans for the Cross Generating Station retirement evaluation and associated transmission evaluations, as well as the results of the study in support of the 2026 comprehensive IRP in the Stakeholder Working Group
- Monitor, track, and report annually the forecasted versus actual load consumption for Economic Development Load
- Update its GHG Rule Portfolio modeling assumptions in the 2025 IRP Update to reflect the latest EPA guidance available at the time the modeling is performed
- Provide updates in future IRPs and IRP Updates regarding the planned solicitation for a battery energy storage system of up to 300 MW of four-hour duration which, according to Santee Cooper's Reply Comments, would be sited at the Jefferies Generating Station, to leverage existing interconnection capacity and the Energy Communities tax credit bonus per the Inflation Reduction Act
- Consider all recommendations of the parties to this Docket when conducting future IRP and IRP Update filings and must specifically address the recommendations raised by ORS in this Docket as Santee Cooper prepares for the 2025 IRP Update

The ORS recommendations regarding discussions with stakeholders and pertinent to Order No. 2025-244 include the following topics.

- Continue to monitor hydrogen availability and discuss forecast assumptions with IRP stakeholders in the SWG prior to the 2026 comprehensive IRP

Recent Activities and Developments

- Continue to discuss updates related to the Inflation Reduction Act and Infrastructure Investment and Jobs Act incentives
- Perform production cost model benchmarking studies of its EnCompass model in conjunction with its comprehensive IRPs and discuss the results in the SWG
- Discuss changes to its assumptions based on changes to the EPA 111 Rule in the SWG prior to the 2025 IRP Update
- Discuss its plans to prepare the next Market Potential Study in the SWG ahead of the Market Potential Study update in 2025

In Order No. 2026-126 and for purposes of the 2026 Triennial IRP, the Commission directed Santee Cooper to:

- Consider “all stakeholder feedback from the SWG regarding large-load penetration, and to the extent Santee Cooper determines that the recommended assumptions are consistent with good utility practice and are reasonable in the context of the design, operation, and plans for the Santee Cooper system, Santee Cooper shall incorporate those assumptions into its new reserve margin studies for the 2026 IRP. Consider the recommended assumptions from the SWG regarding large-load penetration and if, reasonable and consistent with good utility practice, incorporate them into the reserve margin studies for the 2026 IRP.”
- Update the ELCC studies and incorporate SWG recommended associations to the extent reasonable and consistent with good utility practice
- Report on potential new large load and the impact these loads have on the load forecast
- Provide a comprehensive assessment of coal retirements, including the Cross Generation Station
- Discuss resource option assumptions, including the potential to include a 2x1 NGCC resource option, with the SWG
- Provide an evaluation of new resource additions
- Include information about the Fairfield Nuclear Project to the extent it is available and relevant
- Include its latest assessment of transmission planning and short-term resource considerations
- Except for those ORS recommendations for Santee Cooper to address specific matters in its Reply Comments in [the 2025 IRP Update] docket and those recommendations addressed in [Order 2026-126’s] Ordering Paragraphs 2 through 7, Santee Cooper should consider and address any recommendations raised by the ORS Report as well as the comments from all parties in either the SWG or its 2026 IRP as appropriate. Santee Cooper may address such recommendations and comments via its filed IRP or IRP update, filed testimony, filed comments, or any other that it deems appropriate
- Address all requirements or ordering provisions from the Santee Cooper 2023 IRP Decision and the Santee Cooper 2024 IRP Decision in ongoing stakeholder engagement, potential negotiations, or filings for Santee Cooper’s 2026 IRP as appropriate

The ORS recommendations pertinent to Order No. 2026-126 include the following:

Recent Activities and Developments

- With regard to “the new reserve margin studies Santee Cooper conducts for the 2026 Comprehensive IRP, Santee Cooper should] incorporate assumptions regarding large-load penetration consistent with stakeholder feedback from the Stakeholder Working Group”
- “Santee Cooper continue to monitor, track, and file annual reports in future Comprehensive IRPs and IRP Update dockets related to the forecasted versus actual load consumption for economic development loads consistent with the items specified in the [ORS] Report [about the 2025 IRP Update]”
- “Santee Cooper perform an optimal Cross retirement study, co-optimize resource decisions including the retirement date for Winyah, the need for an additional NGCC resource beyond the Joint [NGCC] Resource, the potential for large load additions, and the potential for acquiring capacity from V.C. Summer Units 2 and 3”
- “Santee Cooper provide additional details in the 2026 Comprehensive IRP regarding the additional NGCC resource under consideration for 2035, including a detailed timeline of development activities, natural gas procurement plans, plans for conducting RFPs (including third-party and self-build bid-in options), and site selection considerations”
- “Santee Cooper provide additional details in Reply comments as to why Santee Cooper did not include a 2x1 NGCC resource as a selectable resource, given that other utilities including Santee Cooper are pursuing this configuration of an NGCC resource. Furthermore, Santee Cooper [should] evaluate the inclusion of a 2x1 NGCC as a selectable resource in the 2026 Comprehensive IRP”
- “Santee Cooper [should] provide additional details in the 2026 Comprehensive IRP regarding the potential restart and acquisition of the V.C. Summer Units 2 and 3”

See Appendix I: Cross Reference for Compliance with S.C. Code Ann. § 58-37-40 and Commission Orders 2024-171, 2025-244, and 2026-126 (“Commission IRP Orders”) for a compliance table of statutory and Commission IRP Order requirements with a cross reference to where this 2026 Triennial IRP fulfills each applicable requirement.

CENTRAL COORDINATION AGREEMENT

As noted earlier in the Company Overview section, since 1980, Santee Cooper has served Central under the terms of the Coordination Agreement.¹² This section provides certain details regarding the Coordination Agreement that underscores and explains its influence on the IRP process.

The term of the Coordination Agreement currently extends through at least December 31, 2058. Under the Coordination Agreement's 10-year rolling notice provision, a party must give notice of termination no later than December 31, 2048, to terminate the Coordination Agreement as of the end of 2058. Failing a notice to terminate by either party, the Coordination Agreement will renew for additional periods.

Central has entered into all-requirements agreements with its 19 member cooperatives which extend through December 31, 2058. Those agreements obligate the members to pay Central's costs, including costs paid under the Coordination Agreement.

Generally, Santee Cooper supplies the total power and energy requirements in the territories served by the fourteen (14) Central Member Cooperatives connected to the Combined System as of January 2013, less (i) any amounts Central purchases directly from SEPA, (ii) amounts supplied by Central Non-shared Resources ("NSR"), and (iii) any amounts supplied by allowed alternative purchases in accordance with the Coordination Agreement.

COORDINATED PLANNING REQUIREMENTS

The Coordination Agreement is a comprehensive, long-term agreement that provides for coordinated planning of generation resources needed to serve loads on the Combined System reliably and economically, allocation of a portion of Santee Cooper's production and transmission costs to Central, accounting for new resources undertaken by Santee Cooper and Central, and other related matters. The Coordination Agreement provides for coordinated planning between Santee Cooper and Central regarding future generation resources and sets forth the process for identifying resource needs and planning new resources for the Combined System.

The Coordination Agreement provides for Santee Cooper to dispatch power supply resources provided by Santee Cooper and Central to economically serve loads on the Combined System without respect to ownership—much as a power pool would be dispatched to serve multiple parties' loads. The Coordination Agreement also provides for Santee Cooper to operate the integrated transmission system owned by Santee Cooper and Central. The Coordination Agreement recognizes Santee Cooper operates the balancing authority on behalf of the Combined System.

¹² The Coordination Agreement was last amended in 2013. Since 2013, the parties have also executed multiple Memoranda of Understanding that clarify certain aspects of the administration of the Coordination Agreement.

PROPOSED SHARED RESOURCES AND NON-SHARED RESOURCES

When new Major Resources¹³ are needed to serve Combined System load, the Coordination Agreement requires Santee Cooper to propose to undertake a Proposed Shared Resource (“PSR”) to serve loads on the Combined System. Once a PSR is identified, Central must decide whether it will “Opt In” or “Opt Out” of the resource within 120 days after the date such PSR is identified.

If Central chooses to Opt In, the PSR becomes a Shared Resource under the Coordination Agreement, and Santee Cooper would undertake the needed resource and recover a portion of the costs of the new Shared Resource through charges to Central under the Coordination Agreement. If Central chooses to Opt Out of the PSR, Central and Santee Cooper are then each obligated to provide their respective load ratio share of the PSR capabilities by providing NSRs to the Combined System. NSRs would typically be “Pooled Resources,” meaning Santee Cooper would dispatch the resources to meet the “Pooled Loads” of Santee Cooper and Central without regard to ownership.¹⁴ Under Appendix F of the Coordination Agreement, the output of NSRs, entitlements to Shared Resources, and Interchange Transactions are accounted for in serving the respective hourly demands of each party.

¹³ Under the Coordination Agreement, generally, a Major Resource is a new resource with Net Dependable Capacity of 50 MW or more, a purchase price or aggregate lease payments of \$50 million or more, an agreement or series of related agreements with terms of five years or more or providing for capacity or energy in excess of 50 MW in any hour, or certain Major Resource Modifications to existing resources that increase the resource’s capability by 50 MW or more or extend the resource’s life by five years or more.

¹⁴ Circumstances under which NSRs would be Non-Pooled Resources are beyond the scope of this summary.

STAKEHOLDER ENGAGEMENT PROCESS

Santee Cooper is committed to undertaking a robust IRP process, which includes continually engaging with stakeholders. In advance of the 2023 IRP, Santee Cooper facilitated a stakeholder process that informed the development of the IRP, and Santee Cooper has built on this foundation to improve and extend its stakeholder engagement for the 2024 and 2025 IRP Updates and this 2026 Triennial IRP. Since the time period of the 2023 IRP, Santee Cooper has facilitated a significant number of stakeholder meetings, including:

- Twelve Stakeholder Working Group meetings,
- Four general notice meetings, and
- Nine technical meetings.

As indicated by the above, several different engagement opportunities are available to stakeholders with the goal of providing them with the best opportunity to receive desired information and the most efficient means for providing feedback to Santee Cooper. These efforts include the formation of a stakeholder working group, general notice meetings, and technical meetings requested by interested stakeholders. The engagement process supported the development of the 2024 and 2025 IRP Updates and the 2026 Triennial IRP. Engagement with stakeholders will continue for future IRPs.

Materials for the stakeholder engagement process can be found on the Santee Cooper IRP web page.¹⁵ Additionally, as documented by materials, Santee Cooper has engaged stakeholders on all items required in Commission Orders (which are outlined in the section entitled Requirements from Commission Orders and ORS Recommendations).

OVERVIEW OF THE IRP STAKEHOLDER WORKING GROUP

Santee Cooper has formed a working group of interested stakeholders (“Stakeholder Working Group” or “SWG”), including all intervenors from the 2023 IRP proceeding at Docket 2023-154-E. The Stakeholder Working Group has a set membership that provides a wide range of perspectives and expertise to inform the development of IRPs. Several opportunities were provided for both technical and nontechnical participants, allowing Santee Cooper to gather feedback from stakeholders with a range of backgrounds and perspectives. The working group engages through virtual meetings facilitated by an independent firm, Vanry Associates (Vanry”), and meets approximately every three to four months. Meetings include technical presentations from Santee Cooper, subject matter experts, and consultants and presentations from working group members who desire to share their information and opinions.

Below is a list of the current Stakeholder Working Group membership.

- South Carolina Office of Regulatory Staff
- South Carolina Department of Consumer Affairs
- South Carolina Department of Natural Resources

¹⁵ <https://www.santeecooper.com/about/integrated-resource-plan/2026-irp-stakeholder-process/>

Stakeholder Engagement Process

- South Carolina Department of Environmental Services
- Central Electric Power Cooperative, Inc.
- Industrial Customer Association, J. Pollock
- Century Aluminum
- Nucor
- Messer
- Google
- Palmetto Power Cities
- 4 Individual Members representing Residential and Commercial customers
- Carolina Clean Energy Business Association
- Conservation Voters of South Carolina
- South Carolina Coastal Conservation League
- South Carolina Energy Justice Coalition
- South Carolina Appleseed Legal Justice Center
- South Carolina Research Authority
- Southeastern Wind Coalition
- Southern Alliance for Clean Energy
- Southern Environmental Law Center
- Sierra Club
- Vote Solar

Following the 2023 IRP time period, (between April 2024, and August 2026), Santee Cooper has hosted twelve Stakeholder Working Group meetings.¹⁶ These meetings covered topics such as coal retirement evaluations, transmission studies supporting IRPs, modeling methodologies, the wind study, 2025 Reserve Margin and Effective Load Carrying Capability Study, 2026 Solar Integration Study, 2025 Market Potential Studies, the 2026 Load Forecast, and assumptions and portfolios for the 2026 Triennial IRP. On the Stakeholder Process web page and for each meeting to date, Santee Cooper has posted the presentation and meeting summary.

OVERVIEW OF IRP GENERAL NOTICE MEETINGS

In addition to the SWG meetings, since the 2023 IRP time period, Santee Cooper has held four general notice meetings, which are of a non-technical nature and are intended to garner participation by a broader group of stakeholders (“General Notice Meetings”). Specifically, Santee Cooper hosted meetings on July 18, 2024, April 3, 2025, December 3, 2025, and June 11, 2026; these meetings were in a virtual format and facilitated by Vanry Associates. The meetings followed a similar public notice and registration process utilized during the 2023 IRP stakeholder process, and they allowed any interested person the opportunity to register. Information for the meeting, including a link to register, also was sent out to all previous meeting attendees. Topics discussed at these General Notice Meetings included Santee Cooper resource planning, loading forecasting, major assumptions for the IRP and/or IRP Updates, relevant studies (including the 2025 Reserve Margin Study, the Coal Retirement Study, the 2025 Market Potential Study, and the 2026 Solar Integration Study), and Short-Term Action Plans. On the Stakeholder Process web page and for

¹⁶ These meetings occurred on the following dates: April 25, 2024, June 27, 2024, September 4, 2024, November 13, 2024, February 26, 2025, May 6, 2025, June 4, 2025, September 10, 2025, October 14, 2025, April 9, 2026, June 3, 2026, and August 11, 2026.

Stakeholder Engagement Process

each meeting to date, Santee Cooper posted the presentation, video recording, question and answer log, and meeting summary.

OVERVIEW OF IRP TECHNICAL MEETINGS

At the request of any stakeholder, Santee Cooper periodically hosts technical meetings on specific topics. The meetings provide the opportunity for in-depth conversations on highly technical topics. Since the timeframe of the 2023 IRP, Santee Cooper has hosted the following nine technical meetings:

- May 2, 2024 – Load Forecast Technical Meeting
- July 17, 2024 – BESS Technical Meeting
- April 10, 2025 – Coal Retirement Technical Meeting #1
- May 1, 2025 – Market Potential Studies Technical Meeting #1
- May 29, 2025 – Coal Retirement Technical Meeting #2
- September 10, 2025 – Market Potential Studies Technical Meeting #2
- December 10, 2025 – Market Potential Studies Technical Meeting #3
- January 29, 2026 – Coal Retirement Technical Meeting #3
- April 30, 2026 – Coal Retirement Technical Meeting #4

For each technical meeting, Santee Cooper posted a summary, which includes the presentation, on the Santee Cooper Stakeholder Process web page.

KEY STAKEHOLDER INPUT

The stakeholder process is a cornerstone in producing a robust IRP. Santee Cooper benefited greatly from the conversations, including differing opinions, within the SWG Meetings and in the follow-up. The SWG discussions and lessons learned helped Santee Cooper explore and develop dimensions of its resource planning analysis. The following list is a high-level summary of key areas of contribution from the stakeholders to Santee Cooper's Integrated Resource Plan (also refer to Appendix I for a detailed list of Santee Cooper's approaches to responding to specific regulatory requests):

- Feedback on the overall stakeholder process including content for General Notice Meetings, additional members to include as part of the Stakeholder Working Group, the value of schedules of meetings for stakeholders to be able to plan and participate, and the sharing of data and results for IRP filings
- Feedback on load forecast methodology best practices, including large loads
- Discussion about the development of a quantitative reliability metric
- Discussion about and updates regarding requirements from Commission Orders from prior IRPs, applicable statutory or regulatory requirements, incentives, and applicable ORS recommendations from prior IRPs
- Information on procuring and operating energy storage systems
- Input on assumptions for conventional and renewable resources, including whether to model a 2x1 NGCC as a resource option
- Input on the portfolios, modeling assumptions, and sensitivities considered for IRPs

Stakeholder Engagement Process

- Input and feedback on the below studies (and assumptions for those studies) in support of the 2026 Triennial IRP
 - Reserve Margin, ELCC Study, and Solar Integration Study¹⁷
 - Coal Retirement Study¹⁸
 - Market Potential Studies
 - Wind Study
- Input and discussion on benchmarking studies of its EnCompass model and discussed results
- Information on portfolio reliability assessment process
- Input and discussion regarding the potential for hydrogen as an alternative fuel option
- Discussion on commodity forecasts and how to include in the IRP assumptions

For the 2026 Triennial IRP, Vanry prepared an engagement assessment of Santee Cooper's public stakeholder process, which is included as part of Attachment 5.

¹⁷ In conjunction with these studies, Santee Cooper discussed with the SWG the potential for higher penetration of solar and wind in the ELCC, integration costs, large load penetration, and associated modeling methodologies (including modeling operating reserves).

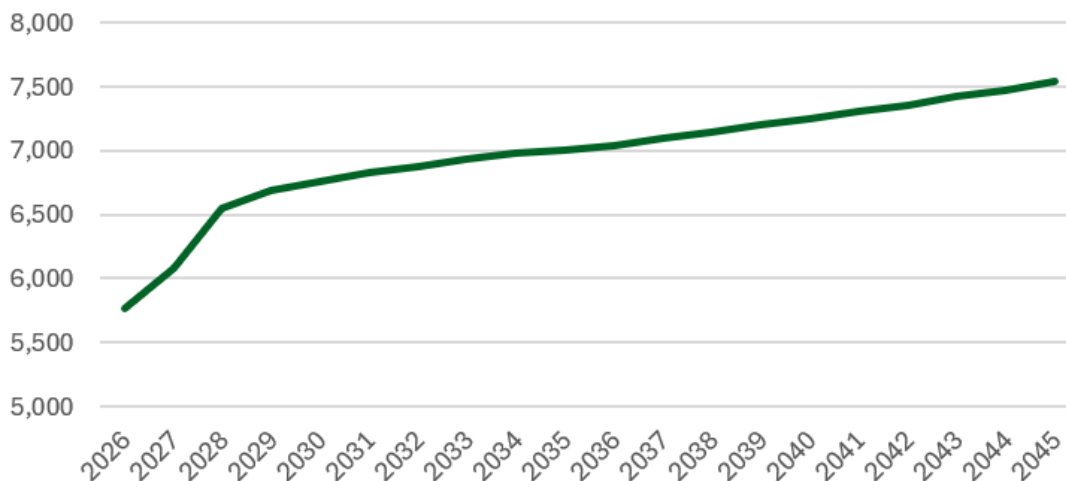
¹⁸ For purposes of this Study, Santee Cooper discussed with the SWG methodologies for evaluating the retirement of Cross Generating Station, associated transmission studies, and potential cost savings from the retirement of remaining coal generation assets. In particular, with regard to Cross, the discussions involved an estimate of transmission investment associated with this generating facility's retirement and updates regarding that future retirement.

ELECTRIC LOAD FORECAST OVERVIEW

South Carolina is undergoing a radical transformation, as nation-leading in-migration, industrial reshoring, and data center construction are reshaping the state and its electrical infrastructure needs. As South Carolina's state-owned power provider, Santee Cooper is responsible for delivering power to over two million customers, with direct service to approximately 222,000 residential and commercial customers in Berkeley, Georgetown, and Horry counties and twenty-seven large industrial companies, and indirect service to Central Electric Power Cooperative members. As one of the cornerstone assumptions driving the Integrated Resource Plan, Santee Cooper's 2026 Load Forecast identifies these changes and how each affects Santee Cooper's electric power obligations. Santee Cooper finalized the load forecast it is utilizing for this 2026 Triennial IRP in May 2026 ("2026 Load Forecast") with assistance and input from Central, other customers, and consultants. It developed the twenty-year projections in the 2026 Load Forecast using an approach similar to the 2024 and 2025 Load Forecasts, which includes a post-modeling adjustment for potential new large loads.

As shown in Figure 7 below, the 2026 Load Forecast reflects that aggregate demand in the winter is forecasted to grow from 5,765 MW in 2026 to 7,540 MW in 2045. Energy sales are projected to grow as well, from 30,108 GWh to 42,011 GWh over the same period. This represents a 1.4 percent compound annual growth rate ("CAGR") for coincident peak demand and a 1.7 percent CAGR for energy. The 2026 Load Forecast reflects the statewide, regional, and national trend of increasing demand in the electric industry.

Figure 7. Projected Winter Peak Demand (MW)

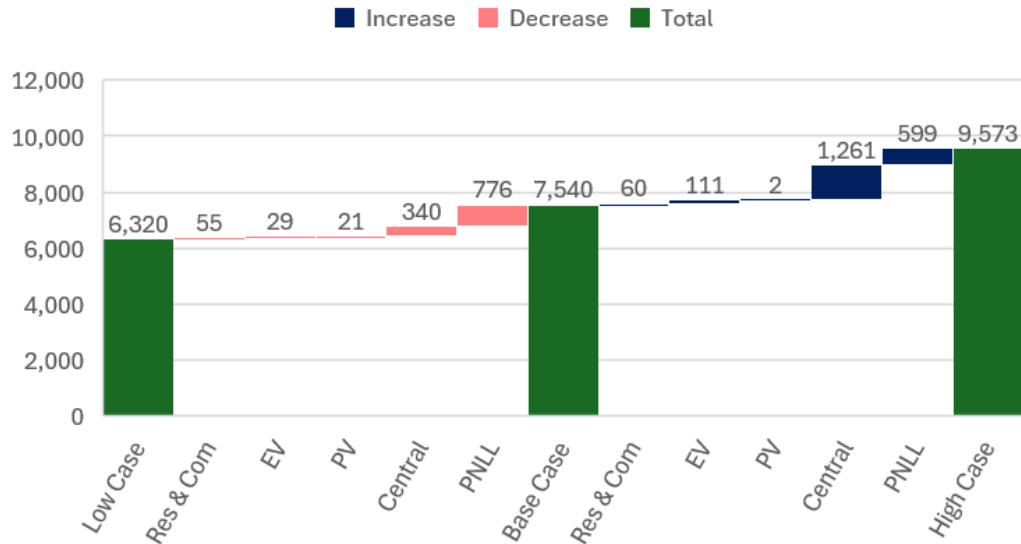


In addition to the base load forecast, Santee Cooper prepares a variety of scenarios to reflect the uncertainty inherent with forecasting over long periods of time that are intended to incorporate a reasonable range of possible outcomes. These scenarios consider uncertainty related to economic activity, demographic shifts, customer photovoltaic ("PV") rooftop solar adoption, distributed battery storage, electric vehicle ("EV") penetration, potential new large loads ("PNLL"),

Electric Load Forecast Overview

and other uncertainties that could impact Santee Cooper customers' needs. They result in variations from the Base Case for 2045 winter peak demand shown in Figure 8.

Figure 8. Variations in Projected Winter Peak (MW)



In the “High Case” scenario, assumptions were adjusted to reflect higher economic growth and other drivers of customer usage relative to the base scenario, resulting in forecasted winter demand growing to 9,573 MW and energy requirements growing to 54,184 GWh by 2045. In the “Low Case” scenario, assumptions were adjusted to reflect lower economic growth and other drivers of customer usage relative to the base scenario, resulting in winter peak demand growing only to 6,320 MW and energy requirements increasing only to 34,452 GWh by 2045.

2026 LOAD FORECAST METHODS AND RESULTS

DIRECT-SERVED RESIDENTIAL AND COMMERCIAL CLASSES

Santee Cooper developed the residential forecast used in the 2026 Load Forecast using statistically adjusted end use (“SAE”) modeling. This technique forecasts the number of customers and average use per customer over the twenty-year forecast time horizon, which are then multiplied to determine total energy sales to the class. The commercial forecast is developed using similar linear forecasting techniques. These methods are further described in Attachment 3: 2026 Load Forecast Report.

Santee Cooper provides power directly to approximately 222,000 residential and commercial customers located in Berkeley, Georgetown, and Horry Counties. The population growth in these areas continues to exceed historical levels, which is partially offset by the continued decline in individual customer usage. This decline is a continuation of the historical trend for this customer class. Over the 20-year forecast, the number of residential customers is expected to increase by approximately 1.6% on average annually, while use per customer is expected to decline very slightly at a rate less than 0.1% on average per year, resulting in overall energy sales growing at a CAGR of 1.5%.

Electric Load Forecast Overview

Santee Cooper's direct-served commercial class continues to experience lower usage needs over time as the energy needs from new customers are offset by lower energy needs from the existing customers. Santee Cooper expects commercial energy use to grow slightly, with a 20-year CAGR of 0.3%. Together, residential and commercial customers' combined contribution to the winter coincident peak is expected to grow at a 20-year CAGR of 0.6%. For the High Case and Low Case scenarios, Santee Cooper used the 90th and 10th percentile of outcomes of the stochastically derived residential and commercial forecasts.

Santee Cooper applied post-modeling adjustments to account for future EV and PV adoption, which are made necessary by the lack of historical data to inform the SAE modeling. Both adjustments use projections taken from the Energy Information Agency's ("EIA") Annual Energy Outlook ("AEO") to forecast growth in adoption rates and use Santee Cooper internal data to approximate usage for each customer that adopts the technology. The electric vehicle forecast results in 30 MW being added to the Winter CP by 2045, while the rooftop PV forecast reflects a reduction of approximately 1 MW.

DIRECT-SERVED INDUSTRIAL CLASS

Santee Cooper's direct-served industrial class is composed of 27 customers, which have signed service agreements, have operations involving industrial, manufacturing, and other energy-intensive economic activities, are directly interconnected with the transmission system, and have a demand of at least one megawatt on a non-coincident basis. The energy sales and demand forecast for these customers are composed based on analysis of recent historical performance, contractual quantities, and consultations with customers to determine any potential changes in the near term. The existing industrial class is forecasted to grow from a winter peak of 763 MW in 2026 to 863 MW by 2029, where it is expected to remain for the duration of the forecast. Similarly, energy sales will increase from 6,818 GWh to 7,184 GWh over the same period. Santee Cooper does not explicitly forecast existing customer growth using econometric or any other methods. Forthcoming and future large customers are forecasted as "potential new large loads" and are discussed below.

CENTRAL

Central prepares a load forecast for its customers' needs using methods similar to Santee Cooper's methods, and this forecast is provided to Santee Cooper for inclusion in the Combined System load forecast. Central's forecast is provided net of demand side management and energy efficiency programs, which are originated and administered independently by individual Central member cooperatives. Central's load forecast reflects similar expectations for continued population and industry growth. Due to this customer growth, Central's energy requirements are expected to increase from 18,305 GWh in 2026 to 26,255 GWh in 2045. Central's demand requirements are expected to increase from 3,885 MW in 2026 to 5,158 MW in 2045. This represents CAGRs of 1.9% and 1.5% for energy and demand, respectively. Central created High and Low case scenarios using methods similar to those used by Santee Cooper.

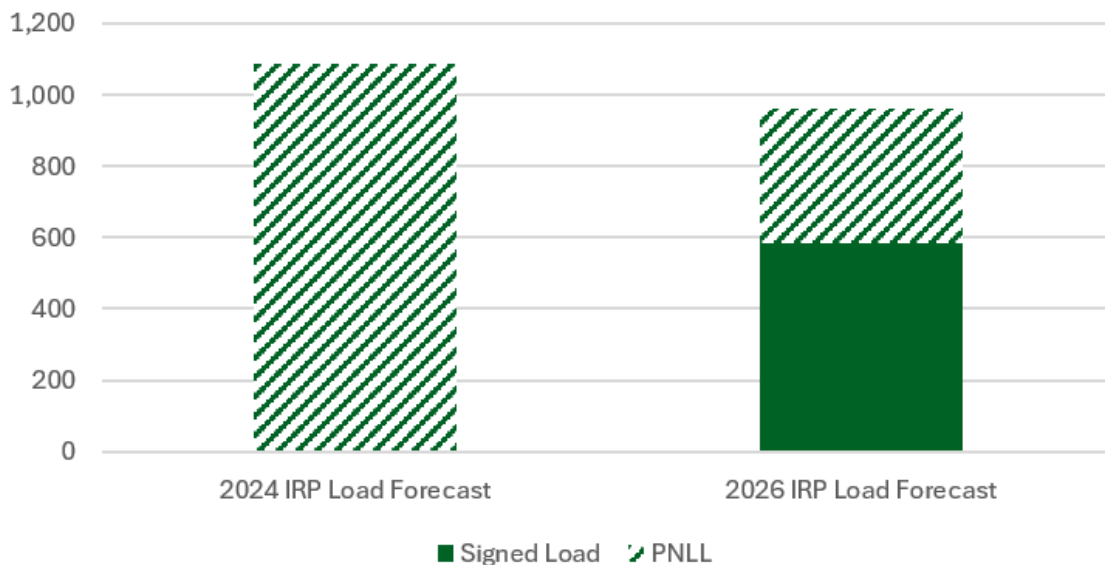
Electric Load Forecast Overview

POTENTIAL NEW LARGE LOAD CUSTOMERS

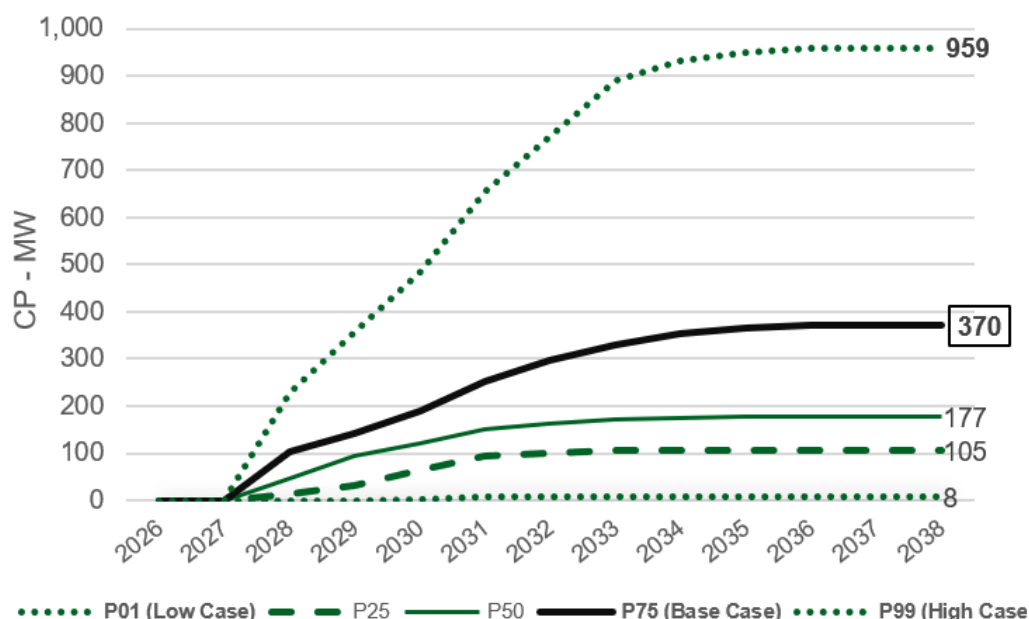
Since the development of the load forecast utilized in the 2023 IRP, Santee Cooper and Central member cooperatives have received inquiries for potential service from industrial and other large load customers that exceed the historical level of interest. To manage this rapid and unprecedented growth in capacity and energy requirements and in consultation with the Stakeholder Working Group, Santee Cooper and Central worked to develop a post modeling adjustment to anticipate and plan for new large loads with a risk adjusted approach, which has now been reflected in the 2024, 2025, and now 2026 Load Forecasts. This approach accommodates uncertainty surrounding the probability of a project that will be sited in Santee Cooper or Central member cooperative service territory, the ultimate size of such potential projects, and the timing and potential delays of such projects. Santee Cooper's stochastic approach evaluated 26 projects varying in size from 3 MW to over 800 MW. After evaluating the results of 50,000 trials, Santee Cooper chose to include the 75th percentile outcome in the 2026 Load Forecast.

Since the 2024 load forecast, several large potential loads have signed contracts in Santee Cooper or Central member cooperative service territory, which have amounted to over 550 MW in estimated coincident peak impact and necessitated their removal from the stochastic model and their inclusion in the individual class level forecasts. This change in PNLL since 2024, illustrated in Figure 9 below (reflecting winter peak contribution), validates the inclusion of the post modeling adjustment in prior forecasts and results in a lower post-modelling adjustment for potential loads.

Figure 9. Change in Potential New Large Load Since 2024 (MW)



As shown in Figure 9, the amount of unsigned PNLL that Santee Cooper has included in its forecasts has decreased since the 2024 load forecast from approximately 1,086 MW to 370 MW.

Figure 10. Range of Projected Potential New Large Loads

For purposes of the High Case scenario, Santee Cooper used the 99th percentile outcome, which reflected nearly 600 MW of additional new large loads by 2038 for a total of 959 MW of new large loads (on a coincident peak demand basis). For the Low Case scenario, Santee Cooper used the first percentile outcome, which represents 8 MW of new large loads. Furthermore, the Low Case scenario includes an additional reduction of 400 MW, representing the loss of an existing large industrial customer or several smaller industrial customers in Santee Cooper or Central Member cooperative territory. These two adjustments lead to a 392 MW reduction in industrial and new large loads.

SANTEE COOPER SYSTEM LOAD FORECAST

The 2026 Load Forecast Base Case reflects Santee Cooper's recognition of and continued expectations for the growth that has been occurring on the Combined System. Ongoing population growth, rapid economic development, and stabilizing customer usage throughout the state have combined to lead to increased energy sales from Santee Cooper's direct served customers and Central. The following tables provide detailed, year by year projections of winter coincident peak demand and energy sales requirements for each class from 2026-2045, as well as system totals for the High and Low cases. Please note that these results are provided inclusive of transmission losses but excluding future demand side management and energy efficiency, which are discussed elsewhere in this report.

Electric Load Forecast Overview

Table 2. Forecasted System Winter Peak Demand (MW)

Year	Direct-Served Residential and Commercial	Direct-Served Industrial	Municipal & Off-System	Central	Potential Large Load	Total	High Case	Low Case
2026	970	763	147	3,885	0	5,765	5,817	5,308
2027	977	880	113	4,109	0	6,079	6,193	5,601
2028	983	853	118	4,485	104	6,544	6,851	5,940
2029	990	863	43	4,646	143	6,685	7,187	6,026
2030	999	863	29	4,679	194	6,763	7,444	6,034
2031	1,007	863	29	4,670	257	6,826	7,800	6,034
2032	1,016	863	29	4,670	302	6,880	7,987	6,024
2033	1,025	863	29	4,681	337	6,934	8,188	6,022
2034	1,033	863	29	4,692	360	6,976	8,293	6,022
2035	1,041	863	29	4,697	373	7,003	8,369	6,016
2036	1,049	863	29	4,723	377	7,041	8,463	6,028
2037	1,057	863	29	4,767	377	7,093	8,569	6,059
2038	1,065	863	29	4,810	377	7,143	8,676	6,087
2039	1,072	863	29	4,857	377	7,198	8,790	6,120
2040	1,080	863	29	4,898	377	7,246	8,902	6,145
2041	1,087	863	29	4,948	377	7,303	9,026	6,179
2042	1,094	863	29	4,998	377	7,360	9,154	6,212
2043	1,102	863	29	5,051	377	7,421	9,291	6,249
2044	1,108	863	29	5,100	377	7,477	9,425	6,280
2045	1,114	863	29	5,158	377	7,540	9,573	6,320

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Electric Load Forecast Overview

Table 3. Forecasted System Energy Sales (GWh)

Year	Direct-Served Residential and Commercial	Direct-Served Industrial	Municipal & Off-System	Central	Potential Large Load	Total	High Case	Low Case
2026	4,390	6,819	594	18,305	0	30,108	30,588	26,455
2027	4,439	7,185	544	20,730	0	32,897	33,596	28,986
2028	4,482	7,185	558	23,115	834	36,174	38,382	31,247
2029	4,531	7,184	184	23,743	1,141	36,784	40,412	31,468
2030	4,592	7,184	170	23,908	1,548	37,402	42,309	31,626
2031	4,651	7,184	169	23,793	2,042	37,838	44,879	31,653
2032	4,706	7,184	167	23,910	2,410	38,378	46,382	31,785
2033	4,767	7,184	166	23,950	2,690	38,757	47,815	31,841
2034	4,825	7,184	164	24,038	2,883	39,094	48,511	31,961
2035	4,878	7,184	162	24,114	2,989	39,329	48,970	32,038
2036	4,931	7,184	161	24,307	3,019	39,602	49,508	32,254
2037	4,990	7,184	159	24,443	3,019	39,796	49,895	32,420
2038	5,043	7,184	158	24,635	3,019	40,039	50,360	32,644
2039	5,098	7,184	156	24,846	3,019	40,303	50,855	32,884
2040	5,149	7,184	155	25,105	3,019	40,612	51,428	33,170
2041	5,203	7,184	153	25,268	3,019	40,828	51,801	33,364
2042	5,255	7,184	152	25,500	3,019	41,110	52,361	33,626
2043	5,315	7,184	150	25,748	3,019	41,416	52,953	33,897
2044	5,358	7,184	148	26,049	3,019	41,758	53,619	34,220
2045	5,405	7,184	147	26,256	3,019	42,011	54,184	34,453

ASSESSMENT OF RESOURCE NEED

CURRENT OWNED RESOURCE OVERVIEW

EXISTING OWNED GENERATING FACILITIES

As of September 2026, Table 4 summarizes the net dependable capacity by fuel type of Santee Cooper's existing, owned generating facilities.

Table 4. Summary of Existing Owned Generating Facilities by Fuel Type

Fuel Type	Winter Net Dependable Capacity (MW)	Summer Net Dependable Capacity (MW)
Coal	3,480	3,465
Natural Gas and Oil	1,413	1,203
Nuclear	322	322
Hydro	142	142
Solar	5	5
Landfill Gas	17	17
Total	5,379	5,154

Information regarding Santee Cooper's existing, owned generating facilities, as of September 2026, is provided in Table 5 below.

