Integrated Resource Plan

2024-2043

BLUE RIDGE Electric Co-op

A Touchstone Energy® Cooperative

CENTRAL ELECTRIC POWER COOPERATIVE, INC.

A Touchstone Energy® Cooperative

In accordance with the amendment of The South Carolina Code of Laws, 1976, section 58-37-40 to include electric cooperatives, Central Electric Power Cooperative Inc. (Central) is submitting its Integrated Resource Plan to the South Carolina State Energy Office on behalf of itself and the 20 South Carolina distribution electric cooperatives. The IRP's development included a planning process that was begun in 2022. Central will complete this process every three years with a review in the off years.

Contents

Glossary of Acronyms

Acronym	Definition
AC	alternating current
AMI	advanced metering infrastructure
ATB	annual technology baseline
BA	balancing authority
BAA	balancing authority area
BAU	business as usual
BE	beneficial electrification
BESS	battery energy storage system
BSER	best system of emissions reduction
CA	Coordination Agreement
CC	combined cycle
CCGT	combined cycle gas turbine
Central	Central Electric Power Cooperative, Inc.
CO2	carbon dioxide
COD	commercial operation date
CT	combustion turbine
CTPC	Carolina Transmission Planning Collaborative
CVR	conservation voltage reduction
DESC	Dominion Energy South Carolina
DLC	direct-load control
DR	demand response
DSM	demand-side management
Duke	Duke Energy Carolinas, LLC
EE	energy efficiency
EIA	Energy Information Administration
ELCC	effective load carrying capability
EPA	U.S. Environmental Protection Agency
EPC	engineering, procurement, and construction
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
G&T	generation and transmission
GDS	GDS Associates Inc.
GWh	gigawatt-hours
HRSG	heat recovery steam generator
HVAC	heating, ventilation, and air conditioning
IRA	Inflation Reduction Act
IRP	integrated resource plan
IRS	Internal Revenue Service

Acronym	Definition
ISO	independent system operator
ITC	investment tax credit
LCOE	levelized cost of energy
LCOS	levelized cost of storage
Li-ion	lithium-ion
LOLE	loss of load expectation
LOLP	loss of load probability
MM	million
MMBtu	one million British thermal units
MOU	memorandum of understanding
MW	megawatts
MWh	megawatt-hour
NC	North Carolina
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	natural gas combined cycle
NHEC	New Horizon Electric Cooperative
NITSA	Network Integrated Transmission Service Agreement
NO_x	nitric oxide
NRC	Nuclear Regulatory Commission
NRECA	The National Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
NSR	non-shared resource
NYMEX	New York Mercantile Exchange
O&M	operations and maintenance
OATT	Open Access Transmission Tariff
Plan	long-range transmission plan
PPA	power purchase agreement
PRM	planning reserve margin
PTC	production tax credit
PURPA	Public Utility Regulatory Policies Act (1978)
PV	photovoltaic
PVRR	present value of revenue requirements
QF	qualified facility
RE	renewable energy
RF	radio frequency
RFP	request for proposal
RICE	reciprocating internal combustion engine
RIM	ratepayer impact measurement

Acronym	Definition
RRO	regional reliability organizations
RTO	regional transmission organization
RUS	Rural Utilities Service
SAE	statistically adjusted end-use
Santee Cooper	South Carolina Public Service Authority
SCGT	simple-cycle gas turbine
SCRTP	South Carolina Regional Transmission Planning
SEEM	Southeast Energy Exchange Market
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SO_2	sulfur dioxide
SOCO	Southern Company
TRC	total resource cost test
TSP	transmission service provider
UCT	utility cost test
VFD	variable frequency drive

1 Executive Summary

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1.1 Blue Ridge Electric Cooperative, Inc

Blue Ridge Electric Cooperative, Inc. (Blue Ridge) is a not for profit, member-owned corporation headquartered in Pickens, South Carolina that was created in 1940 to provide electric service to its member-owners. Blue Ridge currently serves approximately 71,000 member-owners who reside in Anderson, Greenville, Oconee, Pickens, and Spartanburg counties. Blue Ridge owns and maintains 7,279 miles of distribution lines to serve its member-owners. Blue Ridge's mission is to operate as a competitive provider of energy services and a partner with local communities, with a focus on safety, service and integrity.

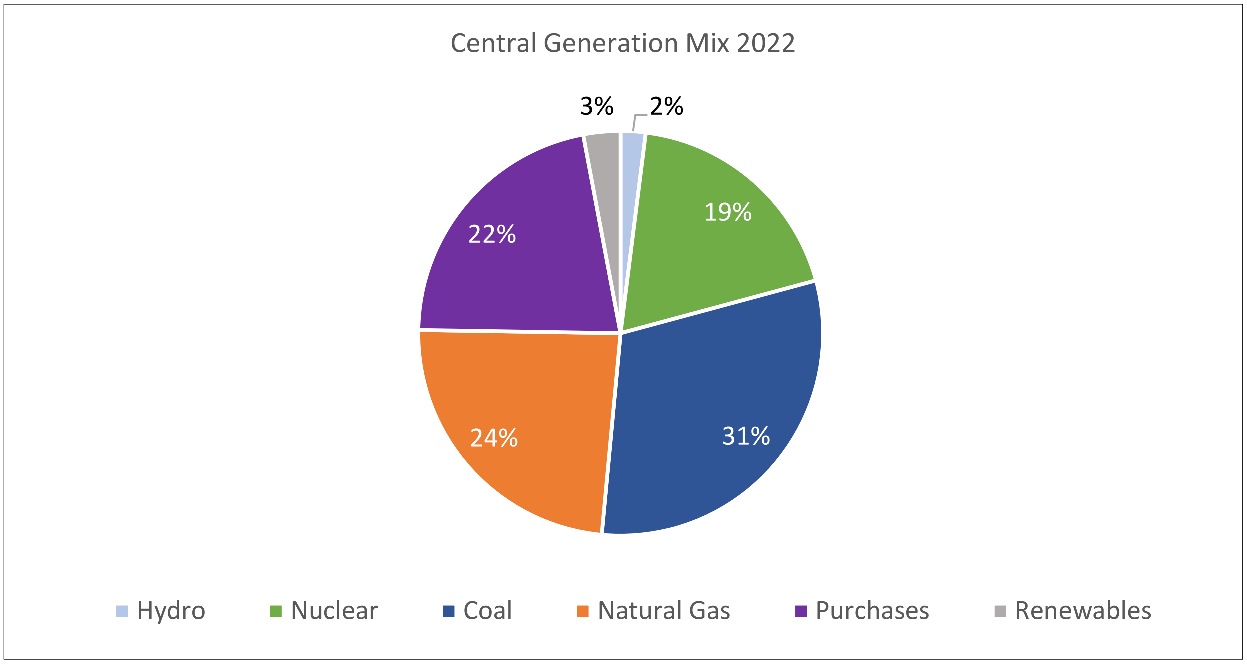
Blue Ridge and the other 19 South Carolina member cooperatives developed this Integrated Resource Plan (IRP) through their wholesale power provider, Central Electric Power Cooperative Inc. (Central). The IRP is written from the Central perspective and will detail Central and its member cooperatives' plan to meet forecasted energy consumption and peak demand throughout the defined planning period of the IRP.

1.2 Central Electric Power Cooperative, Inc.

Central is a wholesale electric generation and transmission cooperative (G&T) headquartered in Columbia, South Carolina. Central is owned by the 20 independent, consumer-owned South Carolina distribution electric cooperatives, referred to in this document as member-cooperatives. These member-cooperatives provide retail electric service to their member-owners, located in every county in South Carolina. Central is an IRS Section 501(c)(12) tax-exempt organization that operates on a not-for-profit, cost-of-service basis with the sole purpose of benefiting its member-cooperatives. The core services provided by Central for its member-cooperatives are power supply, transmission, economic development, member and energy services, and billing services.

Seven South Carolina distribution cooperatives created Central in 1948, pooling resources to form a wholesale power and transmission aggregator that would meet their needs in a reliable and cost-effective manner. Today, Central and its member-cooperatives own transmission and distribution facilities in all 46 counties in South Carolina, serving electricity to more than one-third of the state's population. Central's member-cooperatives serve more than 940,000 meters and more than 2 million residents over 79,000 miles of power lines covering 70% of South Carolina. Currently, Central provides wholesale power to its member-cooperatives primarily through long-term power purchase contracts with the South Carolina Public Service Authority (Santee Cooper), Duke Energy Carolinas LLC (Duke), and the Southeastern Power Administration (SEPA). In 2022, approximately 70% of Central's member-cooperatives' energy needs were met by zero-carbon or reduced carbon-emitting resources. Figure 1-1 on the following page shows the energy mix that Central supplied in 2022.

Figure 1-1: Central's 2022 Resource Mix



1.3 Cooperative Business Model

In the 1930s, electricity was available only in larger cities and along major transportation routes, leaving 90% of rural homes without electricity. Electric cooperatives were formed by citizens across the United States to bring electricity to rural areas and small towns. From the beginning, electric cooperatives were structured as member-owned and not-for-profit organizations. This enabled them to serve rural areas that for-profit companies had historically disregarded, having decided there were too few customers in those communities to make the venture worthwhile. Then and now, electric cooperatives focus on providing their members reliable power at the lowest possible cost. Any excess revenues are returned to their members in the form of capital credits.

Every member-owner has the right to participate in the policy-making process by voting on cooperative bylaws and electing members of their cooperative's governing board. Nationwide, electric cooperatives power more than 21.5 million businesses, homes, schools, and farms across 56% of the landmass in the United States and serve more than 42 million people.

As a G&T cooperative, Central is also owned by its members, which are electric cooperatives. Central does not provide services to retail consumers. This structure is common across America's 832 electric distribution cooperatives and 63 G&T cooperatives.

Central and its member-cooperatives are not-for-profit corporations and are granted federal tax-exempt status provided that 85% or more of their annual revenues are derived from serving member-owners. Central and its member-cooperatives strive to operate at cost but must accumulate capital to build and maintain the electrical system's infrastructure and facilities and provide other services. All amounts received from member-owners in excess of operating costs and expenses are considered patronage capital and are allocated to each member-owner on a cost-of-service basis. Patronage capital is returned to member-owners in accordance with the cooperative's needs and policies.

Central and its member-cooperatives have access to loans at favorable interest rates through the lending programs of the Rural Utilities Service (RUS), an agency of the U.S. Department of Agriculture. RUS loans help finance the large projects that are necessary to maintain and expand the electric generation, transmission, and distribution systems. Access to these loan programs significantly enhances the ability to provide affordable electric service to South Carolina consumers. Central and its member-cooperatives also rely on private-sector sources of financing such as CoBank and the National Rural Utilities Cooperative Finance Corporation.

The homes and businesses powered by Central's member-cooperatives are spread across the state, often in rural areas far from the network transmission lines operated by the local balancing authority (BA). A BA is an entity that has a legal responsibility for balancing load and generation within an assigned geographic territory, or its balancing authority area (BAA). Central's member-cooperatives are included in the BAAs of Santee Cooper, Duke, and Dominion Energy South Carolina (DESC). Central builds transmission lines to connect the substations serving member-cooperatives to the network transmission systems. The economies of scale provided by Central enhance its member-cooperatives' ability to build their systems efficiently while minimizing costs. The transmission lines that Central builds are referred to as "radial lines" because they connect local substations to the network transmission grid. Central does not own, operate, or maintain network transmission lines, nor does Central provide balancing services. Central's board approves construction workplans, which identify all needed radial transmission investments. The current board-approved transmission construction work plan for 2023 through 2025 includes construction of more than 100 miles of transmission line, with a projected budget of $188 million.

1.4 Cooperative Principles

The Seven Cooperative Principles, recognized by cooperatives worldwide, provide philosophical guidance to organizations that are organized as cooperatives. The Seven Cooperative Principles are as follows:

- Open and Voluntary Membership
- Democratic Member Control
- Members' Economic Participation
- Autonomy and Independence
- Education, Training, and Information
- Cooperation Among Cooperatives
- Concern for Community

Electric cooperatives work for the sustainable development of their communities through policies and programs accepted by their member-owners. Central and its 20 member-cooperatives sponsor several charities and fundraisers for causes within each respective community (see Section 8.2 for more information).

Central and its member-cooperatives have a long history of working together to offer demand-side management (DSM) programs to member-owners. These programs help member-owners reduce energy use and allow the member-cooperatives to reduce peak demand, thus reducing wholesale power costs for the entire Central system. Currently, Central and its member-cooperatives offer programs that use smart home devices to reduce energy use and reduce peak demand, on-bill financing options to enable energy efficiency (EE) measures and appliance upgrades, rebates to incentivize lighting efficiency upgrades in commercial and industrial facilities, net metering options for renewables, and several other programs that are discussed in the DSM section of this report. Additionally, member-cooperatives offer demand and time-of-use rates that encourage and incentivize their member-owners to use energy off peak, which provides savings to the member-cooperative and its member-owners.

Central and its member-cooperatives foster economic development through investments in their local communities. They partner through the South Carolina Power Team, a cooperative-owned economic development organization that supports the member-cooperatives in promoting, attracting, and retaining businesses and industries. The South Carolina Power Team provides services such as project management, business retention and expansion, and industrial park development. It also offers a database for potential investors to search for site-ready locations. Since 2014, the commitment to economic development has led to the creation of nearly 40,028 jobs, $13 billion in capital investment and $46 billion in total economic impact. The expansion of industry not only benefits the local community but also member-owners across the state. This industrial load growth reduces wholesale power costs for the entire electric system and benefits the member-owners directly through lower power bills.

1.5 Central's Member-Cooperatives

Member-cooperatives	Number of Active Accounts	Miles of Lines	Member-owners per Mile	Counties Served
Aiken Electric Cooperative	51,376	5,679	9.05	Aiken, Barnwell, Calhoun, Edgefield, Greenwood, Lexington, McCormick, Orangeburg, Saluda
Berkeley Electric Cooperative	121,279	6,230	19.46	Berkeley, Dorchester, and Charleston
Black River Electric Cooperative	34,279	4,048	8.00	Clarendon, Kershaw, Lee, and Sumter
Blue Ridge Electric Cooperative	70,780	7,279	9.70	Anderson, Greenville, Oconee, Pickens, and Spartanburg

Member-cooperatives	Number of Active Accounts	Miles of Lines	Member-owners per Mile	Counties Served
Broad River Electric Cooperative	23,865	2,729	8.74	Cherokee, Newberry, Spartanburg, and Union SC, Cleveland, Polk, and Rutherford NC
Coastal Electric Cooperative	11,967	1,758	6.78	Bamberg, Colleton, and Dorchester
Edisto Electric Cooperative	20,946	3,696	5.70	Allendale, Bamberg, Barnwell, Berkeley, Colleton, Dorchester, Hampton, and Orangeburg
Fairfield Electric Cooperative	33,026	3,607	9.00	Fairfield, Chester, Kershaw, Richland, and York
Horry Electric Cooperative	90,475	5,747	15.70	Horry
Laurens Electric Cooperative	61,960	7,100	8.70	Abbeville, Anderson, Greenville, Laurens, Newberry, Spartanburg, and Union
Little River Electric Cooperative	14,991	2,272	5.90	Abbeville, Anderson, Greenwood, and McCormick
Lynches River Electric Cooperative	22,001	2,930	7.48	Chesterfield, Kershaw, and Lancaster
Marlboro Electric Cooperative	6,474	1,088	6.00	Marlboro and Dillon
Mid-Carolina Electric Cooperative	59,225	4,442	13.34	Aiken, Lexington, Newberry, Richland, and Saluda
Newberry Electric Cooperative	13,355	1,641	8.14	Fairfield, Laurens, Lexington, and Newberry
Palmetto Electric Cooperative	77,074	3,435	22.00	Allendale, Beaufort, Hampton, and Jasper
Pee Dee Electric Cooperative	30,145	2,806	10.85	Chesterfield, Darlington, Dillon, Florence, Lee, and Marion
Santee Electric Cooperative	44,491	5,786	7.69	Clarendon, Florence, Georgetown, and Williamsburg
Tri-County Electric Cooperative	18,377	2,758	6.60	Calhoun, Kershaw, Lexington, Orangeburg, Richland, and Sumter
York Electric Cooperative	67,625	4,159	16.26	Cherokee, Chester, Lancaster, and York

2 South Carolina Electric Cooperative Service Territories

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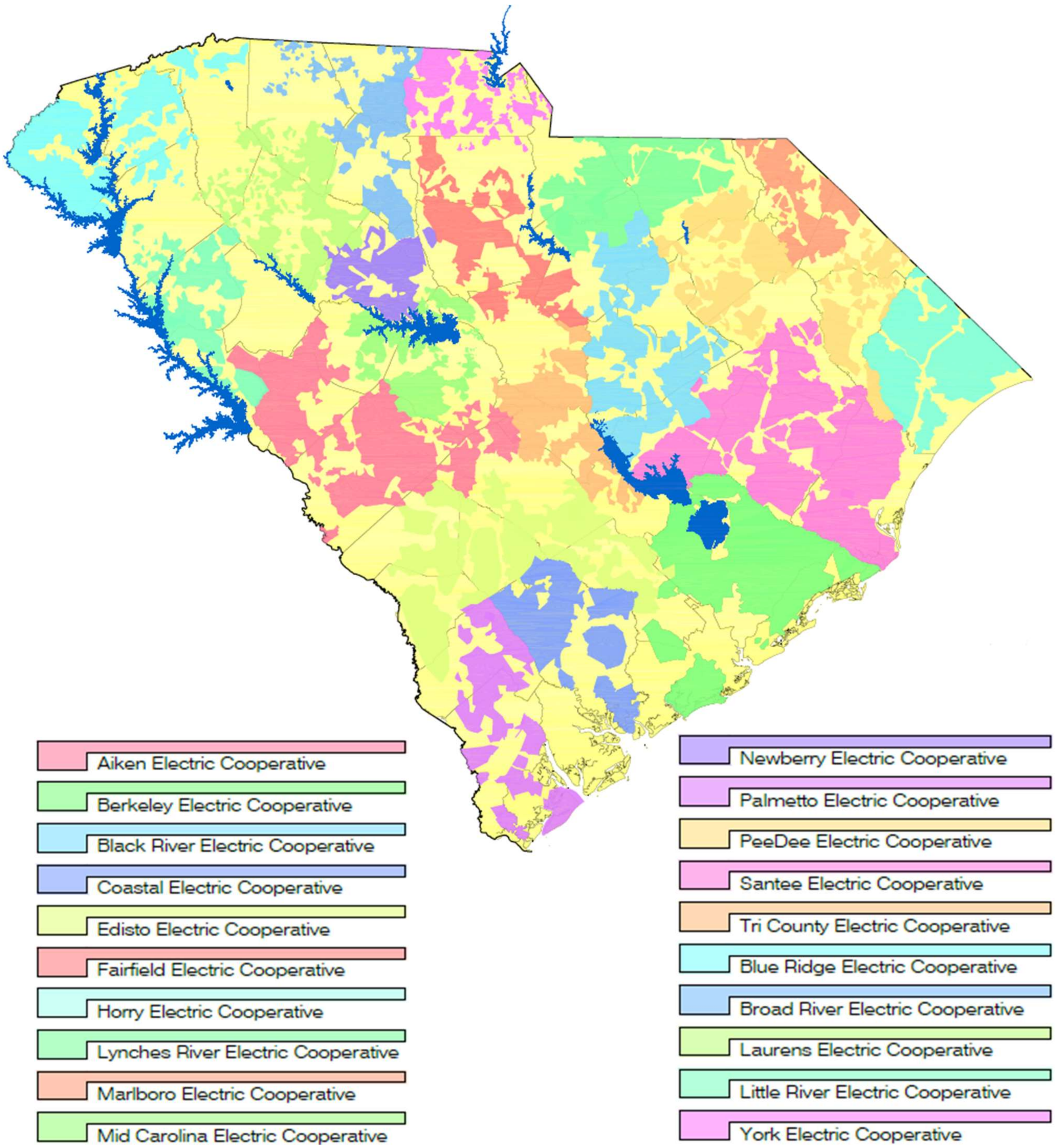
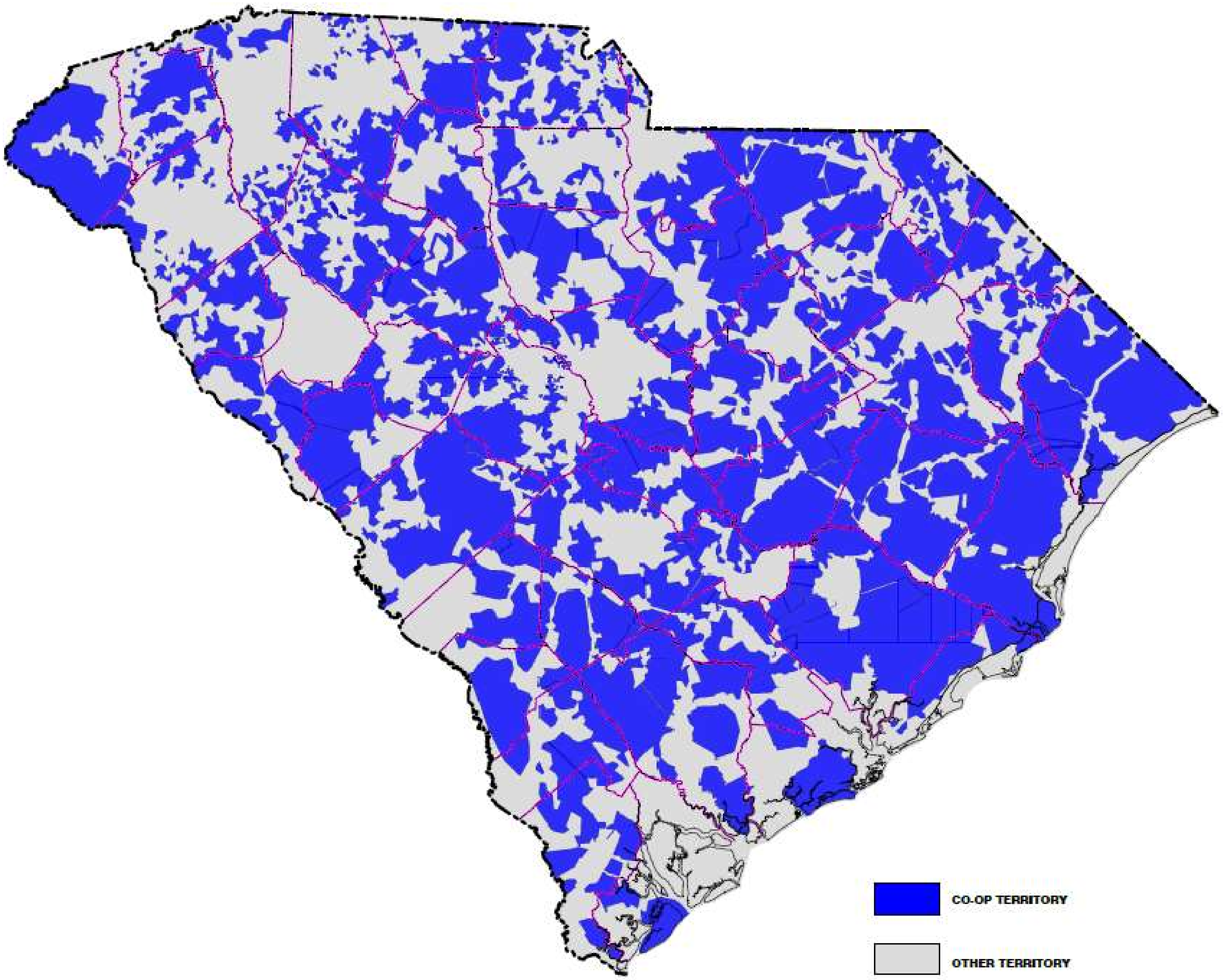
Individual Electric Cooperative Territories