Table 5. Existing Owned Generating Facilities

Generating Facility	Location	Fuel Type	Initial Date in Service	Winter Net Dependable Capacity (MW)	Summer Net Dependable Capacity (MW)
Cross Generating Station	Cross				
Unit 1		Coal	1995	585	580
Unit 2		Coal	1983	570	565
Unit 3		Coal	2007	580	585
Unit 4		Coal	2008	595	605
Winyah Generating Station	Georgetown				
Unit 1		Coal	1975	280	275
Unit 2		Coal	1977	290	285
Unit 3		Coal	1980	290	285
Unit 4		Coal	1981	290	285
Rainey Generating Station	Starr				
Unit 1		Gas	2002	520	460
Unit 2A		Gas	2002	180	146
Unit 2B		Gas	2002	180	146
Unit 3		Gas	2004	90	75
Unit 4		Gas	2004	90	75
Unit 5		Gas	2004	90	75

Assessment of Resource Need

Generating Facility	Location	Fuel Type	Initial Date in Service	Winter Net Dependable Capacity (MW)	Summer Net Dependable Capacity (MW)
Cherokee		Gas	1998	98	86
Myrtle Beach Turbines	Myrtle Beach				
Turbines 1 and 2		Oil/Gas	1962	20	16
Turbines 3 and 4 ⁽¹⁾		Oil	1972	20	19
Turbine 5		Oil	1976	25	21
Hilton Head Turbines	Hilton Head				
Turbine 1		Oil	1973	20	16
Turbine 2		Oil	1974	20	16
Turbine 3		Oil	1979	60	52
Summer Nuclear Unit 1 ^(2, 3)	Jenkinsville	Nuclear	1983	322	322
Jefferies Generating Station ⁽⁴⁾	Moncks Corner	Hydro	1942	140	140
Wilson Dam Generating Station ⁽⁴⁾	Lake Marion	Hydro	1950	2	2
Solar ⁽⁵⁾	Various	Solar	Various	5	5
Horry Landfill Gas	Conway	LFG ⁽⁶⁾	2001	3	3
Lee County Landfill Gas	Bishopville	LFG	2005	11	11
Georgetown County Landfill Gas ⁽⁷⁾	Georgetown	LFG	2010	1	1
Berkeley County Landfill Gas	Moncks Corner	LFG	2011	3	3
Total Owned Generation Facilities				5,379	5,154

(1) Myrtle Beach Combustion Turbine No. 4 is currently unavailable until further notice and is not included in the totals above.

(2) Virgil C. Summer Nuclear Generating Station Unit 1.

(3) Represents Santee Cooper's one-third ownership interest in Virgil C. Summer Nuclear Generating Station Unit 1.

(4) On January 20, 2023, the Santee Cooper Hydroelectric Project was issued a new 50-year FERC license for continued operation.

(5) Capacity values here reflect the nameplate capacity.

(6) Landfill methane gas ("LFG").

(7) Georgetown Landfill Gas is unavailable and is not included in the Total Owned Generation Facilities line. Contract ends in 2028.

PLANNED RETIREMENTS

For the 2026 IRP, Santee Cooper has assumed that Hilton Head and Myrtle Beach Combustion Turbines retire at year-end 2033 and Winyah Generating Station retires at year-end 2034. However, actual retirement dates could be impacted by changes in load projections and the availability of replacement resources.

PERFORMANCE OF CURRENTLY OWNED RESOURCES

Maintaining optimum performance and reliability is of utmost importance to Santee Cooper, and Santee Cooper continues to invest in its generation resources through capital replacements, major component maintenance, efficiency improvement projects, and control system upgrades to achieve low-cost, reliable power over the long term. As a result of these investments Santee Cooper continues to maintain a high level of reliability from its fleet of generators. Santee Cooper's

Assessment of Resource Need

weighted equivalent forced outage rate (“WEFOR”)¹⁹ for its largest assets (e.g. Cross, Winyah, Rainey and Cherokee) was a combined 6.6% for the year 2025, which was 28% lower than the industry average of 9.2%.²⁰

Table 6 and Table 7 below provide recent historical availability and forced outage statistics, respectively, for Santee Cooper’s major generating plants. See Appendix G: Generation Fleet Data, for information by generating unit.

Table 6. Santee Cooper Generator Availability Factors

Generating Unit(s)	2023	2024	2025
Cross	82%	81%	80%
Winyah	82%	83%	79%
Rainey NGCC	85%	70%	94%
Rainey CT	97%	96%	94%
Cherokee	91%	89%	85%
VC Summer	88%	87%	94%

Table 7. Santee Cooper Generator Forced Outage Rates

Generating Unit(s)	2023	2024	2025
Cross	3.0%	12.6%	6.6%
Winyah	3.5%	4.5%	3.7%
Rainey NGCC	0.9%	0.2%	0.1%
Rainey CT	0.1%	1.6%	1.5%
Cherokee	8.3%	0.4%	0.5%
VC Summer	4.2%	0.0%	5.8%

POWER PURCHASE AGREEMENTS

Santee Cooper and Central have entered into various PPAs for capacity and energy needs. Table 8 identifies existing PPAs as of September 2026 (“Existing PPAs”).

¹⁹ WEFOR reflects a weighted average of forced outage rates based on the capacity of the generating units in question.

²⁰ Industry Average WEFOR Source: NERC 2026 GADS State of Reliability Report.

Table 8. Power Purchase Agreements

Generating Facilities	Term End Date/Year	Energy Source	Nameplate Capacity (MW)
<u>Long-Term Contracts</u>			
Domtar	2028	Biomass	38
EDF Renewables	2043	Biomass	36
Southeastern Power Administration	Indefinite	Hydro	305
St. Stephen Hydro ⁽¹⁾	2035	Hydro	<u>84</u>
Total Long-Term Contracts			463
<u>Solar Purchases</u> ⁽²⁾			
Solar Qualifying Facilities	Various	Solar	280
Solar PPA	Various	Solar	245
Central Solar	Various	Solar	<u>224</u>
Total Solar Purchases			749
<u>BESS Purchases</u> ⁽²⁾			
Jefferies BESS	2028-2047	-	300
Central BESS	Various	-	<u>150</u>
Total BESS Purchases			450
Central NSRs	2029-2052	Multiple	672
<u>Purchase Contracts</u>			
Purchase 1	2024-2028	System Purchase	200
Purchase 2	2024-2028	Natural Gas	50
Purchase 3	2025-2028	Nuclear	150
Purchase 4	2027-2028	System Purchase	100
Purchase 5	2027-2028	Natural Gas	49
Purchase 6	2027-2028	System Purchase	200
Purchase 7	2029-2033	System Purchase	<u>200</u>
Total Purchase Contracts			949

(1) Existing contract includes conceptual framework for Santee Cooper taking ownership of St. Stephens.

(2) Capacity values here reflect the nameplate capacity.

COMMITTED RESOURCE ADDITIONS

For the 2026 IRP, Santee Cooper assumed the resource additions identified in Table 9 below (“Committed Resources”) as being online as of the year shown under Commercial Operation Date (“COD”). All projects have been discussed in previous IRPs, and Santee Cooper has received, for the Rainey NGCC Conversion, Canadys Joint NGCC, and Winyah Turbines, a Certificate of Environmental Compatibility and Public Convenience and Necessity (“CECPCN”) from the Commission for each individual project.

Table 9. Committed Resource Additions

Generating Facility	Commercial Operation Date (Winter Season)	Winter Rating (MW)
Rainey Upgrade – Unit 1	2028	56 ⁽¹⁾
Rainey NGCC Conversion	2028	178 ⁽¹⁾
Rainey Upgrades – Units 3, 4, and 5	2028	21 ⁽¹⁾
Canadys Joint NGCC	2033	1,098 ⁽²⁾
Winyah Turbines	2028	108

(1) Represents incremental MW relative to existing capacity at Rainey Generating Station.

(2) Represents Santee Cooper share of the Canadys Joint NGCC with Dominion Energy South Carolina.

CENTRAL NON-SHARED RESOURCES

Central has executed three PPAs (“Central NSRs”), described as follows, to meet its obligations under the Coordination Agreement to provide NSRs to supply a portion of the capabilities of the PSR identified in 2021.

- Base Load PPA – 150 MW from the Catawba Nuclear Station
- NGCC PPA – 230 MW from a 1x1 NGCC on the Southern Company (“SOCO”) system
- Peaking PPA – 292 MW from an NGCT resource, also on the SOCO system

All three PPAs have terms that begin no later than 2029. In addition to the three PPAs above, Central has indicated it intends to execute long-term agreements for BESS resources, which total 150 MW and are expected to be available beginning in 2029, and for three solar projects, which total 224 MW nameplate capacity and have various online dates. The BESS and solar resources are included in the Power Purchase Agreements section above.

PLANNING RESERVE REQUIREMENTS

The 2026 Planning Reserve Margin study concluded that Santee Cooper’s PRM requirement should reflect a winter requirement and that a winter reserve margin of 20 percent was appropriate to ensure the target reliability levels. The study also concluded that a summer reserve margin requirement should be considered as a secondary requirement and that 18 percent was appropriate. PowerGEM’s report, which includes its methodology and study results, is included as Attachment 1: 2025 Reserve Margin and Effective Load Carrying Capability Study. For the Study, Santee Cooper reviewed the assumptions, methodology, and results with stakeholders and incorporated feedback as appropriate.

Based on the 2026 PRM Study, Santee Cooper has set minimum PRM requirements for the winter and summer peak periods of 20% and 18%, respectively.²¹ These values are similar to those Santee Cooper set for its winter and summer minimum PRM for purposes of its 2023 IRP and

²¹ Under its Coordination Agreement with Central, Santee Cooper may only set a new planning reserve margin for the Combined System in consultation with Central.

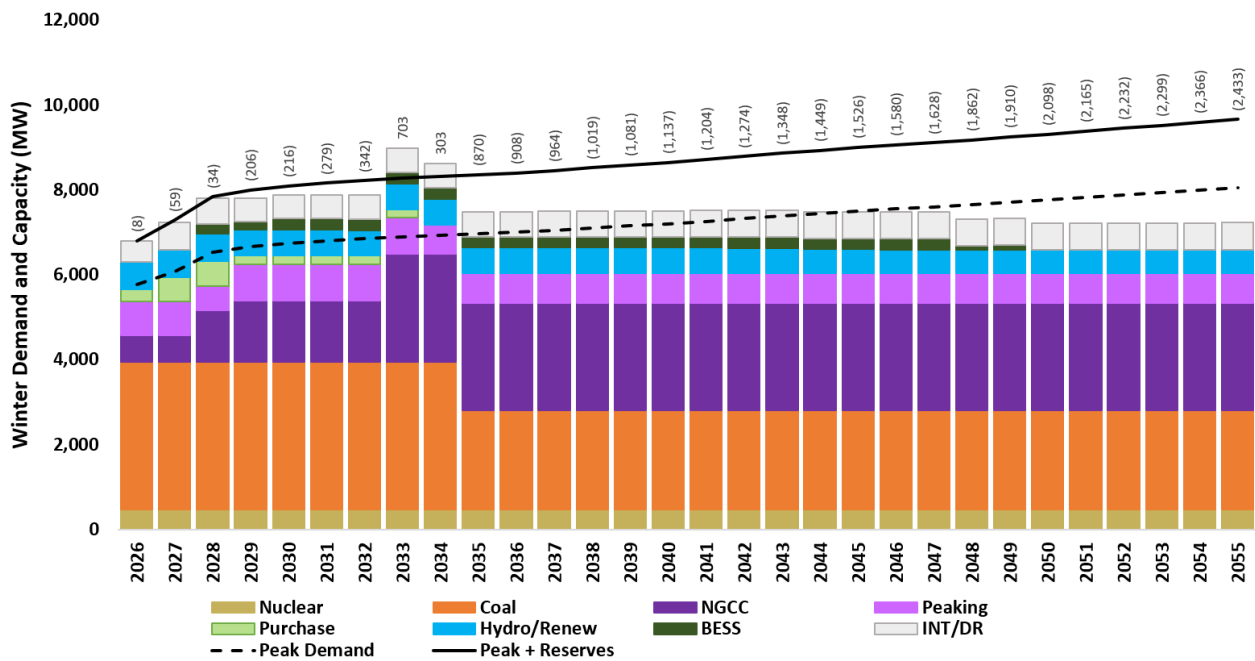
Assessment of Resource Need

2024 and 2025 IRP Updates, which were 18% and 15%, respectively, and were based on a previous PRM study performed by Astrapé Consulting.

SUPPLY AND DEMAND BALANCE

Combining projections from the 2026 Load Forecast, existing owned resources, planned retirements, Existing PPAs identified in Table 8 above, Committed Resources identified in Table 9, and planning reserve requirements yields projections of the future Santee Cooper supply-demand balance depicted in Figure 11 below. In sum, these projections reveal the need for both near-term and long-term increases in supply to meet the growing energy needs of customers.

Figure 11. Projected Winter Supply v. Demand Balance ⁽¹⁾ ⁽²⁾



(1) Numbers above the Peak + Reserves line represent surplus or deficient capacity values.

(2) Solar and BESS resources are shown at their respective Effective Load Carrying Capability values.

DEMAND-SIDE MANAGEMENT OVERVIEW

DEMAND-SIDE MANAGEMENT OVERVIEW

Demand Side Management (“DSM”) is an important component of the services that Santee Cooper and Central Members provide to their customers and an important component of Santee Cooper’s IRP. DSM focuses on reducing electricity demand and consumption through the development of incentive programs offered to retail customers to improve the efficiency of their end uses or otherwise affect their energy consumption.

SANTEE COOPER PROGRAMS

Santee Cooper’s DSM offerings are broken down into Energy Efficiency (“EE”) and Demand Response (“DR”) programs. EE programs are primarily designed to achieve reductions in energy consumption, while DR programs are primarily designed to reduce system demand during peak periods. This section provides background on Santee Cooper’s existing and planned DSM programs, as well as a summary of the EE and DR Market Potential Studies, developed by Resource Innovations, Inc. (“RI”), which have been included in Attachment 4.

EXISTING PROGRAMS

Santee Cooper has been providing DSM programs to its retail customers since the early ‘80s. In 2009, a new portfolio of EE programs was launched for Santee Cooper’s residential and commercial customers. The portfolio was refreshed and rebranded in 2019 under the EmpowerSC brand, which serves as the current umbrella for DSM and other customer-facing programs. EmpowerSC currently consists of three program categories, each containing a variety of DSM measures. Table 10 below provides a listing of the categories of measures included in each of these program umbrellas.

Consistent with the implementation timeline outlined in its 2023 IRP, Santee Cooper expanded its DSM portfolio in 2025 with the introduction of three new programs designed to increase energy savings and demand reduction.

In February 2025, Santee Cooper launched its online Marketplace, providing residential customers with a convenient platform to purchase energy-saving products delivered directly to their homes. In April 2025, Santee Cooper introduced the Power Partners program, a community-based initiative designed to bring energy efficiency solutions directly into residential neighborhoods through in-home assessments and free installation of energy saving measures. In early 2026, Santee Cooper launched a new smart thermostat demand response offering, aimed at reducing system load during periods of high energy use. As part of this transition, Santee Cooper retired its legacy switch-based demand response program due to low customer participation and shifted its focus to the new smart thermostat offering.

Table 10. Current Demand-side Management Program Measures

Umbrella Program in EmpowerSC	Categories of Measures Included in Programs
EmpowerHome for Residential EE 	- HVAC - Whole Home Duct Replacement - Smart Thermostats - Heat Pump Water Heaters - Energy Efficient Pool Measures - ENERGY STAR Appliances - Lighting - Weatherization Measures - Home Energy Rating System (“HERS”) Scores for New Construction
EmpowerBusiness for Commercial EE 	- Lighting - HVAC - Smart Thermostats - Refrigeration - Kitchen Equipment - Domestic Hot Water - Pumps/Motors
Santee Cooper Rewards for Residential DR 	- Smart Thermostats

In addition, Santee Cooper has installed a Conservation Voltage Reduction (“CVR”) application, which allows for the reduction of distribution system peak demand through controlled reduction of voltage across the distribution system. The CVR application and the associated supervisory control and data acquisition (“SCADA”), regulator controls, and metering upgrades have been in operation since 2020 in the Horry, Georgetown, and Berkeley County areas. There are a total of 270 feeders that are capable of running CVR. Of those, 254 are routinely utilized when CVR is required.

MARKET POTENTIAL STUDIES

In 2025, Santee Cooper retained RI to conduct comprehensive EE and DR market potential studies (“MPS”). RI also conducted Santee Cooper’s potential studies for the 2023 IRP and has

Demand-Side Management Overview

significant expertise in conducting similar studies for utilities across the country, including recent potential studies for several Southeast utilities.

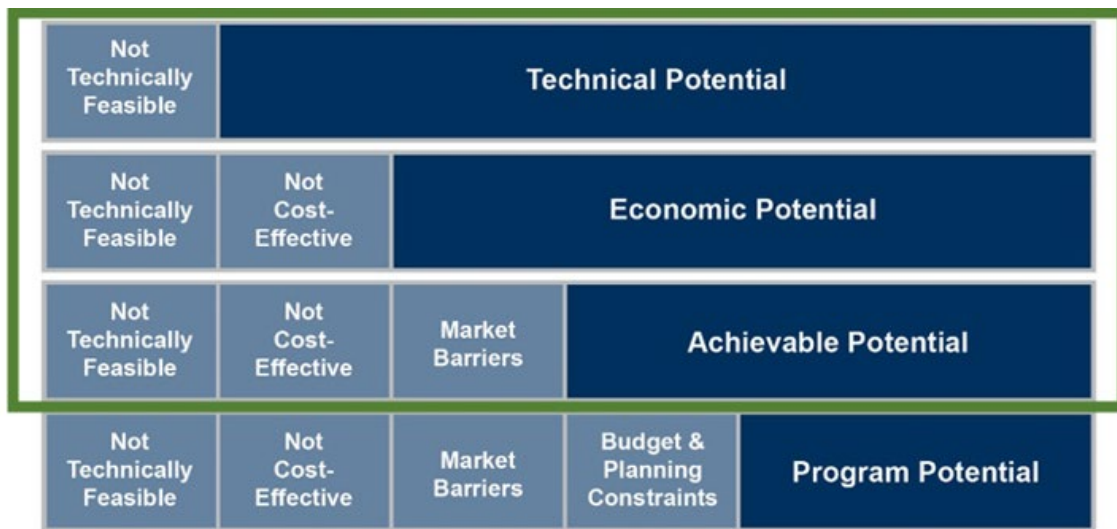
ENERGY EFFICIENCY MARKET POTENTIAL STUDY

The objective for the EE MPS was to determine the maximum amount of energy and demand savings from EE measures that are achievable over the next twenty years. The 2026 Demand Side Management Market Potential Study, which is dated March 2026 and included as Attachment 4, provides estimates of technical, economic, and achievable potential for EE savings among Santee Cooper’s residential and commercial customers. Definitions of each type of potential are as follows.

- Technical Potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- Economic Potential is the amount of energy and capacity that could be reduced by efficiency measures that pass a cost-effectiveness test. The Utility Cost Test (“UCT”) was used for this study, which measures cost and benefits from the viewpoint of the utility.
- Achievable Potential is the energy savings that can feasibly be achieved through program and policy interventions.
- Program potential reflects the application of utility program spending, the estimated impacts of incentives, and resulting customer response to specific EE program offerings. Program potential was not evaluated as part of this study because the purpose of the analysis was to estimate market potential rather than the impacts of specific program designs.

Figure 12 provides an illustration of this progression of EE potential.

Figure 12. Demand-side Management Potential Categories



EPA – National Guide for Resource Planning

Demand-Side Management Overview

In the EE MPS, RI focused on estimates of achievable potential for 2026-2045 based on the following three scenarios.

- **Low Scenario** – The scenario is intended to describe the expected achievable potential from cost-effective measures that could be delivered through the existing Santee Cooper program portfolio. Measures were individually screened and must achieve a benefit-cost ratio (UCT) of 1.0.
- **Medium Scenario** – In this scenario, incentives were increased up to 50% of the incremental measure costs. Additionally, the benefit-cost screening threshold is lowered from 1.0 to 0.7, allowing a broader set of measures to qualify and expand the pool of eligible, cost-effective DSM opportunities. This approach of using a 0.7 UCT at the measure level allows some marginally cost-effective measures to be included in the portfolio and potentially boosts savings while maintaining an overall portfolio that is cost-effective from the UCT perspective.
- **High Scenario** – In this scenario, incentives were further increased up to 75% of the incremental measure costs to encourage higher customer participation rates. The UCT threshold remains at 0.7. Additionally, the avoided marginal energy costs are increased by 50%, enhancing the overall cost-effectiveness of DSM measures and supporting broader market adoption. Based on stakeholder feedback received during the 2023 IRP process, incentive levels were capped at the maximum amount that would allow a measure to maintain a passing UCT score. As a result, measures were not automatically assigned a 75% incentive level if doing so would cause the measure to fail the UCT. Instead, the incentive was reduced to the highest level that preserved cost-effectiveness, allowing otherwise cost-effective measures to remain in the achievable potential rather than being excluded solely due to an excessively high incentive assumption.

Figure 13 presents the annual incremental energy savings identified in the EE MPS under the low, medium, and high achievable potential scenarios over 5-, 10-, and 20-year planning horizons.

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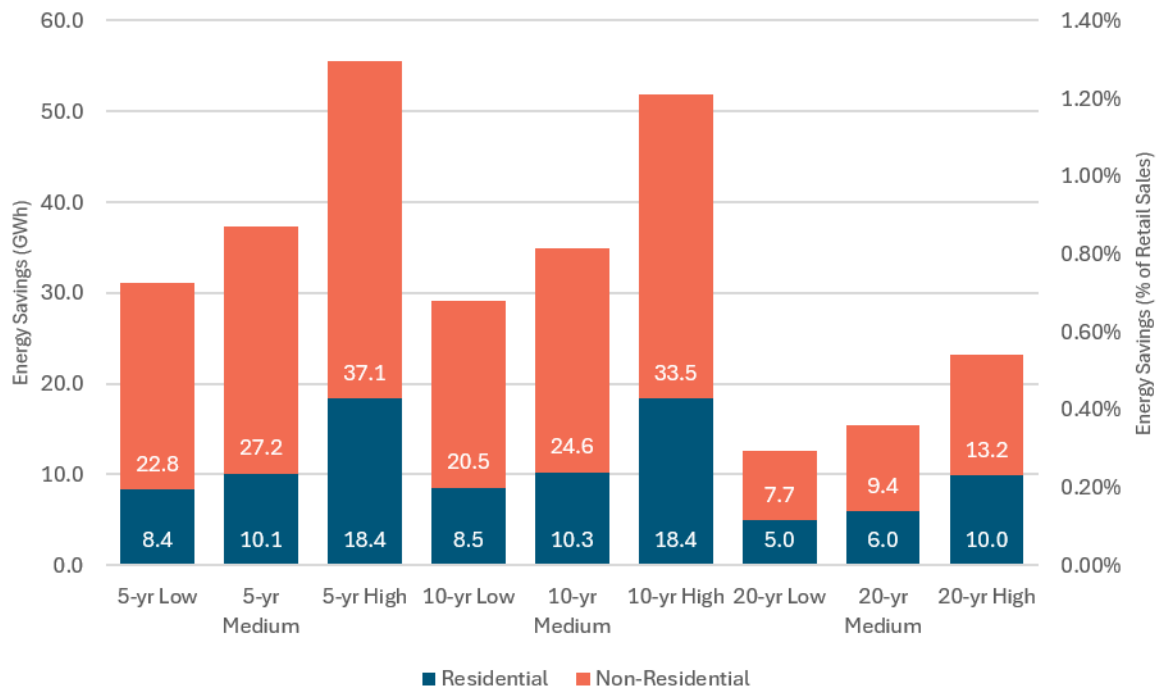
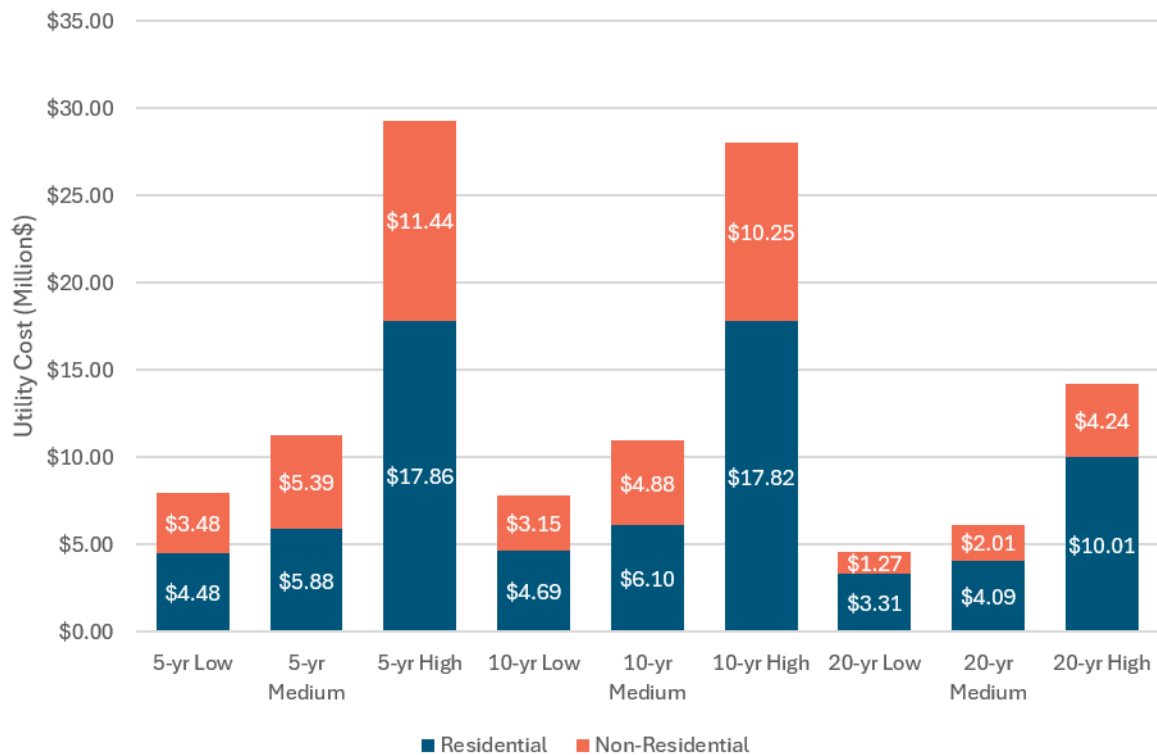
Figure 13. EE Annual Incremental Energy Savings (5-yr, 10-yr, 20-yr)

Figure 14 shows the annual incremental costs needed to support the incremental savings presented in Figure 13.

The decline in energy efficiency savings in year 20 reflects the diminishing opportunities for additional efficiency improvements. As technologies become more widely adopted, the market approaches saturation, leaving fewer opportunities for new savings. At the same time, increasingly efficient equipment, buildings, and processes and more stringent baseline assumptions make it progressively harder to achieve additional savings. The analysis also takes a conservative approach to emerging technologies and does not assume savings from technologies that are not yet commercially established. Together, these factors contribute to lower annual EE savings toward the end of the 20-year horizon.

Additional context is provided in Attachment 4: Demand Side Management Market Potential Study.

Figure 14. EE Annual Incremental Utility Costs (5-yr, 10-yr, 20-yr)

DEMAND RESPONSE MARKET POTENTIAL STUDY

The objective of the DR Market Potential Study is much the same as the EE MPS but is focused on developing estimates of technical, economic, and achievable potential for Santee Cooper's residential and commercial customers temporarily curtailing or shifting portions of their demand to off-peak times to reduce peak demand on the Santee Cooper system. The DR MPS is dated March 2026 and filed collectively with the EE MPS in Attachment 4.

For the peak demand forecast, RI established a baseline forecast of what loads or operational requirements would be absent due to existing dispatchable DR. RI used Santee Cooper's peak forecast and hourly load forecast, adjusting as necessary to determine what the forecast would be in the absence of existing dispatchable DR.

The available measure list for DR-enabling technologies designed to deliver grid support services includes the following:

Residential and Small Commercial

- HVAC Switches (heating and cooling)
- Pool Pump Switches
- Room AC Controls
- Smart Thermostats (bring your own device and utility install)
- Pricing Structures (peak time pricing, peak time rebates, and critical peak pricing)
- Water Heaters (switches and grid-enabled)

Demand-Side Management Overview

- Battery Storage
- EV Charging (telematics and switch)
- Behavioral (residential only)

Large Commercial

- Automated DR
- Contractual DR
- Emergency Load Reduction

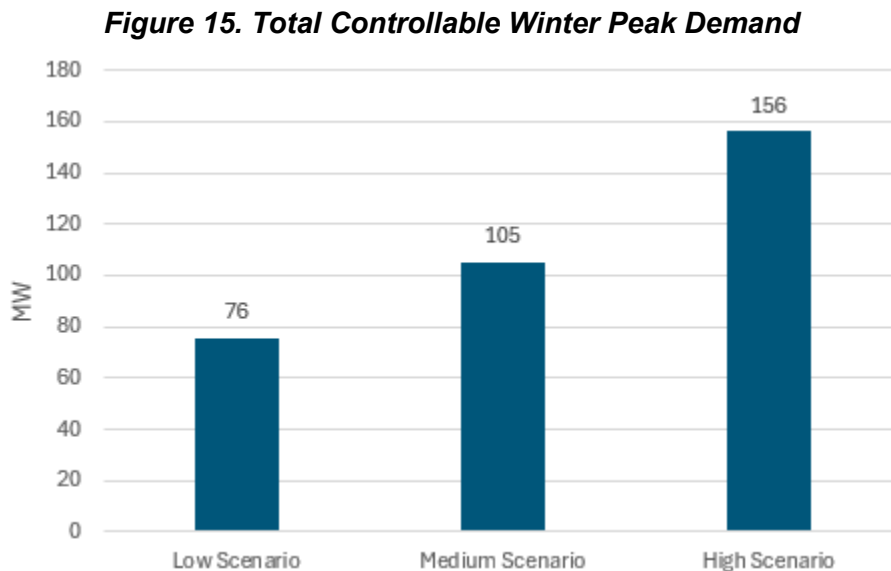
To estimate load impacts and costs for the installation and operation of DR measures, RI leveraged Santee Cooper data, empirical information from other jurisdictions based on RI's experience and other available secondary information.

Like EE, the DR analysis assessed achievable potential under three scenarios:

- **Low Scenario** – The low scenario is intended to align with the existing Santee Cooper residential bring-your-own thermostat DR program. Although Santee Cooper does not currently offer a smart thermostat DR program for small business customers, this measure was included in the low scenario due to its similarity to the existing residential DR program and its potential applicability within the small commercial sector.
- **Medium Scenario** – This scenario includes all economic loads/measures and targets cost-effective customer segments. Customer acquisition costs include medium incentives, marketing, and outreach. The medium scenario also incorporates strategic program design decisions, including the treatment of overlapping programs, to reflect a more realistic and implementable DSM portfolio rather than a comprehensive aggregation of all individually economic program options.
- **High Scenario** – This scenario includes all economic loads/measures and targets all customer segments that maintain overall program cost-effectiveness. Customer acquisition costs include enhanced incentives, marketing, and outreach.

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Figure 15 presents the total controllable winter peak demand estimated in the DR MPS under the low, medium, and high achievable potential scenarios over a 20-year planning horizon.



Existing program plans, budgets, savings targets, and procurement activities were established through planning efforts informed by the 2023 MPS. As a result, near-term DSM activities will continue to reflect the roadmap and priorities developed through that process. The 2026 MPS provides updated insights into long-term savings opportunities, evolving technologies, and changing market conditions, and these findings will be incorporated into future planning and decision-making. This approach allows Santee Cooper to maintain continuity in current program implementation while progressively integrating the updated guidance and opportunities identified in the 2026 MPS.

CENTRAL PROGRAMS

Central works with its member-cooperatives to develop, implement, and administer DSM programs independently of Santee Cooper, though with some coordination with respect to key assumptions and sharing of insights regarding program administration.

As discussed in the Electric Load Forecast Overview section, Central provides a forecast of its member loads to Santee Cooper to incorporate into the aggregate Combined System load forecast. This forecast of Central's loads is net of projected impacts of Central member DSM programs over which Santee Cooper has no control. Hence, for purposes of the 2026 IRP, Santee Cooper has made no adjustments for DSM programs to the Central portion of the load forecast.

TRANSMISSION PLANS AND PLANNING PROCESSES

In compliance with S.C. Code Ann. § 58-37-40(B)(1)(j), Santee Cooper submits the following report about its transmission plans and planning processes. Further discussion about transmission-related modeling and assumptions is in the Major Modeling Assumptions Section of this Report.

Santee Cooper continually performs assessments of transmission system performance in accordance with NERC Reliability Standards associated with transmission planning under many different future scenarios. This allows it to support resource additions or retirements necessary to improve resiliency and reliability of the system and to support load growth and economic development of the State of South Carolina. Updated resource plans are incorporated into the transmission planning processes to evaluate the system's ability to site potential resources. Santee Cooper utilizes a variety of transmission planning studies, including NERC Transmission Planning performance assessment (TPL-001), Generator Interconnection through the Open Access Transmission Tariff ("OATT") process, and regional transmission planning coordination efforts or studies to inform and evaluate its transmission expansion plans with the objective of refining the plans to meet the future needs of the system. Coordinated transmission studies between Santee Cooper and its neighboring utilities are part of the essential transmission planning process. These studies ensure regional planning and system needs are being met and result in new tie line interconnections and/or regional/inter-regional solutions.

Santee Cooper maintains transmission modeling information needed to perform the assessments referenced above with updates for planned transmission and generation facility additions and modifications, load forecast, and other system topology changes. Santee Cooper coordinates with neighboring utilities to update adjacent system models to allow for coordination of local plans and to assess potential impacts on other utilities. Santee Cooper participates in regional reliability planning discussions and/or studies coordinated by SERC, the Eastern Interconnection Planning Collaborative ("EIPC")²², and the South Carolina Regional Transmission Planning ("SCRTP")²³ FERC Order 1000 planning region. Since FERC issued Order 1920 in 2025, Santee Cooper and DESC also began participating in Southeastern Regional Transmission Planning ("SERTP")²⁴ activities, and they will be joining the SERTP planning region concurrent with compliance filings associated with FERC Order 1920 (at which time they will retire the SCRTP). Per Order 1000's process, SCRTP meetings are open to stakeholders and intervenors to participate in local transmission planning collaborative activities. Thus, in anticipation of the Order 1920 process, Santee Cooper will be part of SERTP and will be open to discussing and collaborating on long-term regional and interregional transmission planning.

²² <https://eipconline.com/>

²³ <https://www.scrtp.com/>

²⁴ <https://www.southeasternrtp.com/>

UPDATE TO THE OPEN ACCESS TRANSMISSION TARIFF

On January 27, 2026, Santee Cooper's Board of Directors approved modifications to Santee Cooper's OATT. The approved changes adopt portions of FERC Order No. 2023 and include additional amendments to Santee Cooper's generation interconnection processes. Transmission process related changes to the OATT involve the inclusion of the use of grid-enhancing technology ("GET") or alternative transmission technologies ("ATT") in Santee Cooper's generator interconnection studies. Although Santee Cooper is not a FERC jurisdictional entity, it largely aligns its generator interconnection process with FERC's in its OATT.

PLANNED TRANSMISSION IMPROVEMENTS

Santee Cooper invested approximately \$261 million in capital additions and improvements to its transmission system in 2025. Any project that involved the reconstruction of existing transmission line facilities had existing wood structures replaced with steel, which increases the reliability and resiliency of these facilities under normal and severe weather conditions while also decreasing the overall cost of operation and maintenance.

Santee Cooper has multiple major transmission projects under way or otherwise expected to be completed within the next five years, and some of these are based on transmission considerations and needs for new or upgraded generation facilities. These projects will support resource plans, maintain system reliability, and support existing customers and anticipated load growth. Transmission plans will also facilitate the new or upgraded committed generation facilities, including Canadys Joint NGCC, the Winyah Turbines, the Rainey NGCC Conversion, the Jefferies BESS Project, and other committed generator interconnection projects. Additionally, transmission projects, such as the fold-in of the Varnville-Indian Field 230kV line into the Edisto River 230kV switchyard and the Mateeba-Edisto River 230 kV line project, support the Preferred Portfolio's resource plan. Other major projects needed to support the Preferred Portfolio are discussed in Appendix B: Transmission Projects. In addition to evaluating transmission considerations related to the Preferred Portfolio, Santee Cooper also evaluated transmission system constraints and expansion costs of future scenarios which included the partial and full retirement of the utility's coal generation at Cross Generating Station. Discussion of transmission modeling for coal retirement evaluations and results are discussed in Appendix H: Coal Retirement Study.

TRANSMISSION EVALUATION, INCLUDING NON-WIRE ALTERNATIVES

As part of its transmission planning process, Santee Cooper evaluates a range of transmission solutions and investments, including ATT, as alternatives to traditional transmission infrastructure solutions. To address identified transmission constraints, Santee Cooper values alternative solutions that have well understood risks and a long track record of performing reliably. Santee Cooper will choose solutions and technologies with well understood costs and risks, both, from an implementation and operational perspective. Factors that may support the selection of a traditional solution over an alternative solution may include the anticipated lifespan of the solution, impact on local area or regional transmission plans, maintenance and operational risks, impact to resource plans, and project executability risk (early adopter, supply chain, security risk, etc.). Santee Cooper will comply with all applicable requirements to assess ATTs as alternatives to traditional

Transmission Plans and Planning Processes

transmission infrastructure solutions (line, transformer, station, etc.) but a decision to implement any ATT or combination of technologies will be Santee Cooper's decision, consistent with good utility practice, applicable reliability standards, and other applicable regulatory requirements.

Santee Cooper's transmission planning process has considered various ATTs for years, and it has utilized ATTs, such as high-temperature design conductors, in providing greater transmission capacity and cost savings over traditional solutions of replacing structures. These considerations and practices have been documented in its transmission planning ATT business practice.

Santee Cooper's OATT study considers a range of alternative transmission technologies in its interconnection studies. These grid-enhancing and alternative transmission technologies considerations include:

- **Advanced Power Flow Control Devices ("APFC").** Although there are currently no APFC devices deployed or approved to be deployed on Santee Cooper's transmission system, Santee Cooper will continue to assess proven APFC technology and products commonly used in the utility industry. The use case and choice of APFC technology/devices will be considered during various planning studies.
- **Advanced Transmission Conductors.** Advanced Transmission Conductors, often called high-temperature, low-sag conductors, provide a much higher current-carrying capacity for a similar size as compared to the standard aluminum conductor steel reinforced ("ACSR") conductors, which are typically used by Santee Cooper on standard design. When reconductoring existing transmission infrastructure, Santee Cooper evaluates the ability of advanced conductors to mitigate system constraints by achieving a higher facility rating using existing transmission structures and providing sufficient transmission capacity headroom for future system growth. Reconductoring instead of rebuilding with new structures can save construction time and project cost and should be evaluated where possible. Advanced conductors do require different installation techniques/instructions, connectors, installation tools and equipment. Santee Cooper has utilized the ACSS (aluminum conductor steel supported) conductor in places where it provided much higher capacity, lower cost and shortened the construction schedule while existing structures integrity and design were feasible to support the reconductoring.
- **Dynamic Line Rating ("DLR") Monitoring.** DLR refers to the practice of varying transmission line rating depending on real-time weather conditions, such as ambient temperature, wind speed and direction, and area surroundings such as tree lines affecting conductor temperature and line clearance. Santee Cooper would consider DLR as test solutions only when DLR studies have been performed on the specific transmission line(s) or to the extent actual data collected from deployed DLR devices have proven that additional transmission capacity is available for those periods that transmission thermal constraints may occur. Currently, Santee Cooper is actively pursuing pilot projects for testing DLR vendors and technology to verify its capability potential benefits.
- **Tower Lifting.** Tower Lifting refers to raising the height of existing transmission towers to increase line clearance and achieve capacity gain by allowing existing conductors to operate at a higher temperature, reconductoring to higher ampacity, or facilitating bundling of conductors. However, transmission lines that are identified as potentially feasible for tower lifting will require additional detailed design and engineering analysis to be

conducted to confirm the feasibility, structure-by-structure feasibility for tower lift and evaluation of ampacity gain, and methods in which to provide higher ampacity (higher conductor temp, reconductor, or bundling).

- **Transmission Switching.** Transmission switching is a manual or automated action to mitigate or avoid a system constraint to reconfigure the transmission network to avoid or reduce the constraint. Manual switching is done using operational guides that are followed by transmission system operators. Automatic switching is done using automated remedial action schemes (“RAS”). Santee Cooper has not relied on the implementation of RAS on the system to solve near- or long-term system needs given significant resulting operational risks, such as mis-operation or failure to operate, which can cause increased potential for cascading outages, further instability, and high maintenance/testing requirements to meet mandatory NERC reliability standards. Santee Cooper uses operating guides as temporary solutions when a long-term solution has been identified and is being implemented, which may take several years to complete. NERC allows operating guides to mitigate constraints for specific types of contingencies. Where appropriate, Santee Cooper evaluates the ability of transmission switching to mitigate of thermal or voltage constraints on a temporary basis. Transmission Switching solution will need to be thoroughly tested against all TPL-001 contingency events to ensure it does not negatively impact the system while attempting to mitigate a particular system constraint(s). Further analysis/testing and validations will be required by Operations before a Transmission Switching solution is approved and deployed.
- **Switchable Reactors.** The deployment of switchable reactors requires comprehensive system evaluation to mitigate adverse impacts on interconnected infrastructure. Although these components effectively reduce power flows on thermally constrained facilities, they can introduce unintended operational bottlenecks across broader network segments or placing undue burden on neighboring systems. Consequently, because switchable reactors fail to inject additional capacity into the grid, they are classified as short-term mitigations rather than permanent infrastructure solutions. Financial and operational cost-benefit analyses must rigorously assess these temporary measures, determining the exact window by which they defer required long-term system investments.
- **Phase-shifting transformers (“PST”).** Based on industry trends and supply availability, Santee Cooper currently does not consider the use of PST as an economic and reliable solution to address transmission constraints. Operational reliability has been raised as a concern by other electric utilities and parts supply for repair has been a concern due to the demand decrease and fewer vendors remaining.
- **Static Synchronous Compensator.** Static Synchronous Compensators (“STATCOM”) serve as a high-performance alternative to traditional capacitor banks when rapid reactive power response is required. Santee Cooper considers the use of this solution in addressing system voltage criteria and voltage stability issues. The decision to deploy STATCOM technology depends heavily on localized load variability and specific dynamic response requirements. Unlike fixed capacitor banks, a STATCOM provides bidirectional flexibility, supporting the grid with both leading and lagging reactive power. Additionally, they mitigate the risks of resonance or overvoltage anomalies often introduced by standard capacitor banks. However, it typically commands a higher capital cost and the deployment of

STATCOM is highly locationally sensitive and must be evaluated on a case-by-case basis driven by specific system needs and load profiles.

- **Static Var Compensator (“SVC”).** An SVC is an automated power electronics device connected in parallel with the transmission network to provide dynamic reactive power compensation and voltage regulation. SVCs offer a fast-acting alternative to conventional capacitor banks, providing precise reactive power control and voltage stability. This rapid response capability is vital for mitigating voltage flicker caused by steep load fluctuations and maintaining grid integrity under dynamic system conditions. However, because an SVC relies on complex power electronics, it typically commands a significantly higher capital cost than standard capacitor installations. Similar to STATCOM, Santee Cooper carefully considers all pros and cons of SVCs in addressing a system voltage violation and/or voltage stability issue.
- **Synchronous Condensers.** Synchronous condensers offer dynamic voltage regulation and bidirectional control, allowing them to seamlessly inject or absorb reactive power based on real-time grid needs. Compared to conventional capacitor banks, they provide far superior voltage support during severe grid drops while simultaneously supplying critical system fault current and physical inertia. Synchronous condensers have a high initial cost and have special maintenance requirements. Therefore, Santee Cooper considers placing synchronous condensers when system inertia and/or short-circuit strength is a known concern.
- **Voltage-Source Converters (“VSC”).** VSCs can deliver dynamic voltage regulation and rapid bidirectional reactor power support. Compared to passive capacitor banks, VSCs provide vastly superior voltage support during deep network depressions, maintaining reactive current injection even when grid voltage drops severely. However, Santee Cooper is expecting to continue to increase its inverter-based resources (“IBR”) such as utility-scale solar and BESS resources. The need to have Santee Cooper-owned standalone VSC assets is significantly reduced as these third-party solar and storage facilities utilize advanced VSC technology within their core inverter designs. Planning effort is placed on enforcing and leveraging the advanced grid-support functionalities of these existing IBR inverters by enforcing interconnection standards and requirements such as dynamic reactive power support, voltage-droop control, and fault-ride-through capabilities at the Point of Interconnection (“POI”) to maintain voltage stability and grid resilience.

In summary, Santee Cooper considers and evaluates various ATT solutions in its transmission planning analysis for system benefits and costs. It has deployed the use of advanced conductors recently on the Purrysburg-McIntosh 230 kV double-circuits reconductor project to maximize transmission capacity and increase the interface capability. The use of advanced conductors will continue in the transmission plans where it provides greater benefits with minimal cost impact. Santee Cooper is also in the planning phase of various DLR pilot projects to better understand its potential transmission capacity gain/loss and operational benefits. Switchable/Series Reactor devices are also being evaluated and potentially deployed where they provide short-term system needs and potential savings over more expensive traditional upgrades. It has always been the objective of Transmission Planning to continue to provide for a reliable transmission system using the most economical and robust solutions.

MAJOR MODELING ASSUMPTIONS

This section details major modeling assumptions that underpin the 2026 IRP. These assumptions were developed based on industry best practices, in consultation with stakeholders, and in compliance with Commission Orders.

FINANCING AND ECONOMIC ASSUMPTIONS

The 2026 IRP reflects assumptions regarding future general cost escalation and Santee Cooper cost of debt, which are shown in Table 11 below. The NPV cost results shown herein reflect a discount rate set equal to Santee Cooper's assumed cost of debt.

Table 11. Financial Assumptions

General Inflation	2.5%
Cost of Long-Term Debt	5.1%
Cost of Short-Term Debt	3.5%
Present Value Discount Rate	5.1%

The assumed long-term general inflation rate is based on a historical average of the annual change in the consumer price index, published by the U.S. Bureau of Labor Statistics, over 2006-2025, consistent with Santee Cooper's company-wide inflation assumption. Escalation of certain nominal costs, including capital costs of generation facilities, reflect the combination of specific assumed real escalation rates and the general inflation rate. Fixed and variable operation and maintenance costs reflect the general inflation rate, unless otherwise noted.

The assumed cost of Santee Cooper long- and short-term debt to finance capital equipment, such as generation and transmission facilities, was determined in consultation with Santee Cooper's financial adviser, Public Financial Management™ ("PFM"). Short-Term Debt was used to simulate capital interest costs during project construction; long-term debt was used to simulate long-term debt service for project financing.

SYSTEM ENERGY AND PEAK DEMAND

Forecasts of monthly energy requirements and peak demand for the Santee Cooper system through 2045 were developed as discussed in the section titled Electric Load Forecast Overview and taken directly from Santee Cooper's 2026 Load Forecast. Projections beyond 2045 reflect linear extrapolation.

Projected loads for the Santee Cooper retail system taken from the 2026 Load Forecast are gross of future DSM EE and DR programs. For purposes of the power supply simulations conducted in the 2026 IRP, projected impacts of Santee Cooper's future EE programs are subtracted from the 2026 Load Forecast values, as discussed further in this section under the heading Demand-Side Resources, to arrive at net loads that must be met by supply-side resources. The forecast for Central, which is prepared by Central, is net of projected DSM EE and DR impacts, reflecting

Major Modeling Assumptions

Central member programs and capabilities over which Santee Cooper has no control. Hence, no adjustments to the Central load forecast, as provided by Central, were made for use in the portfolio and production cost simulations and sensitivity analyses presented in the 2026 IRP.

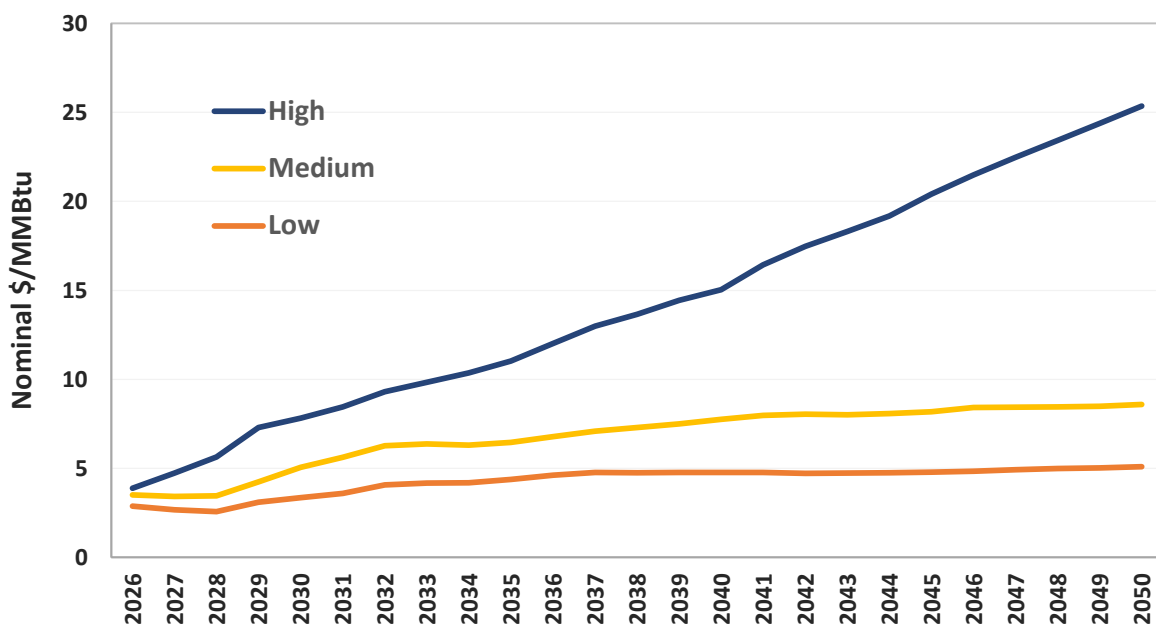
System hourly load profiles were based on 2019 data.²⁵

FUEL FORECASTS

Forecasted fossil fuel prices throughout the Study Period generally reflect forecasts taken from the Energy Information Administration's ("EIA") 2026 Annual Energy Outlook ("AEO") Counterfactual Baseline case (referred to as the "Reference Case" in prior iterations of the AEO). In addition, to study a reasonable range of uncertainty regarding future fuel prices, Low and High Cases were derived from the relative percentage differences between the AEO Counterfactual Baseline case and the High and Low Oil and Gas Supply cases, respectively. The Low Case utilizes the AEO High Oil and Gas Supply Case, which reflects more accessible oil and natural gas resources and lower extraction costs than the Reference Case, while the High Case utilizes the AEO Low Oil and Gas Supply Case, which reflects less accessible resources and higher extraction costs. Additionally, forward prices for Henry Hub natural gas were used to develop monthly variation in the forecasted annual prices for natural gas available through the AEO and to depict near-term natural gas prices for Henry Hub for the Reference Case through 2028.

Forecasts of the annual average Henry Hub natural gas prices used for 2026 IRP are shown in Figure 16, below.

Figure 16. Natural Gas Price Forecasts



²⁵ For this purpose, hourly load profiles in September 2019 were adjusted to remove the estimated effects of Hurricane Dorian, which impacted South Carolina over September 4th through 6th.

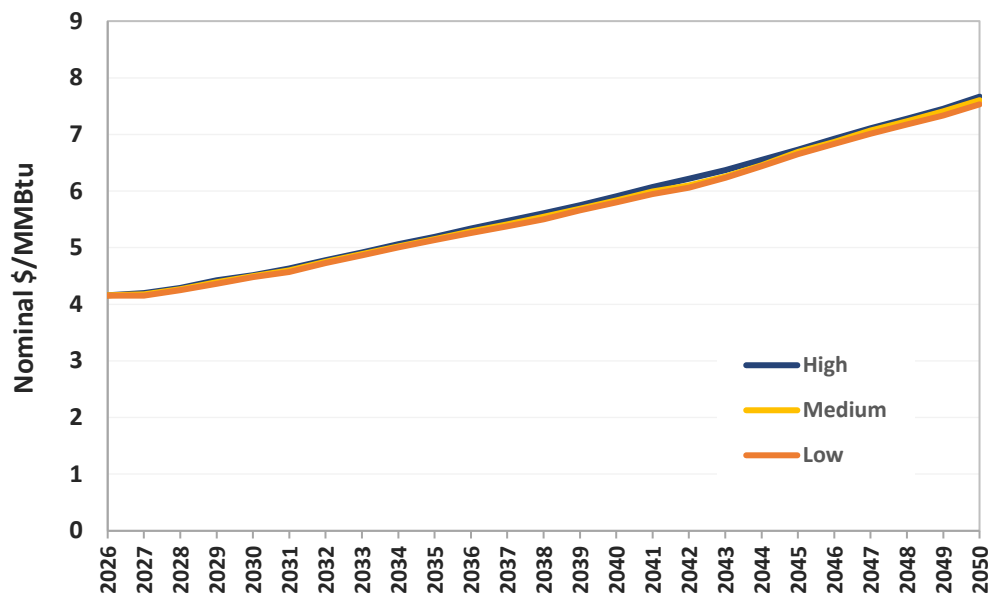
Major Modeling Assumptions

Forecasted delivered natural gas prices used in the EnCompass simulations described herein include both Henry Hub commodity prices and costs to deliver the natural gas to each generating unit. Delivery costs reflect forecasted regional natural gas hub basis forecasts from S&P Platts, and representative variable charges for pipeline transportation.

For prospective new combined cycle natural gas-fired generation, Santee Cooper has assumed prices for new firm natural gas supply based on information provided by natural gas pipeline operators for delivery of natural gas to and within South Carolina.

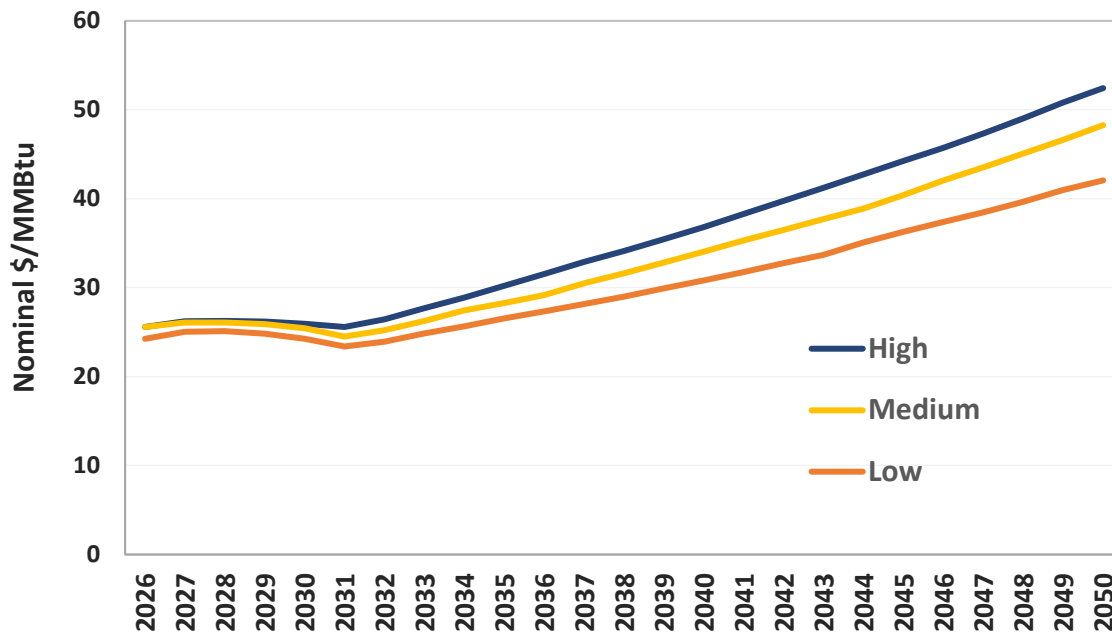
Forecasted delivered coal prices are based on basin price forecasts from the 2026 AEO for Central Appalachian, Northern Appalachian, and Illinois basins and projected rail delivery costs to Santee Cooper. Forecasted annual delivered coal prices to Cross Units 3 and 4 are shown in Figure 17, below. As the High and Low Cases were drawn from the relative differences in these projections in the AEO High and Low Oil and Gas Supply Cases, there is very little variation in coal supply costs among these cases. That is not to suggest that coal prices are not uncertain, but such uncertainty is not correlated with the factors that drive the Oil and Gas Supply Cases, as modeled for the AEO.

Figure 17. Coal Price Forecasts



Forecasted fuel oil prices, as shown in Figure 18, below, were based on forecasts from the 2026 AEO as reported for the SERC East region for the AEO Electricity Market Module, and with High and Low sensitivity cases developed in the same manner as discussed above for natural gas and coal prices.

Figure 18. Distillate Fuel Oil Price Forecasts

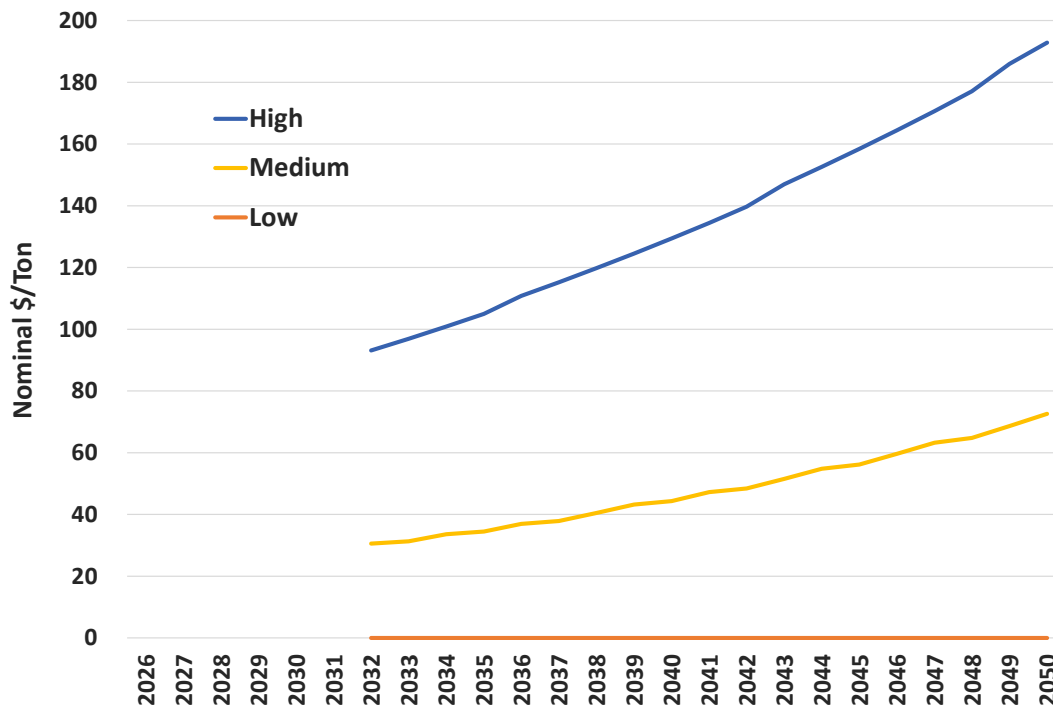


CARBON EMISSIONS PRICING

CO₂ is not currently regulated by the federal government nor by the State of South Carolina. To assess the impact on Santee Cooper's future build plans and the sensitivity of power costs under various build plans to CO₂ regulation, Santee Cooper has developed three scenarios regarding the cost of CO₂ emissions over the coming decades, as described below and illustrated in Figure 19, below.

- **Low Case** – Reflecting no regulation or cost of CO₂ emissions over the Study Period
- **Medium Case** – Reflecting a CO₂ emissions price starting in 2032 at \$31/ton and escalating at 4.9 percent per year
- **High Case** – Reflecting a CO₂ emissions price starting in 2032 at \$93/ton and escalating at 4.1 percent per year

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Figure 19. CO₂ Emissions Price Forecasts

Consistent with the approach utilized in the 2023 IRP, the Medium and High Cases draw on estimates of the social cost of CO₂ (“SCC”) developed by the Interagency Working Group on Social Cost of Greenhouse Gases in February 2021.²⁶ For this purpose, Santee Cooper relied on estimates reflecting discount rates of 5% and 3% for the Medium and High Cases, respectively, and assumed that regulation would be effective beginning 2032, providing for a reasonable period for regulatory, legislative, and legal processes to be completed before the assumed effective date.

The 2026 IRP includes an analysis of prospective portfolios under these sensitivities for the cost of CO₂ emissions.

EXISTING RESOURCE OPERATING COSTS AND CHARACTERISTICS

Variable non-fuel operating costs and characteristics of Santee Cooper’s existing resources modeled in EnCompass are based on historical data and developed jointly by Santee Cooper staff and consultants. Variable non-fuel operating costs reflect the cost of consumables and allowances for start costs and impacts on long-term maintenance costs and are generally assumed to escalate with general inflation.

Fixed operation and maintenance costs and capital costs for existing resources are not included in the portfolio costs reported for the 2026 IRP, except for costs associated with coal-fired resources that are avoided in portfolios in which such resources are assumed to be retired or are incurred for portfolios in which such resources are assumed to continue operating beyond the

²⁶ Available at the following link:

https://costofcarbon.org/files/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

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retirement date reflected in other portfolios. Such costs are developed based on historical data, anticipated capital expenses, and reasonable estimates of long-term requirements to maintain such units, adjusted for inflation.

RESOURCE OPTION ASSUMPTIONS

A wide range of resource technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs, including fossil-fueled, renewable, battery, and nuclear resources. The resource technologies considered for the 2026 IRP were guided by the planning activities of peer utilities, industry research regarding the state of development of various technologies, consultation with Santee Cooper advisers, and input and feedback received during the stakeholder process. These resources and associated assumptions regarding capital and operating costs and characteristics are discussed in the subsections below.

In addition, the 2026 IRP incorporates the simulation of low, medium, and high DSM sensitivity cases reflecting a range of DSM activity and associated costs derived from the conclusions of Santee Cooper's EE MPS and DR MPS.

FOSSIL-FUELED AND NUCLEAR OPTIONS

Base year capital costs, operating costs, operating characteristics, and capital cost escalation for NGCC, NGCT, aeroderivative turbines, reciprocating internal combustion engine ("RICE"), nuclear, and small modular reactor ("SMR") resource options were based on engineering estimates developed by Sargent & Lundy ("S&L"). Capital cost escalation was based on real technology cost trends taken from National Laboratory of the Rockies' ("NLR")²⁷ 2024 Annual Technology Baseline ("ATB") Conservative Case and adjusted for the general rate of inflation. Non-fuel operating costs are assumed to escalate at the general rate of inflation.

Base year capital costs, fixed and variable operating costs, and heat rates of the fossil-fueled and nuclear resources available as options in the resource optimization analyses are shown in Table 12, below. All costs are shown in 2026 dollars. Capacity ratings and per-unit capital costs reflect average ambient conditions; hence, the capacity ratings may not exactly match, or be comparable to, other values reported herein on a winter rating or nameplate basis. Capital costs shown below exclude land, transmission and natural gas pipeline interconnection costs, financing costs, and interest during construction. Fixed O&M costs shown below exclude property taxes (or payments in lieu of taxes) and insurance, as well as firm gas transmission reservation costs, see Fuel Forecasts. These other costs are separately captured in the IRP simulations. Table 12 also shows the assumed earliest timeframe these new resources could be brought online and made available to be selected in the optimization analyses described herein.

²⁷ Previously the National Renewable Energy Laboratory

Table 12. Fossil-Fueled and Nuclear Resource Option Parameters

Type	Technology	Net Capacity (MW; Avg. Ambient)	Base Year Capital Costs (\$/kW)	Fixed O&M Cost (\$/kW-yr.)	Variable O&M Cost (\$/MWh)	Full Load Heat Rate (Btu/kWh)	Year First Available
Combined Cycle	(1) 1x1; H-class	652	2,560	20.79	3.12	6,186	2035
	(2) 1x1; H-class	1,303	2,335	18.97	3.01	6,186	2035
Combustion Turbine	H-class	442	1,790	9.90	1.59	9,096	2035
	F-class	236	2,250	13.99	1.75	10,104	2035
Aeroderivative Turbine	(2) LM6000 ("LM")	110	3,130	31.15	7.54	9,477	2031
RICE²⁸	6 x 18V50DF	106	3,027	31.57	6.28	8,487	2031
Nuclear	Small Modular Nuclear Reactors	300	11,930	191.38	3.55	10,035	2040
	AP1000	1,080	10,073	131.27	3.14	10,500	2040

Based on the 2024 ATB projections, capital costs for NGCC resources are assumed to decline in real dollars by approximately 0.8 percent per year over the Study Period, while capital costs for combustion turbines, aeroderivative combustion turbines, and RICE resources are assumed to decline in real dollars by approximately 0.9 percent per year. Hence, in nominal dollars, given the underlying general inflation assumption utilized in the 2026 IRP, capital costs for NGCC and CT/RICE resources are assumed to increase at approximately 1.7 and 1.6 percent per year, respectively. Fixed and variable O&M are assumed to escalate at the rate of general inflation, or 2.5 percent per year.

RENEWABLE AND ENERGY STORAGE RESOURCES

Utility-scale solar, wind (both onshore and offshore), and BESS resources have been reflected in EnCompass as PPA options based on estimates of the levelized cost of energy ("LCOE"), or in the case of BESS resources, levelized cost of capacity ("LCOC"), over their useful lives. Santee Cooper assumes, for purposes of the 2026 IRP, that renewable and BESS resources will be implemented through PPAs. However, Santee Cooper and Central will determine the implementation method that best meets their needs over time.

Capital and operating cost assumptions for solar, wind, BESS, and long duration energy storage ("LDES") resources are based on estimates developed by S&L. Capital cost estimates from S&L have been adjusted to add transmission interconnection costs based on data taken from NLR's 2024 ATB Conservative Case. Operating cost estimates from S&L have been adjusted to include

²⁸ Reciprocating internal combustion engine ("RICE") resources

Major Modeling Assumptions

allowances for property taxes, insurance, and land lease costs based on allowances developed from NLR data.

The resulting capital and operating costs (in 2026 dollars and reflecting 2026 online dates assumed for the 2026 IRP) are provided in Table 13, below.²⁹ Table 13 also shows the assumed operating life of these resources, which informs the levelized cost analysis and assumed pricing, and the assumed first year these resources are available to be selected in the portfolio optimization analyses described herein.

Table 13. Renewable Resource Option Parameters

Technology	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr.)	Operating Life (Years)	First Year Available
Solar (PV)	2,022	22.43	30	2031
BESS (4-Hour)	2,180	54.36	20	2031
BESS (8-Hour)	3,584	89.08	20	2031
LDES (100-Hour)	5,912	187.51	20	2037
On-shore Wind	2,392	53.17	30	2034
Off-shore Wind	7,819	137.90	30	2040

New solar and BESS resources are assumed to be available beginning in January 2031, which allows for a reasonable procurement and development timeframe (as reflected by existing solar and BESS resources that Santee Cooper and Central already have under development). On-shore wind resources are assumed to be available beginning in January 2034, which allows for the gradual testing, procurement, and development of such resources in the state. LDES resources are assumed to be available beginning in 2037, which reflects the current non-commercial nature of the technology and allows the industry to assess the results of various pilot projects and develop commercially viable offerings. Due to the development and permitting timeframe for offshore wind resources, such resources are assumed to be available beginning in 2040.

Financing costs are based on the 2024 ATB, reflecting the cost structure of a taxable developer, with some adjustments to the assumed after-tax return on equity, to maintain consistency with broader interest rate trends, and financing structure. Table 14, below, provides the debt interest rates and approximate after-tax return on equity values that underpin renewable and BESS PPA pricing.

²⁹ As these technologies typically reflect declining real capital and fixed O&M cost curves for future installations, the capital and fixed O&M cost values (in constant dollars) for future install years will vary from these values.

Table 14. Renewable and BESS Resource Developer Financing Cost Rates

Technology	Interest Rates
Debt Interest Rate	7.00%
Return on Equity:	
Solar	10.75%
BESS	10.75%
Onshore Wind	12.00%
Offshore Wind	13.00%

As a result of the passage of the OBBB in July 2025, tax credits for solar and wind resources under the Inflation Reduction Act of 2022 (“IRA”) are assumed to be unavailable. For BESS resources, the OBBB fixes the “applicable year” for determination of the phase-out of tax credits under the IRA to 2032, resulting in phase-out of the investment tax credit (“ITC”) beginning in 2034. Projected costs for BESS resources reflect the impact of the ITC with a phase-out beginning in 2036 (to allow for a two-year construction period). Assumed PPA prices reflect that 90 percent of BESS facility costs will be eligible for the ITC and that tax credits are sold for 90 percent of their value.³⁰

Assumed capacity factors of solar and wind resources are based on data taken from the ATB Moderate Case.

Solar production profiles were developed from NLR’s System Advisor Model (“SAM”), utilizing 2019 conditions, to represent a diversified aggregate profile based on several representative locations.

An onshore wind production profile was developed using results from the Wind Resource Study described herein. Offshore wind production profiles were provided by an offshore wind developer and are representative of a typical 24-hour profile by month.

The 2026 IRP reflects the following annual implementation limits on solar and onshore wind resources and are based on Santee Cooper’s experience with solar procurement.

- **Solar** – 300 MW per year
- **Onshore Wind** – 100 MW per year

DEMAND-SIDE RESOURCES

Demand-side resources are evaluated in the 2026 IRP by considering a range of Santee Cooper DSM implementation and cost cases, including a medium DSM implementation case for the Reference Case and low and high DSM implementation sensitivity cases. The DSM cases were evaluated to assess the extent to which DSM resources could reduce loads, meet peak demands, and could otherwise displace the use and addition of supply-side resources. Additionally, DSM

³⁰ Industry estimates typically reflect that 85-90 percent of facility costs will be eligible and that tax credit sales are discounted by 5-15 percent versus the tax credit value (i.e., at 85-95 cents on the dollar).

Major Modeling Assumptions

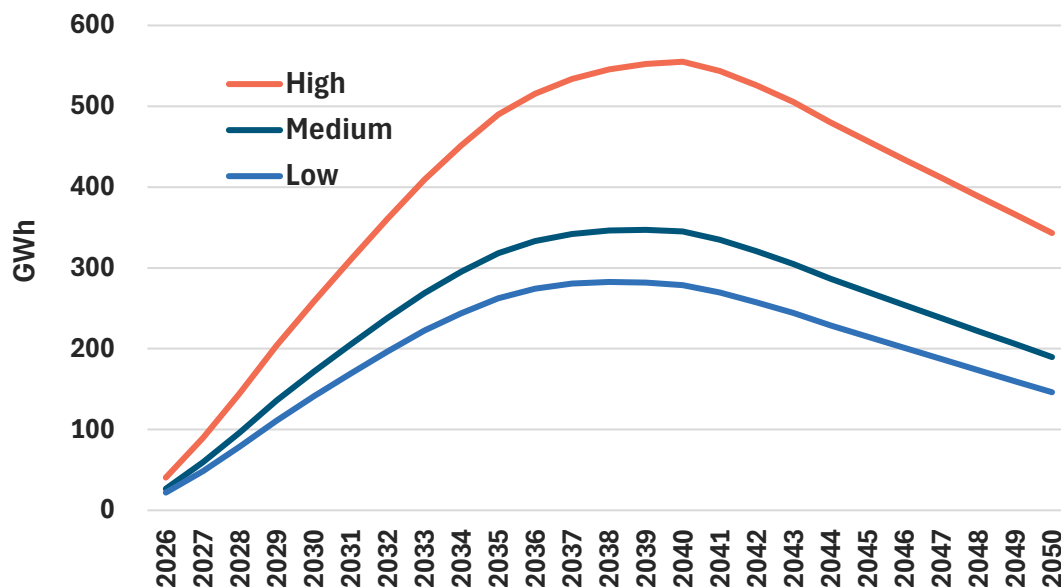
program implementation and operating costs were incorporated in the IRP portfolio evaluations, thereby capturing the net impact that DSM resources have on resource portfolio development and costs. Assumptions for DSM load and demand impacts and DSM program costs are drawn from the market potential studies discussed in the section titled Demand-Side Management Overview.

For EE resources, these variations take the form of reductions to Santee Cooper's load forecast and inclusion of associated program costs. Impacts of future EE program activity are taken from the EE MPS using the following process.

- Monthly energy impacts and seasonal peak demand impacts, as reported in the EE MPS, which reflect the typical energy usage patterns of the underlying impacted end uses
- Monthly peak demand impacts for other months are derived from the above based on the implied seasonal load factor
- Values are extrapolated linearly beyond 2045, the last year of data available from the EE MPS
- All values above are adjusted for distribution and transmission losses

Figure 20 depicts the resulting projected cumulative³¹ reduction in system energy requirements resulting from future EE program activity for the medium, high, and low cases for the Santee Cooper retail system. Projections reflect a decline in cumulative savings beginning around 2040 as a result of a combination of saturation of DSM measures in the equipment stock and improving efficiency in the equipment stock due to future codes and standards.

Figure 20. Santee Cooper Retail System Future DSM EE Energy Savings

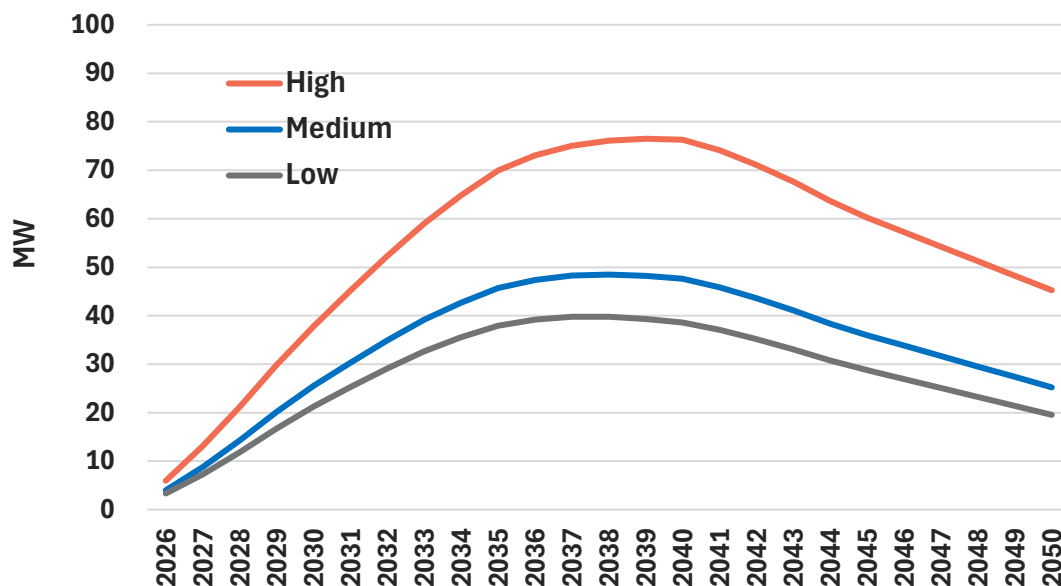


³¹ The term "cumulative" in the context of energy reductions due to DSM programs refers to the reduction in system energy requirements in any year due to the implementation of DSM measures since a base year, in this case 2026, rather than an accumulation of energy reductions since the base year.

Major Modeling Assumptions

Figure 21 depicts the resulting projected reduction in winter peak demand resulting from cumulative future EE program activity for the medium, high, and low cases for the Santee Cooper retail system.

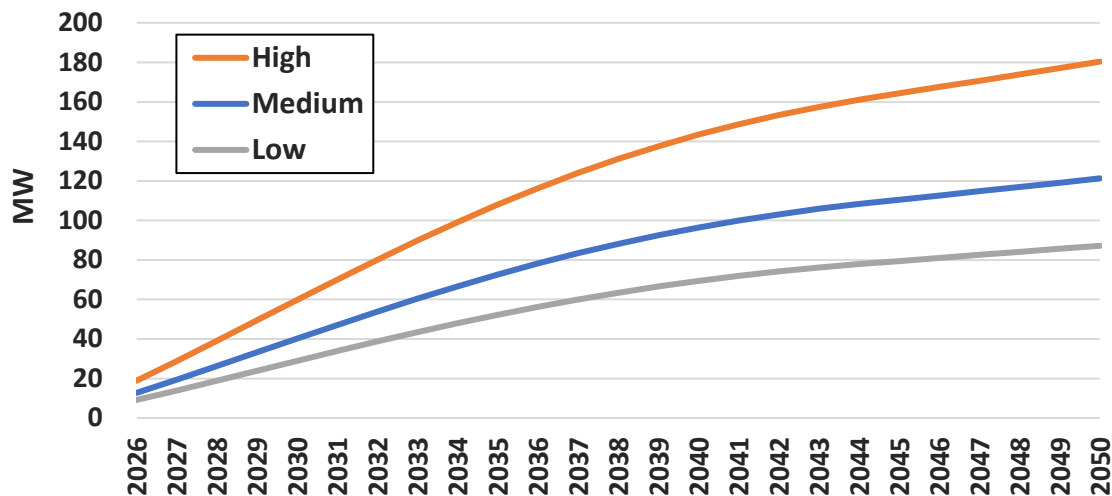
Figure 21. Santee Cooper Retail System DSM EE Winter Demand Savings



For DR resources, these variations reflect differing amounts of DR being available both to offset the need for future supply-side resource additions and, if needed, to meet load during peak load periods. Future assumed DR capability for Santee Cooper's retail system was developed from results of the DR MPS, as discussed in the section titled Demand-Side Management Overview. Monthly impacts were derived from the relevant seasonal peak impacts based on the underlying shape of the relevant segment of Santee Cooper's load, adjusted for losses, as above. Projections beyond 2045 generally reflect a simple linear extrapolation.