All South Carolina Electric Cooperative Territory



2.1 Purpose of the Integrated Resource Plan

Resource planning is an ongoing process at Central and is one of the core responsibilities of the Power Supply department. By design, Central's IRP is detailed and outlines how Central can meet its long-term forecasted energy consumption and peak demand through a combination of supply-side and demand-side resources. The planning period for Central's 2023 IRP is January 1, 2024 – December 31, 2043.

This report provides a comprehensive view of Central's vision, initiatives, and future resource plan to serve the current and growing needs of its member-cooperatives. The IRP is intended to be a working document, used to guide and communicate Central's long-term power supply and infrastructure investment decisions. The plan embodies the commitment of Central's member-cooperatives to provide reliable power supply in a cost-effective manner. As part of its planning process, Central evaluates numerous risk categories, including, but not limited to, transmission risk for off system resources, fuel supply risk, completion risk for new resources, fuel price risk, execution risk, and regulatory risk. All plans involve multiple risks, and Central's goal in its planning process is to balance those risks to minimize the impact that any one variable will have on its member-cooperatives.

The analysis provided that supports the plan helps Central, its member-cooperatives, and their member-owners understand the effect of both near-term and long-term resource decisions on member-owner bills and the future reliability of the electric service. Central's team has examined various reasonable scenarios to determine a series of resource portfolios designed to minimize cost and risk.

3 Existing Resources

3 Existing Resources

Central provides wholesale power to its member-cooperatives primarily through a portfolio of contracts. The two primary contracts are with the South Carolina Public Service Authority, a state-owned utility known as Santee Cooper, and Duke. Central's remaining power-supply resources supplement these contracts. These supplemental resources include backup generators and renewable resources, such as solar and hydroelectricity. Central's member-cooperatives receive hydroelectric capacity and energy from SEPA, an entity of the federal government. Central aggregates the power provided under these various contracts to supply the needs of its member-cooperatives. Wholesale costs are aggregated, and each member-cooperative pays the same posted wholesale power rates. Member-cooperatives' wholesale costs will vary based on their size and member composition. Central manages these contracts with the objective of providing reliable power at the lowest possible price.

Central's contract with Santee Cooper is commonly called the Coordination Agreement (CA), which is an all-requirements contract for member-cooperative load in Santee Cooper's BAA. Approximately 77% of the electricity provided by Central to its member-cooperatives flows through the CA. SEPA provides 2% of electricity and the remaining 21% is served by Duke. The contract with Duke is referred to as the Duke Power Purchase Agreement (PPA). The Duke PPA is an all-requirements contract for member-cooperative load in Duke's BAA. An all-requirements contract requires the provider to supply the purchaser with all the purchaser's energy needs up to the level of reliability specified in the agreement and requires the purchaser to buy all its energy needs from the provider with only specified exceptions.

3.1 Santee Cooper

The CA is a "bundled" contract for generation and transmission services provided by Santee Cooper to Central with a contract end date of 2058. This "bundling" of service is allowed due to Santee Cooper's non-jurisdictional status at the Federal Energy Regulatory Commission (FERC) and the fact that amendments to the long-standing CA have not frustrated this legacy treatment, which is beneficial to both Central and Santee Cooper. Central accounts for more than 69% of Santee Cooper's firm demands. Central accounted for approximately 60% of Santee Cooper's energy sales in 2022.

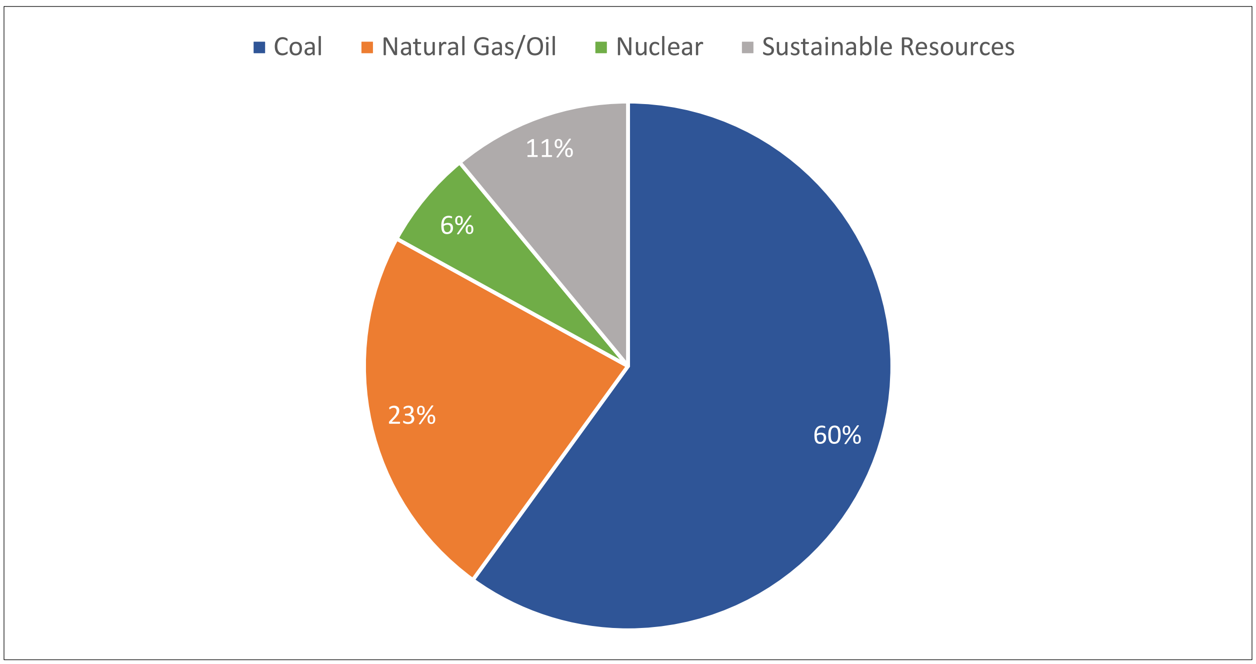
Due to Central's significant share of Santee Cooper's total business, the CA gives Central contractual rights related to resource planning and access to information regarding system operations and fuel purchasing well beyond what is customary in a traditional long term PPA. There are various joint committees between Central and Santee Cooper such as the Joint Planning Committee and the Joint Operating Committee. These committees review and vote on system operations and other critical matters to ensure the combined Central/Santee Cooper system is being planned and operated in a manner consistent with good utility practice.

The CA outlines the generation expansion process. Santee Cooper must engage Central throughout the process of creating potential expansion proposals, and Central must elect to opt into any large, proposed generation resource; otherwise, Santee Cooper cannot collect capital costs related to the proposed resource in its charges to Central. If Central opts out of Santee Cooper's proposed resource, then Central must secure its own generation resource for its pro-rata share of the system shortfall. Central can accomplish this requirement by purchasing capacity from the market, moving load to another regional utility, building new generating units, implementing DSM and EE programs, or some combination of all of the above.

Santee Cooper's current generation fleet has a mix of coal, nuclear, hydroelectric, and natural gas plants, but the generation fleet is primarily coal-based.

Figure 3-1 summarizes Santee Cooper's 2022 generation fleet capacity percentage by fuel type.

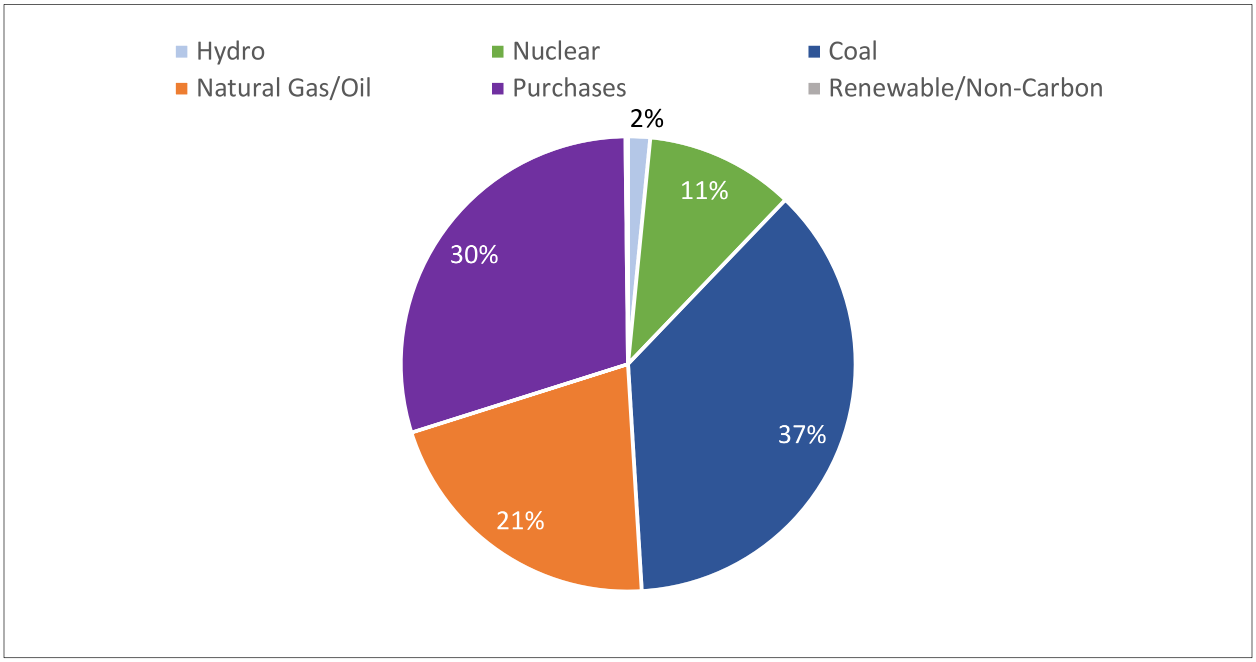
Figure 3-1: Santee Cooper 2022 Generation Fleet Capacity Percentage by Fuel Type[1]



Santee Cooper's actual energy mix is substantially different from its generation fleet capacity. Figure 3-2 shows its 2022 energy mix by fuel type.

[1] 2023 Santee Cooper Integrated Resource Plan

Figure 3-2: Santee Cooper 2022 Energy Mix [2]



One of the most significant changes in the power industry over the past decade has been a sharp decline in the price of natural gas. Natural gas has shifted from a high-cost fuel to the lowest cost source of fossil fuel generation. Efficiency improvements in combustion turbine (CT) technologies have further reduced the cost of natural gas-fired generation. For these reasons, natural gas has become the primary source of purchased power in the Southeast, and Santee Cooper has taken advantage of this lower cost purchased power as an alternative to its coal-fired generation when economical.

Santee Cooper announced plans to retire Winyah Coal Station at the end of 2028. This decision was made to reduce its carbon footprint and avoid ongoing fixed costs associated with maintaining this station. This retirement decision triggered the need for new generation. Santee Cooper and Central conducted a generation expansion study. At the end, Santee Cooper proposed a new shared resource: a 1,083 MW 2x1 natural gas combined cycle (CC) at Winyah, in Georgetown County. Central was concerned about the timeline and the cost and feasibility of building a natural gas pipeline to that part of the state. Based on those reservations, Central opted out of the proposed resource in April 2022. Central then became responsible for delivering its load ratio share of capacity requirements by January 1, 2029.

3.2 Diversified Resource Portfolio

In October 2022, Central's Board approved the Diversified Resource Portfolio. This alternative plan was chosen instead of opting into Santee Cooper's 2x1 CC proposed shared resource. According to the CA, Central is responsible for bringing at least 745 MW of capacity online by January 1, 2029. This capacity is to meet Central's pro rata share of Santee Cooper's capacity needs caused by the retirement of the

[2]2022 Santee Cooper Annual Report

Winyah Generating Station. Central believes this combination of resources will enable Central to fulfill its capacity obligations to the system while minimizing cost and risk. Table 3-1 below outlines those resources:

Table 3-1: Central's Diversified Resource Portfolio

Resource	Capacity MW	Fuel Type	Resource Type	Existing Resource	PPA Start Date	PPA End Date	In-Service Date
Catawba Nuclear	150	Nuclear	Baseload	Yes	2029	2043	1986
Sandersville Gas CTs	292	Natural Gas	Peaking	Yes	2029	2049	2002
Utility-Scale Batteries	150	Lithium Ion	Peaking	No	2029	2048	2029
Santa Rosa CC	215-230	Natural Gas	Intermediate	Yes	2029	2049	2003
Total MW	**807-822**						

Catawba Nuclear

Catawba Nuclear is an existing nuclear facility located in the Duke BAA in South Carolina. Central has acquired contract rights to 150 MW of baseload capacity from Unit #2. The PPA begins in January 2024 and is scheduled to begin serving Santee Cooper load in 2029. This resource produces low-cost, around-the-clock carbon-free energy, which will be an increasingly valuable resource. The agreement provides access to a reliability exchange agreement with three other nuclear units operated by Duke Energy Carolinas. If one of the four units goes offline unexpectedly, Central only loses a portion of the 150 MW capacity, as the other remaining units provide replacement capacity. This makes the Catawba Nuclear agreement more reliable than a typical unit-specific PPA. Central's counterparty is North Carolina Municipal Power Agency Number 1. The contract runs through the life of the plant. The plant life could be extended beyond 2043 if the Nuclear Regulatory Commission (NRC) grants an extension on the operating license.

Sandersville Gas Combustion Turbines (1-4)

Sandersville Gas CTs 1 through 4 are existing natural gas units owned by an independent power producer. These units are located in the Southern (SOCO) BAA and provide up to 292 MW of capacity. They are peaking units, which offer quick start capabilities. Peaking units have lower capacity costs than baseload units but are less fuel efficient, causing them to have higher fuel costs to operate. These units are designed to provide capacity during peak events. Central's counterparty has secured firm natural gas transportation rights to ensure these units will be able to operate during severe weather situations when natural gas transport capacity becomes constrained.

Utility Scale Batteries

Utility scale batteries will consist of multiple four-hour lithium-ion batteries. Central anticipates that these batteries will be charged from the Santee Cooper grid during off-peak hours when energy prices are low and dispatched during peak periods to provide capacity. They are expected to have a useful life of 20 years with minimal site remediation costs once they are retired. Central conducted a request for proposals in 2023 and is currently evaluating the results. As of publication, no vendor has been selected.

These batteries will be located inside the Santee Cooper BAA and will not require wheeling charges. Central has submitted three battery sites into Santee Cooper's interconnection queue study process. Central expects to receive these study results during the first quarter of 2024. Utility Scale Batteries installation timelines are typically one to two years, so there is minimal risk that these units will not be operational on January 1, 2029.

Santa Rosa Combined Cycle

This resource is in northern Florida and holds a grandfathered interconnection into the SOCO BAA. It is a natural gas-fired CC station. Central signed an agreement to purchase 215-230 MW of capacity and energy. It is an efficient resource that provides dependable capacity. Santa Rosa is served off a different gas pipeline than the other natural gas fired units in the Santee Cooper system, providing incremental redundancy to the system.

The diversified resource portfolio was approved by Central's board because it fulfilled Central's obligations under the CA to provide at least 745 MW of capacity by January 1, 2029, in a low-cost, risk-adjusted manner. The plan assumes Central will work to continue adding additional solar generation to the system. These resources provide a diverse fuel mix and operating characteristics to best meet system needs. Excluding the batteries, these resources are already operational. They will be pooled with Santee Cooper's other resources. Santee Cooper's system operators will dispatch these units, as well as Santee Cooper's shared and non-shared resources (NSR), in a least-cost dispatch to provide the system with the lowest-cost power possible. Central looks forward to collaborating with Santee Cooper to use these resources to enhance system reliability while minimizing power costs.

Table 3-2: Benefits of Central's Diversified Resource Portfolio

Benefit	Description
Diversified Fuel Mix	This plan is not heavily weighted towards one type of fuel commodity. Diversifying among natural gas, uranium, solar, and batteries will reduce exposure to fuel price shocks.
Reliance on Existing Resources	More than 650 MW of the Diversified Resource Portfolio are already online with a long history of reliable operation. This reduces the risk inherent in all major generation construction.

Benefit	Description
Carbon Intensity	Neither solar nor nuclear generation produce carbon dioxide. The efficient CC and the peaking units will produce significantly less emissions than the existing Winyah Generating Station.