Figure 22 depicts the resulting DR program capability at the time of the winter peak for the medium, high, and low cases for the Santee Cooper retail system.

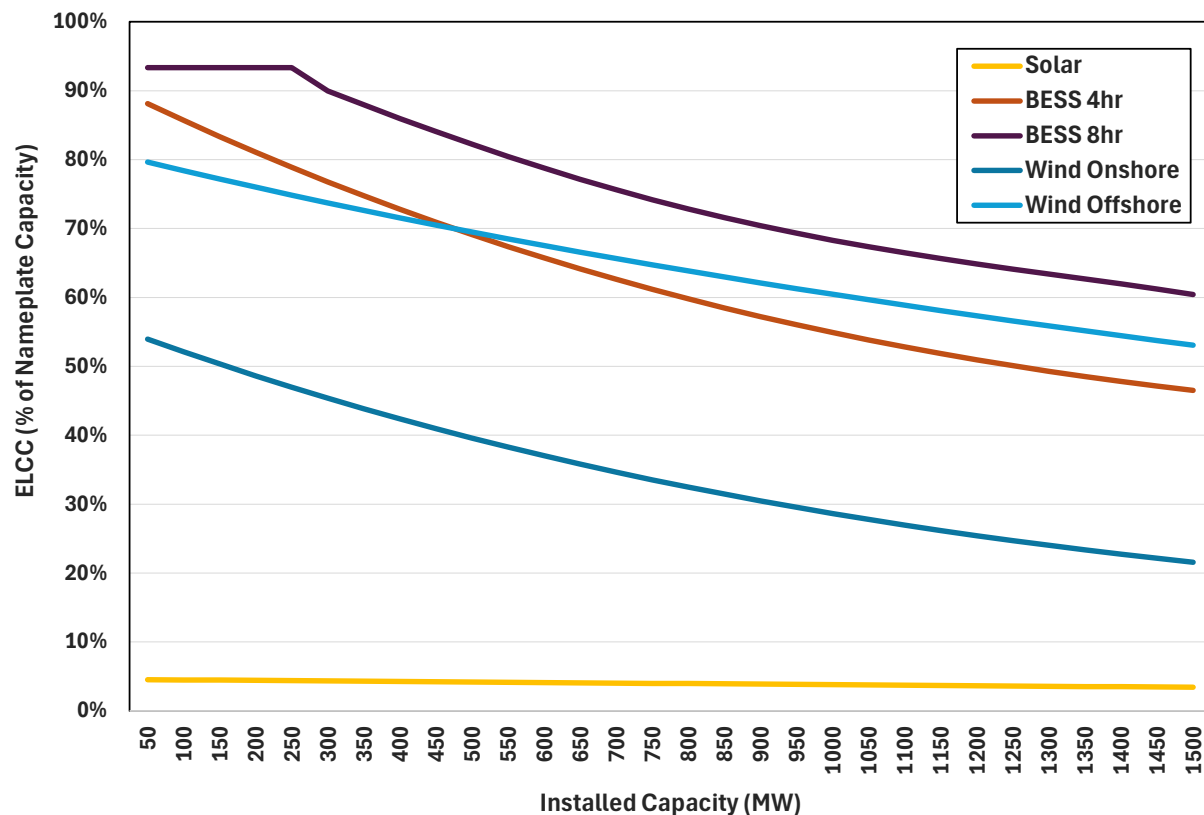
Figure 22. Santee Cooper Retail System Winter DR Capability



EFFECTIVE LOAD CARRYING CAPABILITY

ELCC represents the amount of dependable capacity from a given resource that can be counted on for resource adequacy purposes. The ELCC is determined by finding the amount of additional load that can be served by a given resource without adversely affecting system reliability as compared to a system without the resource. ELCC is represented as a percentage of nameplate capacity and is calculated by dividing the amount of additional peak load that can be served with the resource in place by the nameplate capacity of the additional resource.

In conjunction with the 2026 PRM study and considering input from the Stakeholder Working Group, Santee Cooper worked with PowerGEM to perform an updated ELCC study, including scenarios with higher penetrations of renewable resources. PowerGEM's report providing a discussion of data sources, methodology and results of the study is included herein as Attachment 1: 2025 Reserve Margin and Effective Load Carrying Capability Study. ELCC values for renewable and BESS resources developed from the results of PowerGEM's analyses are depicted in Figure 23, below. The figure reflects that ELCC for any renewable resource type or BESS declines with increasing penetration of a given renewable resource. For wind and solar, this decline is generally due to the intermittent and non-dispatchable nature and diurnal pattern of their output. However, due to the timing of solar output relative to the winter peak, solar ELCC is relatively low even at low levels of penetration. For storage, this decline in ELCC is due to the energy limited nature of the resource. The maximum ELCC any storage resource can contribute is also limited by its outage rate. The graph shows that the 8-hour battery provides full capacity value (limited by its outage rate) until it, too, begins to prove less effective. The ELCC for the 8-hour BESS resource was modeled assuming 750 MW of 4-hour BESS was also in operation.

Figure 23. Effective Load Carrying Capability of Renewable and BESS Resources

TRANSMISSION SYSTEM REQUIREMENTS

Significant investment in the transmission system is expected to be required to support the retirement of existing coal resources which support the Combined System and to integrate replacement resources. This is particularly so if replacement generation of similar magnitude and with similar capabilities is not located at or near the sites of retiring coal facilities. Based on the study discussed in Appendix H: Coal Retirement Study, the estimated cost of incremental transmission investment for portfolios that include the retirement of Cross is assumed to be \$1.2 billion, in 2026 dollars. Otherwise, required transmission investments to accommodate new generation resources are assumed to be similar across the potential resource portfolios studied herein and, as such, are excluded from the portfolio costs reported herein.

This transmission cost estimate should be viewed as a high-level planning estimate that could vary considerably, depending on the precise location and characteristics of resource additions, the amount of new resources being connected at each location, escalation in labor and material costs, changes in interest rates, and transmission siting and permitting requirements.

OPERATING RESERVES

REGIONAL OPERATING RESERVES

For the purposes of the 2026 IRP, the operating reserves modeled in EnCompass include regulating reserves, contingency reserves spinning (spinning reserves), and contingency reserves

Major Modeling Assumptions

supplemental (non-spinning reserves). As a member of the Carolinas Reserve Sharing Group (“CRSG”),³² Santee Cooper is required to carry 235 MW of contingency reserves through 2026, growing to 295 MWs by 2029.

Table 15 below provides the operating reserves modeled half as spinning and half as non-spinning reserves for the IRP analysis and collectively referred to as the Base Ancillary Services Requirements.

Table 15. Base Ancillary Services Requirements

Time Frame	Total Contingency Reserves (MW)	Spinning Reserves (MW)	Non-Spinning Reserves (MW)
2026	235	117.5	117.5
2027	255	127.5	127.5
2028	275	137.5	137.5
2029 & Beyond	295	147.5	147.5

INCREMENTAL OPERATING RESERVES FOR SOLAR

Renewable resources are valued for their ability to produce energy with no emissions and low to no fuel cost. Some renewable resources (e.g., hydro resources) are dispatchable and can be called upon as needed to supply capacity and energy. Other renewable resources (e.g., solar facilities, without storage) are inherently intermittent. While they can inject significant energy into the system, because of the intermittent nature of their production, solar generating resources can require increased operating reserves and ramping capability to reliably manage that intermittency.

For purposes of the 2026 IRP, Santee Cooper relied upon the results of a Solar Integration Study prepared by PowerGEM to evaluate hourly incremental operating reserves required to integrate solar resources into the Santee Cooper system. The 2026 Solar Integration Study Report is included as Attachment 2. The 2026 Solar Integration Study relied on dispatch simulations performed in the SERVIM model that were designed to approximate relative impacts to NERC balancing area standards for Area Control Error and Control Performance Standard 1. The analysis was performed in SERVIM by simulating dispatch of the Santee Cooper system on a five-minute interval basis for a test year while simulating volatility for system loads and solar production. The analysis was performed for a range of solar implementation cases from 250 MW to 2,000 MW, identifying the amount of incremental operating reserves that would be needed to achieve the same level of system reliability as achieved under a case with no solar installed. The results of the study provided a profile of operating reserves required by hour and month for each of the evaluated solar implementation cases.

³² CRSG includes Santee Cooper, Duke Energy Carolina, Duke Energy Progress, and Dominion Energy South Carolina. Each participating member is required to carry its load ratio share of the total contingency reserve requirement for the combined systems based on the previous year’s peak load.

Major Modeling Assumptions

Table 16 summarizes the incremental operating reserve requirements modeled in EnCompass when evaluating portfolios for the 2026 IRP. The table presents an annual average and range of hourly incremental operating reserves modeled in EnCompass during solar production hours as a percent of aggregate solar production.

Table 16. Incremental Operating Reserve Requirements for Solar

Installed Nameplate Solar Capacity (MW)	Range of Incremental Reserves (%)	Average Incremental Reserves (%)
500	0.1% - 15%	3%
750	0.4% - 26%	5%
1000	2% - 40%	8%
1250	13% - 40%	21%
1500	22% - 59%	35%
2000	15% - 55%	26%

RESOURCE PLAN EVALUATION

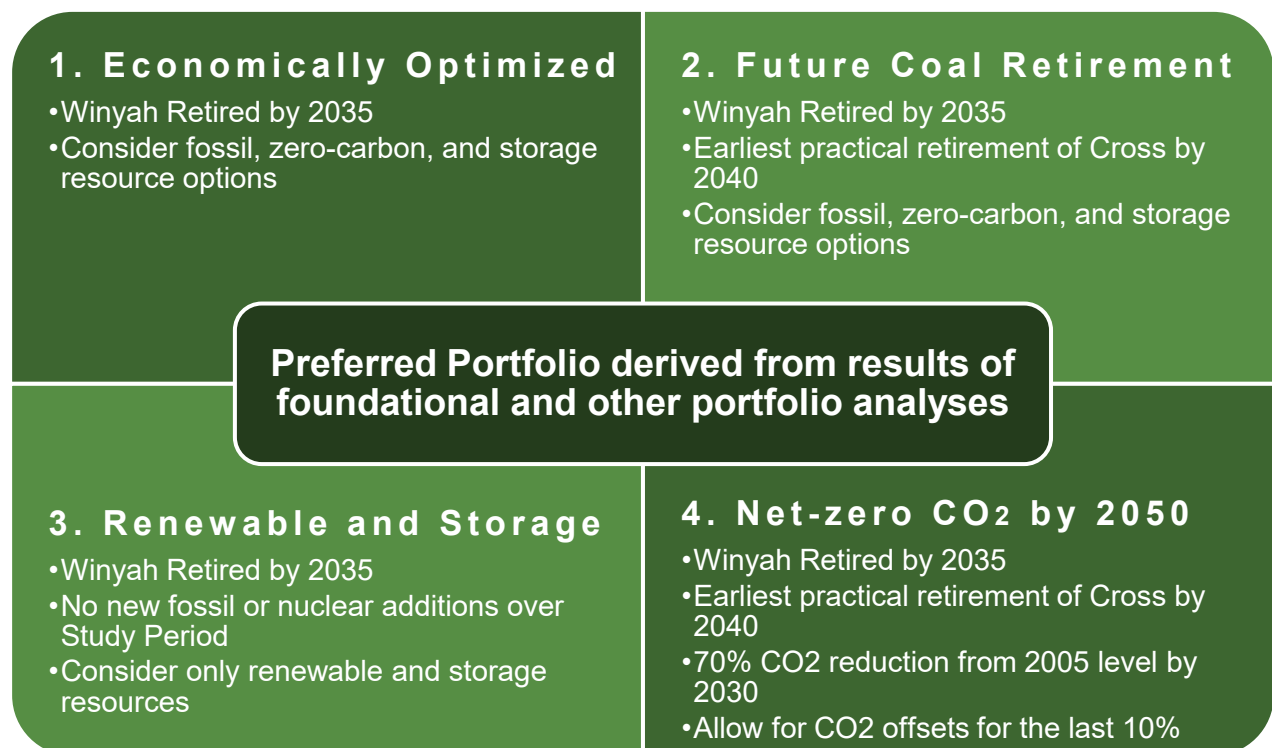
For purposes of the 2026 IRP, Santee Cooper considered four major foundational portfolio alternatives and simulated each for a Base Case set of assumptions and several sensitivity and side cases in order to gain an understanding of the relative impacts on power supply costs, carbon emissions, and other factors of alternative resource options and plans. These alternatives reflect key differences regarding retirement of existing coal resources and constraints on new resources available to meet the system's needs.

Each of these portfolio alternatives, as well as certain side cases, were evaluated under a wide range of assumptions regarding fuel costs, costs of CO₂ regulation, and load growth over the Study Period. Based on those analyses, Santee Cooper formulated its Preferred Portfolio. This approach is similar to that utilized in Santee Cooper's 2023 IRP.

POTENTIAL RESOURCE PORTFOLIOS

Figure 24 lays out the foundational portfolio alternatives Santee Cooper has developed and evaluated within this IRP. These potential strategies have been developed with input from Santee Cooper's stakeholders through the stakeholder engagement process detailed in the Stakeholder Engagement Process section. The portfolio strategies reflect variations in strategies around resource option constraints, coal retirement extent and timing, and the imposition of specific, aggressive carbon reduction targets, as described further below.

Figure 24. Foundational Resource Portfolios



Resource Plan Evaluation

Portfolio 1, the **Economically Optimized Portfolio**, identifies the most cost-effective portfolio assuming Cross continues to operate over the Study Period, without constraints on resource additions.

Portfolio 2, the **Future Coal Retirement Portfolio**, considers the cost impacts and other implications of the retirement of Cross as early as practical, by 2040, in addition to the retirement of Winyah, which is common to all foundational portfolios. The earliest practical date of the retirement of Cross was determined after considering the results of retirement evaluations discussed in Appendix H: Coal Retirement Study and developing a reasonable timeline to implement replacement generation for the 2,330 MW Cross station given the retirement and replacement of the 1,150 MW Winyah station by 2035.

Portfolio 3, the **Renewable and Storage Portfolio** was developed to understand the implications of a build plan considering the addition of only renewables and BESS resources, after the retirement of Winyah by 2035. Cross is assumed to continue to operate in Portfolio 3.

Portfolio 4, the **Net Zero CO₂ by 2050 Portfolio** reflects the retirement of all coal resources and the imposition of CO₂ emissions targets over the Study Period designed to achieve net zero CO₂ emissions by 2050, with allowance for the use of offsets. CO₂ emissions targets were set to achieve an interim goal of reducing emissions to 70% of 2005 levels by 2030 and achieving a 90% reduction from the 2005 level by 2050, leaving the remaining 10% to be met using offsets. This approach is intended to recognize the progressively higher cost of achieving carbon reductions and the likelihood that offsets will represent a more economic means of doing so, on a net basis. The optimization analysis reflects simultaneous objectives of achieving emissions targets and minimizing total production costs.

ASSUMED NEAR-TERM RESOURCES

As discussed in the Electric Load Forecast Overview section, Santee Cooper continues to experience load growth relative to the 2023 IRP. Figure 11, from a previous section, shows that from 2027-2032, prior to the online date of the Canadys Joint NGCC, the Combined System is deficient during the winter season (without the addition of resource during this period). To address this deficiency for modeling purposes, the 2026 IRP assumes a combination of resources to meet near-term capacity needs, including BESS resources brought online in 2029 and 2030, LM resource brought online in 2031, and market capacity available for short-term purchases to meet load requirements from 2027-2030.

Near-term additions to Santee Cooper's resources assumed for modeling purposes in the optimization analyses for the Reference Case (defined and discussed in the next subsection, below) include the following ("Assumed Near-term Resources").

- BESS (4-hour) resources of 350 MW in 2029 and an additional 50 MW in 2030³³
- LM resources totaling 142 MW in 2031³⁴

³³ MW values are nameplate capacity and do not account for the ELCC value.

³⁴ Winter Net Dependable Capacity assuming operation on fuel oil during the winter peak season.

Resource Plan Evaluation

Santee Cooper is evaluating multiple options to obtain near-term resources to fill the capacity needs from 2027-2032 and will determine at a future date the actual resources to be added to the system. Santee Cooper, in coordination with Central, will select resources that reliably and cost effectively meet system needs. Refer to the Short-Term Action Plan section of this IRP for a discussion of how Santee Cooper plans to evaluate meeting the near-term capacity need.

POSSIBLE TENANCY-IN-COMMON INTEREST IN FAIRFIELD NUCLEAR

As discussed in the Recent Activities and Developments section, under the proposed transaction contemplated by the December 8, 2025 MOU with Brookfield, Santee Cooper could receive up to a 25 percent tenancy-in-common interest in the two AP1000 once completed. For the Reference Case, the 2026 IRP assumes Santee Cooper will receive 625 MW, or 312.5 MW from each of two nuclear units, with the units coming online as planned by January 2032 and January 2033, respectively.³⁵ Additionally, to address certain resource planning risks that may occur for Santee Cooper if the Fairfield units are not added as currently planned, the resource plan evaluation includes scenarios in which Fairfield is not developed.

OVERVIEW OF METHODOLOGY

SOFTWARE

For its 2026 IRP, Santee Cooper utilized the EnCompass power systems dispatch and optimization simulation software system from Yes Energy. EnCompass provides a flexible tool for simulating generating resource operations and long-term resource expansion decisions using a mixed integer linear programming algorithm.

For the 2026 IRP, portfolio optimization simulations (resource expansion simulations) were performed in EnCompass for each of the foundational portfolios using a standard set of reference case assumptions (described below). These portfolios were then simulated in EnCompass using a detailed chronological dispatch under the Reference Case assumptions and under sensitivity assumptions for fuel and CO₂ prices to develop projections of production costs over the Study Period. Additionally, sensitivities were performed for low and high load forecast assumptions and low and high DSM implementation assumptions. For these sensitivity cases, the foundational portfolios were reoptimized in EnCompass to identify how resource additions would change under different load and DSM implementation assumptions and were then simulated for projected production costs over the Study Period.

REFERENCE CASE

For purposes of portfolio optimization and dispatch simulation, a Reference Case was developed reflecting assumptions for key variables, as described in Table 17, below.

³⁵ Reflects capacity ratings and dates submitted by the Interconnection Customer through Santee Cooper's Open Access Transmission Tariff interconnection process.

Table 17. Reference Case Definition

Key Uncertainty	Reference Case Assumption	Assumption Basis
Fuel Prices	Medium Case	2026 AEO Counterfactual Baseline
CO₂ Emissions Cost	Low Case	No regulation of CO ₂ (CO ₂ emissions cost of \$0/ton)
Load Forecast	Medium Case	2026 Load Forecast Base Case, as discussed in section titled Electric Load Forecast Overview
Demand-side Management	Medium Case	As discussed in section titled Demand-Side Management Overview
Resource Option Capital and Fixed Costs	As described in the section above titled Resource Option Assumptions	

PORTFOLIO COST ANALYSES

Optimized portfolio simulations were performed for each foundational portfolio under the Reference Case assumptions. Each of the resource portfolios were simulated and optimized using EnCompass over the Study Period, yielding optimized resource additions and resource plans specific to each portfolio definition. To project variable portfolio production costs (e.g., fuel costs, renewable energy costs, emissions costs, etc.), optimized resource plans for each foundational portfolio were simulated using an hourly 8760 chronological representation, resource commitment simulation, resource operating limitations (minimum up/down times, ramp rates, ELCC capability, etc.), system operating reserves, and incremental operating reserve requirements for intermittent resources. Incremental capital costs, fixed operating costs, costs for transmission upgrades, and DSM program costs were included with the simulated variable production costs to determine total portfolio costs.

MODELED POWER COSTS

For the 2026 IRP, reported power supply costs include only those categories that vary between the resource portfolios and sensitivity cases being evaluated. More specifically, the following categories of power supply costs were considered.

- Capital cost for new resources
- Differences in fixed O&M and capital expenses for existing resources evaluated for retirement at differing timeframes (i.e., Cross and Winyah)
- Fixed costs for incremental PPAs, including fixed PPA costs for BESS additions
- Natural gas firm reservation costs
- Fuel cost
- Purchased energy costs
- Variable O&M costs
- Emissions-related costs

Resource Plan Evaluation

- Demand-side management program costs
- Costs of transmission system upgrades (for portfolios that include the retirement of the Cross Generating Station)
- Transmission losses (for resources wheeled from off system)

For purposes of estimating the impact of variations in power costs on rates, additional system costs were separately projected and combined with projected power costs, as described in the Rate Impacts of Portfolios section.

RISK ANALYSIS APPROACH

In addition to the Reference Case assumptions, sensitivity cases were evaluated for each portfolio for the following variables.

- **Fuel Prices** – High and Low Case projections drawn from variations reflected in the AEO High and Low Oil and Gas Supply Cases
- **CO₂ Emissions Costs** – Medium and High Case costs of CO₂ emissions drawn from estimates of the social cost of CO₂ developed by the federal government
- **Load Forecast** – High and Low Case forecasts as described in the Electric Load Forecast Overview section
- **Demand-side Resources** – High and Low Case, drawn from more and less aggressive cases of DSM activity, impacts, and associated costs

Detailed descriptions of the assumptions and associated projections are provided in the preceding sections.

For each sensitivity case simulation, production costs for resource plans resulting from optimization under the Reference Case assumptions were simulated with the variations in fuel prices and CO₂ emissions costs outlined above. Projected values for other sensitive variables were assumed to remain at the Reference Case values. The purpose of evaluating these sensitivity cases is to understand the sensitivity of portfolio costs to changes in certain key assumptions and the resulting impact on power costs and other metrics that may occur after the adoption of key initial resource decisions. For purposes of the load forecast and DSM sensitivities, however, given the variations in future load levels and resource need inherent in these cases, an additional portfolio optimization was run for each sensitivity, which allowed EnCompass flexibility to determine the most economic build plans for each sensitivity case.

The resulting power costs across these sensitivities are utilized, in part, to inform some of the Portfolio Metrics discussed below.

PORTFOLIO METRICS

Guided by S.C. Code Ann. § 58-37-40 and Commission direction in previous IRP proceedings, Santee Cooper's evaluation of portfolios included development and review of the following metrics:

- **NPV Cost** – Total cumulative NPV power supply costs over the Study Period
- **Mini-Max Regret** – Assesses the potential for each resource plan to incur higher costs than other plans under the same sensitivity case

Resource Plan Evaluation

- **Fuel Cost Resiliency** – Measures the degree to which resource plan costs vary with respect to modeled variations in fuel prices
- **CO₂ Emissions** – Total emissions and emissions rate over the Study Period and at specific points in time
- **Generation Diversity** – Measure of the balance in the mix of sources of generation, with no single resource type dominating the generation sources
- **Clean Energy** – Percentage of generation that is from non-CO₂-emitting resources, including solar, wind, hydro, landfill methane gas, biomass, and nuclear facilities
- **Fixed Cost Obligations** – Cumulative capital and fixed costs, including firm natural gas reservation costs, PPA cost obligations, and fixed O&M costs
- **Load Sensitivity** – Measures the extent to which power costs are impacted by variations in load growth and accommodated through changes in the resource build decisions

It is important to recognize that some of the metrics inherently measure highly related issues. However, the metrics nonetheless provide useful information regarding the relative merits of potential resource portfolio directions. A separate evaluation of reliability was also performed, as discussed later in this section.

PORTFOLIO OPTIMIZATION RESULTS

Each of the resource portfolios were simulated and optimized using EnCompass over the Study Period, yielding variations in resource additions and resource plans specific to each portfolio. The resulting build plan for each portfolio is discussed below, and detailed build tables are provided in Appendix C: Optimized Portfolio Builds.

Each portfolio can be directly compared to others because each resulting build plan reflects a portfolio that meets the same future Combined System load, thus allowing a comparison across multiple metrics, including NPV power costs, CO₂ emissions, fuel cost resiliency, and portfolio diversity, among other metrics.

ECONOMICALLY OPTIMIZED PORTFOLIO

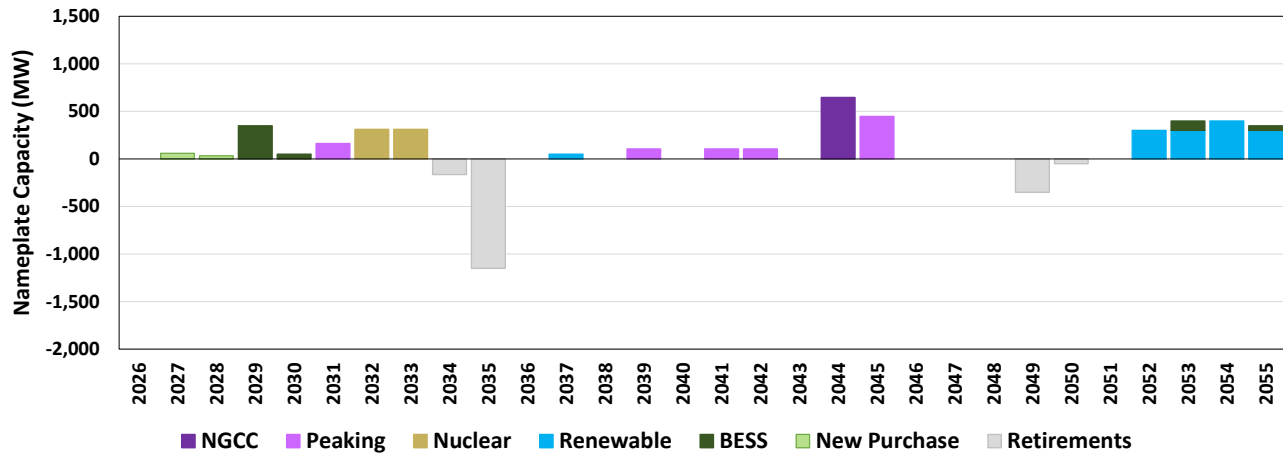
The Economically Optimized Portfolio offers a wide range of resource options to EnCompass to meet system requirements and reflects an unconstrained portfolio optimization minimizing the long-term cost of power. This resulted in the resource changes depicted in Figure 25 below over the Study Period.

Figure 25 depicts resource additions as colored bars of MW capacity amounts (based on nameplate capacity) measured on the positive portion of the Y-axis, each color indicating a particular resource type as shown in the legend. Resource retirements, as well as the expiration of the term of purchases, are shown as gray bars of capacity amounts measured on the negative portion of the Y-axis. For example, the gold bars in 2032 and 2033 depict the addition of the Fairfield TIC, while the negative gray bar in 2035 depicts the retirement of Winyah by year-end 2034. The gray bars over 2048-2050 reflect retirements of early-installed BESS capacity at the end of the twenty-year life of these resources. Similar charts are provided for the other portfolios

Resource Plan Evaluation

below. Changes related to Existing PPAs and Committed Resources are not shown on these charts. Comprehensive build plan tables are provided in Appendix C.

Figure 25. Economically Optimized Portfolio Build Plan



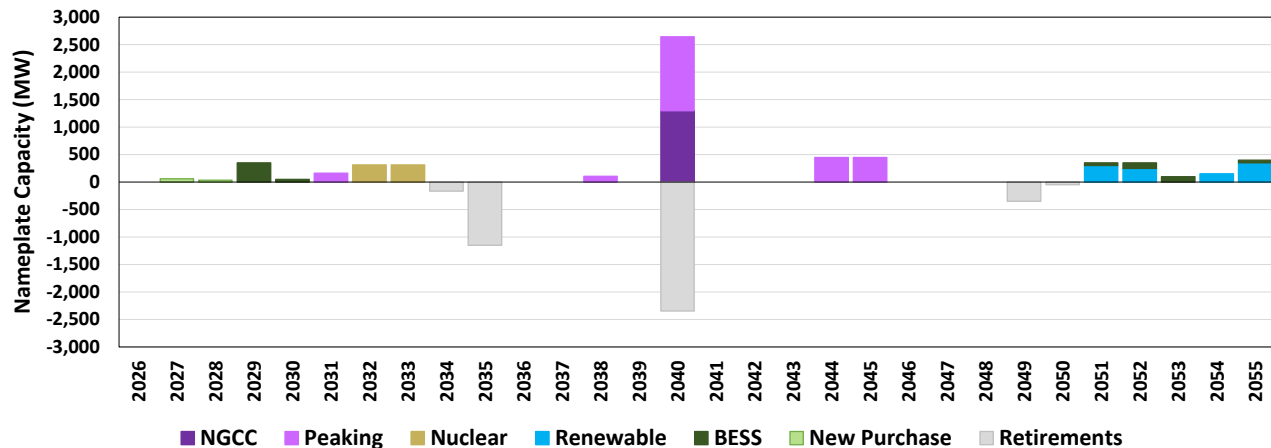
In addition to the common resource changes assumed across the portfolios, the portfolio optimization simulation identifies the following major resource changes.

- Peaking resources, generally RICE units, totaling 318 MW, added over 2039-2042
- New industrial frame NGCT resource (449 MW) added in 2045
- New 1x1 NGCC resource of 648 MW added in 2044
- New solar, wind, and BESS resources totaling 1,200 MW, 100 MW, and 150 MW, respectively, added in the later years of the Study Period. A 50 MW wind resource is also added in 2037, but Santee Cooper views this optimized addition as simply a function of the small resource need in that year and the lack of other modeled options of a similar small size.

Capacity additions for the Economically Optimized Portfolio over the Study Period total approximately 3,000 MW in addition to the Assumed Near-term Resources, changes to Existing PPAs, Committed Resources, and Fairfield modeled for all portfolios.

FUTURE COAL RETIREMENT PORTFOLIO

The Future Coal Retirement Portfolio reflects the retirement of Winyah by 2035 and Cross by 2040 and an optimization minimizing long-term power costs, resulting in the resource changes depicted in Figure 26, below, over the Study Period.

Figure 26. Future Coal Retirement Portfolio Build Plan

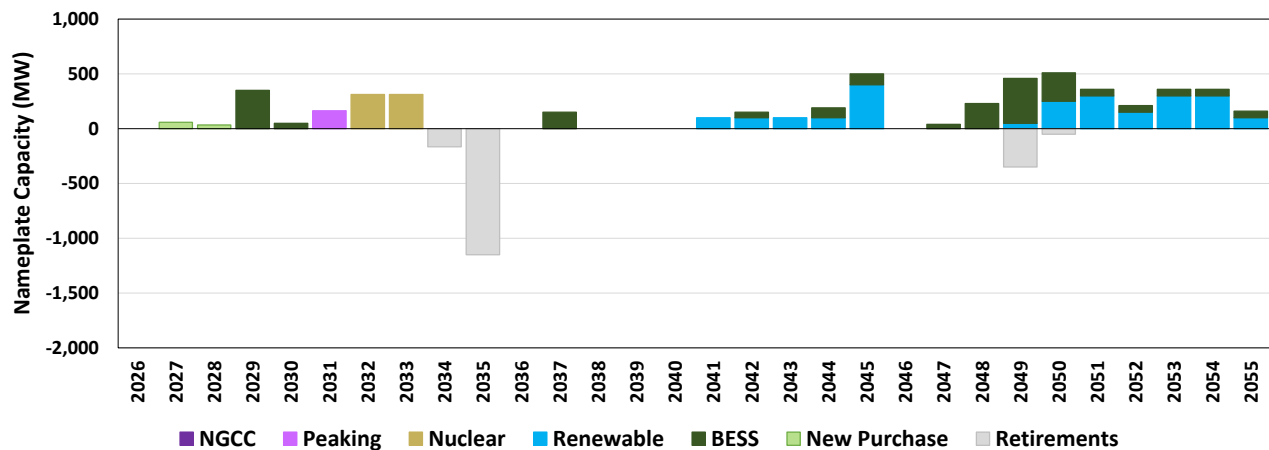
The portfolio optimization simulation identifies the following major resource changes, in addition to the retirement of Cross and the common resource changes assumed across the portfolios.

- Two 1x1 NGCC resources totaling 1,296 MW and three (3) industrial frame NGCT, totaling 1,347 MW, added in 2040 as the primary resources to offset the retirement of Cross
- RICE peaking resources, totaling 106 MW, are added in 2038
- Additional two industrial frame NGCTs, totaling 898 MW, added over 2044-45 (also dual-fueled units)
- New solar, wind, and BESS resources totaling 850 MW, 200 MW, and 300 MW, respectively, added in the later years of the Study Period to meet load requirements

Capacity additions for the Future Coal Retirement Portfolio total nearly 5,000 MW in addition to the Assumed Near-term Resources, changes to Existing PPAs, Committed Resources, and Fairfield modeled for all portfolios.

RENEWABLE AND STORAGE PORTFOLIO

The Renewable and Storage Portfolio reflects an optimization to minimize the long-term cost of power but limits the resource options offered to EnCompass to only solar, wind, and BESS resources. The resource changes over the Study Period for this portfolio are depicted in Figure 27, below.

Figure 27. Renewable and Storage Portfolio Build Plan

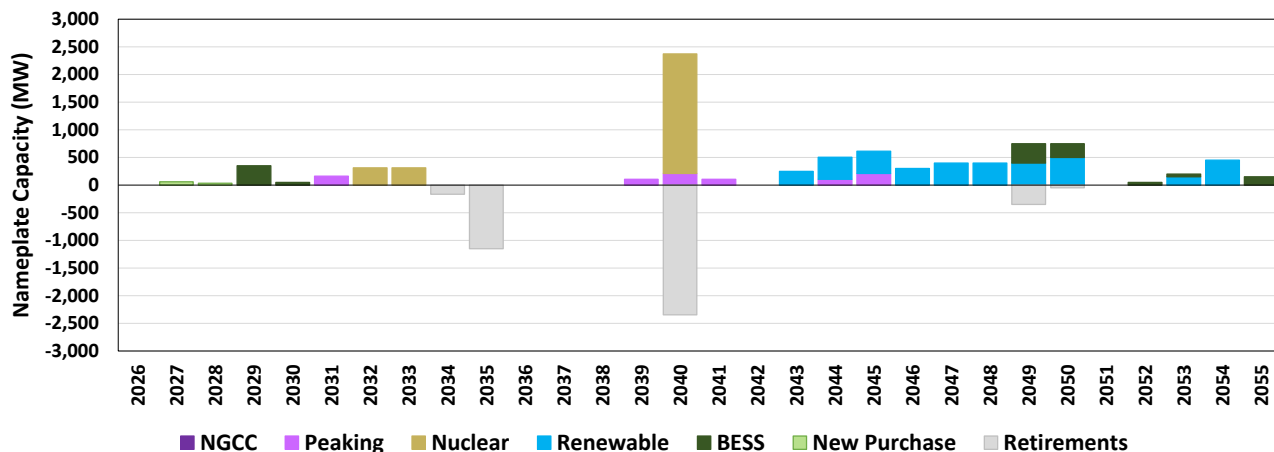
The portfolio optimization simulation identifies the following major resource additions over the Study Period, in addition to the common resource changes assumed across the portfolios.

- New solar resources totaling 1,750 MW of nameplate capacity
- New wind totaling 500 MW of nameplate capacity
- New BESS resources totaling 1,630 MW

Capacity additions for the Renewable and Storage Portfolio total approximately 3,900 MW in addition to the Assumed Near-term Resources, changes to Existing PPAs, Committed Resources, and Fairfield modeled for all portfolios.

NET ZERO CO₂ BY 2050 PORTFOLIO

The Net Zero CO₂ by 2050 Portfolio offers a wide range of resource options to EnCompass to meet system requirements and reflects an optimization to minimize the long-term cost of power while requiring CO₂ emissions to be reduced to 30% of 2005 emission levels by 2040 and further reduced to 10% of 2005 levels by 2050. The portfolio retires Cross by 2040. This portfolio optimization resulted in the resource changes depicted in Figure 28, below, over the Study Period.

Figure 28. Net Zero CO₂ by 2050 Portfolio Build Plan

Resource Plan Evaluation

The portfolio optimization simulation identifies the following major resource changes, in addition to the retirement of Cross by 2040 and the common resource changes assumed across the portfolios.

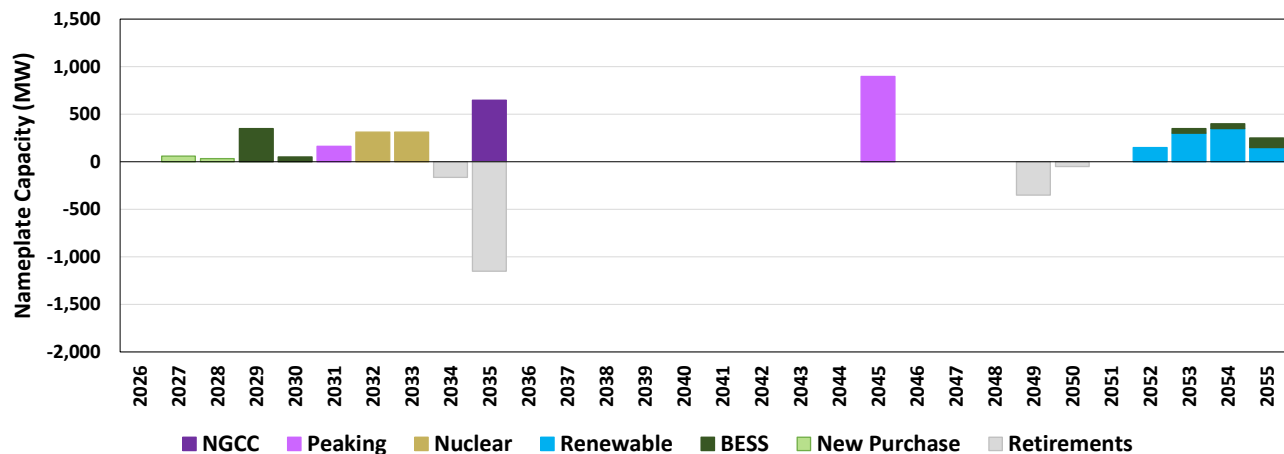
- Two AP1000 nuclear units, totaling 2,160 MW, are added in 2040 as the primary resource to offset the retirement of Cross and to meet CO₂ emission targets
- Peaking resources, generally RICE units, totaling 743 MW, are added over 2039-2045
- New solar, wind, and BESS resources totaling 2,600 MW, 1,050 MW, and 850 MW, respectively, added over 2043-2055

Capacity additions for the Net Zero CO₂ by 2050 Portfolio total approximate 7,400 MW in addition to the Assumed Near-term Resources, changes to Existing PPAs, Committed Resources, and Fairfield modeled for all portfolios.

ADJUSTED ECONOMIC PORTFOLIO

Based on review of the optimized resource builds across the foundational portfolios and considering the need for flexibility to respond to higher load growth, regulatory uncertainty, and/or resource implementation risk, Santee Cooper further developed a variation on the Economically Optimized Portfolio, which reflects the addition of the 2035 NGCC Resource and otherwise optimizes resource builds without further constraints (“Adjusted Economic Portfolio”). This portfolio optimization resulted in the resource changes depicted in Figure 29, below, over the Study Period.

Figure 29. Adjusted Economic Portfolio Build Plan



In addition to the common resource changes assumed across the portfolios, the portfolio optimization simulation identifies the following major resource changes, including the assumed 2035 NGCC Resource.

- The aforementioned 1x1 NGCC of 648 MW is added in 2035 (based on assumption)
- Two new industrial frame CTs are added in 2045, totaling 898 MW (configured as a dual-fuel unit to assure firm fuel supply)
- New solar, wind, and BESS resources totaling 900 MW, 50 MW, and 200 MW, respectively are added in the out years of the Study Period to meet load requirements

Resource Plan Evaluation

Capacity additions for the Adjusted Economic Portfolio over the Study Period total approximately 2,700 MW in addition to the Assumed Near-term Resources, changes to Existing PPAs, Committed Resources, and Fairfield modeled for all portfolios.

COMPARISON OF OPTIMIZED PORTFOLIOS

Table 18 summarizes the build plan for each of the portfolios through 2055. Detailed build plans for each portfolio are shown in Appendix C: Optimized Portfolio Builds. Note that the values below include the Assumed Near-term Resources and the assumed Fairfield TIC but exclude Existing PPAs and Committed Resources.

Table 18. Summary of Optimized Portfolios

Resource Changes Over the Study Period	Optimized Portfolios – Additions (Retirements) in MW				
	Economically Optimized Portfolio	Future Coal Retirement Portfolio	Renewable and Storage Portfolio	Net Zero CO ₂ by 2050 Portfolio	Adjusted Economic Portfolio
Cumulative Capacity Added					
NGCC	648	1,296	0	0	648
Peaking	909	2,493	142	885	1,040
Nuclear	625	625	625	2,785	625
Solar (Nameplate)	1,200	850	1,750	2,600	900
Wind (Nameplate)	150	200	500	1,050	50
BESS (Nameplate)	550	700	2,030	1,250	600
Total	4,083	6,164	5,047	8,570	3,863
Cross Retirement	0	2,330	0	2,330	0

The following key conclusions can be drawn from analysis of the resource builds shown above.

- **NGCC Resources.** The Economically Optimized Portfolio adds a 1x1 NGCC in 2044, while the Future Coal Retirement Portfolio adds two 1x1 NGCC resources in 2040, providing clear indications that additional NGCC resources would be desirable to meet load growth or replace retiring resources. However, it is important to recognize that, without the assumed availability of the Fairfield TIC in the early 2030s, which significantly reduces the need for capacity additions throughout the 2030s under the Reference Case assumptions, additional resources would be required. The Adjusted Economic Portfolio assumes the 1x1 NGCC resource added in 2044 in the Economically Optimized Portfolio is brought forward to 2035, coincident with the timing of Winyah retirement.
- **Solar and Wind Resources.** Only the Renewable and Storage and Net Zero CO₂ by 2050 Portfolios reflect additions of solar and wind resources prior to 2046. With the termination of tax credits, these resources have generally become more expensive than fossil-fueled resource options and are not economic.
- **BESS Resources.** Only the Renewable and Storage Portfolio reflects additions of BESS resources derived through the portfolio optimizations after 2030 but prior to 2046.

- **Nuclear Resources.** The Net Zero CO₂ by 2050 Portfolio reflects the addition of a two-unit nuclear resource, totaling 2,160 MW, as the primary replacement resource for Cross upon its assumed retirement by 2040.

PORTFOLIO RELIABILITY VERIFICATION

Reliability of electric service is an essential product of a utility. To ensure each portfolio achieves reliability thresholds, Santee Cooper requested that PowerGEM simulate and evaluate the reliability of each portfolio for the year 2040 utilizing the SERV model and processes that are similar to those used to establish Santee Cooper's planning reserve margin. Table 19 summarizes the estimated reliability of each of the portfolios on the basis of the following common industry metrics:

- **Loss of Load Expectation ("LOLE")** – The number of individual days with firm load shed—a common threshold is one event day per 10 years or 0.1 days per year
- **Expected Unserved Energy ("EUE")** – The total amount of unserved energy
- **Loss of Load Hours ("LOLH")** – The number of individual hours with firm load shed
- **Normalized Expected Unserved Energy ("nEUE")** – Allows for comparison of EUE between study years and systems with differing load levels

Table 19. Reliability Metrics for the Foundational and Adjusted Economic Portfolios

Scenario	LOLE (Days/Yr)	EUE (MWh)	LOLH (Hours/Yr)	nEUE
Economically Optimized Portfolio	0.072	128	0.24	3.085
Future Coal Retirement Portfolio	0.029	33	0.07	0.795
Renewable and Storage Portfolio	0.088	164	0.31	3.952
Net Zero CO ₂ by 2050 Portfolio	0.037	54	0.11	1.301
Adjusted Economic Portfolio	0.020	23	0.05	0.022

The results verify that each portfolio is reliable without needing to add additional capacity resources and meets the threshold LOLE value of less than 0.1 days/year.

PORTFOLIO METRICS

To evaluate the portfolios, Santee Cooper simulated each portfolio under the Reference Case assumptions and a series of sensitivity cases. The sensitivity cases represent a reasonably broad range of future conditions related to fuel prices, CO₂ emissions cost, DSM program activity, and load levels. To allow for total costs and emissions to be comparable, results are separately provided for sensitivities reflecting Base Load Forecast load levels and those reflecting variations in the load forecast.

Projected NPV power costs are shown herein in billions of dollars. Some differences between portfolios can be within rounding and may impact comparisons that are illustrated as differences in color-coding of resulting values.

NPV POWER COSTS

The NPV Power Cost metric measures the costs to customers of each of the resource portfolios based on NPV modeled power costs in 2026 dollars of each portfolio over the Study Period. Table 20 compares the NPV power cost for the portfolios under the Reference Case Assumptions, with color-coding from green, gold, and then to a rose color indicating lowest to highest values.

Table 20. Comparison of NPV Power Costs for the Reference Case

Portfolios	NPV Power Costs (\$B)
Economically Optimized	\$32.7
Coal Retirement	\$35.8
Renewable and Storage	\$34.0
Net Zero	\$44.1
Adjusted Economic	\$33.3
<u>Difference to Economically Optimized</u>	
Coal Retirement	\$3.1
Renewable and Storage	\$1.3
Net Zero	\$11.4
Adjusted Economic	\$0.6

The Reference Case results show that the Economically Optimized Portfolio is projected to have the lowest NPV power cost, followed closely by the Adjusted Economic Portfolio. The relatively small difference between these cases, as compared to differences with the other portfolios, indicates that the impact of assuming an earlier implementation of the new 1x1 NGCC in 2035, rather than 2044 as in the Economically Optimized Portfolio, has a limited impact on power costs. Additionally, the earlier development of this resource will help ensure adequate resources in the event of greater-than-expected load growth and reduces risk related to resource implementation.

The other portfolios are shown to have somewhat to considerably higher NPV power costs. The Renewable and Storage and Coal Retirement Portfolios are shown to have 4.0 percent and 9.6 percent higher NPV power costs, respectively. The results in Table 20 also demonstrate that the Net Zero CO₂ by 2050 Portfolio is projected to result in NPV power costs that are more than \$11 billion, or 35 percent, higher than the Economically Optimized Portfolio under the Reference Case assumptions. Much of the incremental costs under the Net Zero Portfolio result directly from the additional costs of nuclear replacement resources necessitated by the assumed retirement of Cross and the need to achieve CO₂ emission targets.

A summary of NPV power costs by portfolio over both the full Study Period and a 20-year period from 2036-2055 is provided in Appendix D: NPV Power Cost Summary.

FUEL COST RESILIENCY

Table 21 provides an assessment of the sensitivity of costs for each portfolio by comparing NPV fuel costs across the fuel price cases and the total range of uncertainty for each portfolio. Results

reflect that the Net Zero CO₂ by 2050 Portfolio results in the lowest range of uncertainty; however, it should be noted that the Net Zero CO₂ by 2050 Portfolio achieves this result through resource retirement and significant investment in high capital cost resources. Additionally, as shown in the far-right column of the table, power costs for the Future Coal Retirement Portfolio are much more sensitive to future fuel prices than the other portfolios studied as a result of the replacement of Cross generation primarily with additional natural gas-fueled NGCC resources. Therefore, in addition to incurring the capital costs to replace Cross, a decision to retire Cross would also cause much greater reliance on a single fuel and uncertainty regarding fuel costs over the Study Period.

Table 21. Fuel Price Sensitivity Results

Portfolio	NPV Fuel Costs (\$B)			Range of Uncertainty
	Low Fuel Price	Reference Case	High Fuel Price	
Economically Optimized	\$18.3	\$23.7	\$34.4	\$16.0
Coal Retirement	\$17.5	\$23.5	\$42.4	\$24.9
Renewable and Storage	\$18.5	\$23.3	\$32.6	\$14.1
Net Zero	\$14.4	\$17.6	\$24.2	\$9.8
Adjusted Economic	\$17.9	\$23.6	\$34.5	\$16.6

CO₂ EMISSIONS

Santee Cooper is committed to reducing the carbon footprint of its generating fleet. Table 22 compares CO₂ emissions in millions of tons and CO₂ emissions rates in pounds per MWh of energy produced over the Study Period across the resource portfolios and fixed load sensitivities. Not surprisingly, given the intent of the portfolio, results reflect that the Net Zero CO₂ by 2050 Portfolio would produce the lowest CO₂ emissions, considerably lower than the other portfolios on both a mass and rate basis. However, it is important to consider that this result is achieved in part through significantly higher investment in low-CO₂ resources. The Future Coal Retirement Portfolio is also shown to have modestly lower CO₂ emissions relative to the other portfolios. The other portfolios reflect similar carbon emissions across the sensitivity cases (i.e., within 8% of each other). The Renewable and Storage Portfolio has generally higher CO₂ emissions, because, while it does not add further fossil-fueled resources, it does not reflect the retirement of Cross and in fact relies more heavily on generation by Cross well into the Study Period before significant solar and wind resources are implemented.

Table 22. Comparison of CO₂ Emissions Across Fixed Load Sensitivities

Portfolios	Reference Cases	Low Fuel Price	High Fuel Price	Med CO ₂ Price	High CO ₂ Price
<u>Cumulative Emissions (millions of tons)</u>					
Economically Optimized	552	498	697	512	499
Coal Retirement	475	450	528	459	453
Renewable and Storage	561	512	684	529	513
Net Zero	331	307	383	315	308
Adjusted Economic	537	477	698	491	478
<u>Average Emissions (lbs/MWh)</u>					
Economically Optimized	931	841	1,167	866	844
Coal Retirement	808	765	902	782	771
Renewable and Storage	944	863	1,147	893	867
Net Zero	583	541	675	556	545
Adjusted Economic	905	805	1,169	830	808

MINI-MAX REGRET

The Mini-Max Regret metric evaluates the potential to incur higher power costs by pursuing any resource portfolio relative to other plans as evaluated across the modeled sensitivities. The Mini-Max Regret first measures the difference in NPV power cost between each portfolio and identifies the most cost-effective portfolio for each sensitivity case. That difference can be referred to as the potential regret of choosing a portfolio if the specific sensitivity conditions were to occur. The maximum regret score for each portfolio is the maximum difference observed across all sensitivity cases. This metric indicates which portfolio minimizes the computed maximum regret. The Mini-Max Regret evaluation assumes no change to the portfolios are made in response to the sensitivity conditions unfolding. While this is not necessarily realistic, this evaluation metric provides an indication regarding the relative risks of the various portfolios of the range of sensitivities evaluated.

Table 23 provides the NPV power costs for each portfolio across the fuel and CO₂ price sensitivities and computes the maximum regret by portfolio. The results indicate that the maximum regret is the lowest for the Economically Optimized Portfolio, followed closely behind by the Adjusted Economic Portfolio. The Renewable and Storage Portfolio exhibits a somewhat higher maximum regret driven primarily by the impact of the High CO₂ Price sensitivity given greater reliance on coal generation over the Study Period but still performs relatively well compared to the lowest maximum regret portfolios. The maximum regret for the Future Coal Retirement and Net Zero CO₂ by 2050 Portfolios are considerably higher, in the former case driven by the much greater reliance on natural gas-fueled resources in the High Fuel Price sensitivity and in the latter, by the lack of such resources in the Low Fuel Price sensitivity.

Table 23. NPV Power Costs Across Sensitivities and Maximum Regret (\$B)

Portfolio	Reference Case	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
Economically Optimized	\$32.7	\$27.5	\$43.5	\$40.8	\$54.8
Coal Retirement	\$35.8	\$29.8	\$54.7	\$42.7	\$54.9
Renewable and Storage	\$34.0	\$29.4	\$43.5	\$42.4	\$56.9
Net Zero	\$44.1	\$41.0	\$50.8	\$48.1	\$55.4
Adjusted Economic	\$33.3	\$27.8	\$44.3	\$41.0	\$54.1

Max Regret by Portfolio	
Economically Optimized	\$0.7
Coal Retirement	\$11.3
Renewable and Storage	\$2.8
Net Zero	\$13.5
Adjusted Economic	\$0.9

GENERATION DIVERSITY

The extent to which a resource plan relies significantly upon a single type of resource or fuel can represent a significant source of risk for the system, both in terms of cost and reliability. A useful measure of diversity for this purpose is the coefficient of dispersion, which represents the standard deviation of a series of values divided by the average of the values. A lower coefficient of dispersion corresponds to a more uniform, equally distributed set of values.

Table 24 presents the coefficient of dispersion for capacity and energy by fuel type by the end of the Study Period for each of the portfolios under the Reference Case assumptions. The coefficient of dispersion here represents the standard deviation of portfolio capacity and generation by fuel type in 2055 divided by the average across the fuel types. The Renewable and Storage Portfolio reflects the lowest coefficient of dispersion, reflecting a lower reliance on any one fuel or resource type than the other portfolios, followed by the Net Zero CO₂ by 2050 Portfolio. This greater diversity for these two portfolios is driven primarily from the implementation of greater amounts of renewable and/or nuclear resources.

Table 24. Diversity of Generation Resources Across Portfolios

Portfolios	Coefficient of Dispersion		
	Capacity	Energy	Average
Economically Optimized	1.29	1.46	1.37
Coal Retirement	1.89	1.79	1.84
Renewable and Storage	0.87	1.11	0.99
Net Zero	1.07	1.39	1.23
Adjusted Economic	1.35	1.54	1.45

CLEAN ENERGY PROPORTION

The Clean Energy Proportion metric measures the percentage of system energy that is derived from carbon-free resources, including solar, wind, nuclear, hydro, biomass, and LFG facilities. Table 25 provides the proportion of carbon-free generation across the portfolios over the Study Period for the Reference Case and the fuel price and CO₂ price sensitivities.³⁶ The Net Zero CO₂ by 2050 Portfolio, not surprisingly, derives the highest proportion of system energy from carbon-free resources, due in large part to the retirement of Cross and the installation of nuclear resources as a replacement. The other portfolios reflect a far lower clean energy proportion. The proportion of clean energy for the Renewable and Storage Portfolio is similar to the other portfolios (although slightly higher) as energy produced from solar and wind resources for this portfolio are low relative to the energy produced from existing and committed NGCC resources, thus leading to a greater reliance on energy produced from Cross.

Table 25. Carbon-free Generation Proportion Across Portfolios

Portfolios	Reference Case	Low Fuel Price	High Fuel Price	Med CO ₂ Price	High CO ₂ Price
Economically Optimized	24.4%	24.4%	24.4%	24.4%	24.4%
Coal Retirement	24.2%	24.2%	24.2%	24.2%	24.2%
Renewable and Storage	27.4%	27.4%	27.4%	27.4%	27.4%
Net Zero	52.7%	52.5%	52.9%	52.7%	52.8%
Adjusted Economic	24.0%	24.0%	24.0%	24.0%	24.0%

FIXED COST OBLIGATIONS

The fixed cost obligations metric considers the total fixed costs added to a portfolio that would not vary based on energy provided from the resources being added. These would include debt service and fixed operating costs of new resources, payment obligations under take-or-pay PPAs, and other fixed costs directly attributable to resource decisions. Table 26 provides the total fixed cost obligations across the portfolios on an NPV basis over the Study Period. The results reflect that

³⁶ The values shown are nearly the same for each portfolio across the sensitivities, because the carbon-free resources are non-dispatchable and the energy provided from these resources to serve load is largely the same for a portfolio under all sensitivities.

the Economically Optimized Portfolio incurs the lowest burden of fixed costs of the portfolio options, followed closely by the Adjusted Economic Portfolio. The Net Zero CO₂ by 2050 Portfolio reflects considerably higher fixed cost obligations, driven by the addition of nuclear, solar, wind, and BESS resources.

Table 26.
Fixed Cost Obligations by Portfolio Over the Study Period

Portfolios	NPV (\$B)
Economically Optimized	\$5.4
Coal Retirement	\$8.5
Renewable and Storage	\$7.2
Net Zero	\$22.7
Adjusted Economic	\$6.1

This relative level of fixed cost obligations also provides some indication regarding the sensitivity of the portfolios to the quantity of resources added and the capital intensity of these resources. Variations in capital costs, driven by real escalation in the cost of raw materials (e.g. steel, copper) or equipment that spans all generating resource types, will tend to have the most impact on those portfolios with higher fixed cost obligations, as these are strongly related to capital costs.

FLEXIBILITY TO ADAPT TO LOWER OR HIGHER CUSTOMER LOADS

A key priority for the IRP has been to identify a portfolio that affords Santee Cooper the flexibility to adapt as conditions and levels of customer load changes. Accordingly, Santee Cooper performed sensitivity analyses for each portfolio that assumes variations in the load forecast to understand the flexibility of the portfolios to load levels and the sensitivity of levelized NPV power costs to such load variations. For this purpose, the sensitivity analysis reflects performing an EnCompass optimization to add or eliminate future resources as needed to meet variations in forecast peak demands and capacity requirements. As in the Reference Case optimizations, the assumption was made that the implementation of the Committed Resources and Near-term Assumed Resources would not be affected by potential future variations in load levels, thereby evaluating portfolio flexibility and cost mitigation that may exist outside of these major and early resource decisions.

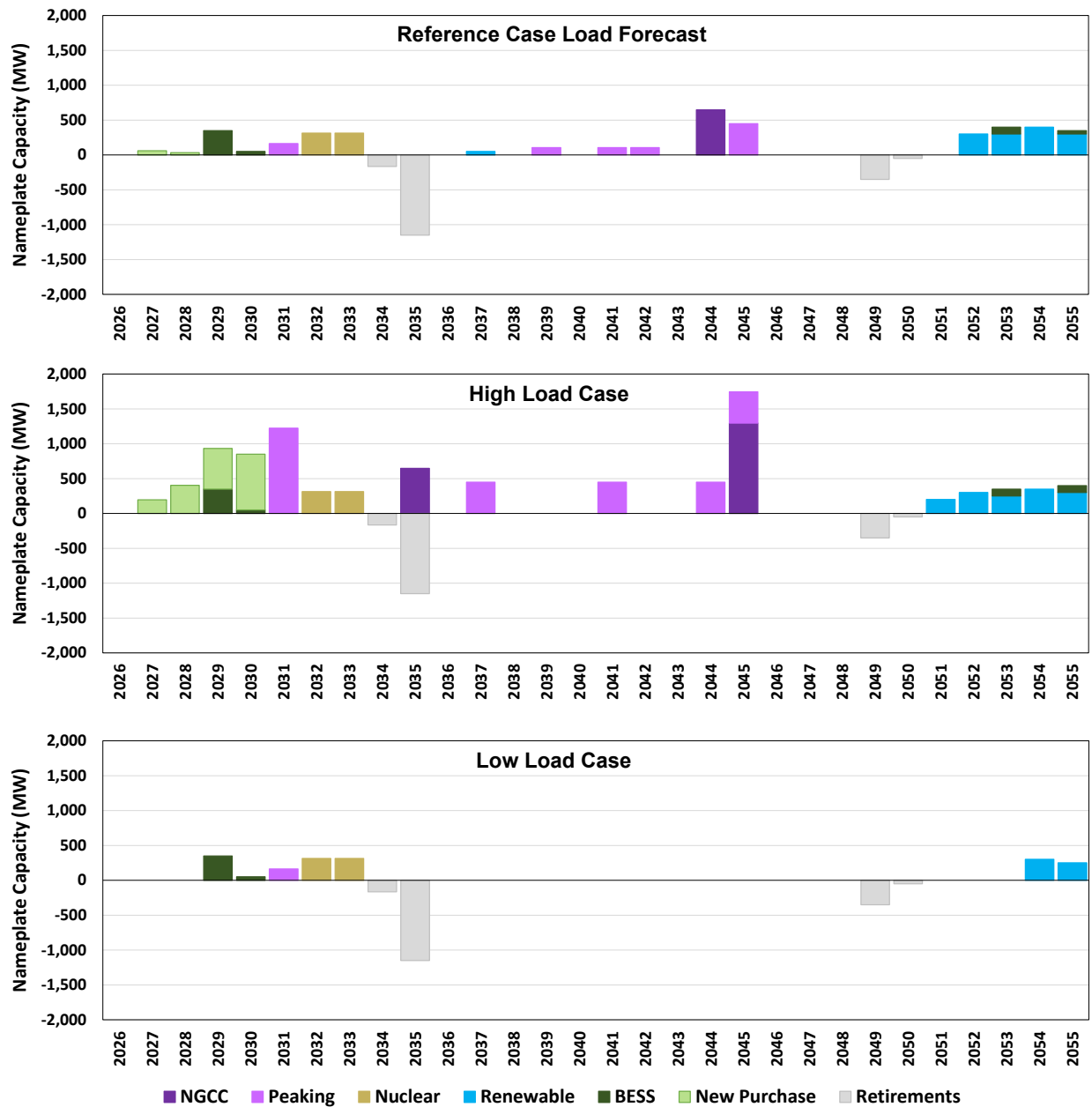
As an example, Figure 30 illustrates the resource build plan resulting from the re-optimization of the Economically Optimized Portfolio across the load growth sensitivity cases.³⁷ Under the High Load case, additional LM6000, solar, and BESS resources are implemented prior to 2032, and additional NGCC and NGCT resources are built in the late 2030s. Conversely, in the Low Load case, the NGCC and NGCT resources through 2040 are not implemented, less solar and wind is implemented, and no BESS resources are added (beyond those included as Assumed Near-term

³⁷ Similar to other build plan charts herein, Existing PPAs and Committed Resources are not depicted.

Resource Plan Evaluation

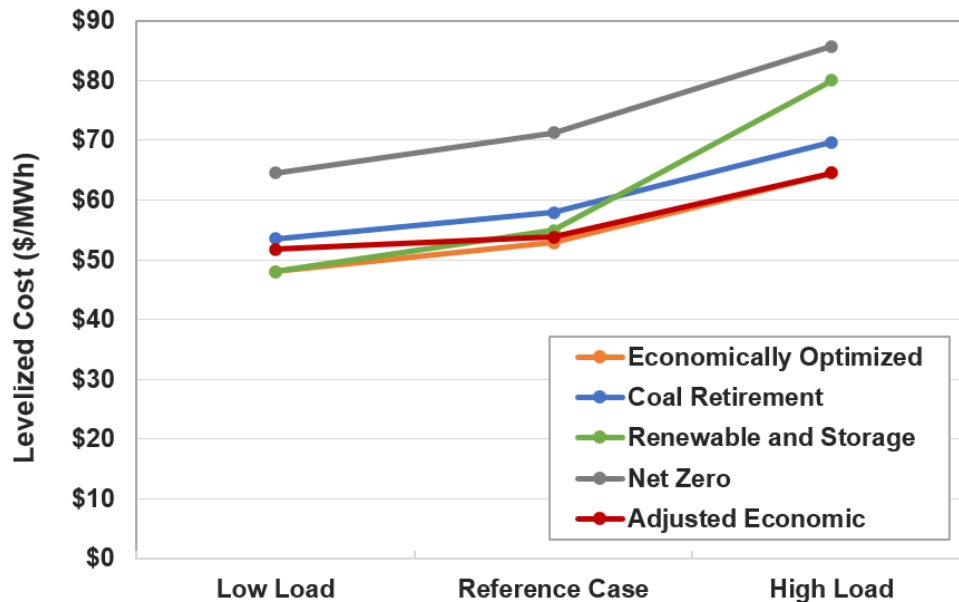
Resources). Detailed, comprehensive build plans are provided in Appendix C: Optimized Portfolio Builds.

Figure 30. Economically Optimized Portfolio Build Across Load Sensitivities



Santee Cooper prepared re-optimized portfolios for the low and high load forecast sensitivity cases for the other portfolios and computed total and levelized NPV costs for the reference and load sensitivity cases to provide a comparison of costs resulting from variations in load forecast assumptions. Figure 31 below depicts the average levelized power cost over the Study Period for each of the portfolios under the three load forecast scenarios.

Figure 31. Sensitivity of Levelized Power Costs to Load Growth Variations



The chart illustrates that the Net Zero CO₂ by 2050 Portfolio is projected to have far higher costs than the other portfolios across all load forecast sensitivities. Additionally, the Renewable and Storage Portfolio reflects the greatest variability across the load forecast sensitivities, with the levelized power costs of the High Load Case projected to be approximately 45 percent higher than the Reference Case.

The Economically Optimized and Adjusted Economic Portfolios studied are projected to have similar average levelized costs for the Reference and High Load Cases, with the Adjusted Economic Portfolio having slightly lower costs under the High Load Case. Under the Low Load Case, the sensitivity analysis reflects that power costs are projected to be somewhat higher under the Adjusted Economic Portfolio versus the Economically Optimized Portfolio. However, this analysis also does not reflect resource retirements that could be implemented to mitigate the impacts of a low load case.

SUMMARY OF PORTFOLIO METRICS

Table 27 summarizes the Portfolio Metrics by ranking the portfolios relative to the others for each of the metrics. In addition, a composite average of the rankings across all metrics is computed and then ranked to provide an overall ranking across the metrics. The composite average reflects an average across the metrics but collapses one pair of metrics, Fuel Cost Resiliency and Generation Diversity, which are highly related and are combined when computing the composite average.

Table 27. Ranking of Potential Portfolios for Evaluation Metrics

Portfolios	NPV Power Cost	Mini-max Regret	Fixed Cost Obligation	Fuel Cost Resiliency	CO2 Emissions	Generation Diversity	Clean Energy	Load Sensitivity
Economically Optimized	1	1	1	3	4	3	3	2
Coal Retirement	4	4	4	5	2	5	4	3
Renewable and Storage	3	3	3	2	5	1	2	5
Net Zero	5	5	5	1	1	2	1	4
Adjusted Economic	2	2	2	4	3	4	5	1

Average Metric Rank

Portfolios	Composite Average	Rank
Economically Optimized	1.9	1
Coal Retirement	3.8	5
Renewable and Storage	3.2	3
Net Zero	3.6	4
Adjusted Economic	2.5	2

The following are key observations from the portfolio evaluation metrics detailed above.

- The Economically Optimized Portfolio has the best composite average rank across the metrics, followed closely by the Adjusted Economic Portfolio.
- The Future Coal Retirement Portfolio reflects the worst-ranked portfolio, performing the worst or second worst across several of the metrics.
- The Economically Optimized Portfolio has the best rank for the NPV Power Cost, Mini-Max Regret, and Fixed Cost Obligation metrics but scores among the worst for CO₂ emissions.
- The Net Zero CO₂ by 2050 Portfolio has the worst rank for the NPV Power Cost, Mini-Max Regret, and Fixed Cost Obligation metrics, and second worst for the Load Sensitivity, but scores well for the other metrics.
- The Renewable and Storage Portfolio scores worst for CO₂ Emissions and Load Sensitivity but best for Generation Diversity, as it reflects additions of relatively large amounts of solar, wind, and storage resources, but mostly relatively late in the Study Period.
- The Renewable and Storage and Net Zero CO₂ by 2050 Portfolios score poorly on the Load Sensitivity metric as these reflect the need to add types of capacity that are among the most expensive when load is higher.
- The Adjusted Economic Portfolio is the best-ranked portfolio for Load Sensitivity and scores well across many of the other metrics but ranks among the worst for Fuel Cost Resiliency, Generation Diversity, and Clean Energy metrics.

A key takeaway of the resource plan evaluation is that renewable resources are considerably more expensive than other resources, particularly when considering their lower ELCC values. Even in the Renewable and Storage Portfolio, such resources tend not to get added until later in the Study Period, such that the portfolio must rely more heavily on coal generation to meet energy requirements.

EVALUATION OF VARIATIONS IN DEMAND-SIDE RESOURCES

The NPV power cost comparisons reported in prior sections reflect assumptions for Santee Cooper's medium case DSM program implementation that are based on Santee Cooper's EE and DR Market Potential Studies, as discussed in the Demand-Side Management Overview section. To understand the economics of variations in demand-side resources, a sensitivity analysis that assumes variations in Santee Cooper's DSM programs has been prepared.

For this sensitivity, the Economically Optimized Portfolio was re-optimized under both Low DSM and High DSM cases, with all other assumptions consistent with the Reference Case. Variations in assumed DSM implementation resulted in differences in the optimized resource build, as additional demand-side resources can substitute, to some degree, for supply-side resources or can allow the timing of such resources to be delayed under the High DSM case, and reduced DSM implementation can result in supply-side resources being installed earlier or increased in magnitude under the Low DSM case.

Figure 32 summarizes the resource build plan resulting from the optimization of the Economically Optimized Portfolio across the DSM sensitivity cases.³⁸ Under the Low DSM case, the wind resource added in 2037 in the Reference Case is not implemented, an additional peaking resource is implemented, another peaking resource is brought forward a year, slightly less solar is implemented, and the timing of BESS resources in the out years is a bit different. In the High DSM case, the wind resource added in 2037 in the Reference Case is avoided, some peaking resources are delayed slightly, less solar resources are implemented in the 2046-2055 period, and the timing of BESS resources in the out years is a bit different. Detailed build plans for each portfolio are provided in Appendix C: Optimized Portfolio Builds.

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³⁸ Similar to other build plan charts herein, Existing PPAs and Committed Resources are not depicted.

Figure 32. Economically Optimized Portfolio Build Across DSM Sensitivities

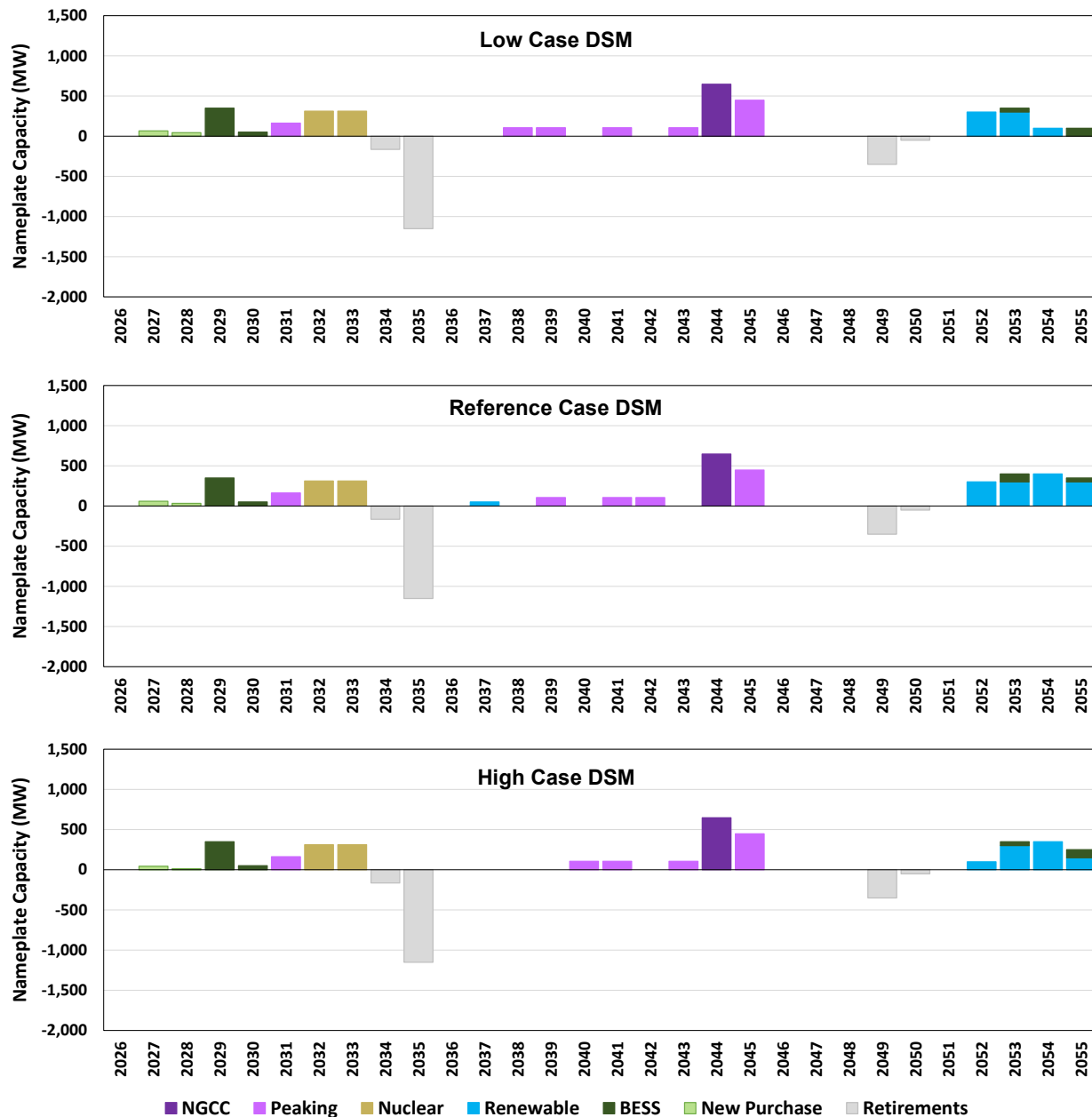


Table 28 compares the NPV power costs resulting from power cost simulation for the Low DSM and High DSM cases to those under the Reference Case. As shown, the NPV power costs across the three cases are very close, implying that the supply-side and DSM program cost differences across the three cases are negligible. However, projected overall power supply costs under the Reference DSM Case are lower than under either the Low DSM Case or the High DSM Case (though the latter is within rounding, as depicted below), indicating that the Medium DSM case provides the lowest total portfolio costs.

Table 28. NPV Power Costs Across Demand-side Management Sensitivities

Portfolios	NPV Power Costs (\$B)
Low DSM	\$32.8
Reference Case (Medium DSM)	\$32.7
High DSM	\$32.7
<u>Difference to Reference Case</u>	
Low DSM	\$0.1
High DSM	\$0.0

RATE IMPACTS OF PORTFOLIOS

Portfolio costs reported in the 2026 IRP depict total fuel and purchased energy costs plus fixed costs that vary between portfolios (e.g., debt service for new resources, fixed O&M for new resources, changes in fixed O&M for resource retirements, PPA fixed costs for new resources, and natural gas reservation costs for new NGCC resources). However, the portfolio costs that are captured in the analyses presented elsewhere herein are only part of the total costs that must be recovered from future Santee Cooper charges to customers. The information below places the projected portfolio costs compared elsewhere in the IRP in the context of the projected impact on Santee Cooper's average rates to customers.

To approximate the average rate level, Santee Cooper's total cost-of-service has been projected by adding, to the portfolio costs, allowances for other Santee Cooper costs that would be approximately the same for all portfolios. These other costs have been projected based on debt service schedules and estimates for existing and Committed Resources and by escalating other production, transmission, distribution, and customer costs to capture load and customer growth, general inflation, and planned projects. It should be noted that the cost-of-service projected for this purpose includes the impact of fuel cost escalation, as simulated in the portfolio evaluation, which Santee Cooper passes through to customers as actual incurred fuel and purchased energy expenses.

Figure 33 below provides the resulting trend in projected rates indexed to 2026 for Santee Cooper's customers for each of the portfolios studied based on the Reference Case assumptions.³⁹

³⁹ Similar information for the fuel and CO₂ price sensitivity cases is provided in Appendix F.