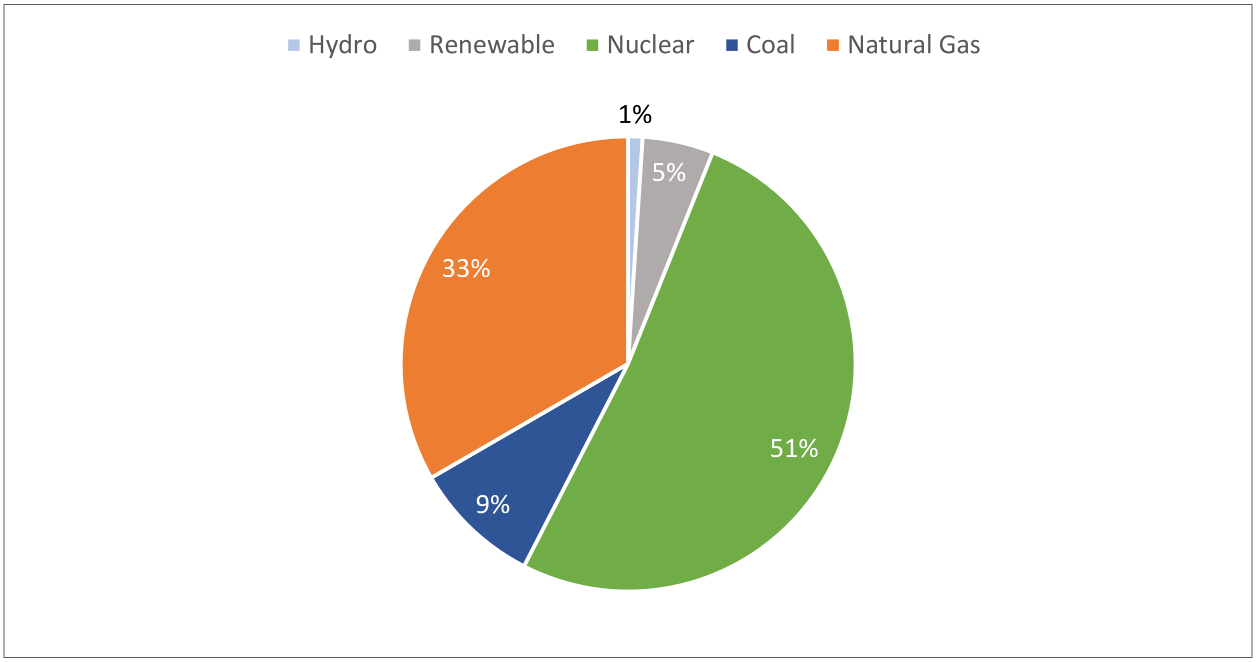
3.3 Duke Energy Carolinas, LLC

Central's other all-requirements contract, with Duke, is a more traditional PPA, with a contract term through 2030. The PPA is regulated by FERC under a cost-based tariff, and the PPA's terms and rate structure align with FERC's cost-based rate formula methodology.

Central has also contracted for a Network Integration Transmission Service Agreement (NITSA) with Duke. The NITSA requires Duke to serve all Central delivery points connected to Duke's transmission system as network load, with no adverse distinction between Central's delivery points and Duke's retail loads. The term of the NITSA remains in effect for as long as Duke provides transmission services as a BAA and is independent of the PPA term. If Central does not extend the PPA by 2025, the load will begin ramping down in 2029. One-third of Central's load currently served by Duke would transition out of the PPA in January 2029, followed by another third in January 2030, with the contract terminated at the end of 2030.

Duke relies heavily on nuclear generation, which accounts for 51% of the energy it produces. In recent years, Duke has retired coal generation and replaced it with natural gas generation, renewable generation, and market purchases. Duke has steadily added solar generation to its system. Duke's market purchases include multiple PPAs with third-party solar developers.

Figure 3-3: Duke Energy Carolinas 2022 Generation Mix by Fuel Type[3]



Duke Energy Carolinas and Duke Progress plan to retire their remaining coal units by 2036. By 2036, Duke intends to fill this resource gap with the following generation assets: utility-scale battery energy storage systems, solar plus storage, natural gas units, and small modular nuclear reactors. This transition will substantially reduce Duke's system's carbon footprint and keep it on track to achieve its corporate goal to be carbon neutral by 2050.

3.4 Southeastern Power Administration

SEPA is a federal power marketing agency that provides power from hydroelectric dams on the Thurmond, Russell, and Hartwell reservoirs, which are operated by the U. S. Army Corps of Engineers on the Savannah River. The power is sold to electric cooperatives and municipal utilities in the Southeast, including all 20 of Central's member-cooperatives. This low-cost power source reduces member-cooperative costs and decreases Central's capacity and energy requirements from Duke and Santee Cooper. SEPA's power belongs to the member-cooperatives, and SEPA is obligated to provide capacity to member-cooperatives. That capacity is referred to as each cooperative's SEPA allocation; however, the PPAs are contracted directly between SEPA and Central. Central acts as the member-cooperatives' agent, managing the contracts and ensuring the power benefits the member-cooperatives. SEPA's costs are directly passed through to each member-cooperative based on its SEPA allocation. SEPA currently supplies 200 MW of capacity and associated energy monthly to Central's member-cooperatives.

[3] 2022 Duke Energy Carolinas FERC Form 1

3.5 Renewables – Community Solar, Horry County Schools, Volvo Solar

Central's PPAs with Santee Cooper and Duke include limitations on the ability of Central and its member-cooperatives to build renewable generation without incurring penalties. Central and its member-cooperatives are assisting commercial, industrial, and residential member-owners throughout the state to access renewable options that meet their needs and benefit the system while minimizing any penalties assessed to Central.

Under the Public Utility Regulatory Policies Act (PURPA) of 1978, Central and other utilities must contract with a third-party renewable developer if its project meets the PURPA criteria to be a Qualified Facility (QF) and if its offer price is less than or equal to the utility's avoided energy cost. This avoided energy cost is specific to each utility but represents the production costs a utility avoids by purchasing energy from the QF provider. Santee Cooper's and Duke's contracts with Central acknowledge and account for PURPA-required purchases. Central can transact with these PURPA suppliers, and it can reduce its energy purchases from Santee Cooper and Duke without financial penalties. PURPA law supersedes Central's contract limits. If the renewable energy (RE) comes from a QF, Central will not be penalized by its power providers for having excess generation.

Solar power's inherent intermittent production profile will not significantly reduce Central's capacity purchases. The winter peak occurs early in the morning when solar irradiance is low, so solar production would be minimal during the winter peak. Central's summer peak typically occurs as the sun is beginning to set.

Details of the current and upcoming renewable projects Central and its member-cooperatives have in their resource mix are included below.

Georgetown PURPA

Solar developer Silicon Ranch is developing a 50 MW AC site in Georgetown County, South Carolina. Silicon Ranch will sell the generation output of this QF to Central. This solar project will be interconnected with Santee Cooper. The PPA will start January 2025 and is expected to operate for 20 years. Central's member-cooperatives will benefit from zero-emission energy purchased at or below avoided cost.

Lambert 1 and 2

Central and Santee Cooper have agreed to jointly develop 200 MW AC at the Lambert 1 and 2 sites. These sites will also be developed by Silicon Ranch in Georgetown County. These sites will come online in May 2024, and the PPA term is 20 years. Central and Santee Cooper have agreed to split the output from these sites based on each partner's respective load share of the Santee Cooper system; therefore, Central will take 72% of the sites' output and Santee Cooper will receive the other 28%.

Table 3-3: Central's Utility Scale Power Purchase Agreements

Solar Sites	Total Santee Cooper System (MW)	Central Share (MW)	In-Service Date	Retirement Date
Lambert 1	100	72	4Q 2024	3Q 2043
Lambert 2	100	72	4Q 2024	3Q 2043
Additional Joint Solar	300	216	TBD	TBD
Total	**500**	**360**		

Central and Santee Cooper have signed a memorandum of understanding (MOU) to develop up to 500 MW AC in the Santee Cooper BA. Each entity can bring on its load ratio share of solar to meet this goal. Central and Santee Cooper are already working together to develop 200 MW (Lambert 1 and 2) and retain the right to develop up to 300 MW of additional solar by 2030.

Volvo Solar

As a partial solution to Volvo's corporate goals to procure carbon-free energy for its production facilities, Central has executed a PPA with a solar developer for the output of a project located at Volvo's manufacturing site in Berkeley County. These solar arrays have a cumulative nameplate capacity of 6.5 MW (AC) and became operational in March 2020. Volvo is one of the many cooperative member-owners with sustainability goals, and Central is working with its member-cooperatives to help these member-owners achieve their goals.

Horry County School Solar

Horry Electric Cooperative serves two schools in Horry County with fixed rooftop solar installations that were energized in 2018. The sites possess a combined 860 kW (AC) of solar nameplate capacity. Central purchases one-half of the St. James Intermediate and Socastee Elementary schools' generation through a PPA. The remaining generation can be used by the schools to serve their loads, or they can sell a portion of the solar generation back to Horry Electric. Horry Electric compensates those schools with a net metering bill credit, which reduces the schools' monthly electric bills.

Community Solar

Central's Board authorized the construction for up to 5 MW (AC) of community solar available to all of Central's member-cooperatives. Construction on these sites began in 2016, and they are a mixture of ground-mount and canopy configurations. Some of these sites are owned by Central's member-cooperatives, and Central has PPAs with third-party solar developers to purchase the energy output from the remaining sites. Currently, 18 member-cooperatives have access to community solar.

Community solar allows Central's member-cooperatives to offer their member-owners the opportunity to support renewable generation development without the requirement to install those resources on their homes or property. Member-cooperatives can lease the panels to their member-owners. This opens access to solar energy for renters and mobile homeowners, who would not be able to access solar energy under a rooftop ownership business model. In total, the community solar sites have generated 42 GWh of energy since 2016, which would equal the production needed to fully supply 36,500 homes. As of the end of 2022, 4.2 MW (AC) has come online.

Table 3-4 illustrates the total community solar that each of Central's member-cooperatives has built and/or plans to construct.

Table 3-4: Member-Cooperative Solar Breakdown

Electric Cooperative	Total kW AC
Aiken	250
Berkeley	220
Black River	240
Blue Ridge	245
Broad River	270
Coastal	250
Fairfield	120
Horry	240
Laurens	276
Little River	240
Lynches River	240
Marlboro	165
Newberry	240
Palmetto	240
Pee Dee	240
Santee	255
Tri-County	240
York	240
Total	**4,211**

Berkeley Electric Cooperative Community Solar + Battery Installation

Berkeley Electric and Central are installing a battery system at Berkeley Electric's community solar site, which is expected to be completed and operational by the end of 2023. Berkeley Electric and Central will be able to use lessons learned from this installation for future solar and battery development. This pilot project will provide an additional load management tool to reduce Central's peak demand.

The battery will be a Tesla lithium-ion battery pack, with a maximum discharge rate (1 hour) of 116 kW (AC) and a total energy rating of 464 kWh. It will charge during low-demand, low-cost hours and discharge during high-load, high-cost hours. The battery will have the dual capability of being charged from the attached solar site or from the electric grid. The attached solar site will have a capacity rating of 120 kW (AC).

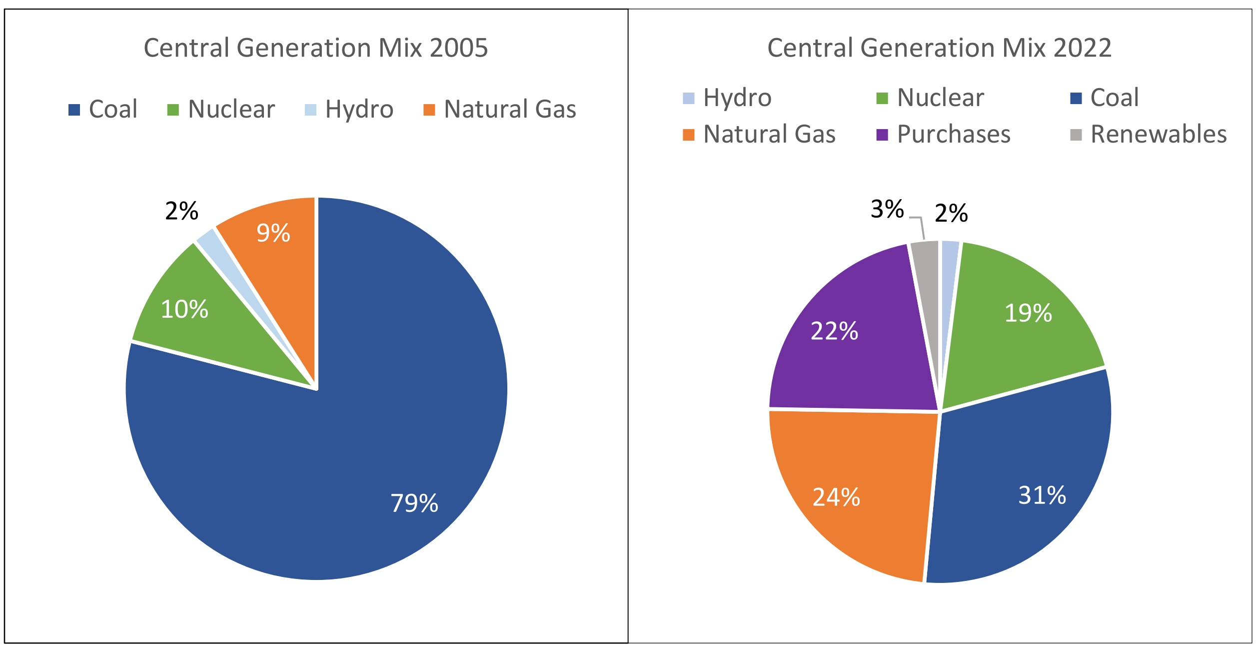
3.6 Diesel Generators

Central purchased six 3 MW diesel generators from Santee Cooper in 2012. Four of the generators can be used by Central to reduce Duke's annual coincident peak. The other two generators are connected to Dominion transmission and are used as backup generation for Central's member-cooperatives. These generators are from the General Motors 645F4B series and were placed into service in 1996. They have undergone substantial environmental compliance upgrades, meet current environmental emission standards, and are RICE-NESHAP compliant. Their quick-start abilities and high ramp rates make these generators effective peak-shaving resources.

3.7 Central's Energy Mix

Combining the production of the various power suppliers previously listed with Central's own resources produces Central's energy mix for 2022 shown in Figure 3-4:

Figure 3-4: Central's 2005 Energy Mix vs 2022 Energy Mix



In 2022, Central's member-cooperatives received 31% of their energy from coal-fired generation, a reduction of more than one-half compared to 2005. Market purchases from other suppliers and natural gas generation have displaced coal's dominant share of power production over time. Coal's share of Central's future energy mix will continue to decrease as Central's utility-scale solar PPAs begin to become operational in 2024. This additional solar production will expand the percentage of energy supplied to Central's member-cooperatives from non-emitting renewable resources.

4 Demand-Side Management

4 Demand-Side Management

GDS Associates Inc. (GDS) was tasked with updating the DSM analysis reflected in the 2020 IRP for Central's 2024 IRP, covering 2024 through 2043. To complete this task, GDS first reviewed the 2020 IRP and the associated DSM inputs, as well as the underlying analysis supporting the development of these inputs. GDS then developed a similar, but updated, analysis for the 2024 IRP. This section describes the updated scenarios included in the analysis and demonstrates the demand and energy impacts and costs associated with the DSM inputs.

This section is presented with the following sub-sections:

- DSM Resources Considered
    - This provides an overview of the five types of resources considered in the analysis: EE, demand response (DR), beneficial electrification (BE), RE, and conservation voltage reduction (CVR)
- Existing DSM Offerings
    - This provides a list and description of the DSM measures and programs (by resource type) that are currently offered by Central and/or are currently under consideration
- Estimating Future DSM Savings from Existing Resources
    - This provides a demonstration of the impact of existing DSM resources (through 2023) on a going forward basis
- Business as Usual Scenario
    - This provides a description of a business as usual (BAU) scenario and the associated results
- 25+ MW Scenario
    - This provides a description of a scenario that achieves at least 25 MW of additional DR savings by 2029 (above and beyond current 2023 DR levels) and the associated results
- Aggressive Scenario
    - This provides a description of a scenario that achieves aggressive savings through DSM spending that ramps up to 1% of Central's revenues by 2028, and the associated results

4.1 DSM Resources Considered

DSM is a broad category of resources whereby Central and its member-cooperatives encourage member-owners to modify consumption of electricity either through various programs or grid-related projects to reduce capacity and/or energy consumption. For the purposes of this IRP, Central categorizes five types of DSM programs:

1. EE – Support of efficient equipment or technology with the objective of reducing overall energy consumption

2. DR – Programs or tariffs designed to reduce consumption of electricity when the grid is most constrained, or the economic benefits are the greatest
    a. Typically, the objective of DR programs is to shift load away from peak periods rather than reduce the total amount of consumption.
3. BE – Programs or initiatives that encourage member-owners to transition energy-intensive equipment or processes from fossil fuel to electricity
    a. As the electric grid becomes cleaner, BE measures have the potential to reduce total emissions
    b. If the added load occurs primarily during off-peak periods, BE measures can improve system utilization and place downward pressure on rates
4. RE – Technologies such as behind-the-meter solar photovoltaic arrays reduce the amount of energy that must be supplied by the utility
5. CVR – This is the intentional operation of the transmission and distribution system to provide customer voltages in the lower end of the acceptable range, with the goal of achieving energy and demand reductions for customers

4.2 Existing DSM Offerings

Central and its member-cooperatives have pursued various DSM strategies since the 1980s and intend to continue offering member-owner programs over the planning horizon. The base case energy and peak demand forecasts in the base load forecast section of this IRP report reflect the impacts of current DSM resources, so no additional adjustments to the load forecast are required. However, the impact of future DSM programming is not incorporated in the base load forecast, so the expected impacts of EE and DR need to be subtracted from the base forecasts, while BE impacts need to be added to the base forecast, as appropriate, to determine the resource requirements of the system net of projected DSM activity.

Table 4-1 below provides a list and high-level description of existing DSM offerings as well as additional options that were considered in the analysis.

Table 4-1: DSM Measures and Descriptions

Status	Sector	Measure(s)	Description
Existing	Residential	Direct-load control (DLC) AC Thermostat - Summer Only	Uses Wi-Fi connected devices to adjust the cooling set points of homes with central electric air conditioning and fossil fuel heat
Existing	Residential	DLC AC Thermostat - All Seasons	Uses Wi-Fi connected devices to adjust the cooling and heating set points of homes with central electric air conditioning and electric heat
Existing	Residential	DLC AC Switch	Direct DR devices installed on the HVAC unit of homes to reduce cooling load during peak demand events

Status	Sector	Measure(s)	Description
Existing	Residential	DLC Water Heaters AMI	Direct DR devices on electric water heaters controlled through the advanced metering infrastructure (AMI) network
Existing	Residential	DLC Water Heaters Wi-Fi	Wi-Fi connected devices used to shift water heating loads off peak during curtailment events
Existing	Residential	DLC Water Heaters Radio Frequency (RF) Signals	Direct DR devices on electric water heaters controlled through a cooperative radio system
Existing	Residential	Electric Vehicle Charging	For current EV owners, direct load control of chargers or price signal to encourage member-owners to charge off-peak
Existing	Residential	Beat the Peak	Provides behavioral messaging via email, text, and phone calls encouraging member-owners to shift demand off-peak
Considered	Residential	Residential Battery Storage	Financial incentive to homeowners to install a battery backup that can be discharged during peak periods to provide load relief
Considered	Commercial	Commercial Battery Storage	Financial incentive to commercial businesses to install a battery backup that can be discharged during peak periods to provide load relief
Existing	Residential	Residential Generator DR	Provide financial incentives to homeowners with backup generators to self-generate electricity during curtailment events instead of taking power from the grid
Existing	Residential	On-bill Weatherization/ Infiltration (existing)	Blower door testing is used to identify leaks, and air sealing measures are installed to make the home tighter and thermally efficient
Existing	Residential	On-bill Weatherization/ Duct System (existing)	Duct blaster testing is used to identify air circulation issues, and repairs are made to improve the supply and return of conditioned air to the home
Existing	Residential	On-bill Weatherization/ HVAC System (existing)	HVAC contractors identify HVAC issues and repair or upgrade electric systems with new high-efficiency units
Existing	Residential	On-bill Weatherization/ Infiltration	Expansion of current On-bill Weatherization offering; blower door testing is used to identify leaks, and air sealing measures are installed to make the home tighter and thermally efficient

Status	Sector	Measure(s)	Description
Existing	Residential	On-bill Weatherization/ Duct System	Expansion of current On-bill Weatherization offering; duct blaster testing is used to identify air circulation issues, and repairs are made to improve the supply and return of conditioned air to the home
Existing	Residential	On-bill Weatherization/ HVAC System	Expansion of current On-bill Weatherization offering; HVAC contractors identify HVAC issues and repair or upgrade electric systems with new high-efficiency units
Considered	Residential	Residential EE/ Appliance Recycling	Recycling of old an inefficient refrigerator/freezer
Existing	Residential	Residential EE/ Heat Pump Water Heater	Incentivize member-owners who have electric resistance tank water heaters to upgrade to high-efficiency heat pump water heaters
Existing	Residential	Residential EE / High efficiency variable speed heat pump	Incentivize member-owners with electric space heat to upgrade to high-efficiency air source heat pumps
Considered	Residential	Residential EE/ Ductless Mini-split (existing)	Incentivize member-owners who have existing electric space heat to upgrade to high-efficiency ductless mini-split heat pump
Considered	Residential	Residential EE/ Ductless Mini-split (new construction)	Incentivize member-owners who to upgrade to high-efficiency ductless mini-split heat pump during new construction
Considered	Residential	Residential EE/ Geothermal heat pump	Incentivize member-owners who have electric space heat to upgrade to high-efficiency ground source heat pumps or to install geothermal units during new construction
Considered	Residential	Building Audits	Used to identify efficiency and peak-demand saving upgrades
Existing	Commercial	Commercial EE/ Lighting (existing)	Rebates for the installation of high-efficiency lamps, fixtures, and control systems in commercial facilities
Considered	Commercial	Building Audits	Used to identify efficiency and peak-demand saving upgrades
Existing	Commercial	Commercial EE/ HVAC	Rebates for installation of high-efficiency heating, ventilation, and air conditioning units and controls in commercial facilities