Figure 33. Projected Rate Index Across Portfolios (Reference Case)

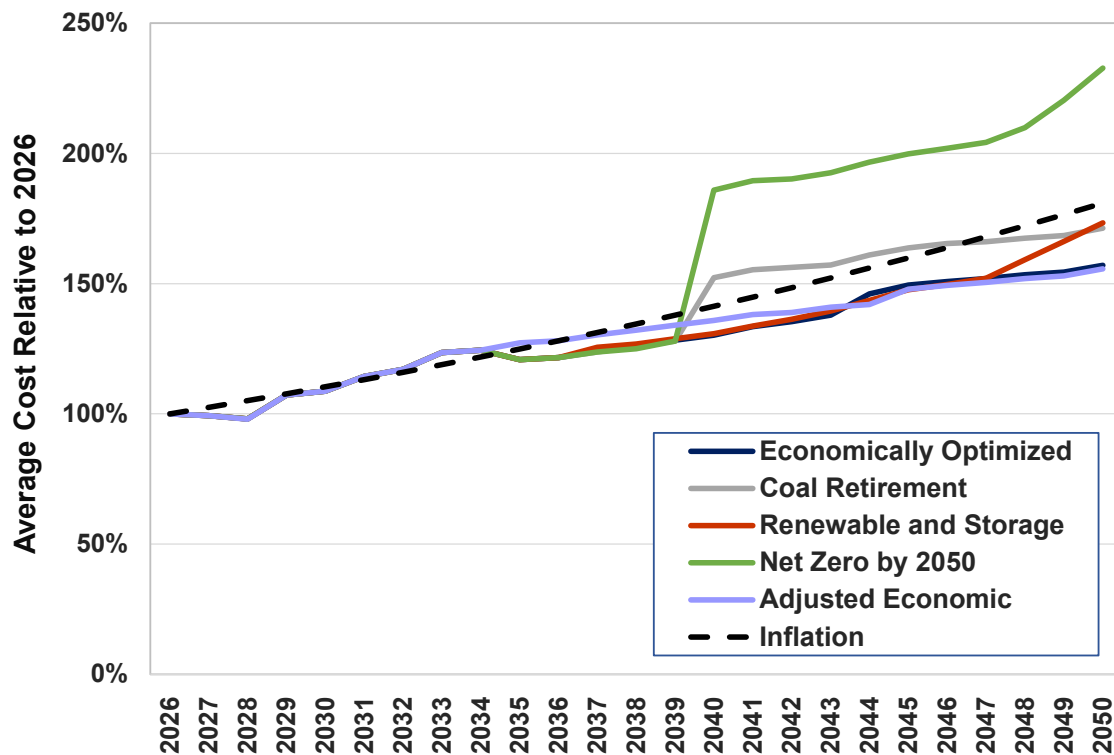
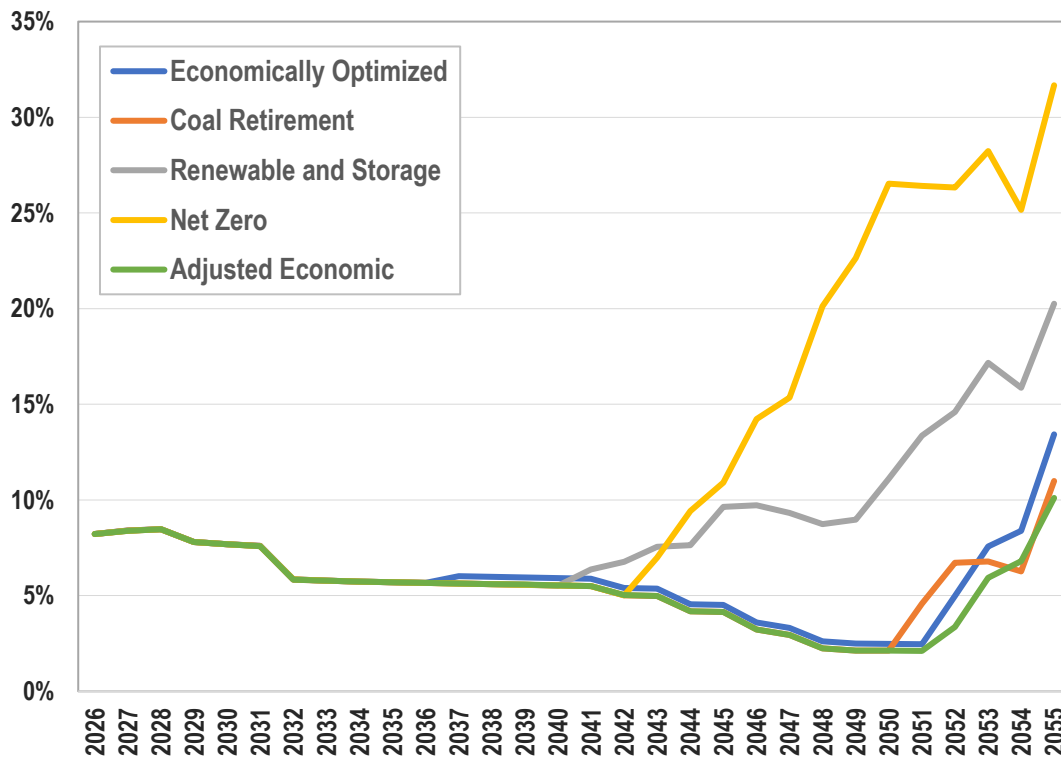


Figure 33 indicates that all portfolios other than the Net Zero CO₂ by 2050 Portfolio result in projected cost increases that are generally similar to or below the rate of inflation over the Study Period. The Net Zero CO₂ by 2050 Portfolio, on the other hand, results in a large cost increase in 2040, when Cross is retired and replaced by two large nuclear units (required to meet CO₂ reduction targets), resulting in projected average costs that exceed the inflation trend over the Study Period.

RENEWABLE ENERGY FORECAST

Figure 34 depicts the trend in the proportion of system energy requirements served from renewable resources⁴⁰ over the Study Period. As should be expected, the Net Zero CO₂ by 2050 and Renewable and Storage Portfolios reflect considerably higher concentration of renewable resources over most of the Study Period. Santee Cooper intends to regularly conduct CPRE processes for solar resources to gauge the market and secure these resources when cost-effective.

⁴⁰ Renewable generation includes solar, hydro, wind, LFG, and biomass.

Figure 34. Percentage of System Energy Served from Renewables

Renewable generation amounts by year across the portfolios are provided in Appendix E.

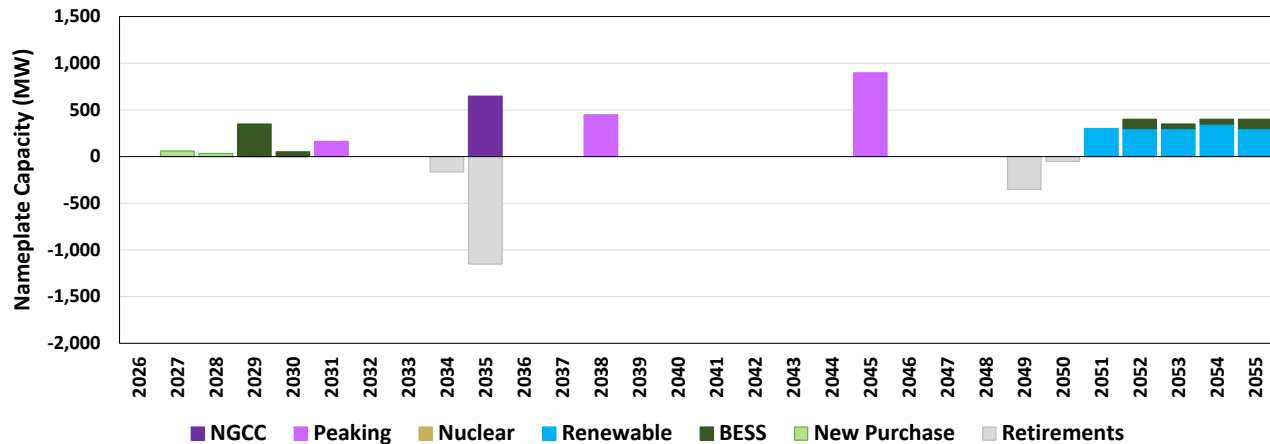
FAIRFIELD NUCLEAR IMPLEMENTATION SENSITIVITY

For this IRP, Santee Cooper's Fairfield TIC has been reflected in the Reference Case. To test the impact of the Fairfield project on the resource build of the Economically Optimized portfolio, Santee Cooper considered a sensitivity in which the Fairfield TIC is not available during the Study Period.

Figure 35 depicts the resulting optimized build plan under assumptions consistent with the Economically Optimized Portfolio but assuming the Fairfield TIC are not available to Santee Cooper.⁴¹ The key changes to the portfolio optimization under assumptions with Fairfield removed are that (i) a 1x1 NGCC is added in 2035, coincident with the retirement of Winyah (rather than in 2044 as in the Economically Optimized Portfolio), and (ii) additional peaking capacity is added (including one incremental NGCT unit added in 2038 and another in 2045 and 318 MW fewer RICE units added for 2039 through 2042). Note that this resulting build plan strongly resembles the Adjusted Economic Portfolio in its key features—implementation of a 1x1 NGCC in 2035 and significant CT capacity added in the mid-2040s.

⁴¹ Similar to other build plan charts herein, Existing PPAs and Committed Resources are not depicted.

Figure 35. Economically Optimized – No Fairfield Portfolio Build Plan



Detailed build plans are provided in Appendix C: Optimized Portfolio Builds.

CAPITAL COST SENSITIVITY

To test the sensitivity of the conclusion that NGCCs and NGCTs represent important, cost-effective generation capacity additions, Santee Cooper prepared sensitivity analyses assuming capital costs for all fossil-fueled resource types would be approximately 50% higher than assumed under the Reference Case assumptions and re-optimizing the Economically Optimized Portfolio. This sensitivity case does not assume higher costs of renewable, BESS, or other resource types considered in this IRP even though most of the circumstances that would result in higher fossil-fueled resource capital costs would also adversely impact costs of those other resources. Santee Cooper has taken this conservative approach to “stress test” the consideration of NGCC and NGCT resources. This higher fossil resource capital cost sensitivity results in fossil-fueled resource additions that are consistent with those under the Reference Case for the Economically Optimized Portfolio.

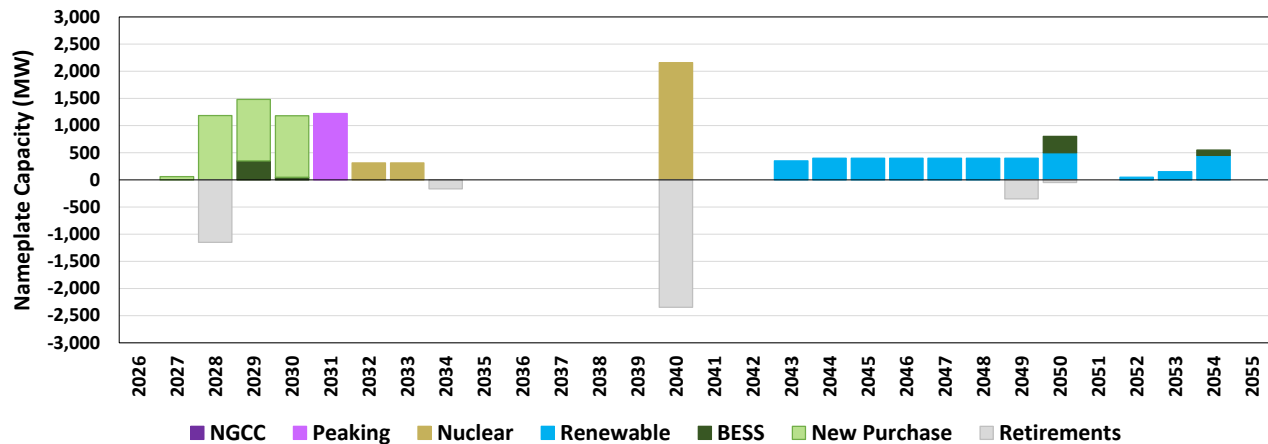
Santee Cooper also tested the impact of higher fossil resource capital cost on the No Fairfield case discussed in the previous subsection and found that the conclusion above was found to be consistent under the No Fairfield sensitivity. The new 1x1 NGCC reflected in 2035 in the Economically Optimized – No Fairfield case under the Reference Case capital cost assumptions is still included in the optimization under the higher capital cost sensitivity.

These build plans are provided in Appendix C: Optimized Portfolio Builds.

NET ZERO CO₂ WITH WINYAH 2028 RETIREMENT PORTFOLIO

As required by S.C. Code Ann. § 58-37-40(A)(4)(c), Santee Cooper has evaluated a Net Zero CO₂ by 2050 portfolio that reflects Winyah being retired by the end of 2028. Figure 36 depicts the resulting optimized build plan, reflecting the need for short-term purchases to offset the loss of Winyah's capacity until new peaking resources can be built in 2031 as a permanent replacement for Winyah. Otherwise, the build plan is similar to the Net Zero CO₂ by 2050 Portfolio. Detailed build plans are provided in Appendix C: Optimized Portfolio Builds.

Figure 36. Net Zero CO₂ by 2050 with Winyah 2028 Retirement Build Plan



NPV power costs over the Study Period can be expected to be dramatically higher under this case. Table 29 compares the NPV power cost for a Net Zero CO₂ by 2050 with a Winyah 2028 Retirement portfolio as compared to the Economically Optimized Portfolio under the Reference Case assumptions, reflecting higher power costs by nearly \$14 billion over the Study Period (or \$2.3 billion higher cost than the foundational Net Zero CO₂ by 2050 Portfolio).

Table 29. NPV Power Costs of Net Zero CO₂ by 2050 with Winyah 2028 Retirement

Portfolios	NPV Power Costs (\$B)
Economically Optimized	\$32.7
Net Zero and Winyah Retire by 2028	\$46.4
Difference	\$13.7

KEY CONSIDERATIONS AND CONCLUSIONS

The table below provides discussion of key considerations and conclusions from the 2026 IRP.

Topic	Key Considerations and Conclusions
Load Growth	▪ Loads continue to grow on the combined Santee Cooper and Central system. Additionally, load growth is being experienced throughout the Southeast and nationally and is not expected to abate in the near term. ▪ This load growth is directly related to economic development that benefits the State of South Carolina. ▪ Santee Cooper has an obligation to serve and must be prepared to serve the continued load growth through the development of additional reliable generating resources.
Cost of Generation Resources	▪ The electric utility industry is facing greater demand for generation and related equipment, creating upward pressure on costs, tightening equipment availability, and increasing competition for the limited pool of skilled labor capable of constructing generation projects. ▪ The assumptions that underpin the 2026 IRP reflect the impact of this upward pressure on capital costs for generation resources, particularly dispatchable resources. ▪ Santee Cooper must work with its partners in the state to procure the resources needed to meet load growth and ensure it is developing the most cost-effective and least risk portfolio.
Near-Term Resource Additions	▪ With continued load growth, Santee Cooper must add resources within the next five years and prior to the online date of the Canadys Joint NGCC. ▪ Santee Cooper will continue to coordinate with Central to evaluate all options to fill this resource need, including but not limited to extending current PPAs, evaluating bids received through the 2026 Capacity RFP and 2026 CPRE for solar, and considering the addition of self-build options.
2035 NGCC Resource	▪ Santee Cooper must begin due diligence for the 2035 NGCC Resource. ▪ The 2035 NGCC Resource is required and optimal under high load growth scenarios. ▪ The 2035 NGCC Resource provides valuable baseload capacity and reduces risk related to resource implementation.
Fairfield Nuclear Project	▪ Fairfield would provide significant benefits to customers in the form of low-cost, carbon-free, and highly reliable baseload generation.

Key Considerations and Conclusions

Topic	Key Considerations and Conclusions
	▪ Additionally, the project would provide reduction of debt through the one-time \$2.7B payment to Santee Cooper.
Solar Resources	▪ Termination of tax credits has increased the net cost of solar resources leading to fewer solar resources installed across all portfolios compared to previous IRPs. ▪ Santee Cooper intends to continue to monitor the costs of solar resources and to seek opportunities to add cost-effective solar to its portfolio over time.
Coal-Fired Generating Stations	▪ Both Cross and Winyah Generating Facilities continue to provide reliable power for the Santee Cooper system. ▪ Santee Cooper intends to retire Winyah when reliable replacement generation is available and is actively working to add the required generation resources. ▪ The 2026 IRP confirms conclusions from previous IRPs that continuing to operate Cross Generating Station reduces costs for customers. Santee Cooper intends, with stakeholders, to continue to evaluate retirement of Cross and develop viable pathways for the eventual retirement of this valuable generating asset.

PREFERRED PORTFOLIO

Based on the results of the resource plan evaluations and conclusions presented in previous sections, Santee Cooper recommends and proposes to adopt the Adjusted Economic Portfolio as Santee Cooper's Preferred Portfolio for the 2026 IRP.

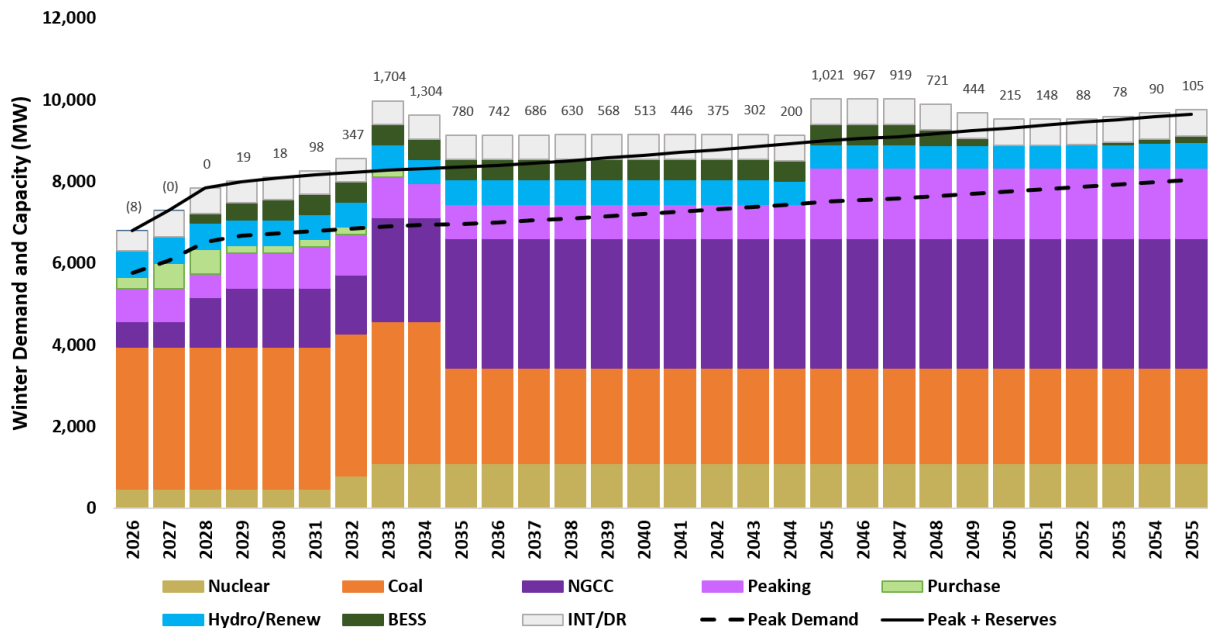
All portfolios reliably meet the needs of the Combined System, but Santee Cooper has identified the Adjusted Economic Portfolio as its Preferred Portfolio for the following reasons:

- Provides flexibility to meet higher than projected load growth and support economic development.
- Provides a diverse set of dispatchable, on-system resources to meet the requirements of the Combined System.
- Positions Santee Cooper to respond to potential changes in applicable regulations and the potential for requirements to retire coal-fired facilities.
- Positions Santee Cooper to be able to continue to serve system load growth while mitigating resource development risks.
- Provides a set of resources to reliably meet the Combined System needs, in a manner that is the most cost-effective and least risk for rate payers.

While the Economically Optimized Portfolio has the lowest projected NPV power cost under the Reference Case and scores well across many of the portfolio metrics, the Adjusted Economic Portfolio performs similarly to the Economically Optimized Portfolio across most of the portfolio metrics. In addition, the Adjusted Economic Portfolio supports continued load growth and reduces risk related to resource implementation.

Figure 37 depicts Santee Cooper's projected winter peak demand and winter resource requirement versus the winter firm capacity ratings of Santee Cooper's existing resources and resource additions reflected in the Adjusted Economic Portfolio. It includes the Rainey NGCT upgrades and NGCC conversion in 2028, the addition of the Winyah Turbines and Jefferies BESS resources in 2028, Central NSRs added in 2029, the addition of the Fairfield TIC over 2032-2033, the addition of the Canadys Joint NGCC in 2033, the retirement of Winyah, the installation of an additional NGCC resource by 2035, and the addition of a mix of peaking, BESS, and solar resources over the Study Period.

Figure 37. Supply-Demand Balance Under the Adjusted Economic Portfolio ^{(1) (2)}



(1) Numbers above the Peak + Reserves line represent surplus or deficient capacity values.

(2) Solar and BESS resources are shown at their respective Effective Load Carrying Capability values.

While the Adjusted Economic Portfolio is projected to reflect reserve margins that are above the minimum target from approximately 2033 through 2040, it is important to recognize that if load growth is greater than that reflected in the Base Case Load Forecast or if there are issues or delays in the implementation of any of the resources included as part of the portfolio, then the additional capacity will be needed to maintain system reliability. Overall, the chart illustrates the transition of the Santee Cooper portfolio from being dominated by coal resources to reflecting a more diverse mix of resources.

Figure 38 depicts the projected generation mix for the Adjusted Economic Portfolio under the Reference Case assumptions. The projections reflect a transition away from coal generation and toward greater natural gas and nuclear generation. The projections also reflect a limited, but important, contribution from renewable resources. Santee Cooper intends to continue assessing the market for renewable resources and considering the addition of such resources if economic; however, in the current market and regulatory environment, these resources are projected to be more expensive than the high-efficiency natural gas generation identified for the Adjusted Economic Portfolio.

Figure 38. Projected Generation Mix Under the Adjusted Economic Portfolio

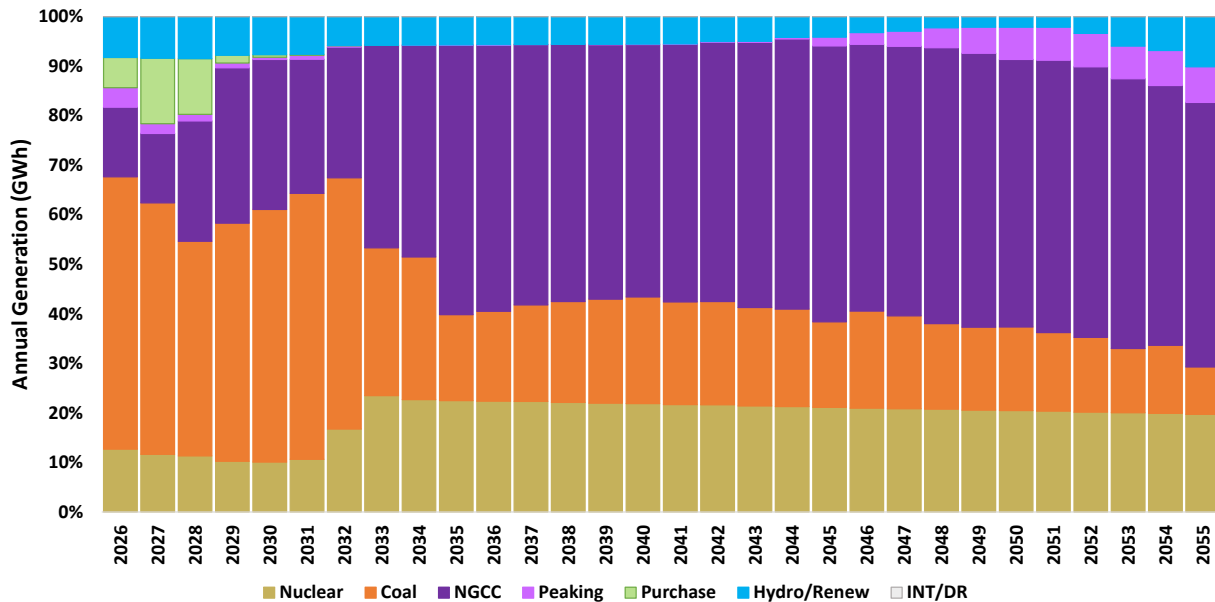
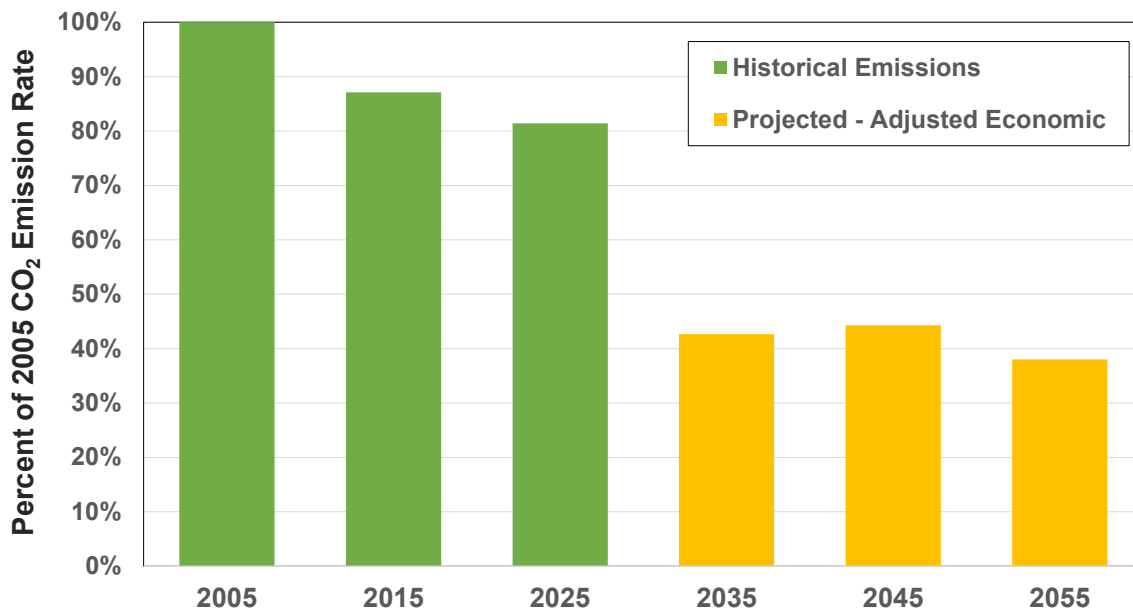


Figure 39 depicts the historical and projected CO₂ emissions rate⁴² under the Adjusted Economic Portfolio for representative years as a percentage of the emissions rate in 2005. The projected CO₂ emissions rate resulting from the significant transition in generation mix above reflects a reduction to approximately 43 percent of 2005 levels by 2035 and below 40 percent by 2050.

Figure 39. Projected CO₂ Emissions Rate as a Percent of 2005



⁴² The CO₂ emissions rate used herein refers to emissions per unit of electricity generation.

SHORT-TERM ACTION PLAN

Considering the results of the planning analyses summarized above and explained further in the body of the 2026 IRP report, Santee Cooper plans to proceed as follows, subject, where appropriate, to acceptance of the 2026 IRP by the Commission.

DELIVER ON RESOURCES UNDER DEVELOPMENT

With higher projected load growth compared to previous IRPs, it is important that the resources Santee Cooper currently has under construction are completed on time and on budget. This includes the Canadys Joint NGCC, Rainey Generating Station upgrades, the new turbines at Winyah Generating Station, and the Jefferies BESS project. Santee Cooper will continue to make progress on these vital resources and update the Commission as required.

UPDATE THE LOAD FORECAST AND MONITOR CHANGES IN POTENTIAL NEW LARGE CUSTOMERS

Santee Cooper and Central will continue to coordinate in order to monitor and update the load forecast, including the potential for the addition of new customer loads. Santee Cooper will also continue to engage with stakeholders in discussing the probability of large new customers joining the Combined System. Future IRPs will reflect updated load forecasts and, if warranted, changes to recommended resources or implementation schedules.

IDENTIFY NEAR-TERM RESOURCES

Ensuring reliable power and meeting load growth is essential for Santee Cooper and the Combined System. The paragraphs below describe how Santee Cooper, working with Central, will evaluate options to meet the near-term needs identified by the 2026 IRP.

Santee Cooper has issued the 2026 Capacity RFP. Responses to the RFP were received on September 4, 2026, and Santee Cooper intends to shortlist potential projects by early October 2026.

Additionally, Santee Cooper is evaluating options including:

- Extending current PPAs
- Self-build options
- Upgrades of existing facilities

Santee Cooper may make decisions about which options are most appropriate to pursue during the 2026 IRP proceeding. It will keep the Commission informed of the evaluation and what options it chooses to pursue.

BEGIN DUE DILIGENCE ON THE 2035 NGCC

As discussed in previous sections, Santee Cooper must begin due diligence on the 2035 NGCC resource. To date, Santee Cooper has begun the following activities:

- Commenced studies to refine project costs, schedule, and transmission infrastructure assessments, which are ongoing and described below:
 - Engaged Sargent and Lundy to perform a FEED study for a 1x1 NGCC.

Short-Term Action Plan

- Submitted the resource into Santee Cooper's OATT generator interconnection process.
- Solicited for alternatives through the 2026 Capacity RFP.

Santee Cooper plans to complete the studies described above and the comparison of alternatives in coordination with Central. In addition, Santee Cooper plans to begin environmental assessments at a site owned by Santee Cooper and located in Hampton County, begin fuel procurement planning, and issue an RFP for an owner's engineer to support the development of the NGCC resource. In future IRPs, Santee Cooper will update the Commission on the status of the 2035 NGCC and associated studies.

FAIRFIELD NUCLEAR PROJECT

The Fairfield Nuclear Project has the potential to benefit the State of South Carolina and Santee Cooper's customers. Santee Cooper will continue to serve its role to promote the project's progress. In future IRPs, Santee Cooper will update the Commission on the status of Fairfield.

SOLAR RESOURCES

Santee Cooper is currently evaluating the bids received in the 2026 CPRE Request for Proposals solicitation for solar. Santee Cooper has and will continue to file status reports with the Commission, as required by Commission Order No. 2024-2. Additionally, at this time, Santee Cooper anticipates continuing to pursue CPRE solicitations for solar on a regular basis. Doing so will ensure every opportunity to bring this valuable energy resource to the system when cost-effective.

MONITOR REGULATORY DEVELOPMENTS

Changes in regulations can impact new resource decisions and retirements of current facilities. Santee Cooper will continue to monitor changes at the Federal and State level in requirements that could impact resource plans.

CONTINUE STAKEHOLDER ENGAGEMENT

The IRP Stakeholder process ensures a robust and effective resource planning process. Santee Cooper is committed to continuing to engage stakeholders for future IRPs.

APPENDIX A: ABBREVIATIONS

AEO	Annual Energy Outlook	EPRI	Electric Power Research Institute
ATB	Annual Technology Baseline	EV	Electric vehicle
ATT	Alternative transmission technology	FEED	Front-end engineering design
BACT	Best available control technology	FERC	Federal Energy Regulatory Commission
BAT	Best available technology	FGD	Flue gas desulfurization
BATW	Bottom ash transport water	GADS	Generating Availability Data System
BESS	Battery energy storage system	GET	Grid-enhancing technology
CAA	Clean Air Act	GHG	Greenhouse gas
CAGR	Compound average growth rate	GWh	Gigawatt-hour (i.e., 1,000 MWh)
CCS	Carbon capture and sequestration	IRA	Inflation Reduction Act
CO ₂	Carbon dioxide	IRP	Integrated resource plan
COD	Commercial operation date	ITC	Investment tax credit
CRL	Combustion residual leachate	kV	Kilovolt
CRSG	Carolinas Reserve Sharing Group	kW	Kilowatt
CT	Combustion turbine generator	kWh	Kilowatt-hour
CVR	Conservation voltage reduction	LCOE	Levelized cost of energy
DEC	Duke Energy Carolinas, LLC	LCOC	Levelized cost of capacity
DEP	Duke Energy Progress, LLC	LDES	Long duration energy storage
DESC	Dominion Energy South Carolina	LFG	Landfill methane gas
DG	Distributed generation	LOLE	Loss of load expectation
DLR	Dynamic line rating	MMBtu	1 million British thermal units
DR	Demand response	MPS	Market potential study
DSM	Demand-side management	MW	Megawatt
EE	Energy efficiency	MWh	Megawatt-hour
EFOR	Equivalent forced outage rate	NCP	Non-coincident peak
EGU	Electric generating units	NERC	North American Electric Reliability Corporation
EIA	Energy Information Administration (of the Department of Energy)	NGCC	Natural gas-fired combined cycle
EIPC	Eastern Interconnection Planning Collaborative	NGCT	Natural gas-fired combustion turbine
ELCC	Effective load carrying capability	NPV	Net Present Value
ELG	Effluent limitation guidelines	NRC	Nuclear Regulatory Commission
EPA	Environmental Protection Agency		

Appendix A: Abbreviations

NLR	National Laboratory of the Rockies (Formerly the National Renewable Energy Laboratory)	SOCO	Southern Company
NSR	Non-Shared Resource	SVC	Static var compensator
OATT	Open Access Transmission Tariff	SWG	Stakeholder Working Group
OBBS	One Big Beautiful Bill Act (i.e., HR1)	TEA	The Energy Authority
ORS	Office of Regulatory Staff	UCT	Utility cost test
O&M	Operation and maintenance	VSC	Voltage-source converters
PCT	Production tax credit	WEFOR	Weighted equivalent forced outage rate
PMPA	Piedmont Municipal Power Agency	ZLD	Zero liquid effluent discharge
PNLL	Potential new large load		
PO	Planned maintenance outage		
PPA	Power purchase agreement		
PRM	Planning reserve margin		
PSR	Proposed Shared Resource		
PURC	Public Utilities Review Committee		
PV	Photovoltaic		
PVRR	Present value revenue requirement		
RFP	Request for proposal		
RICE	Reciprocating internal combustion engine		
SAE	Statistically-adjusted end-use		
SAM	NLR System Advisory Model		
SCC	Social cost of carbon (i.e., CO ₂)		
SERC	SERC Reliability Corporation		
SERVM	Strategic Energy and Risk Evaluation Model		
SEPA	Southeastern Power Administration		
SCRTP	South Carolina Regional Transmission Planning		
SERTP	Southeast Regional Transmission Planning		
SMR	Small modular reactor		

APPENDIX B: TRANSMISSION PROJECTS

ACTIVE PROJECTS

Reconductor Purrysburg – McIntosh 230kV Tie Lines

This project is necessary to mitigate thermal loading under contingency conditions and increases transfer capability with neighboring utilities to support scheduled transmission service reservations. This project is scheduled to be completed in 2026.

Indian Field 230-115kV Substation

This substation will support 230 kV network expansion plans and load growth in the St. George area. The scope of this project includes folding in the existing Harleyville – St. George 115kV line to a new Indian Field 230-115kV substation and constructing a new 115kV transmission line from the Indian Field 230-115kV Substation to the existing St. George 115kV Switching Station. This project is scheduled to be completed in 2026.

Indian Field – Wassamassaw 230kV Line

This project will support load growth in Dorchester, Berkeley and Charleston counties. This project, along with the future Varnville-Indian Field 230 kV line project, will create an additional 230 kV networked transmission path from the Southern region of the system directly to areas where load is growing. Transfer capability through the southern interface will also be improved by this additional 230 kV path, allowing Santee Cooper to continue to support the large load growth while maintaining transmission reliability.

The scope of this project includes the construction of an approximately 22-mile 230kV line from the proposed Indian Field 230-115kV substation to the Wassamassaw 230-115kV substation utilizing existing rights-of-way. This project is scheduled to be completed in 2026.

Indian Field – Sugar Hill #1 and #2 230 kV Lines and Substation

The 230 kV Lines and the new Sugar Hill Substation will provide the electric infrastructure needed to support an industrial retail customer of Edisto Electric Cooperative, a member cooperative of Central Electric Power Cooperative. The project is being fully funded by the customer and is scheduled to be completed in 2026.

Purrysburg Station Improvements

Upgrade the station 230kV buses and disconnected switches for higher ampacity operation. Project also replaces some 230 kV circuit breakers with higher continuous and interrupting capability. Project will also update protection systems to meet NERC Reliability Standard TPL-001-5.1 redundancy requirements. Upgrading the Purrysburg 230-115 kV Substation is necessary to maintain transmission reliability and mitigate thermal loading under contingency conditions. The project is scheduled to be completed in 2027.

Cross – Wassamassaw 230 kV Line #2

This 230 kV circuit provides an additional path from Cross to Wassamassaw to provide a parallel network path to load and to mitigate thermal loading under contingency conditions. This project

Appendix B: Transmission Projects

will use existing structures on the Cross– Jefferies 230 kV line for 15 miles from Cross and then use existing right-of-way to construct the remaining 3-mile section to the Wassamassaw 230-115 kV Substation. This project is scheduled to be completed in 2027.

Bennettsville – Latta 69 kV Rebuild as Double Circuit

This 69 kV line rebuild will upgrade the existing circuit and provide an additional path to an area in Marion County seeing industrial load growth. This project alleviates multiple thermal and voltage violations identified under contingency conditions. This project rebuilds the existing Latta – Bennettsville 69 kV line as a double circuit 69/69 kV line, which will increase the overall reliability in the area and to delivery points served from this line. This project is scheduled to be completed in 2027.

Varnville – Indian Field 230 kV Line

This 230 kV line project is necessary to add an additional 230 kV transmission path from the Southern region of the system to the Eastern region of the system. Planning assessments indicate that the existing Southern path will be constrained under contingency conditions. The scope of this project includes the construction of a 230 kV transmission line (approximately 40.5 miles in length) from the Varnville 230-115 kV Substation to the new Indian Field 230-115 kV Substation as well as rebuilding the existing Bells Crossroads – Varnville 115 kV Line for 230/115 kV double-circuit on the existing right-of-way. The scope also includes rebuilding the St. George – Bells Crossroads 115 kV Line #2 for 230/115 kV double-circuit on the existing right-of-way. This project is scheduled to be completed in 2028.

Kingstree – Hemingway 230 kV Line #2

This 230 kV line will provide an additional path from generating resources in the western part of the state toward load centers in the east and alleviates multiple thermal and voltage violations identified under contingency conditions. This project rebuilds the existing Kingstree – Hemingway 115 kV line as a double circuit 230/115 kV line, which will increase the reliability to delivery points served from this line. This project is scheduled to be completed in 2029.

Bluffton – Market Place #2 115 kV Line Phase 2

This project will provide additional transmission capacity to support load growth, and it will also provide increased electric reliability to residents and businesses on Hilton Head Island. The new transmission line will be constructed to the most up-to-date standards and codes that will provide more resilience during adverse weather conditions. This project will establish a new 115 kV line from the Bluffton area to Hilton Head Island and terminate at the Hilton Head 115 kV Switching Station in Jasper County. This new line section will be extending an existing 115 kV line from the Buckingham area in Bluffton to the Hilton Head plantation area. This project is scheduled to be completed in 2028.

Appendix B: Transmission Projects

Flat Bay 230 kV Switching Station

Construct a 230 kV switching station for the interconnection of new aeroderivative gas turbine units (LM6000s) to be installed on the existing Winyah Generating Station plant property. The switching station will be connected by folding-in the Winyah-Charity 230 kV transmission line approximately 0.5 mile from the Winyah 230-115 kV Switchyard.

Jefferies BESS Interconnection

Construct a 115 kV tie line approximately 0.2 miles in length from the Jefferies 115-34.5-12 kV Substation to the BESS Collector Substation. The Battery Energy Storage System (BESS) has a maximum output of 300MW for 4-hour duration. This project is scheduled to be completed in 2027.

Colleton BESS Interconnection

Construct a 115 kV three-breaker switching station to interconnect the generator project to the Bells Crossroads – St George #1 115 kV Line. The BESS has a maximum output of 74.5 MW for a 4-hour duration. This project is scheduled to be completed in 2029.

Williamsburg BESS Interconnection

Construct a 69 kV three-breaker switching station to interconnect the generator project to the Kingstree – Lake City 69 kV Line. The BESS has a maximum output of 74.5 MW for a 4-hour duration. This project is scheduled to be completed in 2029.

Rainey Heat Recovery Steam Generator HRSG Interconnection

A new HRSG Unit ST2S will be installed to establish a combined cycle gas turbine (Power Block 2) using CT2A, CT2B and ST2S generating units. Construct a 230 kV generator tie line from the Rainey Generating Station 230 kV Switchyard to the Generator Step-up Transformer (GSU). Rainey CT2A and CT2B units will be upgraded to provide increased output. This project is scheduled to be completed in early 2028. Other existing units at Rainey Generating Station will also have some upgrades starting but does not require additional transmission upgrades.

Yemassee – Varnville 230 kV Line Rebuild

This 230 kV line project is necessary to facilitate an additional 230 kV transmission path from the Southern region of the system toward the Eastern region of the system. Planning assessments indicate that the existing Southern path will be constrained under contingency conditions. This project will rebuild the existing Yemassee – Varnville 230 kV line as two parallel 230 kV circuits from the Yemassee 230 kV Switching Station to the Varnville 230-115 kV Substation (approximately 9 miles) along the existing transmission corridor. This project is scheduled to be completed in 2030.