Status	Sector	Measure(s)	Description
Existing	Commercial	Commercial EE/ Cold storage	Incentives for upgrades to commercial refrigeration equipment and building envelope improvements in cold storage facilities
Existing	Commercial	Commercial EE/ VFD motors and controls	Incentives for upgrades to commercial motors and controls
Existing	Residential	Residential electrification/ Dual-Fuel Heat Pump	Incentivize member-owners with natural gas service to install dual fuel heat pumps, which use the heat pump compressor as the primary heating source and natural gas combustion as auxiliary heat at extreme conditions
Considered	Residential	Residential electrification/ Dual-Fuel Heat Pump	Incentivize member-owners with natural gas service to install dual fuel heat pumps, which use the heat pump compressor as the primary heating source and natural gas combustion as auxiliary heat at extreme conditions
Existing	Residential	Pilots/EVs	Encourage the adoption of EVs in South Carolina through rebates on EV chargers that allow the member-cooperatives to interrupt on peak charging either directly or via tariffs (participation encouraged but not required); could also include funds for facilitating installation of public charging infrastructure once sufficient EV adoption is achieved
Existing	Residential	Residential electrification/ Heat pump water heater	Incentivize member-owners who have fossil fuel water heaters to upgrade to a high-efficiency electric heat pump unit
Existing	Residential	Residential electrification	Incentivize member-owners who have fossil fuel space heat to upgrade to a high-efficiency air source heat pump
Considered	Residential	Residential electrification/ Geothermal (fuel conversion)	Incentivize member-owners who have fossil fuel heat to upgrade to a high-efficiency ground source heat pump
Existing	Commercial	Commercial Electrification/ Off road vehicles	Encourage commercial accounts to transition from delivered fuel to electric charging and to charge the equipment off peak

Status	Sector	Measure(s)	Description
Existing	Commercial	Commercial Electrification/ Heavy duty machinery	Encourage commercial accounts to transition energy-intense processes from natural gas and delivered fuel to electricity
Existing	Commercial	Commercial Electrification	Provide education, awareness, and incentives for adoption of electric lawn and garden tools
Existing	Commercial	Commercial Electrification/ Golf carts	Incentivize golf courses and golf communities to adopt electric golf carts and charging infrastructure instead of gasoline
Existing	System	Renewable	Solar PV arrays installed in residential, commercial, industrial, or community settings; this includes mostly behind-the-meter solar installations
Existing	System	CVR	Process by which cooperatives reduce voltages at the substation or feeder level during peak hours to lower demand while maintaining minimum service levels

Cost Effectiveness Framework

To assess the economics of the future portfolio, Central modeled lifetime benefits and costs for each measure/program over the IRP timeline using participation forecasts that align with projected budgets. These lifetime benefits and costs were assessed from the following three perspectives using industry standard benefit-cost tests:

- Utility Cost Test (UCT)
  - Assesses the system benefits and costs of a DSM program as a resource option based on the costs incurred by the utility (including incentive costs) excluding any costs incurred by the participant
- Ratepayer Impact Test (RIM)
  - Assesses fairness and equity by measuring what happens to cooperatives' rates due to changes in a utility's (Central) revenues and operating costs caused by the program
- Total Resource Cost Test (TRC)
  - Assesses economic efficiency and societal impact by measuring the system benefits and costs of a DSM program as a resource option based on the total costs of the program, including both the participants' and the utility's costs

Note, for the IRP inputs, the analysis projected existing and future DSM activity for the member systems under the Santee Cooper and Duke contracts separately but following the same methodology throughout. Additionally, the cost-effectiveness of the future portfolio was also assessed at this level. For the purposes of reporting, this section primarily reflects the total impacts and economics of both areas combined.

4.3 Estimating Future DSM Savings from Existing Resources

Central's current portfolio of DSM programs totals approximately 109 MW of summer capacity and 92 MW of winter capacity. Figure 4-1 and Figure 4-2 show the respective existing resources for summer and winter and the projected reduction in the existing resources over time. Key drivers of the decrease include the following:

- Useful life and connectivity of connected devices, switches, and equipment
- Declining productivity of distributed energy resource systems over time (the energy production of solar panels degrades approximately 1% annually)

The observed increase beginning in the second decade is a result of continued CVR, and there is a modest increase in load on feeders where CVR is deployed.

Figure 4-1: Existing DSM Resources, Summer Season (MW)

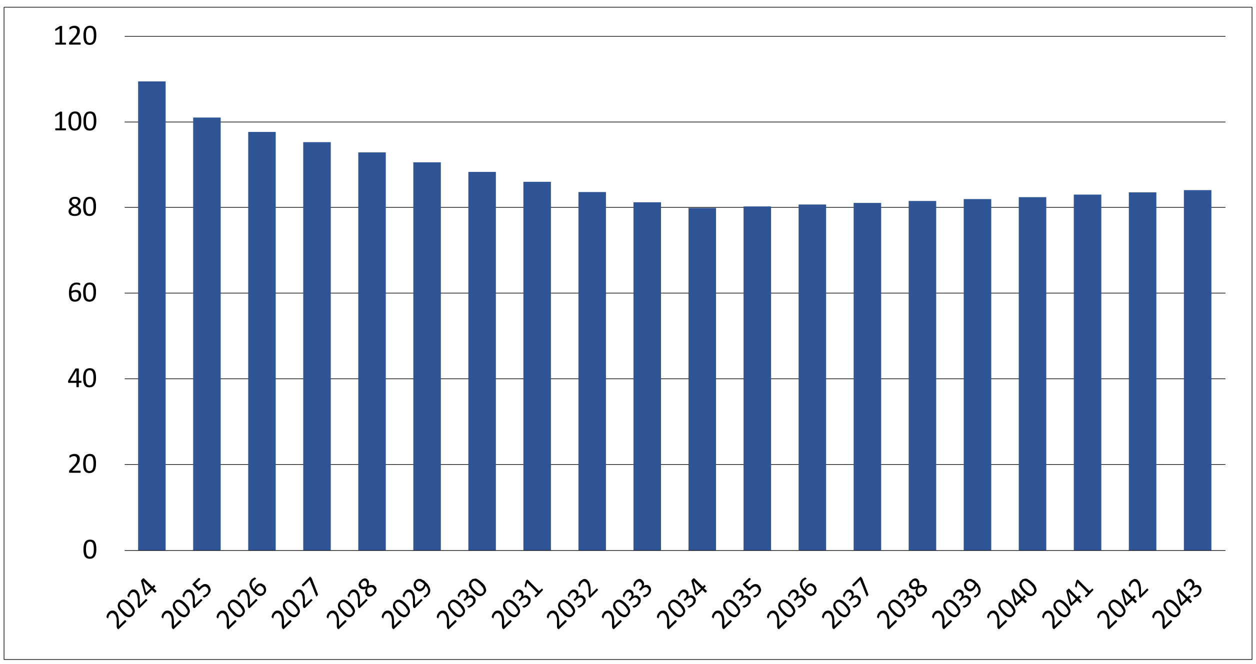


Figure 4-2: Existing DSM Resources, Winter Season (MW)

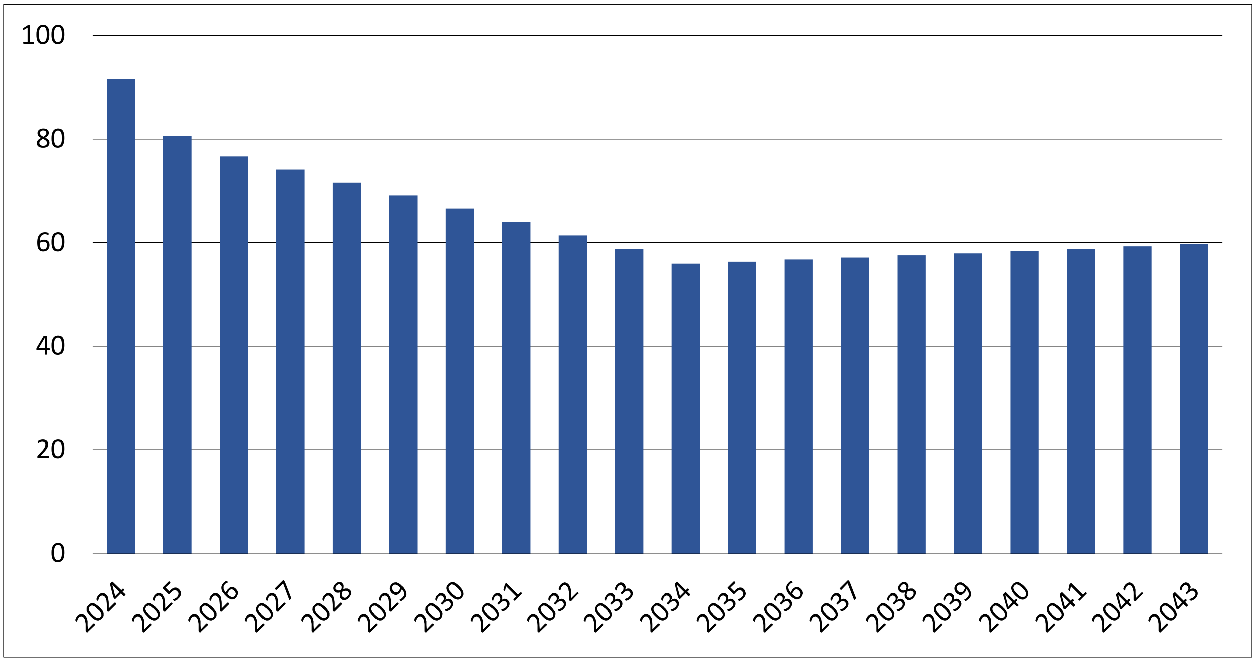


Figure 4-3 shows the breakdown of existing resources by resource type. Detailed tables are available in Section 8.1. Some resources are expected to phase out in the next few years as Central redirects investments toward newer technologies. For example, Wi-Fi connected water heaters are being piloted and will replace RF and AMI water heater switches. Similarly, Central and its member-cooperatives will no longer deploy HVAC switches and will instead grow the existing smart thermostat program.

Figure 4-3: Existing DSM by Resource Type, Summer Season (MW)

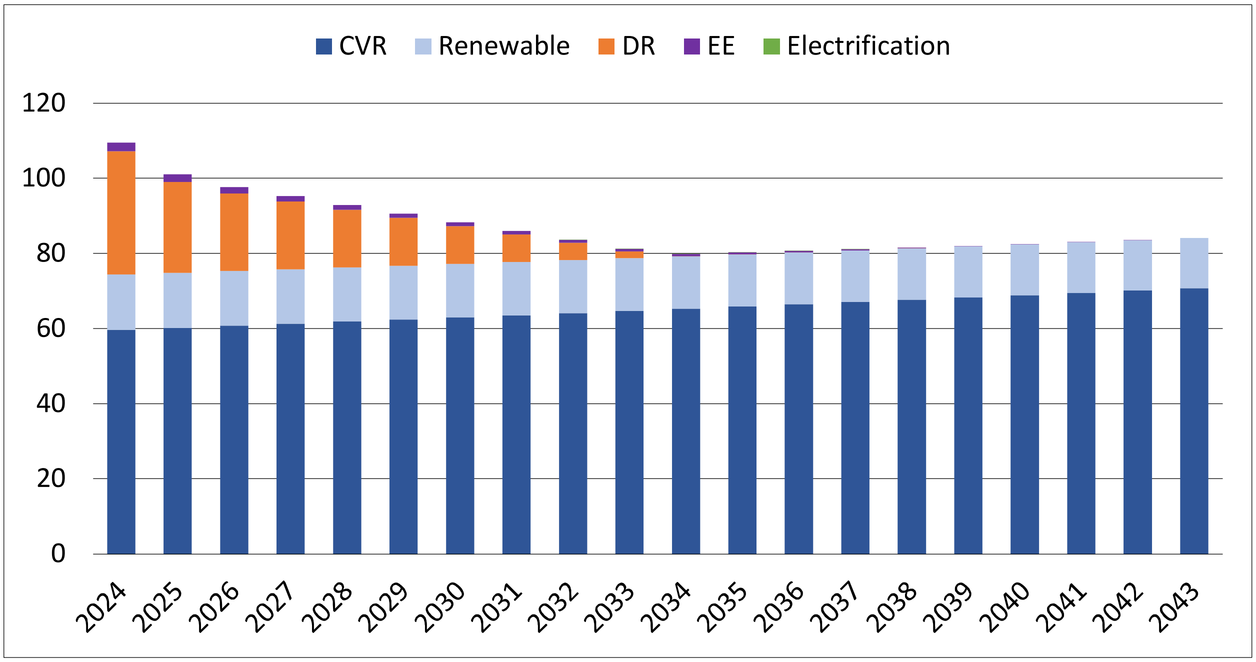
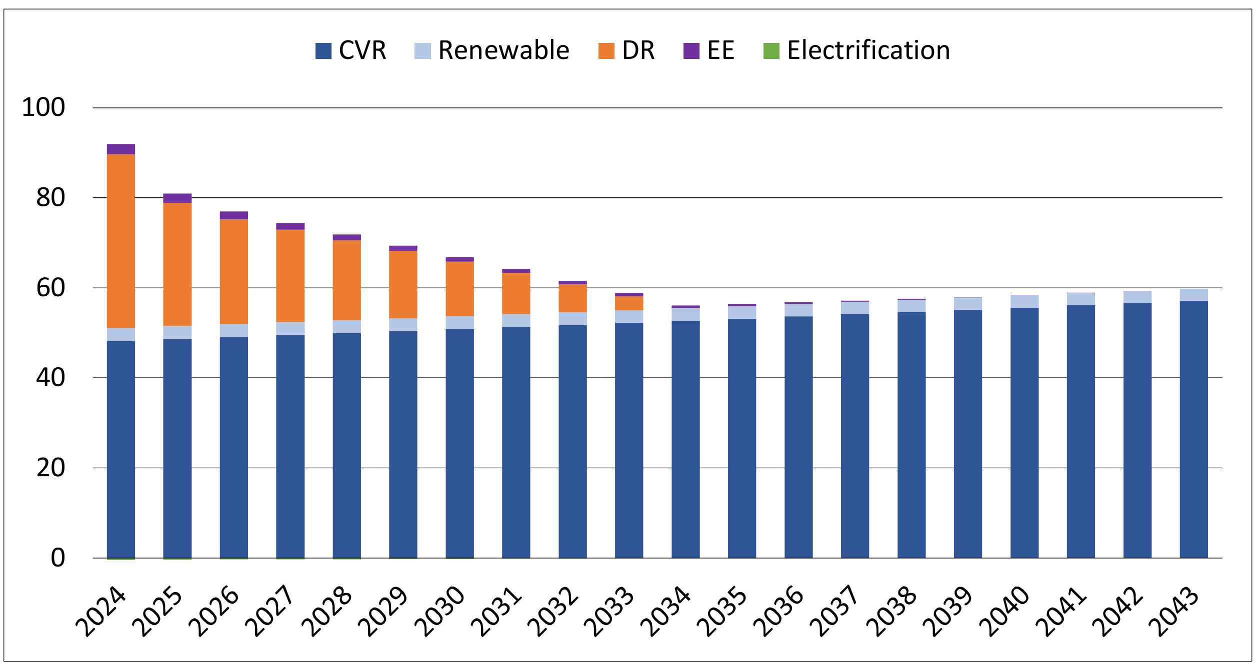


Figure 4-4: Existing DSM by Resource Type, Winter Season (MW)



4.4 Business as Usual Scenario

Central and the member-cooperatives contribute funding and administrative labor to DSM measures, and some member-cooperatives also administer programs tailored to their local communities. For the BAU economic assessment, the collective DSM budget was assumed to remain at current levels, adjusted for inflation, for the duration of the IRP study period. While budget estimates include a modest level of spending associated with renewables and CVR, the future DSM scenarios do not assume any related increase in renewable or CVR resources, beyond those captured in the baseline sales forecast. Thus, the estimated incremental impacts from DSM are associated with DR, EE, and BE only.

BAU Scenario Parameters

The BAU scenario assumes a budget of approximately $3.4 million in 2024, escalated at the rate of inflation over the IRP timeframe. The budget allocations across the DSM resource types is shown in Table 4-2. The 2024 allocations reflect some legacy RE projects and associated net metering costs, with the budget for renewables reallocated across the remaining resource options beginning in 2025.

Table 4-2: BAU Scenario DSM Resource Budget Allocations

Year	DR	EE	Electrification	Renewable	CVR
2024	45.0%	10.0%	5.0%	39.2%	0.8%
2025 and Beyond	60.0%	17.5%	21.7%	0.0%	0.8%

Another important parameter in the BAU scenario, as well as the other future DSM scenarios included in the IRP and discussed later in this section, is the treatment of the EV forecast. Although Central maintains a forecast of future EV adoption at the member system level, not all member systems have chosen to include these impacts in their base load forecast. For those member systems that did not include EVs in their base forecast, the associated energy and demand impacts were instead included in the development of the DSM electrification resource impacts.

The future adoption of EVs in the Central forecast is expected to outpace the available funding in the allocated electrification budgets in the BAU DSM scenario, and not all EVs were assumed to receive direct rebates from Central. As a result, Central characterizes the electrification impacts, both energy and demand, associated directly with the DSM budget, as well as any additional net impacts of EV forecast not already captured in the Central base forecast.

BAU Scenario Results

Participation and resource forecasts for each program were developed by scaling granular “bottom up” forecasts based on near- to medium-term plans to match these “top down” budget allocations. Forecasts for energy and capacity avoided by these incremental resources are a function of the participation forecasts and the assumptions for per-participant energy and demand impacts, as well as useful life for each measure. Impacts and measure-life assumptions are based on a combination of program measurement and validation and industry standards.

Figures 4-5 and 4-6 show cumulative capacity reductions for the additional DSM resources forecasted in the BAU scenario, by resource type. The initial increase in resources reflects the increase in funding as the budget is reallocated away from renewables. Most measures have an assumed useful life of 10 to 15 years, so resources stabilize in the early 2030s as existing resources retire and are replaced by newer resources.

The vast majority of DSM capacity comes from demand response. EE contributes relatively minimal capacity reduction, and electrification contributes only a small increase.