Nixons Crossroads – Red Bluff #1 115 kV Line

This project will provide support to the north Myrtle Beach area and help to maintain system reliability under contingency conditions. The scope of this project includes the construction of a

Appendix B: Transmission Projects

115 kV transmission line from Nixon's Crossroads 115-12 kV Substation to the Brooksville Cooperative Delivery Point Substation.

Cross – Jefferies 230 kV #2 Line

This project will add an additional 230 kV transmission network path to support load growth in Berkeley, Dorchester and Charleston counties. Planning assessments indicate that this project will mitigate thermal loading violations under contingency. The scope of this project includes the construction of a 230kV transmission line (approximately 23 miles in length) from the Cross Generation Station to the Jefferies 230-115 kV Substation, mostly on existing right-of-way. The scope includes rebuilding of sections of an existing 115 kV line as double circuit 230/115 kV and building a single 230 kV circuit utilizing existing corridors.

Marion– Red Bluff 230 kV Line

The Marion – Red Bluff 230 kV line will provide an additional 230 kV source to the northern end of the Horry-Georgetown area which is continuing to experience high load growth. This project mitigates thermal loading issues in the eastern part of the transmission system under contingency conditions. This project will construct a 230 kV line from the Marion 230-115-69 kV Substation to the Red Bluff 230-115 kV Substation using a combination of existing right-of-way and new right-of-way and would result in rebuilding portions of the Marion – Latta #2 69 kV Line, the Allen – Pine Level #2 115 kV line and the Pine Level – Red Bluff 115 kV Line for double circuit 230/115 kV construction, which will increase reliability to delivery points served from these lines.

Fold Varnville-Indian Field 230 kV Line into Edisto River

This project will break the proposed Varnville-Indian Field 230 kV line and construct two 230 kV single circuits for approximately 6 miles from the fold-in point to the new Edisto River 230 kV Switchyard. The purpose of this project is to facilitate the planned Canadys generator interconnection projects. This project establishes a Varnville - Edisto River 230 kV line and a Edisto River – Indian Field 230 kV line.

Edisto River – Mateeba 230 kV Line

This project will construct a 230 kV transmission circuit approximately 28 miles in length from the Edisto River 230 kV Switchyard to Santee Cooper's Mateeba 230 kV Switching Station. The purpose of this project is to facilitate the planned Canadys generator interconnection projects.

PLANNED PROJECTS

Rebuild Perry Rd – Myrtle Beach #2 115 kV Line

This project will alleviate thermal loading identified under contingency conditions and maintain transmission reliability in the area. The project scope includes rebuilding the existing 556 ACSR section of the Perry Road-Myrtle Beach #2 115 kV Line with 1272 ACSR conductor.

Appendix B: Transmission Projects

Orangeburg – Indian Field 230 kV Line

This project will add an additional 230 kV transmission path to the Eastern region of the system to support load growth in the southern region of the system. Planning assessments indicate that the existing transmission paths into the area will be constrained under contingency conditions. The scope of this project includes the construction of a 230kV transmission line (approximately 26 miles in length) from the Indian Field 230-115kV substation to the Orangeburg 230-115kV substation. The majority of the transmission project construction involves rebuilding of an existing 115 kV line as 230/115 kV double circuits from the Orangeburg 230-115 kV Substation to the St. George 115 kV Switching Station along the existing transmission corridor.

Cedar Knoll 230-69kV Substation

This project will support load growth in the Blythewood and Columbia areas and alleviate transformer loading in the area identified under contingency conditions. The scope of this project includes the construction of the new 230-69 kV Cedar Knoll substation as well as the fold in of the Pomaria – Sandy Run 230kV Line, the Bythewood - Pomaria 69 kV line, and the Blythewood - Columbia 69 kV lines into the new substation.

APPENDIX C: OPTIMIZED PORTFOLIO BUILDS

INTRODUCTION

Below are detailed tables providing annual changes in resource capacity for existing resources, purchased power agreements (“PPA”), and new resources. New resources include resources determined from the optimization simulation for each portfolio as well as committed and assumed resources. Changes in existing and new resources are provided by resource type. Capacity values for thermal resources reflect assumed firm capacity, while values for renewable and BESS resources reflect the nameplate capacity. Resource types for existing resources that are not projected to change over the Study Period are not included in the tables.

- Changes in Existing Resources
 - Coal
 - NGCC
 - NGCT
 - RICE/LM (peaking resources that are dual-fueled)
 - Existing Solar
 - Bio/LFG (includes output from biomass resources purchased through PPAs and Santee Cooper resources that operate on landfill methane gas)
 - INT/DR (interruptible load and demand response programs)
- PPAs (including both existing PPAs of various terms that have been implemented by Santee Cooper and assumed PPAs required to meet capacity requirements in the near term before other resources are assumed able to be implemented, but excluding PPAs for biomass, solar, and BESS resources)
- New Resources (new resources that are implemented over the Study Period)
 - Central NSRs
 - NGCC
 - NGCT
 - RICE/LM
 - New Solar
 - Wind
 - BESS
 - Nuclear

Appendix C: Optimized Portfolio Builds

Table C-1: Economically Optimized Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	353	0	0	0	0	0	0	0	0	613
2028	0	594	(339)	142	0	(20)	(26)	0	0	0	108	0	0	300	0	759
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	0	0	0	0	0	0	0	(1,144)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	50	0	0	55
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	106	0	0	0	0	110
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	0	106	0	0	0	0	110
2042	0	0	0	(74)	0	3	0	0	0	0	106	0	0	0	0	35
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	648	0	0	0	0	0	0	617
2045	0	0	0	0	0	2	0	0	0	449	0	0	0	0	0	451
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2052	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2053	0	0	0	0	0	2	0	0	0	0	0	300	0	100	0	402
2054	0	0	0	0	0	2	0	0	0	0	0	300	100	0	0	402
2055	0	0	0	0	0	2	0	0	0	0	0	300	0	50	0	352
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	1,746	449	569	1,200	150	150	625	3,655

Appendix C: Optimized Portfolio Builds

Table C-2: Future Coal Retirement Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	353	0	0	0	0	0	0	0	0	613
2028	0	594	(339)	142	0	(20)	(26)	0	0	0	108	0	0	300	0	759
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	0	0	0	0	0	0	0	(1,144)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2038	0	0	0	0	0	5	0	0	0	0	106	0	0	0	0	111
2039	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2040	(2,330)	0	0	0	0	4	0	0	1,296	1,347	0	0	0	0	0	317
2041	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	0	449	0	0	0	0	0	418
2045	0	0	0	0	0	2	0	0	0	449	0	0	0	0	0	451
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	300	0	50	0	352
2052	0	0	0	0	0	2	0	0	0	0	0	250	0	100	0	352
2053	0	0	0	0	0	2	0	0	0	0	0	0	0	100	0	102
2054	0	0	0	0	0	2	0	0	0	0	0	50	100	0	0	152
2055	0	0	0	0	0	2	0	0	0	0	0	250	100	50	0	402
Total	(3,480)	594	(504)	(480)	(72)	147	(441)	672	2,394	2,244	357	850	200	300	625	3,406

Appendix C: Optimized Portfolio Builds

Table C-3: Renewable and Storage Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	352	0	0	0	0	0	0	0	0	612
2028	0	594	(339)	142	0	(20)	(25)	0	0	0	108	0	0	300	0	760
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	0	0	0	0	0	0	0	(1,144)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	150	0	155
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	0	0	0	100	0	0	104
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	100	50	0	79
2043	0	0	0	0	0	3	0	0	0	0	0	0	100	0	0	103
2044	0	0	0	0	(34)	2	0	0	0	0	0	0	100	90	0	159
2045	0	0	0	0	0	2	0	0	0	0	0	300	100	100	0	502
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	40	0	(8)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(70)	0	(168)
2049	0	0	0	(42)	0	2	0	0	0	0	0	50	0	60	0	70
2050	0	0	0	0	0	2	0	0	0	0	0	250	0	61	0	313
2051	0	0	0	0	0	2	0	0	0	0	0	300	0	60	0	362
2052	0	0	0	0	0	2	0	0	0	0	0	150	0	60	0	212
2053	0	0	0	0	0	2	0	0	0	0	0	300	0	60	0	362
2054	0	0	0	0	0	2	0	0	0	0	0	300	0	60	0	362
2055	0	0	0	0	0	2	0	0	0	0	0	100	0	60	0	162
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	1,098	0	251	1,750	500	1,630	625	4,619

Appendix C: Optimized Portfolio Builds

Table C-4: Net Zero CO₂ by 2050 Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	352	0	0	0	0	0	0	0	0	612
2028	0	594	(339)	142	0	(20)	(25)	0	0	0	108	0	0	300	0	760
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	0	0	0	0	0	0	0	(1,144)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	106	0	0	0	0	110
2040	(2,330)	0	0	0	0	4	0	0	0	0	212	0	0	0	2,160	46
2041	0	0	0	0	0	4	0	0	0	0	106	0	0	0	0	110
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	150	100	0	0	253
2044	0	0	0	0	(34)	2	0	0	0	0	106	300	100	0	0	475
2045	0	0	0	0	0	2	0	0	0	0	212	300	100	0	0	614
2046	0	0	0	(200)	0	2	0	0	0	0	0	300	0	0	0	102
2047	0	0	0	(50)	0	2	0	0	0	0	0	300	100	0	0	352
2048	0	0	0	(100)	0	2	0	0	0	0	0	300	100	(300)	0	2
2049	0	0	0	(42)	0	2	0	0	0	0	0	300	100	0	0	360
2050	0	0	0	0	0	2	0	0	0	0	0	300	200	51	0	553
2051	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2052	0	0	0	0	0	2	0	0	0	0	0	0	0	50	0	52
2053	0	0	0	0	0	2	0	0	0	0	0	50	100	50	0	202
2054	0	0	0	0	0	2	0	0	0	0	0	300	150	0	0	452
2055	0	0	0	0	0	2	0	0	0	0	0	0	0	150	0	152
Total	(3,480)	594	(504)	(480)	(72)	147	(441)	672	1,098	0	993	2,600	1,050	850	2,785	5,812

Appendix C: Optimized Portfolio Builds

Table C-5: Adjusted Economic Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	352	0	0	0	0	0	0	0	0	612
2028	0	594	(339)	142	0	(20)	(25)	0	0	0	108	0	0	300	0	760
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	648	0	0	0	0	0	0	(496)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	0	0	0	0	0	0	0	(31)
2045	0	0	0	0	0	2	0	0	0	898	0	0	0	0	0	900
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2052	0	0	0	0	0	2	0	0	0	0	0	150	0	0	0	152
2053	0	0	0	0	0	2	0	0	0	0	0	300	0	50	0	352
2054	0	0	0	0	0	2	0	0	0	0	0	300	50	50	0	402
2055	0	0	0	0	0	2	0	0	0	0	0	150	0	100	0	252
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	1,746	898	251	900	50	200	625	3,435

Appendix C: Optimized Portfolio Builds

Table C-6: Economically Optimized (High Load) Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	490	0	0	0	0	0	0	0	0	750
2028	0	594	(339)	142	0	(20)	206	0	0	0	108	0	0	300	0	991
2029	0	0	0	0	(38)	(68)	(358)	672	0	0	0	0	0	499	0	707
2030	0	0	0	0	0	7	215	0	0	0	0	0	0	50	0	272
2031	0	0	0	0	0	7	(799)	0	0	0	1,203	0	0	0	0	411
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	648	0	0	0	0	0	0	(496)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	449	0	0	0	0	0	454
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	449	0	0	0	0	0	452
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	0	449	0	0	0	0	0	418
2045	0	0	0	0	0	2	0	0	1,296	449	0	0	0	0	0	1,747
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	200	0	0	0	202
2052	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2053	0	0	0	0	0	2	0	0	0	0	0	250	0	100	0	352
2054	0	0	0	0	0	2	0	0	0	0	0	300	50	0	0	352
2055	0	0	0	0	0	2	0	0	0	0	0	300	0	100	0	402
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	3,042	1,795	1,311	1,350	50	200	625	7,140

Appendix C: Optimized Portfolio Builds

Table C-7: Economically Optimized (Low Load) Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	293	0	0	0	0	0	0	0	0	553
2028	0	594	(339)	142	0	(20)	0	0	0	0	108	0	0	300	0	785
2029	0	0	0	0	(38)	(68)	(539)	672	0	0	0	0	0	499	0	526
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	0	0	0	0	0	0	0	(1,144)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	0	0	0	0	0	0	0	(31)
2045	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2052	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2053	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2054	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2055	0	0	0	0	0	2	0	0	0	0	0	250	0	0	0	252
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	1,098	0	251	550	0	0	625	1,289

Appendix C: Optimized Portfolio Builds

Table C-8: Economically Optimized (High DSM) Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	140	338	0	0	0	0	0	0	0	0	601
2028	0	594	(339)	142	0	(17)	(32)	0	0	0	108	0	0	300	0	757
2029	0	0	0	0	(38)	(65)	(552)	672	0	0	0	0	0	499	0	516
2030	0	0	0	0	0	10	0	0	0	0	0	0	0	50	0	60
2031	0	0	0	0	0	10	0	0	0	0	142	0	0	0	0	153
2032	0	0	0	(280)	0	10	0	0	0	0	0	0	0	0	313	43
2033	0	0	0	0	0	10	0	0	1,098	0	0	0	0	0	313	1,420
2034	0	0	(165)	0	0	9	(195)	0	0	0	0	0	0	0	0	(350)
2035	(1,150)	0	0	0	0	9	0	0	0	0	0	0	0	0	0	(1,141)
2036	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	8
2037	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	8
2038	0	0	0	0	0	7	0	0	0	0	0	0	0	0	0	7
2039	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2040	0	0	0	0	0	6	0	0	0	0	106	0	0	0	0	112
2041	0	0	0	0	0	5	0	0	0	0	106	0	0	0	0	111
2042	0	0	0	(74)	0	5	0	0	0	0	0	0	0	0	0	(69)
2043	0	0	0	0	0	4	0	0	0	0	106	0	0	0	0	110
2044	0	0	0	0	(34)	4	0	0	648	0	0	0	0	0	0	618
2045	0	0	0	0	0	3	0	0	0	449	0	0	0	0	0	452
2046	0	0	0	(200)	0	3	0	0	0	0	0	0	0	0	0	(197)
2047	0	0	0	(50)	0	3	0	0	0	0	0	0	0	0	0	(47)
2048	0	0	0	(100)	0	3	0	0	0	0	0	0	0	(300)	0	(397)
2049	0	0	0	(42)	0	3	0	0	0	0	0	0	0	(350)	0	(389)
2050	0	0	0	0	0	3	0	0	0	0	0	0	0	(199)	0	(196)
2051	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2052	0	0	0	0	0	3	0	0	0	0	0	100	0	0	0	103
2053	0	0	0	0	0	3	0	0	0	0	0	300	0	50	0	353
2054	0	0	0	0	0	3	0	0	0	0	0	300	50	0	0	353
2055	0	0	0	0	0	3	0	0	0	0	0	150	0	100	0	253
Total	(1,150)	594	(504)	(480)	(72)	205	(441)	672	1,746	449	569	850	50	150	625	3,263

Appendix C: Optimized Portfolio Builds

Table C-9: Economically Optimized (Low DSM) Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	134	360	0	0	0	0	0	0	0	0	618
2028	0	594	(339)	142	0	(22)	(22)	0	0	0	108	0	0	300	0	761
2029	0	0	0	0	(38)	(70)	(584)	672	0	0	0	0	0	499	0	479
2030	0	0	0	0	0	5	0	0	0	0	0	0	0	50	0	55
2031	0	0	0	0	0	5	0	0	0	0	142	0	0	0	0	147
2032	0	0	0	(280)	0	5	0	0	0	0	0	0	0	0	313	37
2033	0	0	0	0	0	5	0	0	1,098	0	0	0	0	0	313	1,415
2034	0	0	(165)	0	0	5	(195)	0	0	0	0	0	0	0	0	(355)
2035	(1,150)	0	0	0	0	4	0	0	0	0	0	0	0	0	0	(1,146)
2036	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2037	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2038	0	0	0	0	0	3	0	0	0	0	106	0	0	0	0	109
2039	0	0	0	0	0	3	0	0	0	0	106	0	0	0	0	109
2040	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2041	0	0	0	0	0	3	0	0	0	0	106	0	0	0	0	109
2042	0	0	0	(74)	0	2	0	0	0	0	0	0	0	0	0	(72)
2043	0	0	0	0	0	2	0	0	0	0	106	0	0	0	0	108
2044	0	0	0	0	(34)	2	0	0	648	0	0	0	0	0	0	616
2045	0	0	0	0	0	2	0	0	0	449	0	0	0	0	0	450
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2052	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2053	0	0	0	0	0	2	0	0	0	0	0	300	0	50	0	352
2054	0	0	0	0	0	2	0	0	0	0	0	0	100	0	0	102
2055	0	0	0	0	0	2	0	0	0	0	0	0	0	100	0	102
Total	(1,150)	594	(504)	(480)	(72)	113	(441)	672	1,746	449	675	600	100	150	625	3,077

Appendix C: Optimized Portfolio Builds

Table C-10: Economically Optimized (No Fairfield) Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	353	0	0	0	0	0	0	0	0	613
2028	0	594	(339)	142	0	(20)	(26)	0	0	0	108	0	0	300	0	759
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	0	(273)
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	0	1,104
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	648	0	0	0	0	0	0	(496)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2038	0	0	0	0	0	5	0	0	0	449	0	0	0	0	0	454
2039	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	0	0	0	0	0	0	0	(31)
2045	0	0	0	0	0	2	0	0	0	898	0	0	0	0	0	900
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2052	0	0	0	0	0	2	0	0	0	0	0	300	0	100	0	402
2053	0	0	0	0	0	2	0	0	0	0	0	300	0	50	0	352
2054	0	0	0	0	0	2	0	0	0	0	0	300	50	50	0	402
2055	0	0	0	0	0	2	0	0	0	0	0	300	0	100	0	402
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	1,746	1,347	251	1,500	50	300	0	3,959

Appendix C: Optimized Portfolio Builds

Table C-11: Economically Optimized (No Fairfield, High Capital Cost) Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	353	0	0	0	0	0	0	0	0	613
2028	0	594	(339)	142	0	(20)	(26)	0	0	0	108	0	0	300	0	759
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	0	(273)
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	0	1,104
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	648	0	0	0	0	0	0	(496)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	449	0	0	0	0	0	453
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	0	0	0	0	0	0	0	(31)
2045	0	0	0	0	0	2	0	0	0	898	0	0	0	0	0	900
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	300	0	(199)	0	103
2051	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2052	0	0	0	0	0	2	0	0	0	0	0	300	0	100	0	402
2053	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2054	0	0	0	0	0	2	0	0	0	0	0	300	100	50	0	452
2055	0	0	0	0	0	2	0	0	0	0	0	0	0	50	0	52
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	1,746	1,347	251	1,500	100	200	0	3,909

Appendix C: Optimized Portfolio Builds

Table C-12: Economically Optimized (High Capital Cost) Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	353	0	0	0	0	0	0	0	0	613
2028	0	594	(339)	142	0	(20)	(26)	0	0	0	108	0	0	300	0	759
2029	0	0	0	0	(38)	(68)	(573)	672	0	0	0	0	0	499	0	492
2030	0	0	0	0	0	7	0	0	0	0	0	0	0	50	0	57
2031	0	0	0	0	0	7	0	0	0	0	142	0	0	0	0	149
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	(1,150)	0	0	0	0	6	0	0	0	0	0	0	0	0	0	(1,144)
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	50	0	0	55
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	106	0	0	0	0	110
2040	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2041	0	0	0	0	0	4	0	0	0	0	106	0	0	0	0	110
2042	0	0	0	(74)	0	3	0	0	0	0	106	0	0	0	0	35
2043	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
2044	0	0	0	0	(34)	2	0	0	648	0	0	0	0	0	0	617
2045	0	0	0	0	0	2	0	0	0	449	0	0	0	0	0	451
2046	0	0	0	(200)	0	2	0	0	0	0	0	0	0	0	0	(198)
2047	0	0	0	(50)	0	2	0	0	0	0	0	0	0	0	0	(48)
2048	0	0	0	(100)	0	2	0	0	0	0	0	0	0	(300)	0	(398)
2049	0	0	0	(42)	0	2	0	0	0	0	0	0	0	(350)	0	(390)
2050	0	0	0	0	0	2	0	0	0	0	0	0	0	(199)	0	(197)
2051	0	0	0	0	0	2	0	0	0	0	0	300	0	0	0	302
2052	0	0	0	0	0	2	0	0	0	0	0	0	0	100	0	102
2053	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2054	0	0	0	0	0	2	0	0	0	0	0	300	100	0	0	402
2055	0	0	0	0	0	2	0	0	0	0	0	0	0	100	0	102
Total	(1,150)	594	(504)	(480)	(72)	147	(441)	672	1,746	449	569	600	150	200	625	3,105

Appendix C: Optimized Portfolio Builds

Table C-13: Net Zero CO₂ With Winyah 2028 Retirement Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources						PPAs	New Resources								Total
	Coal	NGCC	NGCT	Solar	Bio / LFG	INT / DR		Central NSRs	NGCC	NGCT	RICE / LM	Solar	Wind	BESS	Nuclear	
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	124	0	136	353	0	0	0	0	0	0	0	0	613
2028	(1,150)	594	(339)	142	0	(20)	1,124	0	0	0	108	0	0	300	0	759
2029	0	0	0	0	(38)	(68)	(592)	672	0	0	0	0	0	499	0	473
2030	0	0	0	0	0	7	1	0	0	0	0	0	0	50	0	58
2031	0	0	0	0	0	7	(1,132)	0	0	0	1,203	0	0	0	0	78
2032	0	0	0	(280)	0	7	0	0	0	0	0	0	0	0	313	39
2033	0	0	0	0	0	7	0	0	1,098	0	0	0	0	0	313	1,417
2034	0	0	(165)	0	0	6	(195)	0	0	0	0	0	0	0	0	(354)
2035	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2036	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	6
2037	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2038	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	5
2039	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2040	(2,330)	0	0	0	0	4	0	0	0	0	0	0	0	0	2,160	(166)
2041	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	4
2042	0	0	0	(74)	0	3	0	0	0	0	0	0	0	0	0	(71)
2043	0	0	0	0	0	3	0	0	0	0	0	250	100	0	0	353
2044	0	0	0	0	(34)	2	0	0	0	0	0	300	100	0	0	369
2045	0	0	0	0	0	2	0	0	0	0	0	300	100	0	0	402
2046	0	0	0	(200)	0	2	0	0	0	0	0	300	100	0	0	202
2047	0	0	0	(50)	0	2	0	0	0	0	0	300	100	0	0	352
2048	0	0	0	(100)	0	2	0	0	0	0	0	300	100	(300)	0	2
2049	0	0	0	(42)	0	2	0	0	0	0	0	300	100	(350)	0	10
2050	0	0	0	0	0	2	0	0	0	0	0	300	200	101	0	603
2051	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
2052	0	0	0	0	0	2	0	0	0	0	0	0	50	0	0	52
2053	0	0	0	0	0	2	0	0	0	0	0	50	100	0	0	152
2054	0	0	0	0	0	2	0	0	0	0	0	300	150	100	0	552
2055	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	2
Total	(3,480)	594	(504)	(480)	(72)	147	(441)	672	1,098	0	1,311	2,700	1,200	400	2,785	5,930

APPENDIX D: NPV POWER COST SUMMARY

Table D-1: Net Present Value Power Costs by Portfolio Across Sensitivities (\$B; 2026\$)

Portfolio	Sensitivity Case	Study Period (2026-55)	20 Years (2036-55)
Economically Optimized	Reference	\$32.7	\$20.5
Coal Retirement	Reference	\$35.8	\$23.6
Renewable and Storage	Reference	\$34.0	\$21.8
Net Zero	Reference	\$44.1	\$31.9
Preferred	Reference	\$33.3	\$21.0
Economically Optimized	Low Fuel	\$27.5	\$16.6
Coal Retirement	Low Fuel	\$29.8	\$18.9
Renewable and Storage	Low Fuel	\$29.4	\$18.5
Net Zero	Low Fuel	\$41.0	\$30.1
Adjusted Economic	Low Fuel	\$27.8	\$16.8
Economically Optimized	High Fuel	\$43.5	\$29.8
Coal Retirement	High Fuel	\$54.7	\$41.1
Renewable and Storage	High Fuel	\$43.5	\$29.8
Net Zero	High Fuel	\$50.8	\$37.2
Adjusted Economic	High Fuel	\$44.3	\$30.5
Economically Optimized	Med CO2	\$40.8	\$27.2
Coal Retirement	Med CO2	\$42.7	\$29.1
Renewable and Storage	Med CO2	\$42.4	\$28.8
Net Zero	Med CO2	\$48.1	\$34.5
Adjusted Economic	Med CO2	\$41.0	\$27.3
Economically Optimized	High CO2	\$54.8	\$38.4
Coal Retirement	High CO2	\$54.9	\$38.6
Renewable and Storage	High CO2	\$56.9	\$40.6
Net Zero	High CO2	\$55.4	\$39.0
Adjusted Economic	High CO2	\$54.1	\$37.8
Economically Optimized - High Load	High Load	\$48.6	\$32.3
Coal Retirement - High Load	High Load	\$52.5	\$36.2
Renewable and Storage - High Load	High Load	\$60.3	\$42.9
Net Zero - High Load	High Load	\$64.6	\$48.4
Adjusted Economic - High Load	High Load	\$48.6	\$32.3
Economically Optimized - Low Load	Low Load	\$24.7	\$14.8
Coal Retirement - Low Load	Low Load	\$27.5	\$17.6
Renewable and Storage - Low Load	Low Load	\$24.7	\$14.8
Net Zero - Low Load	Low Load	\$33.2	\$23.3
Adjusted Economic - Low Load	Low Load	\$26.6	\$16.5
Economically Optimized - High Capital	High Cap Cost	\$33.6	\$21.3
Net Zero and Winyah Retire by 2028	2028 Winyah Ret	\$46.4	\$32.2
Economically Optimized - Low DSM	Low DSM	\$32.8	\$20.6
Economically Optimized - High DSM2	High DSM	\$32.7	\$20.4

APPENDIX E: RENEWABLE GENERATION FORECAST

Table E-1: Renewable Generation by Portfolio (GWh)⁴³

Year	Economically Optimized	Coal Retirement	Renewable and Storage	Net Zero	Adjusted Economic
2026	2,470	2,470	2,470	2,470	2,470
2027	2,758	2,758	2,755	2,755	2,755
2028	3,057	3,057	3,057	3,057	3,057
2029	2,867	2,868	2,867	2,868	2,867
2030	2,870	2,870	2,870	2,870	2,869
2031	2,868	2,869	2,868	2,866	2,866
2032	2,236	2,234	2,235	2,235	2,236
2033	2,234	2,233	2,232	2,232	2,232
2034	2,232	2,232	2,232	2,232	2,232
2035	2,230	2,230	2,232	2,231	2,230
2036	2,233	2,233	2,233	2,233	2,233
2037	2,383	2,229	2,229	2,230	2,229
2038	2,383	2,229	2,229	2,229	2,229
2039	2,388	2,234	2,234	2,234	2,234
2040	2,388	2,232	2,233	2,234	2,234
2041	2,386	2,231	2,585	2,232	2,233
2042	2,212	2,056	2,776	2,057	2,058
2043	2,211	2,056	3,122	2,881	2,056
2044	1,893	1,737	3,183	3,926	1,737
2045	1,889	1,736	4,046	4,569	1,736
2046	1,518	1,363	4,111	6,010	1,363
2047	1,402	1,248	3,962	6,517	1,247
2048	1,111	957	3,747	8,587	960
2049	1,070	915	3,879	9,751	914
2050	1,071	918	4,836	11,513	918
2051	1,069	1,997	5,864	11,547	916
2052	2,181	2,947	6,450	11,594	1,471
2053	3,342	2,998	7,645	12,518	2,619
2054	3,727	2,791	7,122	11,229	3,025
2055	6,014	4,924	9,155	14,253	4,525

⁴³ Renewable generation includes solar, hydro, wind, and biomass.

APPENDIX F: RATE IMPACTS

Figure F-1: Projected Rate Index for the Portfolios Studied Under Low Fuel Prices

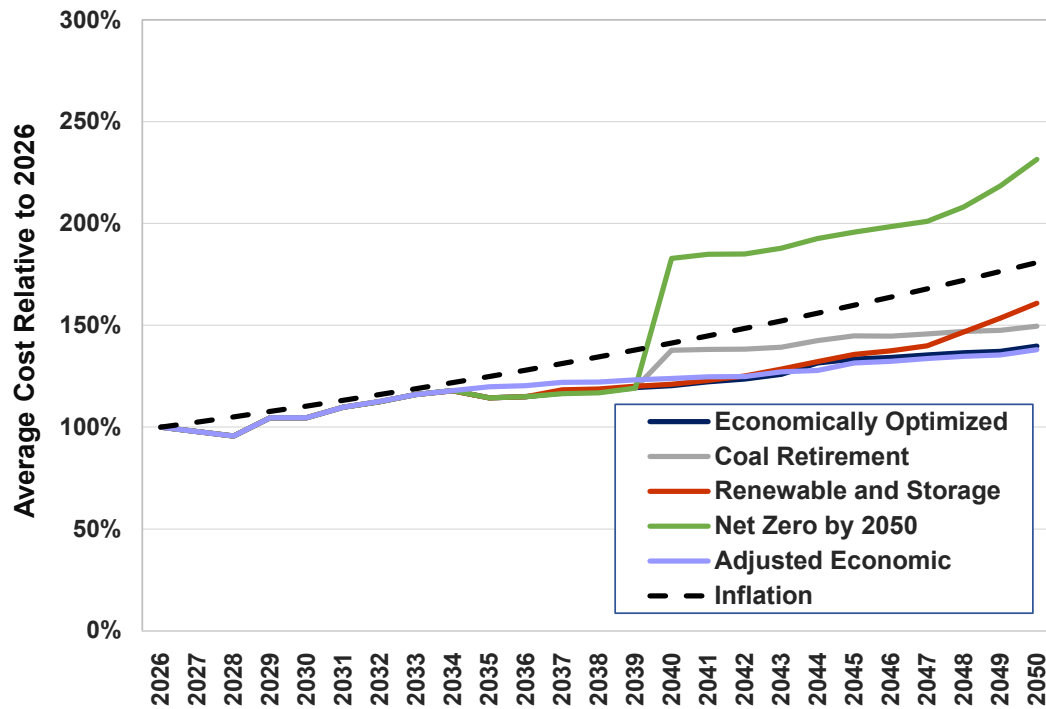


Figure F-2: Projected Rate Index for Foundational Portfolios Under High Fuel Prices

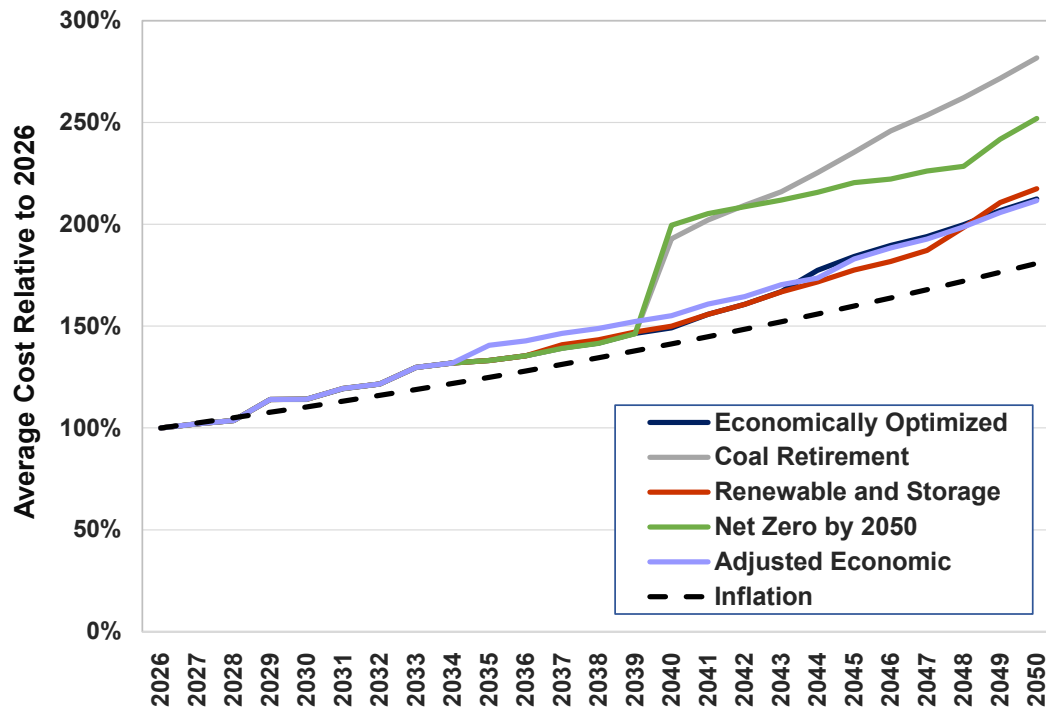
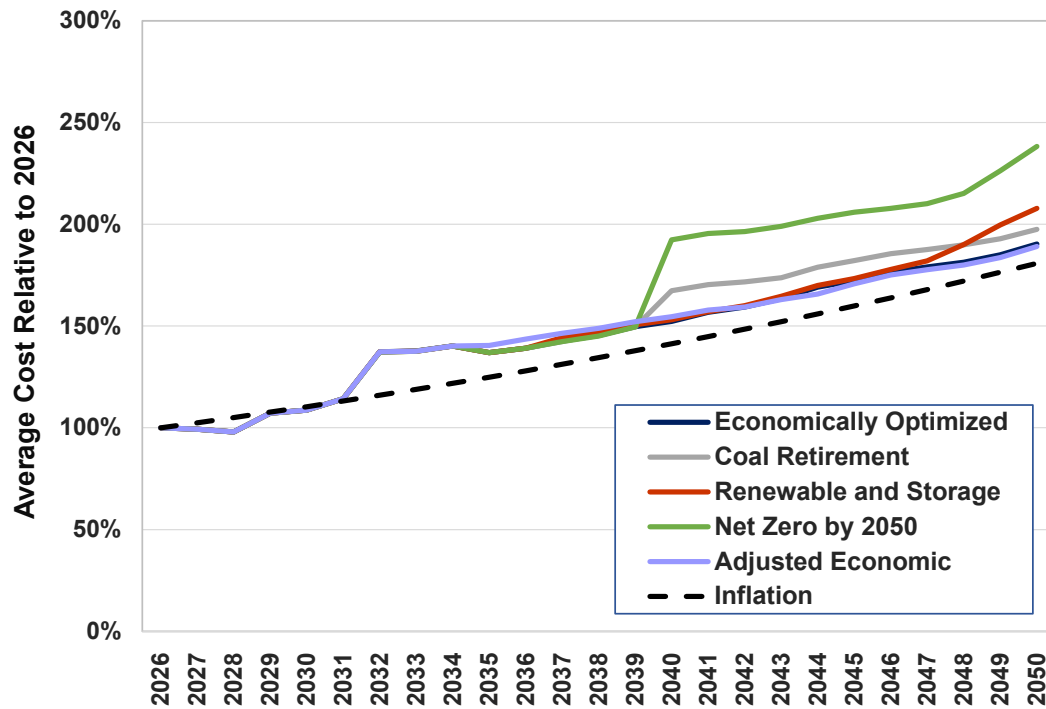
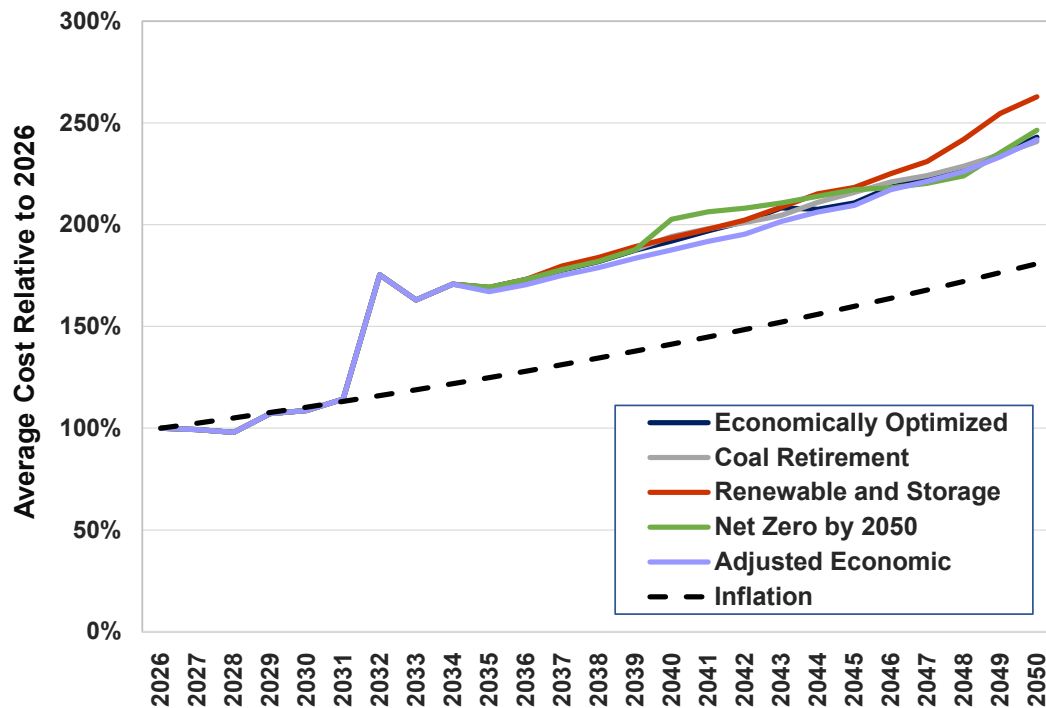


Figure F-3: Projected Rate Index for Foundational Portfolios Under Medium CO₂ Prices**Figure F-4: Projected Rate Index for Foundational Portfolios Under High CO₂ Prices**

APPENDIX G: GENERATION FLEET DATA

Table G-1: Generation Fleet Summary

Generating Station	Unit #	Service Date	End of Useful Life ¹	Fuel Type	Technology	Winter Rating ² (MW)	Summer Rating ² (MW)
Cross Pineville, SC	1	1995	2055	Coal	ST	585	580
	2	1983	2053	Coal	ST	570	565
	3	2007	2067	Coal	ST	580	585
	4	2008	2068	Coal	ST	595	605
Winyah Georgetown, SC	1	1975	2035	Coal	ST	280	275
	2	1977	2035	Coal	ST	290	285
	3	1980	2035	Coal	ST	290	285
	4	1981	2035	Coal	ST	290	285
Rainey Iva, SC	1 ³	2002	2052	NG	CC	520	460
	2A	2002	2052	NG	CT	180	146
	2B	2002	2052	NG	CT	180	146
	3	2004	2054	NG	CT	90	75
	4	2004	2054	NG	CT	90	75
	5	2004	2054	NG	CT	90	75
Cherokee Gaffney, SC		2023 ⁴	2052	NG	CC	98	86
Myrtle Beach	1	1962	2034	NG	CT	10	8
	2	1962	2034	NG	CT	10	8
	3	1972	2034	NG	CT	20	19
	4 ⁵	1972	2034	NG	CT	20	19
	5	1976	2034	NG	CT	25	21
Hilton Head	1	1973	2034	Oil	CT	20	16
	2	1974	2034	Oil	CT	20	16
	3	1979	2034	Oil	CT	60	52
V.C. Summer Nuclear Unit 1 Jenkinsville, SC	1	1983	2062 ⁶	Uranium	NUC	322	322
Jefferies Lake Moultrie	1	1942	2062	Water	Hydro	30	30
	2	1942	2062	Water	Hydro	36	36
	3	1942	2062	Water	Hydro	30	30
	4	1942	2062	Water	Hydro	36	36
	6	1942	2062	Water	Hydro	8	8
Spillway Lake Marion	-	1950	2070	Water	Hydro	2	2
Landfill Gas (multiple sites)	- ⁽⁷⁾	2001 - 2011		LFG	CT, IC	17	17
Total Capacity						5374	5149
1) Referenced end of useful life of resources were developed for use for IRP planning and modeling. Estimated potential lives are not based on any information on the condition of Santee Cooper facilities. 2) Ratings shown are Net Dependable Capacity values. 3) Rainey 1 denotes the combined capacity of combustion turbine Units 1A and 1B combined with steam turbine Unit 1S in a combined cycle configuration. 4) Purchased by Santee Cooper 2023. 5) Myrtle Beach Combustion Turbine No. 4 is unavailable until further notice and is not included in the totals above. 6) Current operating license expires 2062. 7) Georgetown LFG is unavailable and is not included in total.							