Figure 4-5: BAU DSM by Resource Type, Summer Season (MW)

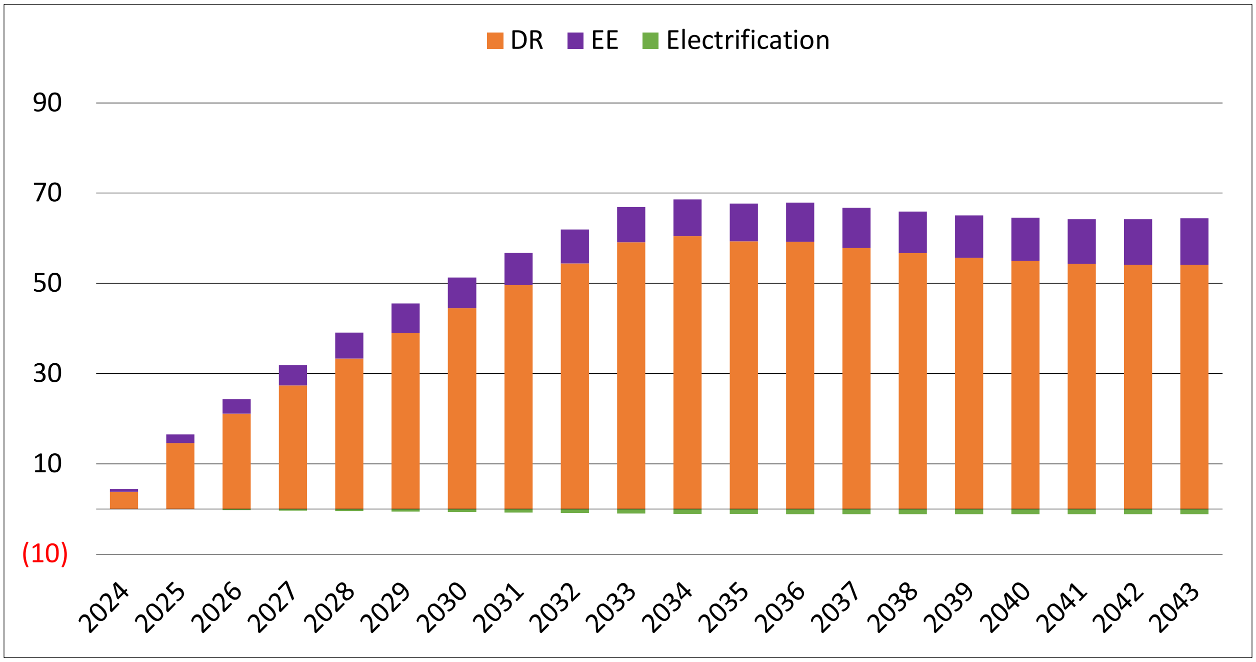


Figure 4-6: BAU DSM by Resource Type, Winter Season (MW)

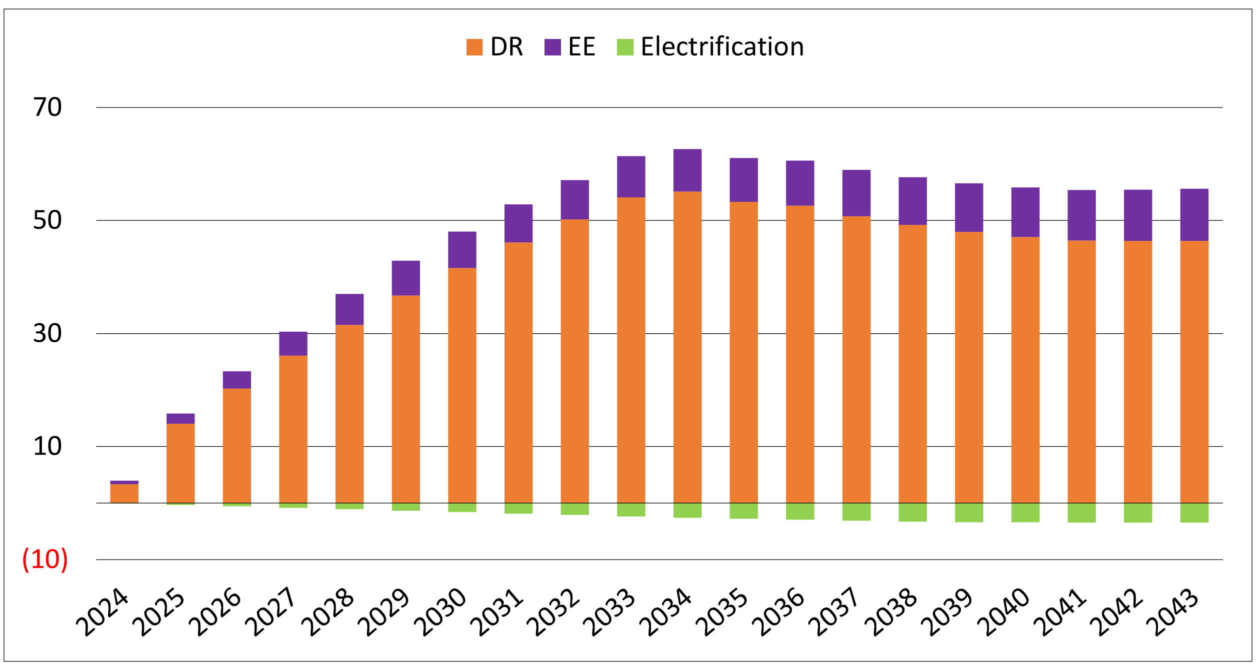


Figure 4-7 shows the cumulative energy reductions in the BAU scenario associated with the additional DSM portfolio resources, above and beyond what is included in the set of existing DSM offerings. The reductions in energy consumption associated with EE is primarily offset by increases associated with BE. The remaining DSM resources in the BAU scenario are not forecasted to impact energy consumption beyond what is anticipated with the existing DSM offerings.

Figure 4-7: BAU Energy Savings by Resource Type (MWh)

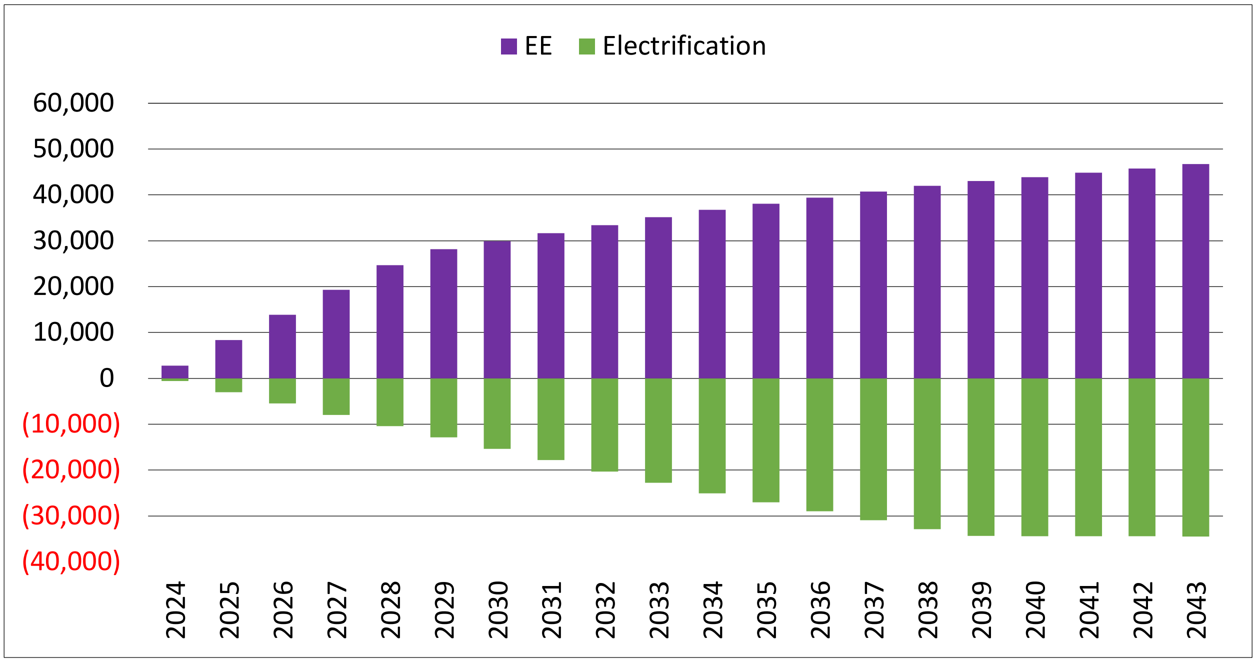


Figure 4-8 and Figure 4-9 show the capacity forecast for additional resources provided in the BAU scenario stacked on the existing resources. While existing resources decline over time, the decline is primarily offset by resources in the BAU scenario, which causes the overall DSM resource savings capacity to reach and level off at nearly 150 MW in the summer and more than 100 MW in the winter.

Figure 4-8: BAU and Existing DSM Resources, Summer Season (MW)

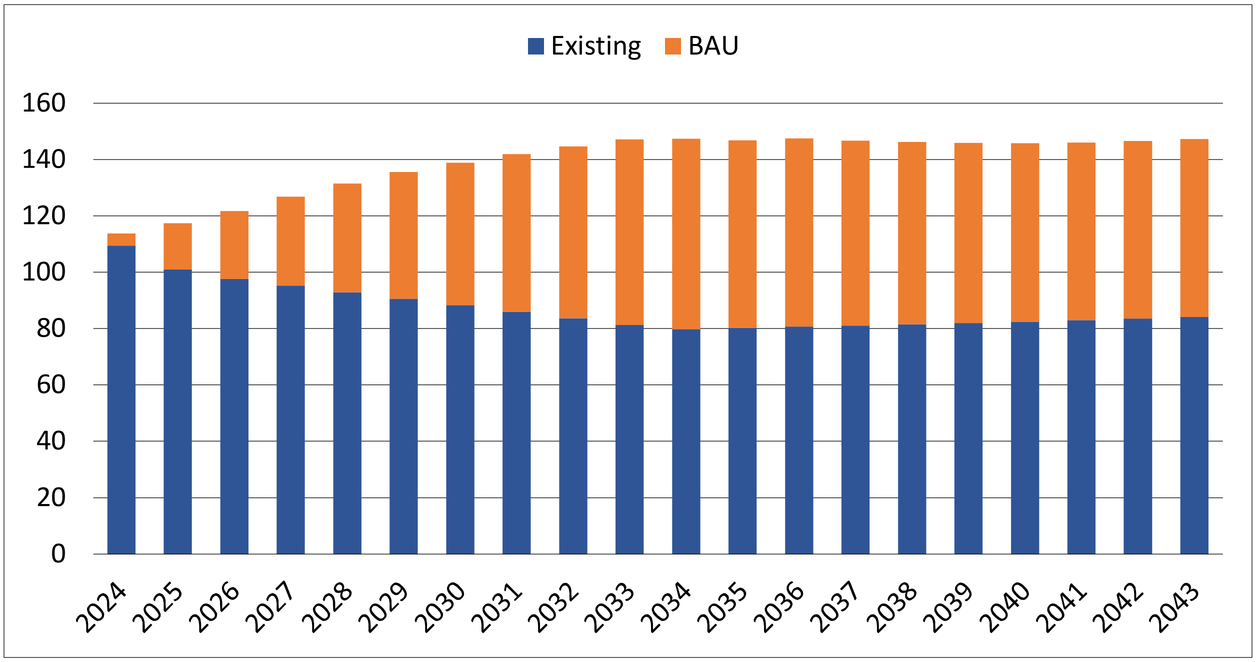
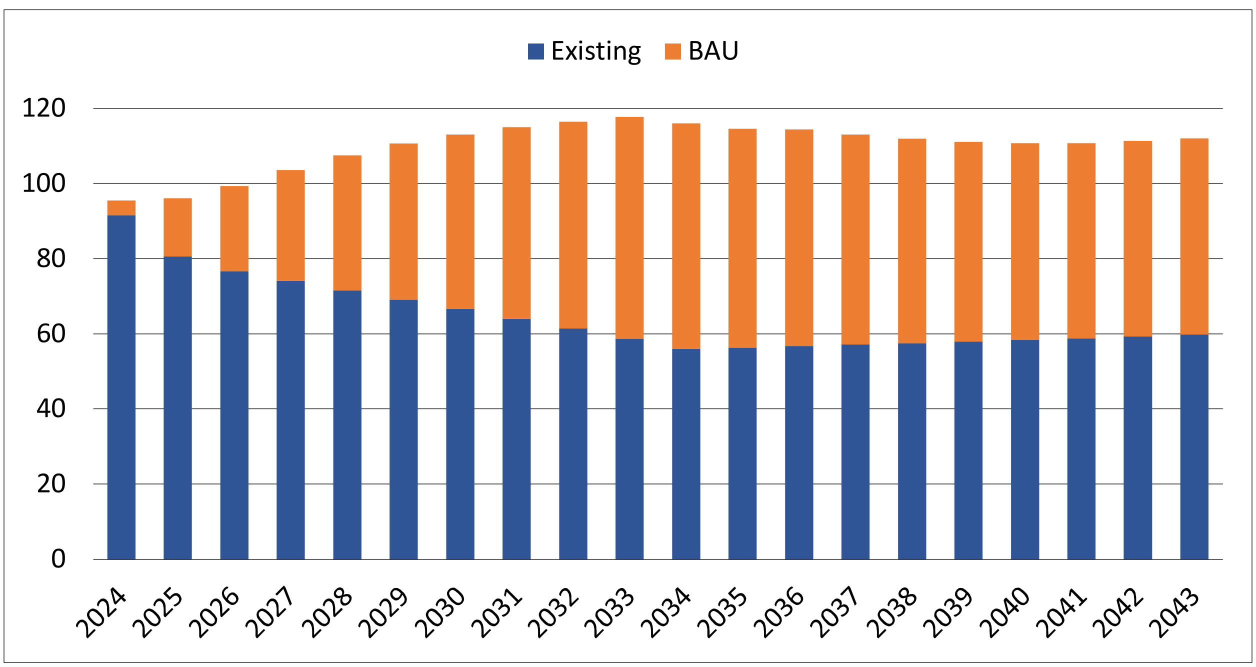


Figure 4-9: BAU and Existing DSM Resources, Winter Season (MW)



The annual MW (average of summer and winter) of the existing and incremental BAU MW impacts,separated by Santee Cooper and Duke systems, are shown in Table 4-3 below.

Table 4-3: Existing and Incremental BAU DSM Capacity Forecast (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Santee Cooper											
Existing	83	82	75	72	70	68	67	65	58	60	62
Incremental	-	3	12	18	23	29	33	37	47	44	44
Duke											
Existing	19	19	16	15	14	14	13	12	10	10	10
Incremental	-	1	4	5	7	9	10	11	15	14	14

As noted earlier, the DSM IRP inputs also needed to capture the net added load from EV sales not already reflected in Central's base forecast or the BAU electrification forecast. These net MW impacts are summarized in Table 4-4 below. The estimated peak MW impacts are based on off-peak charging and an assumed 0.1 kW per EV, derived from an analysis performed for Central by Optiwatt in 2022. The annual energy impacts per EV are between 4,100 kWh and 4,500 kWh over the study horizon.

Table 4-4: Net EV Forecast Associated with BAU Scenario (MW)

	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Net EV MW	-0.18	-0.17	-0.17	-0.20	-0.23	-0.30	-0.37	-0.86	-2.12	-3.54

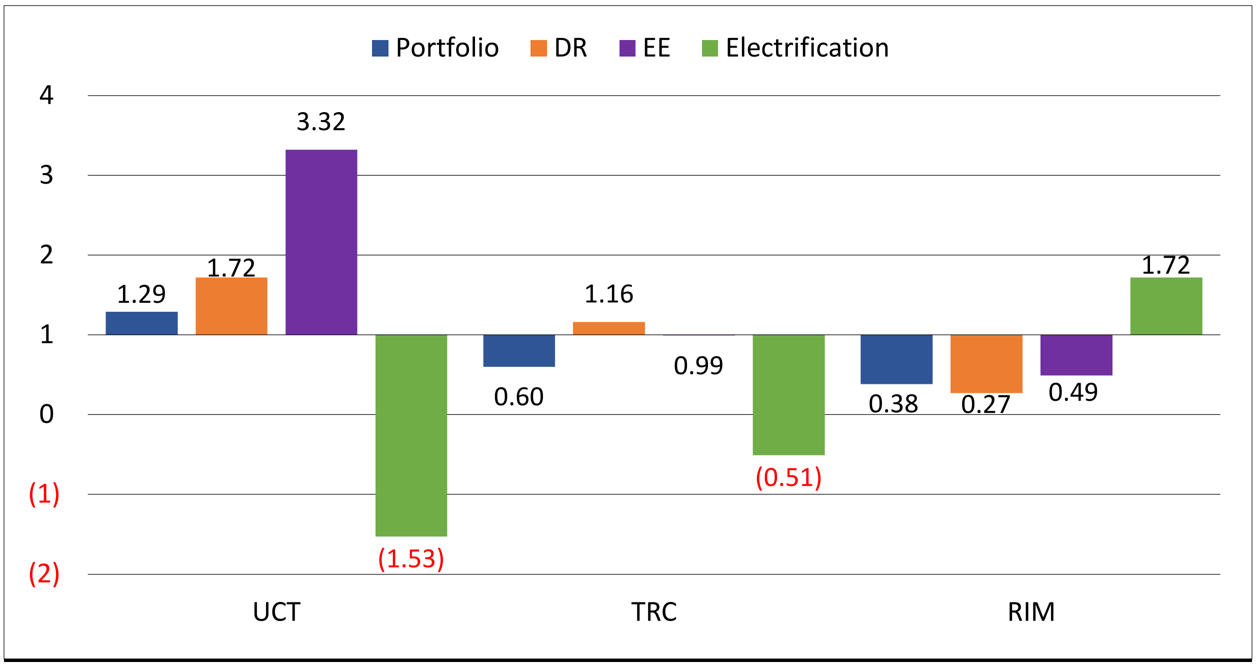
The economic assessment of the Central BAU DSM portfolio evaluated the UCT perspective, the RIM perspective, and the TRC perspective. Including these standard cost tests provides a more complete assessment of portfolio economics. This assessment includes lifetime benefits and costs for incremental DSM resources forecasted for 2024 through 2043. Importantly, the assessment focused on electric resources only and did not include fuel costs avoided by participants, which would improve outcomes for electrification, or any estimated reduction of participant utility due to load curtailment, which would decrease outcomes for DR.

Figure 4-10 shows the benefit-cost ratios from the three perspectives. Outcomes are shown for DR programs, EE programs, BE, and for the whole DSM portfolio. Key observations include the following:

- From the utility perspective, the BAU DSM portfolio is cost-effective (benefit-cost ratio higher than 1.0), with a benefit-cost ratio of 1.29. DR (benefit-cost ratio of 1.72) and EE (benefit-cost ratio of 3.32) programs are each cost effective. BE programs have a negative benefit-cost ratio (-1.53) because of the increase in energy and capacity (and a reduction in avoided costs) that results from electrification of new end uses. However, electrification also provides benefits in the form of potential emission reductions and new revenue sources that partially offset lost revenue due to DR and EE programs. Importantly, a utility that supplies electricity and natural gas would recognize avoided fuel costs due to end-use fuel switching. Because Central is an electric-only utility, it experiences electric resource cost increases without commensurate fuel resource cost savings.

- EE and DR resource categories and portfolios are not cost effective from a RIM perspective. This is expected because it considers changes in utility revenue. However, relative to the other budget categories the benefit-cost ratio is higher than 1.0 for electrification due to the increase in energy sales from newly electrified end uses.
- From the TRC perspective, only DR is cost-effective (higher than 1.0) due to the inclusion of the cost of participant measures,[4] though the energy portfolio is only minimally lower than the 1.0 threshold. This test essentially increases the denominator (costs) while keeping the numerator (benefits) constant when compared to the UCT.

Figure 4-10: Benefit-Cost Ratios for DSM Portfolio Categories – BAU Scenario



4.5 25+ MW Scenario

For the 25+ MW economic assessment, the collective DSM budget reflects additional spending on DR resources, as described in the following subsections, for the duration of the IRP study period. While budget estimates include a modest level of spending associated with renewables and CVR, the future DSM scenarios do not assume any related increase in renewable or CVR resources (beyond those captured in the baseline sales forecast). Thus, the estimated incremental impacts from DSM are associated with DR, EE, and BE only.

[4] Though the TRC Test included participant measure costs, it does not fully reflect the economics to the participant because it includes marginal avoided costs (costs to the system) as benefits rather than avoided retail resource costs (cost to the end-use customer). The Participant Cost Test (PCT) can be used to assess economics to the end-use customer but given the system-wide focus of an IRP, the test was not included in the assessment.

25+ MW Scenario Parameters

The 25+ MW scenario assumes a total budget of approximately $4 million in 2024, with DR budgets 40% greater than the BAU scenario, while the remaining DSM resource budgets are equal to those in the BAU scenario over the IRP timeframe. The budget allocations across the DSM resource types are shown in Table 4-5 below.

Table 4-5: 25+ MW Scenario DSM Resource Budget Allocations

Year	DR	EE	Electrification	Renewable	CVR
2024	55.0%	10.0%	5.0%	29.4%	0.8%
2025 and Beyond	65.0%	16.0%	18.4%	0.0%	0.8%

Another important parameter in the 25+ MW scenario is the treatment of the EV forecast. This analysis characterizes the electrification impacts associated directly with the DSM budget, as well as the additional net impacts of EV forecast not already captured in the Central base forecast. Any reporting of DSM economics exclude these net EV impacts.

25+ MW Scenario Results

As in the BAU scenario, participation and resource forecasts for each program were developed by scaling granular "bottom up" forecasts based on near- to medium-term plans to match these "top down" budget allocations. Forecasts for energy and capacity avoided by these incremental resources are a function of the participation forecasts and the assumptions for per-participant energy and demand impacts as well as useful life for each measure. Impacts and measure-life assumptions are based on a combination of program measurement, validation, and industry standards.

Figures 4-11 and 4-12 show cumulative capacity reductions for the additional DSM resources forecasted in the 25+ MW scenario, by resource type. The initial increase in resources reflects the increase in funding towards DR. BE impacts are less than 5 MW in this scenario.

Figure 4-11: 25+ MW DSM by Resource Type, Summer Season (MW)

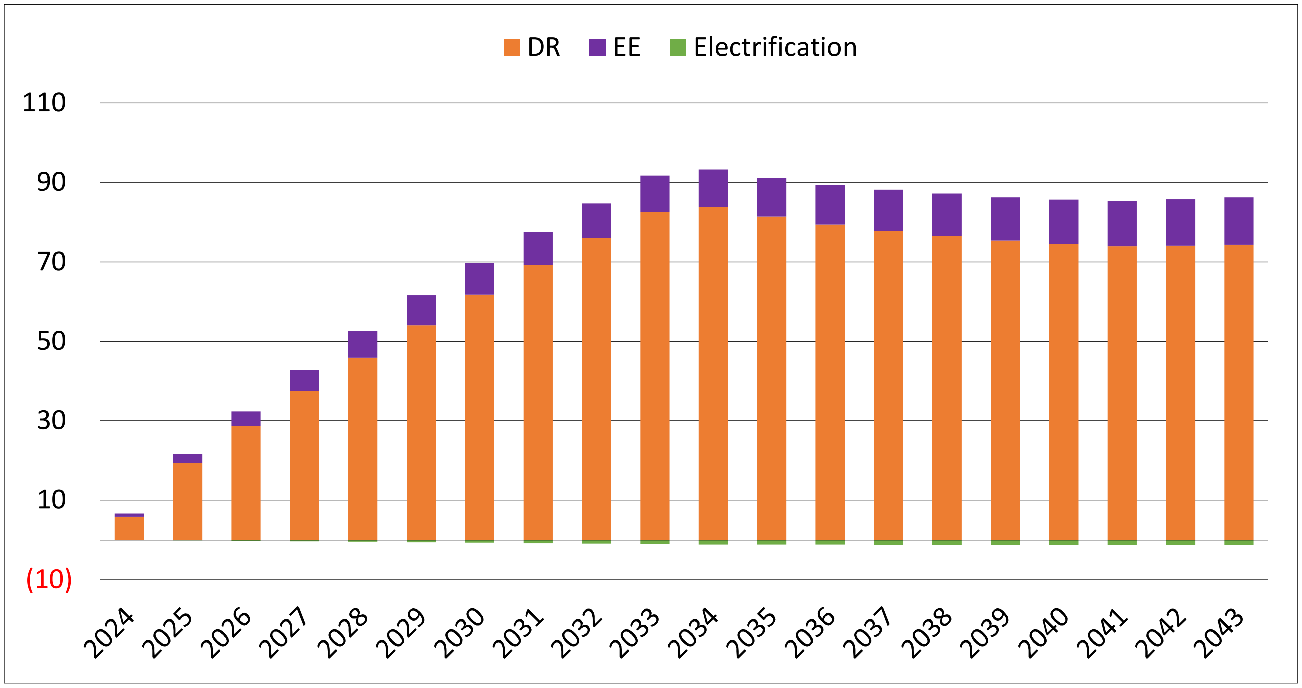


Figure 4-12: 25+ MW DSM by Resource Type, Winter Season (MW)

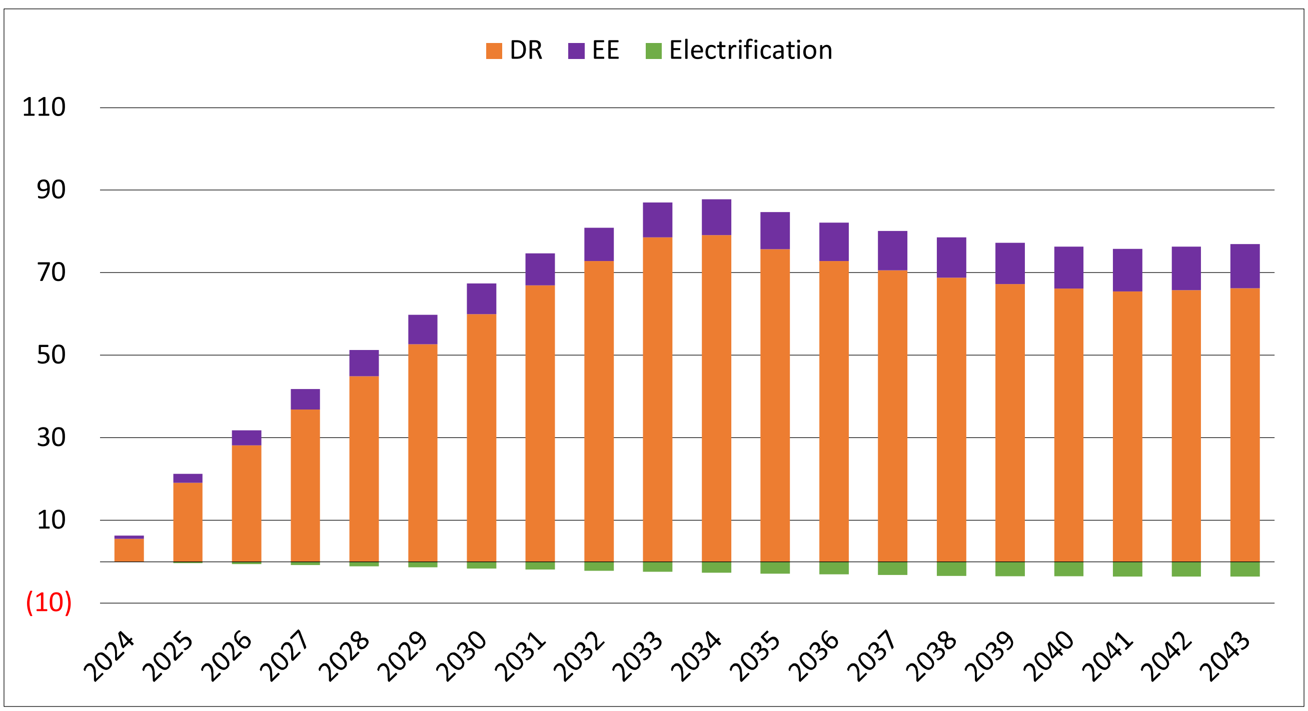


Figure 4-13 shows the cumulative energy reductions in the 25+ MW scenario associated with the additional DSM portfolio resources. The reductions in energy consumption associated with EE is primarily offset with increases associated with BE.

Figure 4-13: 25+ MW Scenario Energy Impacts by Resource Type (MWh)

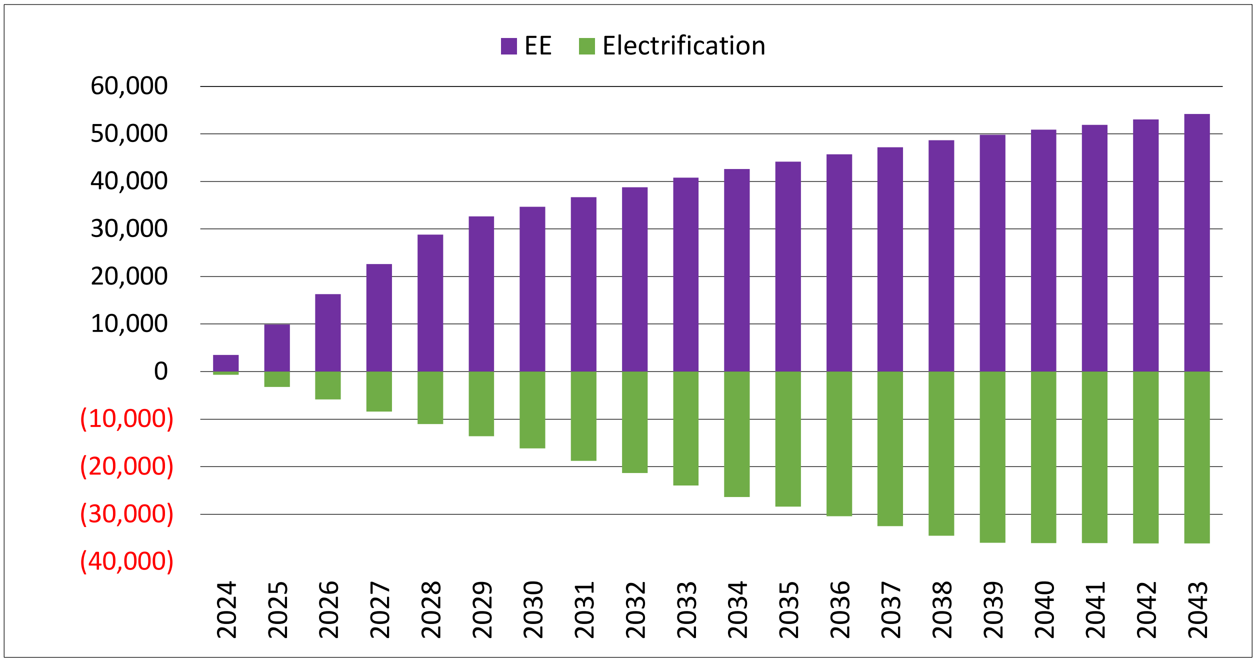


Figure 4-14 and Figure 4-15 show the capacity forecast for additional resources provided in the 25+ MW scenario stacked on the existing resources. The increase in resources in the 25+ MW scenario follows the same trend as the BAU scenario, with a greater increase in resources as the DR budget is expanded.

Figure 4-14: 25+ MW Scenario and Existing DSM Resources, Summer Season (MW)

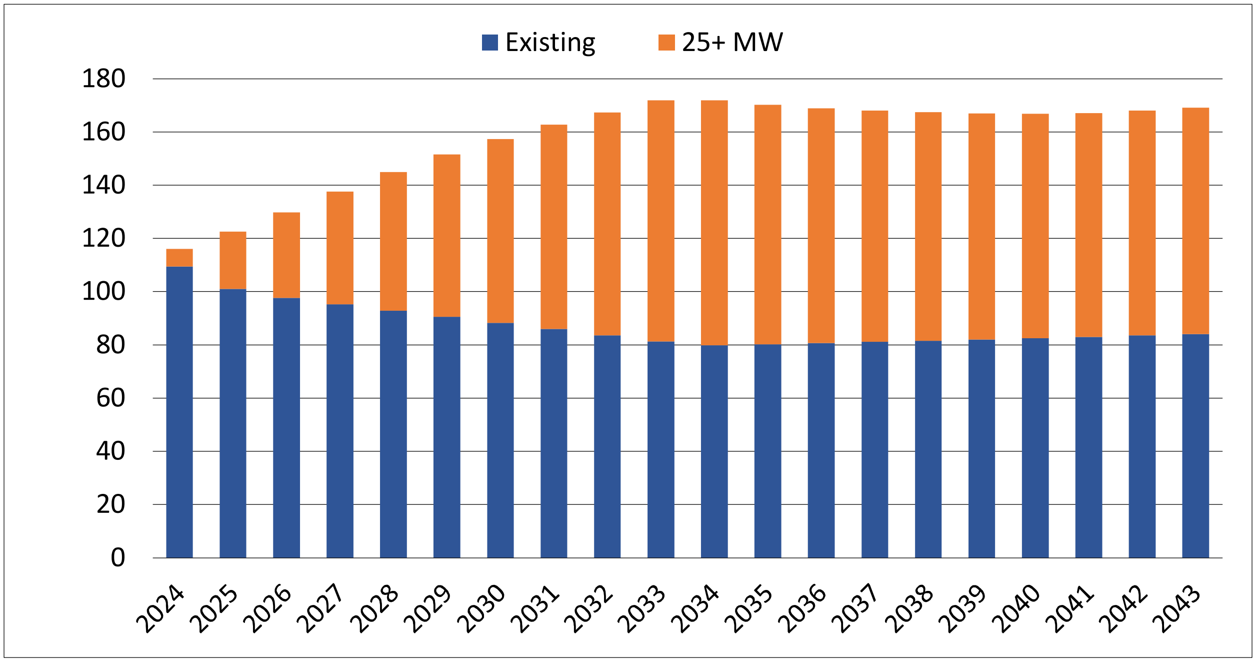
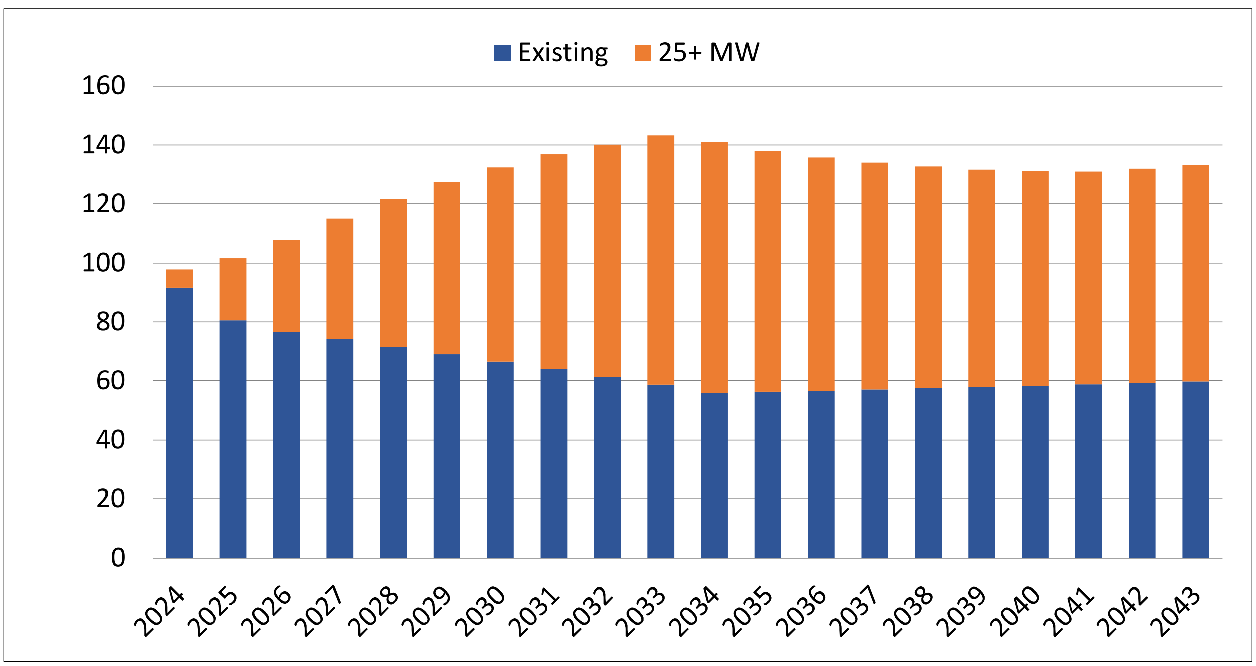


Figure 4-15: 25+ MW Scenario and Existing DSM Resources, Winter Season (MW)



The annual MW (average of summer and winter) of the existing and incremental 25+ MW scenario impacts, separated by Santee Cooper and Duke systems is shown in Table 4-6 below.

Table 4-6: Existing and Incremental 25+ MW DSM Capacity Forecast (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Santee Cooper											
Existing	83	82	75	72	70	68	67	65	58	60	62
Incremental	-	5	16	24	32	39	46	52	66	60	60
Duke											
Existing	19	19	16	15	14	14	13	12	10	10	10
Incremental	-	1	5	7	10	12	14	15	20	19	19

As noted earlier in this report, the DSM IRP inputs also needed to capture the net added load from electric vehicles sales not already reflected in either Central's base forecast or the 25+ MW scenario electrification forecast. These net MW impacts are summarized in Table 4-7 below. The net EV MW impacts are slightly less than the BAU scenario because the minimal increase in the electrification budget under the 25+ MW scenario allows for additional EV impacts to be attributed under the DSM funding.

Table 4-7: Net EV Forecast Associated with 25+ MW Scenario (MW)

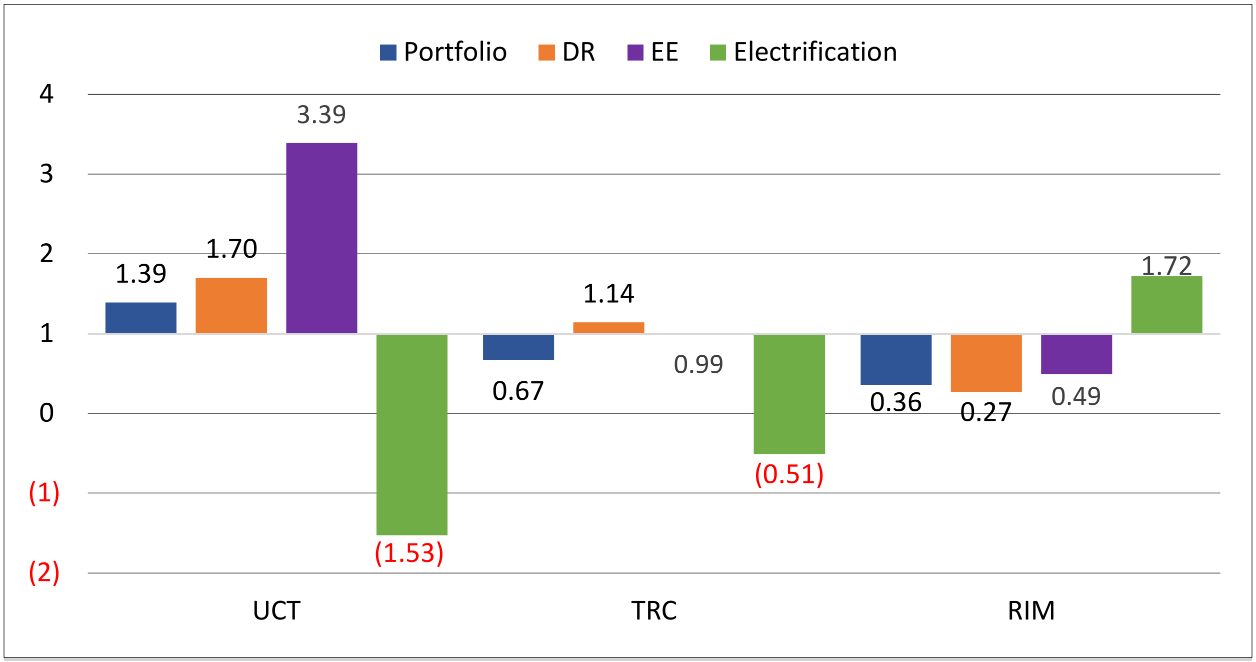
	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Net EV MW	-0.17	-0.17	-0.16	-0.19	-0.22	-0.29	-0.35	-0.83	-2.09	-3.51

Like the BAU scenario, the economic assessment of the Central 25+ MW DSM portfolio evaluated the UCT, the RIM Test, and the TRC Test. Including these standard cost tests provides a more complete assessment of portfolio economics.

Figure 4-16 shows the benefit-cost ratios from the three perspectives. Outcomes are shown for DR programs, EE programs, BE programs, and for the whole DSM portfolio. Key observations include the following:

- From the utility perspective, the 25+ MW DSM portfolio is cost effective (with a benefit-cost ratio of 1.39). DR (benefit-cost ratio of 1.70) and EE (benefit-cost ratio of 3.39) programs are each cost effective. Electrification programs have a negative benefit-cost ratio (-1.53).
- EE and DR resource categories and portfolios are not cost effective from a RIM perspective. However, relative to the other budget categories the benefit-cost ratio is higher than 1.0 for electrification due to the increase in energy sales from newly electrified end uses.
- From the TRC perspective, only DR is cost effective (higher than 1.0) due to the inclusion of the cost of participant measures.

Figure 4-16: Benefit-Cost Ratios for DSM Portfolio Categories – 25+ MW Scenario



4.6 Aggressive Scenario

For the Aggressive scenario economic assessment, the collective DSM budget reflects an increase in spending on DSM resources, as described in the following section. While budget estimates include a modest level of spending associated with renewables and CVR, the future DSM scenarios do not assume any related increase in renewable or CVR resources (beyond those captured in the baseline sales forecast). Thus, the estimated incremental impacts from DSM are associated with DR, EE, and BE only.

Aggressive Scenario Parameters

The Aggressive scenario assumes a budget of approximately $4 million in 2024, as in the BAU scenario, with the budgets increasing by 38% annually through 2028 before leveling off at nearly $16 million and increasing at the rate of inflation across the remaining timeframe of the IRP. The budget allocations across the DSM resource types are shown in Table 4-8 below.

Table 4-8: Aggressive Scenario DSM Resource Budget Allocations

Year	DR	EE	Electrification	Renewable	CVR
2024	45.0%	10.0%	5.0%	39.4%	0.6%
2025 and Beyond	60.0%	17.5%	22.0%	0.0%	0.5%

As previously noted, another important parameter in the Aggressive scenario is the treatment of the EV forecast. This analysis characterizes the electrification impacts associated directly with the DSM budget, as well as the additional net impacts of the EV forecast not already captured in the Central base forecast. Any reporting of DSM economics excludes these net EV impacts.