Appendix G: Generation Fleet Data

Table G-2: Annual Forced Outage Rate

Annual Forced Outage Rate						
Generating Station	Unit	2021	2022	2023	2024	2025
Cross Pineville, SC	1	1.31%	3.15%	3.60%	29.79%	7.06%
	2	5.37%	35.50%	8.16%	11.21%	3.28%
	3	8.52%	1.67%	2.19%	6.72%	6.94%
	4	1.84%	4.41%	2.20%	4.58%	7.15%
Winyah Georgetown, SC	1	5.08%	2.75%	3.42%	6.60%	6.23%
	2	4.92%	3.72%	3.90%	11.46%	0.25%
	3	0.69%	1.81%	3.22%	0.55%	5.80%
	4	0.00%	8.99%	3.29%	1.39%	3.30%
Rainey Iva, SC	1	0.38%	0.10%	0.91%	0.24%	0.23%
	2A	0.11%	0.01%	0.10%	0.07%	0.88%
	2B	0.14%	0.02%	0.00%	0.55%	0.19%
	3	0.59%	0.00%	0.72%	4.97%	0.13%
	4	5.91%	0.00%	0.36%	3.58%	1.29%
	5	1.71%	0.93%	0.00%	4.73%	11.21%
Cherokee Gaffney, SC	1	0.29%	0.56%	8.25%	0.41% 0.46%	0.48%
Myrtle Beach	1	99.76%	90.90%	99.17%	99.75%	98.52%
	2	70.21%	47.19%	99.80%	88.41%	0.00%
	3	98.87%	12.32%	0.00%	0.00%	0.00%
	4	100.00%	N/A	N/A	N/A	N/A
	5	0.00%	93.19%	99.98%	95.80%	99.34%
Hilton Head	1	0.00%	99.05%	0.00%	0.00%	94.76%
	2	0.00%	0.00%	99.92%	98.83%	0.00%
	3	26.37%	79.62%	75.28%	93.92%	22.41%
Summer Nuclear Unit 1 Jenkinsville, SC	1	8.36%	0.00%	4.20%	0.00%	5.80%
Jefferies Lake Moultrie	1	4.35%	46.24%	0.16%	22.61%	1.85%
	2	0.17%	0.12%	0.80%	1.07%	0.00%
	3	24.77%	0.45%	0.33%	0.18%	20.15%
	4	0.15%	3.24%	0.08%	0.91%	0.42%
	6	0.00%	0.00%	0.00%	0.00%	0.00%

Appendix G: Generation Fleet Data

Table G-3: Annual Availability Factor

Annual Availability Factor						
Generating Station	Unit	2021	2022	2023	2024	2025
Cross Pineville, SC	1	91.54%	67.38%	91.51%	74.60%	67.31%
	2	89.26%	66.44%	54.75%	79.46%	76.27%
	3	61.26%	95.85%	89.67%	87.77%	85.11%
	4	75.82%	92.62%	92.99%	81.10%	90.45%
Winyah Georgetown, SC	1	91.38%	90.01%	77.42%	92.90%	73.84%
	2	71.68%	93.12%	91.85%	67.89%	94.75%
	3	75.29%	95.10%	89.16%	77.81%	75.54%
	4	43.21%	86.37%	71.10%	92.69%	70.23%
Rainey Iva, SC	1	88.71%	94.70%	85.27%	69.61%	93.61%
	2A	95.06%	97.68%	93.85%	97.33%	89.67%
	2B	95.66%	98.78%	98.36%	88.85%	96.74%
	3	96.23%	98.32%	97.92%	97.53%	88.65%
	4	97.10%	96.78%	98.04%	96.94%	98.58%
	5	92.88%	99.10%	98.12%	97.57%	97.99%
Cherokee Gaffney, SC	1	90.85%	93.40%	90.73%	88.60%	85.16%
Myrtle Beach	1	96.67%	94.90%	94.97%	72.73%	97.19%
	2	99.94%	99.34%	96.19%	95.19%	99.06%
	3	75.93%	99.82%	99.77%	98.45%	99.91%
	4	0.00%	N/A	N/A	N/A	N/A
	5	100.00%	81.37%	72.78%	85.04%	80.67%
Hilton Head	1	100.00%	41.49%	99.79%	99.72%	89.09%
	2	100.00%	99.88%	77.30%	79.74%	93.83%
	3	95.52%	93.45%	99.43%	88.10%	95.35%
Summer Nuclear Unit 1 Jenkinsville, SC	1	82.50%	99.40%	87.90%	86.90%	94.20%
Jefferies Lake Moultrie	1	99.12%	79.56%	89.41%	98.18%	96.82%
	2	99.64%	99.95%	99.48%	94.14%	96.53%
	3	86.48%	98.80%	88.05%	99.81%	92.97%
	4	99.19%	96.80%	93.40%	96.44%	84.66%
	6	99.67%	99.11%	100.00%	99.27%	100.00%

Appendix G: Generation Fleet Data

Table G-4: Annual Capacity Factor

Annual Capacity Factor						
Generating Station	Unit	2021	2022	2023	2024	2025
Cross Pineville, SC	1	39.00%	17.51%	22.23%	30.22%	27.03%
	2	9.45%	0.45%	10.56%	12.92%	14.67%
	3	41.75%	67.65%	64.09%	63.47%	61.37%
	4	54.38%	62.29%	66.36%	58.07%	66.48%
Winyah Georgetown, SC	1	55.50%	36.90%	32.82%	54.92%	49.38%
	2	36.87%	30.56%	35.68%	27.88%	51.43%
	3	31.13%	22.89%	16.69%	27.77%	35.33%
	4	1.54%	3.57%	21.17%	35.32%	32.98%
Rainey Iva, SC	1	82.20%	89.63%	78.34%	65.70%	88.18%
	2A	45.44%	53.81%	69.60%	53.48%	28.75%
	2B	48.21%	54.54%	74.91%	50.34%	32.24%
	3	7.44%	13.43%	5.99%	12.86%	6.83%
	4	6.95%	13.34%	9.11%	12.26%	6.55%
	5	6.37%	12.96%	7.15%	11.14%	5.42%
Cherokee Gaffney, SC	1	47.13%	53.55%	14.83%	82.48%	81.35%
Myrtle Beach	1	-0.16%	0.13%	-0.13%	-0.14%	-0.15%
	2	-0.14%	0.30%	-0.15%	0.18%	0.03%
	3	-0.05%	0.51%	-0.09%	-0.01%	-0.05%
	4	0.00%	N/A	N/A	N/A	N/A
	5	-0.04%	0.17%	-0.09%	-0.02%	-0.09%
Hilton Head	1	0.03%	0.30%	0.01%	0.13%	0.06%
	2	0.03%	0.41%	0.01%	0.08%	0.04%
	3	0.05%	0.53%	-0.01%	0.06%	-0.02%
Summer Nuclear Unit 1 Jenkinsville, SC	1	82.70%	101.50%	88.80%	87.50%	95.50%
Jefferies Lake Moultrie	1	5.61%	4.69%	6.95%	5.09%	2.66%
	2	34.40%	34.53%	34.41%	32.89%	33.49%
	3	5.45%	5.59%	6.80%	9.06%	9.78%
	4	34.43%	33.06%	32.43%	33.54%	28.61%
	6	-1.26%	-0.77%	-1.29%	-1.23%	-1.16%

APPENDIX H: COAL RETIREMENT STUDY

INTRODUCTION AND OBJECTIVES

As part of the 2026 IRP, Santee Cooper conducted an evaluation of the cost effectiveness of continued operation of its coal-fired Cross Generating Station. Santee Cooper established in prior IRPs that Winyah Generating Station will retire when suitable new resources are available to replace Winyah and allow Santee Cooper to continue to reliably serve load. Therefore, for the 2026 IRP, Winyah is assumed to retire January 1, 2035. Upon the closure of Winyah, the Cross facility will be the only remaining coal-fired generation on the Combined System.

For the evaluation of the potential retirement of Cross, Santee Cooper studied the following retirement options for multiple years over the Study Period as compared to a base configuration that reflected continued operation of Cross throughout the Study Period.

- Partial Retirement – Retirement of units 1 and 2, the oldest of the Cross units
- Full Retirement – Retirement of the entire Cross Generating Station

Retirement studies must consider and evaluate transmission impacts and potential associated upgrades, capital and operating and maintenance costs that can be avoided depending on the year of retirement, cost of replacement generation, and impacts to production costs that results from a different mix of resources being available to serve load.

Santee Cooper's coal-fired facilities have provided low cost, reliable, and dispatchable power for decades, and any replacement resource must provide the same benefits to the system. Retirement and replacement of Cross Generating Station is especially critical given the size of the current facility, which is approximately 2,330 MW Winter Net Dependable Capacity.

STAKEHOLDER INVOLVEMENT AND FEEDBACK

As part of the study, Santee Cooper worked with the Stakeholder Working Group to review assumptions and methodology. The following technical meetings were held with the Working Group:

- Coal Retirement Technical Meeting 1 on April 10, 2025, covering proposed transmission and retirement scenarios.
- Coal Retirement Technical Meeting 2 on May 29, 2025, covering feedback from Technical Meeting 1 and updates on the status and timeline of the study.
- Coal Retirement Technical Meeting 3 on January 29, 2026, providing an update on the status of the study.
- Coal Retirement Technical Meeting 4 on April 30, 2026, covering the methodology for the transmission evaluation, results from the transmission evaluation, and proposed assumptions for the retirement study.

Stakeholders provided feedback on the study and helped to ensure a robust evaluation.

Appendix H: Coal Retirement

EVALUATION OF TRANSMISSION IMPACTS

The following scenarios were provided to the Transmission Planning team at Santee Cooper to determine the potential impacts of retiring Cross for both a partial and full retirement, resulting in four (4) scenarios for evaluation.

- Scenario 1 – No Cross retirement (for comparison)
- Scenario 2 – Optimized replacement resources
- Scenario 3 – Replaced with peaking resources and renewables (with relaxed build limits)
- Scenario 4 – Replaced with nuclear and peaking resources at the Cross site

Each scenario assumed Cross units were retired in the year 2035, and replacement resources were determined utilizing the EnCompass model and resource planning analysis consistent with the 2025 IRP assumptions and process.

The Transmission Planning team then studied what transmission projects would be required under the different retirement scenarios. For each scenario, a 2035 Summer and Winter peak model was used and approved transmission projects were assumed to be included in the base models. Internal planning models with the most updated information were used based on the 2024 series Multi-Regional Modeling Working Group (MMWG) models. It was assumed that Winyah, Myrtle Beach, and Hilton Head generation were retired by 2035.

Steady state analysis was conducted on all four (4) scenarios for both the partial and full Cross retirement in order to assess the system impact. System stability analysis was conducted on partial and full Cross retirement Scenario 3 only as the Transmission Planning team estimated that scenario would have the highest potential of greater stability impact among all scenarios due to potential stability concerns with higher renewable penetration.

Santee Cooper considered and evaluated the use of alternative transmission technologies (ATTs) in the transmission analysis conducted for the Coal Retirement Study. ATTs such as advanced power flow control devices, advanced conductors, tower lift, and other types were all considered and some were selected as potential transmission solutions that would lower transmission upgrade costs. The use of static VAR compensators, synchronous condensers, and voltage source converters were not evaluated as those devices and technologies are primarily used for voltage support by providing reactive power. Additional inertia also was not required from the study as there were no expected system stability issues. Voltage source converters are primarily used with HVDC systems. These ATTs were not deemed necessary during this study.

Capital and operating costs of transmission upgrades were estimated for the various projects deemed to be required across the scenarios. Scenario 1 was established as a base case configuration, to which the estimated costs of upgrades for the other three Cross retirement scenarios were compared. The following table shows the estimated transmission costs by retiring Cross by 2035 in each scenario.

Appendix H: Coal Retirement

	Scenario Cost (\$M)	
	Partial Cross Retirement	Full Cross Retirement
Scenario 1	12.4	12.4
Scenario 2	1,639.1	1,893.5
Scenario 3	1,273.5	1,198.9
Scenario 4	12.4	12.4

Out of the retirement scenarios studied, Scenario 3 incurred the least amount of costs for both a partial and full Cross retirement. It should be noted that Scenario 3, with higher renewable resources, assumed future renewable generation sited at optimal transmission locations, thus minimizing required transmission upgrades. However, actual project siting, to the extent different from assumptions made in the transmission study, may increase transmission cost.

Using the results of the transmission evaluation, and after adjusting for costs of transmission upgrades allocated to integrating the new resources added to replace the Cross capacity, it was established that both a partial and full retirement would require approximately \$1.2 billion in associated transmission upgrades (in 2026 dollars). This cost was then included as an incurred cost for the Cross retirement cases described in section below.

RETIREMENT STUDY AND RESULTS

For the Coal Retirement Study, Santee Cooper evaluated both partial and full retirements of Cross for each of the years 2035, 2040, 2045, and 2050, totaling eight retirement scenarios, plus a base case with no retirements. Projected capital expenses and fixed operating and maintenance costs for the Cross facilities were assumed avoided beginning the year of retirement. Additionally, investments in equipment to comply with zero liquid discharge requirements were assumed avoided for scenarios that modeled a 2035 retirement year. The EnCompass model was utilized to identify a least-cost portfolio of replacement resources when the Cross units were retired and subsequent production cost runs were performed to compute total costs for each scenario. Moreover, for the Coal Retirement Study, Santee Cooper assumed that new thermal resources could be installed throughout the Study Period to ensure that the incremental cost of portfolios identified for the 2050 Cross retirement scenarios would remain conservatively low.

The following table presents the results of the coal retirement optimization and production cost runs for each scenario compared to a no retirement scenario.

Appendix H: Coal Retirement

NPV Power Costs (2026 \$B, 2026-2055)	NPV	Diff
2026 IRP - No Retirement	\$32.6	
2026 IRP - Partial Retirement 2035	\$35.2	\$2.6
2026 IRP - Partial Retirement 2040	\$34.5	\$1.9
2026 IRP - Partial Retirement 2045	\$33.7	\$1.1
2026 IRP - Partial Retirement 2050	\$33.2	\$0.6
2026 IRP - Full Retirement 2035	\$37.3	\$4.7
2026 IRP - Full Retirement 2040	\$35.8	\$3.2
2026 IRP - Full Retirement 2045	\$34.5	\$1.9
2026 IRP - Full Retirement 2050	\$33.6	\$1.0

Results show declining NPV costs as the retirement of Cross is delayed under both partial and full retirement scenarios and higher incremental NPV costs when retiring the full Cross station relative to a partial retirement. These results, under the assumptions in this study, lead to a conclusion that continuing to operate the Cross facility is the least cost option. Therefore, the base assumption for the 2026 IRP is continued operation of all Cross units through the end of the Study Period.

In future triennial IRP filings, Santee Cooper, working with stakeholders, will continue to evaluate the Cross Generating Station to determine the potential benefits of further retirements of coal-fired facilities for its customers.

APPENDIX I: CROSS REFERENCE FOR COMPLIANCE WITH S.C. CODE ANN. § 58-37-40 AND COMMISSION ORDERS 2024-171, 2025-244, AND 2026-126

The following table outlines the requirements of S.C. Code Ann. § 58-37-40, S.C. Code Ann. § 58-31-227, and Commission IRP Orders for Santee Cooper's Triennial IRP reports and references the applicable section and page number of this 2026 Triennial IRP report demonstrating Santee Cooper's compliance with each requirement.

Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
S.C. Code Ann. § 58-37-40(A)(3)	Santee Cooper "shall develop a public process allowing for input from all stakeholders prior to submitting the [IRP]. The [IRP] must be developed in consultation with the electric cooperatives and municipally owned electric utilities purchasing power and energy from [Santee Cooper] and consider any feedback provided by retail customers and shall include the effect of demand-side management activities of the electric cooperatives and municipally owned electric utilities that directly purchase power and energy from [Santee Cooper] or sell power and energy generated by [Santee Cooper]."	Stakeholder Engagement Process (P. 29); Demand-Side Management Overview (P. 46); Attachment 4
S.C. Code Ann. § 58-37-40(A)(3)	"The [IRP] must be posted on the commission's website and on [Santee Cooper's] website."	Link to website (www.santeecooper.com/IRP)
S.C. Code Ann. § 58-37-40(A)(4)(a)	Santee Cooper's IRP "shall include an analysis of long-term power supply alternatives and enumerate the cost of various resource portfolios over various study periods including a twenty-year study period and, by comparison on a net present value basis, identify the most cost-effective and least ratepayer-risk resource portfolio to meet [Santee Cooper's] total capacity and energy requirements while maintaining safe and reliable electric service."	Resource Plan Evaluation (P. 74); Preferred Portfolio (P. 104)
S.C. Code Ann. § 58-37-40(A)(4)(c)	Santee Cooper's IRP "must be developed in consultation with the electric cooperatives, including Central Electric Power Cooperative, and municipally owned electric utilities	Stakeholder Engagement Process (P. 29); Demand-Side Management Overview (P. 46); Attachment 4

Appendix I: Cross Reference for Compliance

Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
	purchasing power and energy from [Santee Cooper], and consider any feedback provided by retail customers and shall include the effect of demand side management activities of the electric cooperatives, including Central Electric Power Cooperative, and municipally owned electric utilities that directly purchase power and energy from [Santee Cooper] or sell power and energy generated by [Santee Cooper].”	
S.C. Code Ann. § 58-37-40(A)(4)(c)	Santee Cooper’s IRP “shall include and evaluate at least one resource portfolio, which will reflect the closure of the Winyah Generating Station by 2028, designed to provide safe and reliable electric service while meeting a net zero carbon emission goal by the year 2050.”	Assessment of Resource Need: Planned Retirements (P. 41); Resource Plan Evaluation (P. 74)
S.C. Code Ann. § 58-37-40(B)(1)(a)	An IRP shall include a “long-term forecast of the utility’s sales and peak demand under various reasonable scenarios.”	Electric Load Forecast Overview (P. 33)
S.C. Code Ann. § 58-37-40(B)(1)(b)	An IRP shall include “the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios.”	Major Modeling Assumptions (P. 59); Resource Plan Evaluation: Portfolio Optimization Results (P. 79)
S.C. Code Ann. § 58-37-40(B)(1)(c)	An IRP shall include “projected energy purchased or produced by the utility from a renewable energy resource.”	Resource Plan Evaluation: Renewable Energy Forecast (P. 98); Appendix E (P. 131)
S.C. Code Ann. § 58-37-40(B)(1)(d)	An IRP shall include “a summary of the electrical transmission investments planned by the utility.”	Transmission Plans and Planning Processes (P. 54); Appendix B (P.111)
S.C. Code Ann. § 58-37-40(B)(1)(e)	An IRP shall include “several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility’s service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand	Major Modeling Assumptions (P. 59); Resource Plan Evaluation (P. 74)

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
	response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks.”	
S.C. Code Ann. § 58-37-40(B)(1)(f)	An IRP shall include “data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio.”	Assessment of Resource Need: Performance of Currently Owned Resources (P. 41); Appendix G: Table G1 (P. 134)
S.C. Code Ann. § 58-37-40(B)(1)(g)	An IRP shall include “plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan.”	Resource Plan Evaluation: Rate Impacts of Portfolios (P. 97); Preferred Portfolio (P. 104); Key Considerations and Conclusions (P. 102)
S.C. Code Ann. § 58-37-40(B)(1)(h)	An IRP shall include “an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs.”	Resource Plan Evaluation (P. 74); Appendix D (P. 130)
S.C. Code Ann. § 58-37-40(B)(1)(i)	An IRP shall include “a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.”	Executive Summary (P. 1); Electric Load Forecast Overview (P. 33); Major Modeling Assumptions (P. 59); Assessment of Resource Need: Table 5 (P. 40)
S.C. Code Ann. § 58-37-40(B)(1)(j)	An IRP shall include “a report addressing updates to the utility's transmission plan under the utility's open access transmission tariff pursuant to the federal jurisdictional planning process. In this report, the utility shall, when applicable, describe planned transmission improvements specific to siting of new resources expected to impact interconnection constraints or other operations of the systems. The utility shall also describe how it evaluated alternate transmission	Transmission Plans and Planning Processes (P. 54); Appendix B (P. 111); Major Modeling Assumptions: Transmission System Requirements (P. 71) Appendix H (P. 138)

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
	technologies when developing solutions for identified transmission needs for interconnecting resources. The utility's transmission report must include how the utility evaluates transmission investments, including: (i) a description of how the utility evaluated a range of transmission solutions, including non-wires alternatives, joint projects with neighboring and other regional utilities, other upgrades to existing facilities, and other best practices. Modeling may consider, as appropriate, grid-enhancing technologies and alternate transmission technologies such as static synchronous compensators, static Volt-Ampere Reactive (VAR) compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors, switchable reactors, and tower lifting in a manner consistent with common utility practice; (ii) A description of how transmission factored into the utility's evaluation of the range of future scenarios included in the fifteen-year time period of the utility's resource plan, including significant continued economic growth and the retirement of the utility's coal generation; (iii) a discussion of transmission considerations for facilities included in the utility's preferred resource plan for	

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
	which there are particular sites specified; (iv) information such that intervenors and stakeholders can pursue participation in local transmission planning collaborative activities which are held pursuant to orders from the Federal Energy Regulatory Commission; and (v) any other information that the utility believes is relevant to its resource plan or future transmission investments.	
S.C. Code Ann. § 58-37-40(B)(2)	An IRP “may include distribution resource plans or integrated system operation plans.”	N/A
S.C. Code Ann. § 58-31-227	Santee Cooper “shall file for commission approval of a program for the competitive procurement of energy capacity, and environmental attributes from renewable energy facilities to meet needs for new generation resources identified by [it] in its Integrated Resource Plans or other planning processes.”	Recent Activities and Developments: Procurement of Solar Resources (P. 18)
Order No. 2024-171, p. 99 (Ordering Paragraph 3)	Santee Cooper must “consider other approaches to load forecasting and resource portfolio analysis to plan for future industrial load growth due to economic development and provide updates to the Commission in future IRP filings.	Electric Load Forecast Overview (P. 33)
Order No. 2024-171, p. 99 (Ordering Paragraph 4)	Santee Cooper must “incorporate actual solar additions and any updates to future planned solar additions in its annual IRP Updates.”	Assessment of Resource Need: Current Owned Resource Overview (P. 40); Assessment of Resource Need: Power Purchase Agreements (P. 42); Short-Term Action Plan: Solar Resources (P. 108)
Order No. 2024-171, p. 92	The Commission concluded that Santee Cooper has provided sufficient justification for its 300 MW target of solar additions per year from 2026-2030 and “instructs Santee Cooper to work with	Major Modeling Assumptions: Resource Option Assumptions: Renewable and Energy Storage Resources (P. 65); Stakeholder Engagement Process (P. 29)

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
	stakeholders if revisions to the assumption are warranted for future IRPs and IRP Updates.”	
Order No. 2024-171, p. 99 (Ordering Paragraph 5) and p. 66	Santee Cooper is directed to continue to evaluate the natural gas combined cycle shared resource in the analyses conducted for future IRP Updates and IRPs; Santee Cooper must continue to consider the NGCC and alternatives to the NGCC in the analyses conducted for future IRP Updates and IRPs.	Executive Summary (P. 1); Recent Activities and Developments: 2023 IRP and 2024 and 2025 IRP Update Short-Term Action Plan Items (P. 17); Assessment of Resource Need: Committed Resource Additions (P. 43); Resource Plan Evaluation (P. 74); Key Considerations and Conclusions (P. 102); Short-Term Action Plan (P. 107)
Order No. 2024-171, p. 94	The Commission does not find it necessary to require Santee Cooper to update or revise its capital or operating cost assumptions utilized for its proposed NGCC resource for the purposes of this IRP. Santee Cooper has committed to updating stakeholders and the Commission, through future IRPs and IRP Updates, as well as compliance with all requirements of [the Siting Act].	N/A; but see Major Modeling Assumptions: Existing Resource Operating Costs and Characteristics, (P. 63); Major Modeling Assumptions: Resource Option Assumptions, (P. 64)
Order No. 2024-171, p. 99 (Ordering Paragraph 2)	Santee Cooper is directed to review and address the recommendations of the ORS witnesses to discuss seven issues with stakeholders no later than the 2026 Triennial IRP.	Recent Activities and Developments: Requirements from Commission Orders & ORS Recommendations (P. 23); Stakeholder Engagement Process (P. 29)
Order No. 2024-171, p. 99 (Ordering Paragraph 2); pp. 35-37; ORS Recommendation D1	ORS recommends all commodity forecasts, including coal and carbon dioxide (“CO ₂ ”) forecasts, should continue to be discussed in the Stakeholder Working Group.	Stakeholder Engagement Process (P. 29); Major Modeling Assumptions: Fuel Forecasts, (P. 60); Major Modeling Assumptions: Carbon Emissions Pricing (P. 62)
Order No. 2024-171, p. 95 (Ordering Paragraph 2); pp. 35-37, 95; ORS Recommendation E1	ORS recommends Santee Cooper investigate higher penetrations of solar and wind resources in the next ELCC study and discuss the results in the Stakeholder Working Group. “The Commission concludes that the ELCC values utilized in this [2023] IRP are reasonable and instructs Santee	Stakeholder Engagement Process (P. 29); Major Modeling Assumptions: Effective Load Carrying Capability (P. 70)

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
	Cooper to discuss this topic with stakeholders.”	
Order No. 2024-171, p. 99 (Ordering Paragraph 2); pp. 35-37; ORS Recommendation E3	ORS recommends integration costs and associated modeling methodologies, including modeling operating reserves, be discussed further in the Stakeholder Working Group.	Stakeholder Engagement Process (P. 29); Major Modeling Assumptions (P. 59); Major Modeling Assumptions: Operating Reserves (P. 71)
Order No. 2024-171, p. 99 (Ordering Paragraph 2), pp. 35-37; ORS Recommendation E4	ORS recommends Santee Cooper discuss potential impacts of the United States Environmental Protection Agency (EPA) Section 111 proposed rule in the Stakeholder Working Group and consider including a sensitivity scenario in the 2024 IRP Update to address the proposed rule if adopted and not stayed.	N/A; but see Stakeholder Engagement Process (P. 29); Executive Summary (P. 1); Recent Activities and Developments: Environmental Regulatory Developments: EPA Greenhouse Gas Rule (P. 21); Resource Plan Evaluation (P. 74)
Order No. 2024-171, p. 99 (Ordering Paragraph 2), pp. 35-37; ORS Recommendation F2	ORS recommends Santee Cooper discuss in the Stakeholder Working Group the scope for further studies to analyze any potential cost savings from the retirement of remaining coal generation assets.	Recent Activities and Developments: Cross Generation Station Retirement Evaluations (P. 19); Stakeholder Engagement Process (P. 29); Assessment of Resource Need: Planned Retirements (P. 41); Appendix H (P. 138)
Order No. 2024-171, p. 99 (Ordering Paragraph 2); pp. 35-37; ORS Recommendation G1	ORS recommends Santee Cooper discuss the development of a quantitative reliability metric in the Stakeholder Working Group.	Stakeholder Engagement Process (P. 29); Resource Plan Evaluation (P. 74)
Order No. 2024-171, p. 99 (Ordering Paragraph 2); pp. 35-37; ORS Recommendation G2	ORS recommends Santee Cooper discuss the methodology it will use to estimate transmission investment associated with the retirement of the Cross Unit in the Stakeholder Working Group.	Stakeholder Engagement Process (P. 29); Recent Activities and Developments: Cross Generation Station Retirement Evaluations (P. 19); Major Modeling Assumptions: Transmission System Requirements (P. 71); Short Term Action Plan: Continue Stakeholder Engagement (P. 108); Appendix H (P. 138)

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
Order No. 2025-244, p. 46 (Ordering Paragraph 3)	"All requirements or ordering provisions from the Santee Cooper 2023 IRP decision, Commission Order No. 2024-171, and decisions in all subsequent IRP Updates shall be addressed in ongoing stakeholder engagement, potential negotiations, and testimony for the 2025 Santee Cooper IRP Update."	Stakeholder Engagement Process (P. 29)
Order No. 2025-244, p. 46 (Ordering Paragraph 4)	"Santee Cooper shall continue to engage with stakeholders as outlined in the processes described in the Santee Cooper 2024 IRP Update."	Stakeholder Engagement Process (P. 29); Short-Term Action Plan: Continue Stakeholder Engagement (P. 108)
Order No. 2025-244, p. 46 (Ordering Paragraph 5)	Santee Cooper shall consider all recommendations of the parties to the 2024 IRP Update Docket (Docket No. 2024-18-E) when conducting future IRP and IRP Update filings.	Recent Activities and Developments: Requirements from Commission Orders and ORS Recommendations (P. 23); Stakeholder Engagement Process (P. 29)
Order No. 2025-244, p. 46 (Ordering Paragraph 6)	"Santee Cooper shall continue to provide updates regarding its plans for the Cross Generating Station retirement evaluation and associated transmission evaluations, as well as the results of the study in support of the 2026 comprehensive IRP in the SWG."	Recent Activities and Developments: Cross Generation Station Retirement Evaluations (P. 19); Stakeholder Engagement Process (P. 29); Major Modeling Assumptions: Transmission System Requirements (P. 71); Short Term Action Plan: Continue Stakeholder Engagement (P. 108); Appendix H (P. 138)
Order No. 2025-244, p. 46 (Ordering Paragraph 7)	"Santee Cooper shall continue to monitor hydrogen availability and discuss price forecast assumptions with IRP stakeholders in the SWG prior to the 2026 comprehensive IRP."	Stakeholder Engagement Process (P. 29)
Order No. 2025-244, p. 46 (Ordering Paragraph 8)	"Santee Cooper shall continue to discuss updates related to the Inflation Reduction Act and Infrastructure Investment and Jobs Act incentives in the SWG."	Stakeholder Engagement Process (P. 29)
Order No. 2025-244, p. 46 (Ordering Paragraph 9)	"Santee Cooper shall perform production cost model benchmarking studies of its EnCompass model in conjunction with its comprehensive IRPs and discuss the results in the SWG."	Stakeholder Engagement Process (P. 29)

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
Order No. 2025-244, p. 16-17, 47 (Ordering Paragraph 10)	“For future IRPs and IRP Updates, Santee Cooper shall monitor, track, and report annually the forecasted versus actual load consumption for Economic Development Load.” “It is reasonable for Santee Cooper to monitor, track, and report annually on potential new large load in future IRPs and IRP Updates to keep the Commission, ORS, and stakeholders apprised of the impact these loads have on the load forecast, including explanations of variances from prior forecasts.”	Executive Summary (P. 1); Electric Load Forecast Overview (P. 33)
Order No. 2025-244, p. 47 (Ordering Paragraph 11)	“Santee Cooper shall update its GHG Rule Portfolio modeling assumptions in the 2025 IRP Update to reflect the latest EPA guidance available at the time the modeling is performed. Santee Cooper shall discuss changes to its assumptions based on changes to the EPA 111 Rule in the SWG prior to the 2025 IRP Update.”	N/A, but see Recent Activities and Developments: Environmental Regulatory Developments: EPA Greenhouse Gas Rule (P. 21); Stakeholder Engagement Process (P. 29)
Order No. 2025-244, p. 47 (Ordering Paragraph 12)	“Santee Cooper shall provide updates in future IRPs and IRP Updates regarding the planned solicitation for a battery energy storage system of up to 300 MW of four-hour duration which, according to Santee Cooper’s Reply Comments, would be sited at the Jefferies Generating Station, to leverage existing interconnection capacity and the Energy Communities tax credit bonus per the Inflation Reduction Act.”	Recent Activities and Developments: Implementation of Battery Energy Storage System Resources (P. 19); Resource Plan Evaluation (P. 74)
Order No. 2025-244, p. 47 (Ordering Paragraph 13)	“In advance of future IRPs and IRP Updates, and as required by S.C. Code Ann. § 58-37-40(A)(3), Santee Cooper shall continue to host the SWG. Further, Santee Cooper shall provide updates to the Commission about the activities of the group and Santee Cooper’s plans to incorporate lessons learned into future IRP filings.”	Stakeholder Engagement Process (P. 29)
Order No. 2025-244, p. 47	Santee Cooper shall discuss its plans to prepare the new Market Potential Study	N/A, but see Stakeholder Engagement Process (P. 29);

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
(Ordering Paragraph 14)	in the SWG ahead of the Market Potential Study update in 2025.	Demand-Side Management Overview: Market Potential Studies (P. 47)
Order No. 2025-244, p. 47 (Ordering Paragraph 15)	“Any ordering provision(s) from previous Santee Cooper IRP decisions issued by the Commission that have not already been addressed by Santee Cooper shall be incorporated in any ongoing stakeholder engagement, potential negotiations, and in its 2025 IRP Update.”	Recent Activities and Developments: Requirements from Commission Orders & ORS Recommendations (P. 23); Stakeholder Engagement Process (P. 29)
Order No. 2026-126, p. 66 (Ordering Paragraph 2)	“Santee Cooper shall consider all stakeholder feedback from the SWG regarding large-load penetration, and to the extent [it] determines that the recommended assumptions are consistent with good utility practice and are reasonable in the context of the design, operation, and plans for the Santee Cooper system, [it] shall incorporate those assumptions into its new reserve margin studies for the 2026 IRP.”	Stakeholder Engagement Process (P. 29); Assessment of Resource Need: Planning Reserve Requirements (P. 44); Short-Term Action Plan: Continue Stakeholder Engagement (P.108)
Order No. 2026-126, p. 66 (Ordering Paragraph 2)	Santee Cooper must update its ELCC studies, incorporating those recommended assumptions from the SWG that Santee Cooper determines are reasonable and consistent with good utility practice.”	Stakeholder Engagement Process (P. 29); Major Modeling Assumptions: Effective Load Carrying Capability (P. 70)
Order No. 2026-126, p. 66 (Ordering Paragraph 3)	“Consistent with Order No. 2025-244, in future Comprehensive triennial IRPs and annual IRP Updates, Santee Cooper shall report on potential new large load and the impact these loads have on the load forecast, including explanations of variances from prior forecasts.”	Executive Summary (P. 1); Electric Load Forecast Overview (P. 33)
Order No. 2026-126, p. 67 (Ordering Paragraph 4)	“Santee Cooper shall include a comprehensive assessment of coal retirements, including the Cross generation station, in its 2026 Comprehensive IRP.”	Recent Activities and Developments: Cross Generation Station Retirement Evaluations (P. 19); Appendix H (P. 138)
Order No. 2026-126, p. 67 (Ordering Paragraph 5)	“Santee Cooper shall discuss resource option assumptions for the 2026 IRP, including the potential to include a 2x1 NGCC resource option, with the SWG.	Stakeholder Engagement Process (P. 29)

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Authority	Requirement	2026 Triennial IRP Section Satisfying Requirement
	Further, Santee Cooper shall provide an evaluation of new resource additions.”	
Order No. 2026-126, p. 67 (Ordering Paragraph 6)	“Santee Cooper shall include information about the Fairfield Nuclear Project in the 2026 IRP to the extent it is available and relevant.”	Recent Activities and Developments: 2023 IRP and 2024 and 2025 IRP Update Short-Term Action Plan Items (P. 17); Resource Plan Evaluation (P. 74); Key Considerations and Conclusions (P. 102)
Order No. 2026-126, p. 67 (Ordering Paragraph 7)	“Santee Cooper shall include its latest assessment of transmission planning and short-term resource considerations in its 2026 IRP.”	Transmission Plans and Planning Processes (P. 54); Appendix B (P. 111)
Order No. 2026-126, p. 58	“Santee Cooper has agreed to include updates on the on-going activities associated with transmission requirements for the Joint NGCC as part of its 2026 IRP filing.”	Recent Activities and Developments: 2023 IRP and 2024 and 2025 IRP Update Short-Term Action Plan Items (P. 17)
Order No. 2026-126, p. 67 (Ordering Paragraph 8)	“Except for those ORS recommendations for Santee Cooper to address specific matters in its Reply Comments in this docket and those recommendations addressed in Ordering Paragraphs 2 through 7 [in Order No. 2026-126], Santee Cooper should consider and address any recommendations raised by the ORS Report as well as the comments from all parties in either the SWG or its 2026 IRP as appropriate. Santee Cooper may address such recommendations and comments via its filed IRP or IRP update, filed testimony, filed comments, or any other that it deems appropriate.”	Stakeholder Engagement Process (P. 29)
Order No. 2026-126, p. 67 (Ordering Paragraph 9)	“All requirements or ordering provisions from the Santee Cooper 2023 IRP Decision, Order No. 2024-171, and the Santee Cooper 2024 IRP Decision, Order No. 2025-244 shall be addressed in ongoing stakeholder engagement, potential negotiations, or filings for Santee Cooper’s 2026 IRP as appropriate.”	Stakeholder Engagement Process (P. 29)