Aggressive Scenario Results

As in the BAU and 25+ MW scenarios, participation and resource forecasts for each program were developed by scaling granular "bottom up" forecasts based on near- to medium-term plans to match these "top down" budget allocations. Forecasts for energy and capacity avoided by these incremental resources are a function of the participation forecasts and the assumptions for per-participant energy and demand impacts, as well as useful life for each measure. Impacts and measure-life assumptions are based on a combination of program measurement, validation, and industry standards.

Figures 4-17 and 4-18 show cumulative capacity reductions for the additional DSM resources forecasted in the Aggressive scenario, by resource type. The increase in resources reflects the increase in spending.

Figure 4-17: Aggressive Scenario DSM by Resource Type, Summer Season (MW)

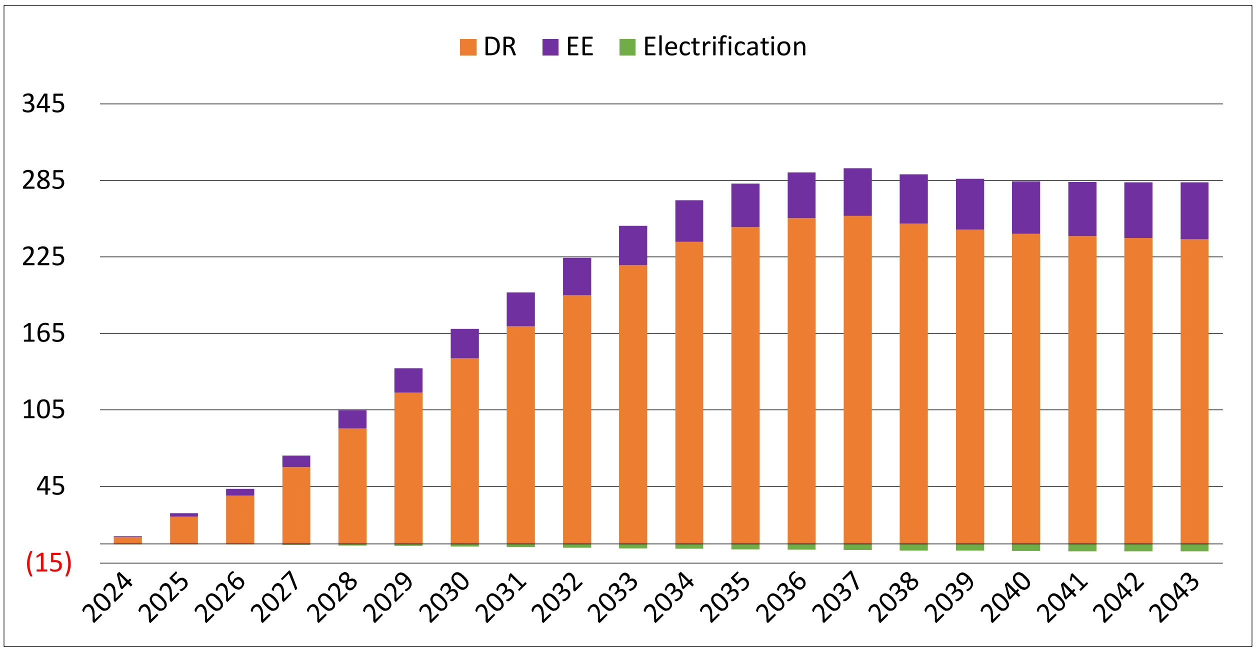


Figure 4-18: Aggressive Scenario DSM by Resource Type, Winter Season (MW)

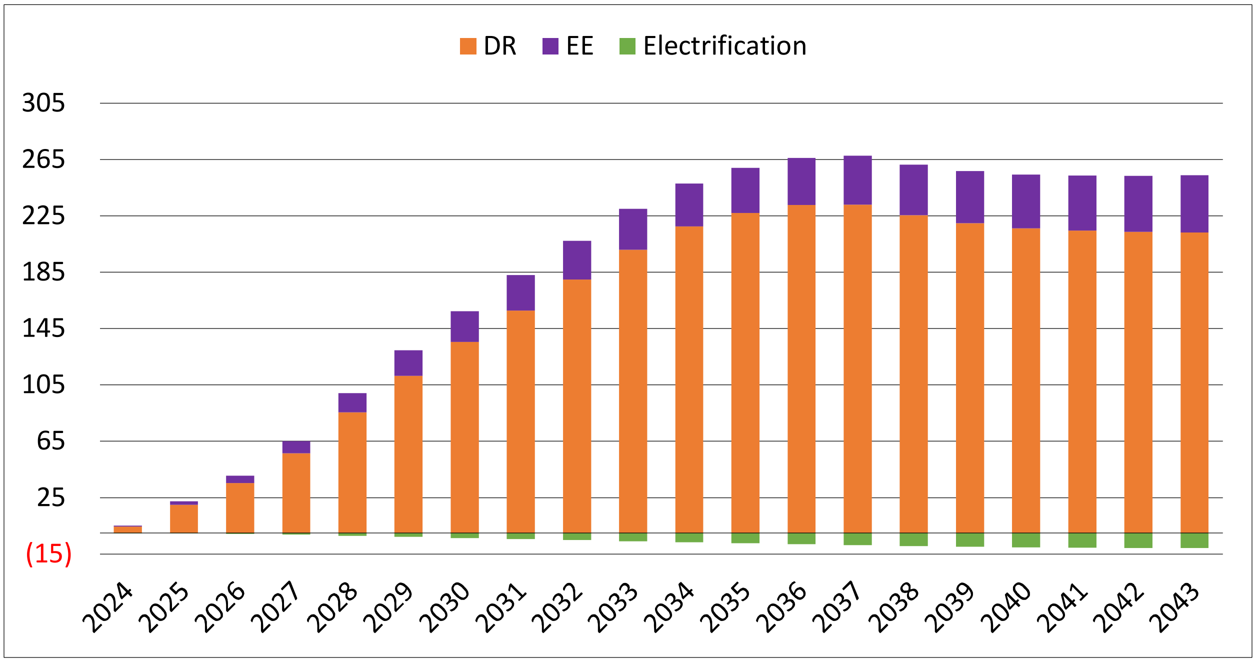


Figure 4-19 shows the cumulative energy reductions in the Aggressive scenario associated with the additional DSM portfolio resources. The reductions in energy consumption associated with EE is primarily offset by increases associated with BE.

Figure 4-19: Aggressive Scenario Energy Impacts by Resource Type (MWh)

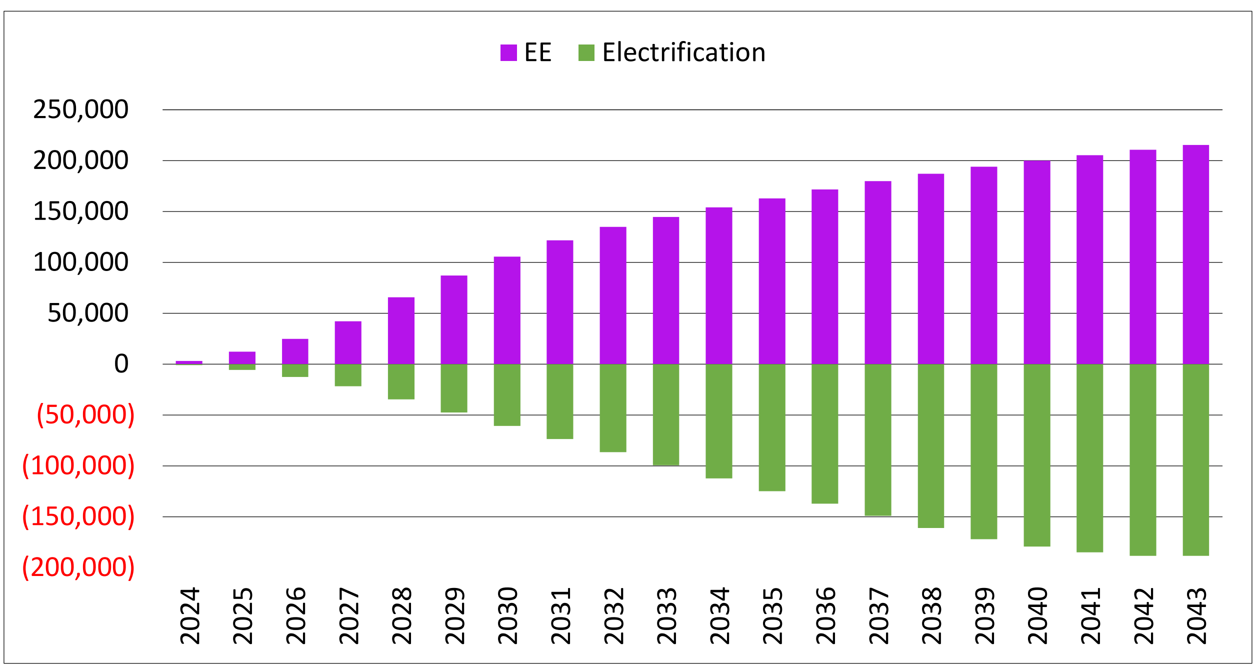


Figure 4-20 and Figure 4-21 show the capacity forecast for additional resources provided in the Aggressive scenario stacked on the existing resources. The sharp increase in resources in the Aggressive scenario is due to the increase in DSM budgets over the first several years of the IRP timeframe.

Figure 4-20: Aggressive Scenario and Existing DSM Resources, Summer Season (MW)

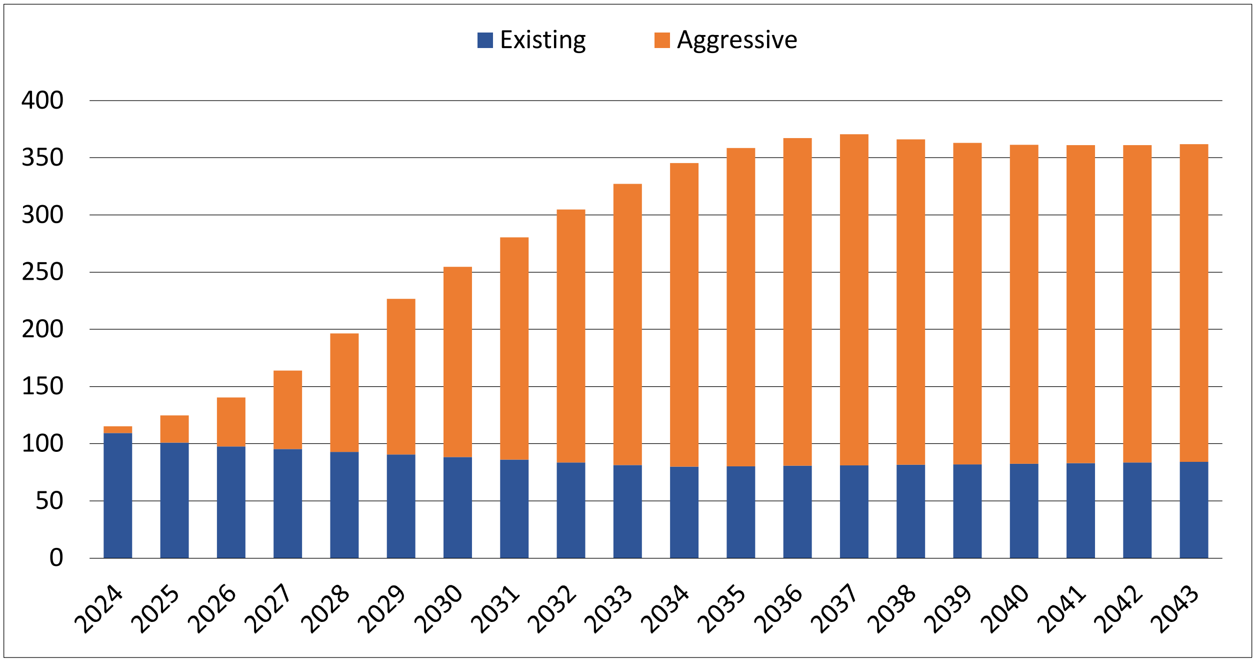
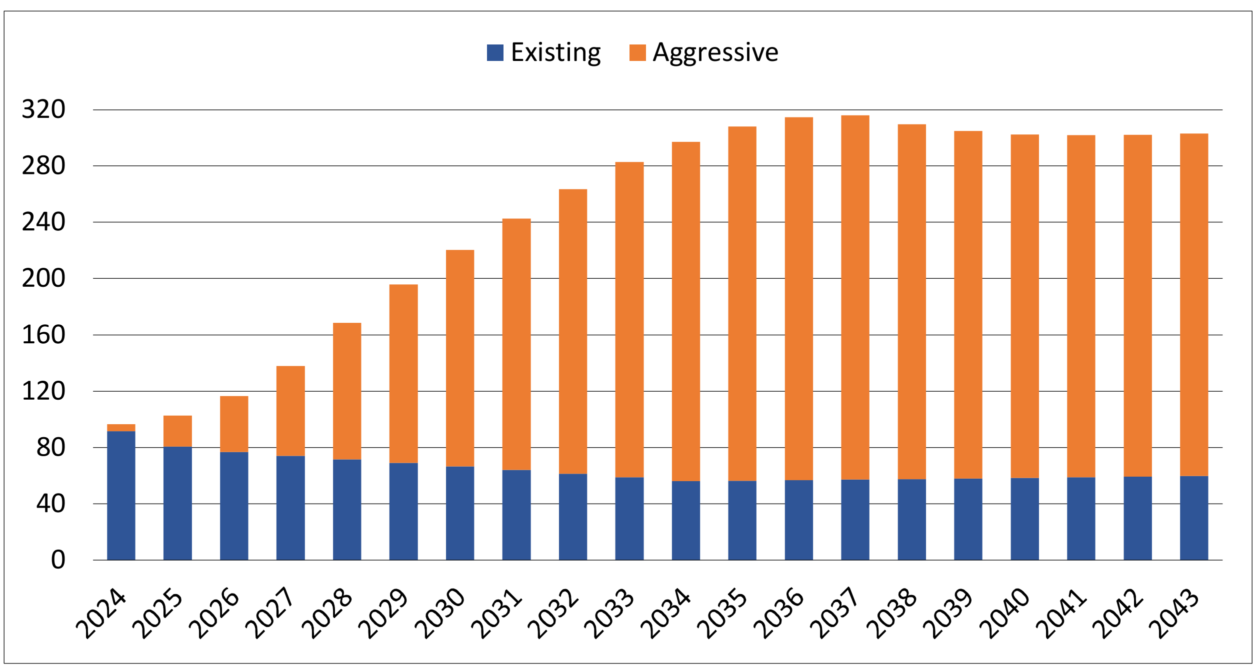


Figure 4-21: Aggressive Scenario and Existing DSM Resources, Winter Season (MW)



The annual MW (average of summer and winter) of the existing and incremental Aggressive scenario MW impacts, separated by Santee Cooper and Duke systems, are shown in Table 4-9.

Table 4-9: Existing and Incremental Aggressive Scenario DSM Capacity Forecast (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Santee Cooper											
Existing	83	82	75	72	70	68	67	65	58	60	62
Incremental	-	4	18	32	51	77	102	125	206	202	202
Duke											
Existing	19	19	16	15	14	14	13	12	10	10	10
Incremental	-	1	5	10	15	23	29	35	59	60	59

As noted earlier in this report, the DSM IRP inputs also needed to capture the net added load from EV sales not already reflected in either Central's base forecast or the Aggressive scenario electrification forecast. These net MW impacts are summarized in Table 4-10 on the next page. The net EV MW impacts under the Aggressive scenario are less than the BAU and 25+ MW scenarios because the increase in the electrification budget under the Aggressive scenario allows for a larger portion of EVs to be captured under the DSM allocation.

Table 4-10: Net EV Forecast Associated with Aggressive Scenario (MW)

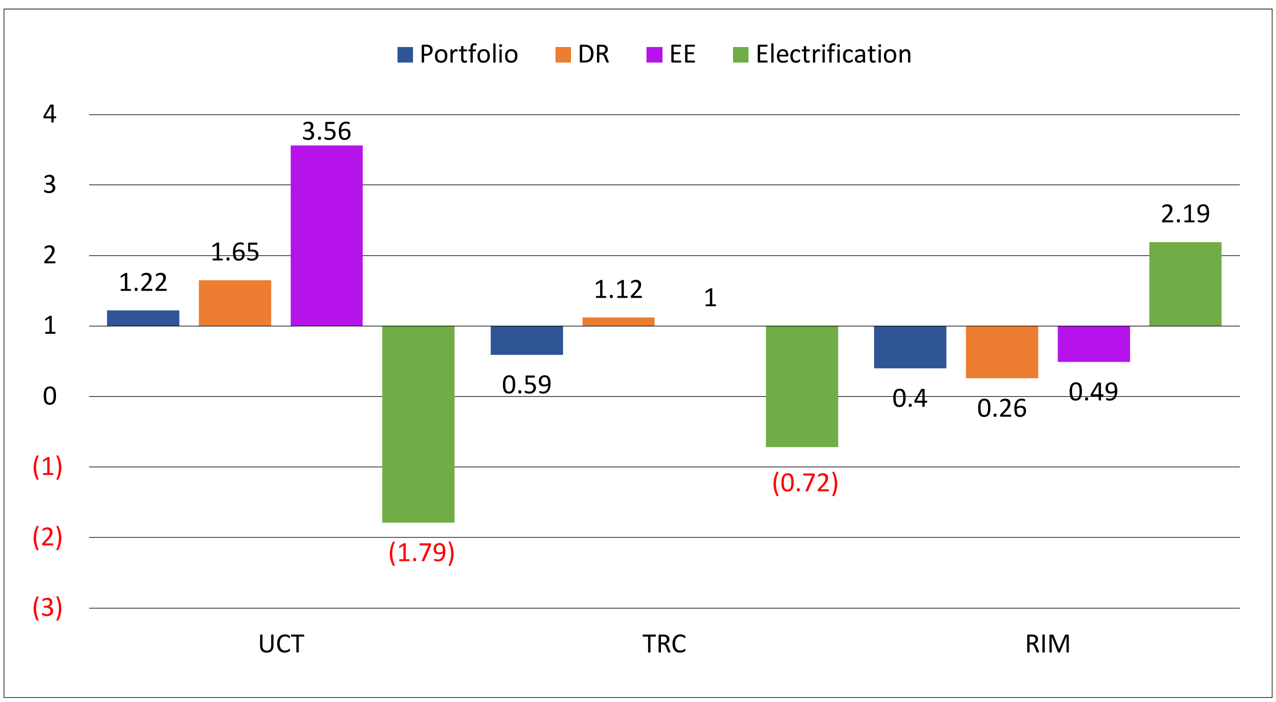
	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Net EV MW	-0.17	-0.09	0.03	0.17	0.40	0.59	0.79	1.60	1.56	0.36

Like the BAU and 25+ MW scenarios, the economic assessment of the Central Aggressive DSM portfolio evaluated the UCT, the RIM Test, and the TRC Test. Including these standard cost tests provides a more complete assessment of portfolio economics.

Figure 4-22 shows the benefit-cost ratios from the three perspectives. Outcomes are shown for DR programs, EE programs, BE, and for the whole DSM portfolio. Key observations include the following:

- From the utility perspective, the Aggressive DSM portfolio is cost effective (with a benefit-cost ratio of 1.22). DR (benefit-cost ratio of 1.65) and EE (benefit-cost ratio of 3.56) programs are each cost effective. Electrification programs have a negative benefit-cost ratio (-1.79).
- EE and DR resource categories and portfolios are not cost effective from a RIM perspective. However, relative to the other budget categories the benefit-cost ratio is higher than 1.0 for electrification due to the increase in energy sales from newly electrified end uses.
- From the TRC perspective, only DR is cost effective (higher than 1.0) due to the inclusion of the cost of participant measures.

Figure 4-22: Benefit-Cost Ratios for DSM Portfolio Categories– Aggressive Scenario



5 Load Forecast

5 Load Forecast

5.1 Methodology

The load forecast is a key input in Central's resource plan. The 2023 Central load forecast is the sum of the 20 member-cooperative forecasts through 2043. The peak forecast identifies the capacity requirements necessary for the system to maintain reliability. Central completes a load forecast annually for each of its 20 member-cooperatives by allocating member-cooperative loads into classes according to standards set forth in RUS Form 7. The Form 7 classes are: Residential, Small Commercial, Large Commercial and Industrial, Seasonal, Irrigation, Lighting, and Other load classes.

Residential and Small Commercial classes are forecasted using the industry standard Statistically Adjusted End-Use (SAE) modeling, which is discussed in more detail later in this section. Residential energy is modeled by forecasting the number of residential member-owners and the average use per member-owner. Due to EE trends, most residential growth comes from new residential member-owners on the system. Similarly, Small Commercial growth is driven by additional member-owners. The Industrial subset of Large Commercial and Industrial is forecasted individually in close consultation with member-cooperatives. The remaining classes (Seasonal, Irrigation, Lighting, and Other) are forecasted using linear trends and historical averages.

Weather-sensitive loads are modeled using 30-year rolling temperature averages. Central's member-cooperatives are each assigned one of the following airport weather stations: Greenville-Spartanburg, Columbia, Savannah, Charleston, or Florence. Peak Heating Degree Days are calculated with a base of 55°F, and Cooling Degree Days with a base of 75°F. Energy forecasts use the Degree Day base of 65°F for both heating and cooling. Deviations from the base temperature cause increases in the Degree Days.[5] Degree Days are a forecasting tool used to better analyze the impact of temperature on electric loads. Increases in Degree Days result in increases in weather related loads, such as heating and air conditioning.

Economic and demographic projections are obtained from S&P Global, a nationally recognized economic forecasting firm. These are county-level forecasts for South Carolina. Each member-cooperative's economic forecast is based on the counties in its service territory. Table 5-1 shows the projected average annual growth rates of key economic drivers for South Carolina. Economic data for individual member-cooperatives can vary from the state averages due to the economic data of the counties in their service territories.

Table 5-1: Average Annual Growth for South Carolina 2023-2043

Category	Percentage
Real Gross State Product	1.8%
Real Personal Income	2.6%
Households	1.1%

[5] Using a base of 75°F, an average peak day temperature of 90°F will yield a cooling degree day value of 15. Degree Days are non-negative, so the Heating Degree Day value in this example is 0.

For EVs, 2023 is viewed as a transition year for the cooperatives. Cooperatives were given the opportunity to include EVs in their base load forecasts for the first time, and most cooperatives chose to include EVs. The EV forecasts come from a modeling study that Central performed in cooperation with the University of California (UC) Davis and NRECA. This model creates EV forecasts by zip code. This is then shared with the cooperatives using the percentage of the zip code served. EV adoption is primarily driven by income and clustering effects. Clustering effects in this instance mean that areas with relatively high concentrations of EVs are more likely to experience high EV growth. Factors such as EV infrastructure and increased familiarity with EVs help cause clustering effects.

Behind-the-meter solar adoption is accounted for in the base forecast. Projections from the United States Energy Information Administration (EIA) for the South Atlantic census region are tuned to the cooperative's history using the load forecast model.

Scenario forecasts are explained in Section 5.3 of this report. The base forecast uses most probable economic growth forecasts. The high and low scenarios vary this forecast one standard deviation higher and lower for the forecast period.

5.2 Base Load Forecast

The SAE modeling methodology combines linear regression analysis with end-use models. It employs end-use data, housing information, weather data, economic data, and price projections. It explicitly accounts for future energy efficiencies that may not be included in the load history. The end-use data includes appliance efficiency trends and appliance saturations.

Linear regression analysis calculates the historical relationship between variables by estimating a line-of-best-fit through the sample. In this process, the predictor variables are measured against the dependent variable, and the resulting coefficients quantify the relationship. For example, the forecast uses linear regressions to estimate coefficients between total households in a county and a member-cooperative's residential member-owners. SAE modeling uses the linear regression framework on end-use models to create the energy and peak forecasts. End-use models use appliance stock to forecast retail use. Estimates of household appliances, such as electric water heaters, heat pumps, televisions, and refrigerators, are used. Commercial end-use models use heating, cooling, floor space, lighting, and refrigeration. The total appliance stock is multiplied by the average electric use of the appliance (use-per). This method requires significant data collection — even estimates of the square footage of a house or commercial building — and appliance use analysis to make total energy balance with existing sales. SAE models allow reasonable end-use estimates to be calibrated to actual load using linear regression. These models depend on reliable efficiency projections. Central uses EE projections for the South Atlantic census region produced annually by the EIA. Central then customizes the appliance share forecasts using the member-cooperatives' most recent appliance saturation survey results.

Central's member-cooperatives collect appliance saturation surveys from their member-owners every three years. These surveys collect information on home air conditioning type, kitchen appliances, and lighting type. The survey gives Central and its member-cooperatives a clearer understanding of the characteristics of the residential housing stock in member-cooperative service territories, forming the basis for updating current appliance share estimates and forecasts for each member-cooperative. The average-use-per-household forecast is the product of the appliances operated in the household and the efficiency of those appliances. Future efficiency improvements are naturally occurring, as technology improvements make their way into member-owner households, and they are based on federal mandates. Efficiency mandates are not immediately adopted, and the EIA predicts the rate at which these efficiencies are adopted into the average household.

There are two primary elements to the load forecast: peaks and energy. Energy, the total amount of electricity consumed over a month, is forecasted as previously described. Peaks, the highest electric load level on the system in an hour, are modeled using a combination of SAE and historical averages. Large Industrial peaks are modeled individually using historical peaks. New Large Industrials are projected using future billing estimates provided by each member-cooperative. Non-industrial load is modeled using SAE. Weather-sensitive load is estimated by interacting monthly energy forecasts with average peak-day temperatures. Baseload is not weather sensitive and uses peak fractions to determine the contribution to the monthly peak. Peak fractions are estimates of appliance load during the monthly peak hour. For example, if 15% of electric water heaters are online during the February peak hour, electric water heaters would have a peak fraction of 0.15 in February.

Member-Owner Forecasts

Table 5-2 below shows the forecasted number of member-owners served by the member-cooperatives, categorized by class designations from RUS Form 7.

Table 5-2: Member-Owner Accounts Forecast by Class

Year	Residential	Small Commercial	Large Commercial	Other	Lighting	Irrigation	Seasonal
2023	786,335	89,333	396	2,481	1,745	1,518	1,686
2024	800,985	90,649	398	2,481	1,745	1,518	1,686
2025	814,659	91,933	400	2,481	1,745	1,518	1,686
2026	827,129	93,179	401	2,481	1,745	1,518	1,686
2027	838,633	94,405	401	2,481	1,745	1,518	1,686
2028	849,717	95,587	401	2,481	1,745	1,518	1,686
2029	860,342	96,725	401	2,481	1,745	1,518	1,686
2030	870,838	97,850	401	2,481	1,745	1,518	1,686
2031	881,317	98,982	401	2,481	1,745	1,518	1,686
2032	891,803	100,119	401	2,481	1,745	1,518	1,686
2033	902,276	101,240	401	2,481	1,745	1,518	1,686
2034	912,723	102,357	401	2,481	1,745	1,518	1,686
2035	922,981	103,445	401	2,481	1,745	1,518	1,686
2036	933,046	104,497	401	2,481	1,745	1,518	1,686
2037	943,046	105,533	401	2,481	1,745	1,518	1,686
2038	953,060	106,565	401	2,481	1,745	1,518	1,686

Year	Residential	Small Commercial	Large Commercial	Other	Lighting	Irrigation	Seasonal
2039	963,136	107,603	401	2,481	1,745	1,518	1,686
2040	973,347	108,649	401	2,481	1,745	1,518	1,686
2041	983,681	109,679	401	2,481	1,745	1,518	1,686
2042	993,940	110,693	401	2,481	1,745	1,518	1,686
2043	1,004,306	111,716	401	2,481	1,745	1,518	1,686
Growth Rate	1.23%	1.12%	0.06%	0.00%	0.00%	0.00%	0.00%

Central Demand and Energy Forecast

Table 5-3 below shows the base peak and energy forecasts for Central. These projections are at the generation level, meaning they include all losses incurred as power flows between the generating stations and the member-owner.

Table 5-3: Central Demand and Energy Forecast

Year	Summer (MW)	Winter (MW)	Energy (MWh)
2023	4,150	4,539	20,955,156
2024	4,232	4,650	21,646,804
2025	4,319	4,722	22,189,749
2026	4,394	4,800	22,905,930
2027	4,646	4,980	24,735,750
2028	4,814	5,200	26,169,508
2029	4,974	5,347	27,345,836
2030	5,046	5,468	27,858,368
2031	5,089	5,507	27,948,965
2032	5,125	5,546	28,213,144
2033	5,166	5,574	28,319,729
2034	5,203	5,606	28,413,254
2035	5,244	5,642	28,579,221
2036	5,288	5,687	28,874,061
2037	5,342	5,727	29,032,087
2038	5,395	5,773	29,185,151
2039	5,450	5,821	29,407,286
2040	5,502	5,871	29,738,179
2041	5,552	5,913	29,835,300
2042	5,609	5,962	30,002,234
2043	5,666	6,009	30,266,304
Growth Rate	1.57%	1.41%	1.86%

DSM and Energy Efficiency in the Base Forecast

The base forecast has more than 90 MW of existing DSM. Naturally occurring energy efficiencies are embedded in the base forecast using the EIA's efficiency projections of the South Atlantic census region. These are based on national efficiency mandates unfolding throughout the forecast period. Current mandates will not be reflected in the average appliance for several years, as consumers gradually replace existing appliances. Further explanation of existing and forecasted DSM is covered in Section 4 of this report.

Load Duration Curves

Figure 5-2 is a projected load duration curve for 2023 using normal weather. Load duration curves are created by ranking hourly loads from highest to lowest. This demonstrates the overall shape of the utility's load. The shape of a utility's load helps determine the resource plan. A utility with a relatively flat load shape will prioritize resources differently from a utility with a heavily residential load shape. Residential load tends to have high peaks when member-owners are at home and temperatures are most extreme.

HVAC load is the largest contributor to a home's energy use. This translates into low energy use when temperatures are mild or when the home is unoccupied. Residential energy sales are lowest during temperate months, such as March, April, October, and November.

Central's high saturation of residential load makes member-cooperative load sensitive to weather, so a simulation with average weather is used. In Figure 5-1, load duration curves for 2022 (a severe-weather winter) and 2021 (a mild-weather winter) are also included to give a range of weather impacts.

Figure 5-1: Historical Hourly Load Duration Curves

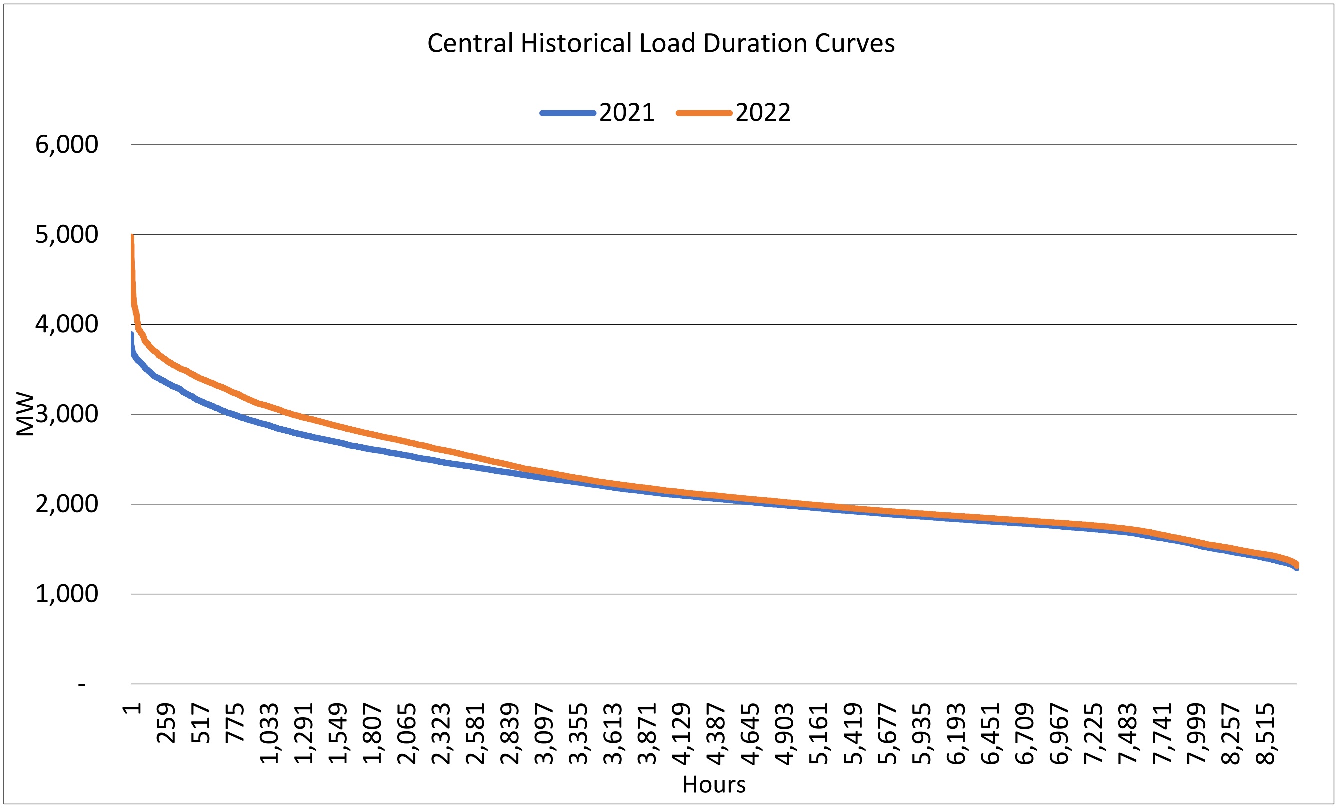
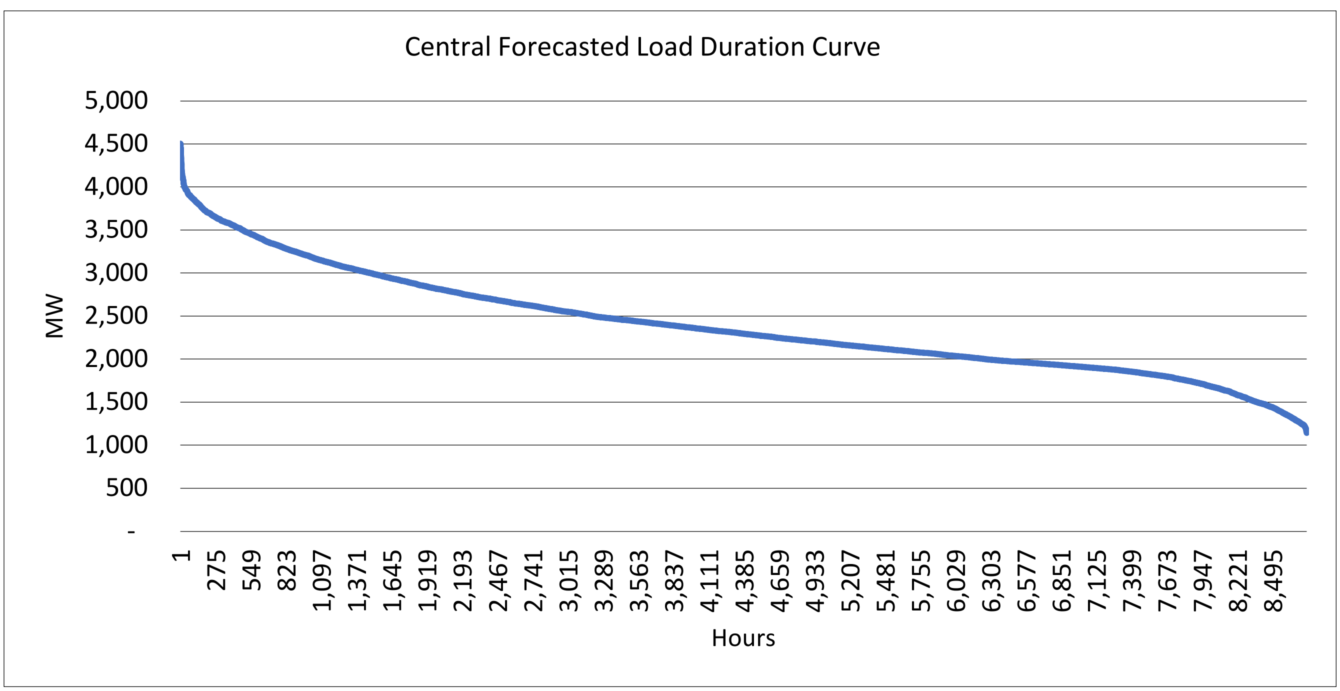


Figure 5-2: 2023 Forecasted Hourly Load Duration Curve



5.3 Load Forecast Scenarios

High and low load growth scenarios are demonstrated in Figure 5-3. The low load growth scenario uses economic growth that is one standard deviation below the S&P Global base forecast. Standard deviation measures the variability of individual values from the average. The growth rates for all economic and demographic categories are reduced by the standard deviation calculation. For example, a standard deviation estimate of 0.5% and a growth estimate of 1.2% yields 0.7% growth in the low load growth scenario. Residential member-owner forecasts are also one standard deviation lower than projections. High load growth scenarios are calculated similarly, but one standard deviation is added for economic growth and the member-owner forecasts.

Standard deviations are calculated for each member-cooperative using 2012 through 2022. These estimates assume normal distributions around the base forecast. The base forecast values of the residential member-owner forecasts and economic projections serve as the mean. The range between the high and low load growth rates represents 68.3% of the possible values.

High scenarios were created for EVs. As previously mentioned in the report, high and base forecasts were created in cooperation with UC Davis. The high scenario projects cooperative members to adopt EVs earlier and faster than the base. High EV scenarios are created for each cooperative and added to the high load band. The low load scenario uses the same cooperative EV projections as the base forecast.

Industrial high and low scenarios are calculated using a combination of probability weights and expert judgment. The high industrial load scenario is a probability weighted average of prospective industrial members. The weighted average is calculated by multiplying the probability of the load being served by the cooperative by the confidence in the forecast. These estimates are based on judgment and are completed in cooperation with Central's economic development staff. Since the cooperatives employ a conservative method to forecast industrial load, the base forecast and low scenario are the same. Existing industrial loads are generally kept at the most recent averages. Only known expansions or new industrial member-owners increase the forecast.

The low load growth scenarios project approximately 1.1% growth per year over the IRP period, while the high load growth scenario projects 2.75% annual growth. For all scenarios, energy grows faster than peaks due to the strong expected growth of high load factor loads in the industrial sector.

Figure 5-3: Energy Forecast Scenarios (MWh)

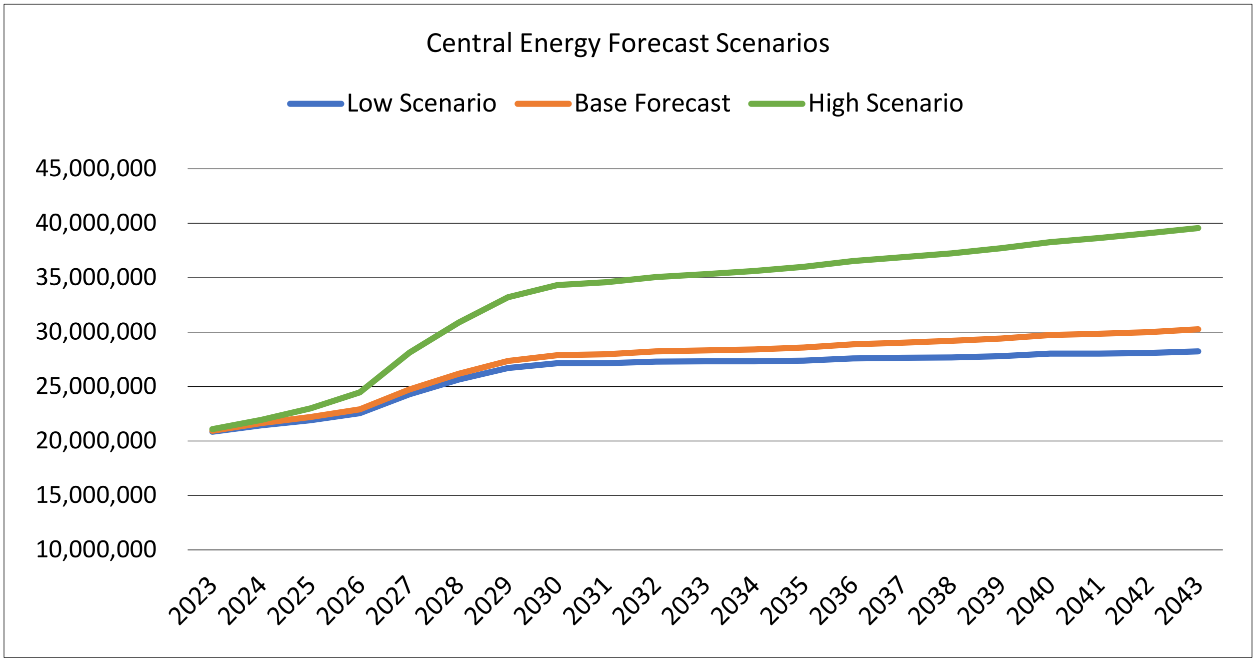


Figure 5-4: Winter Peak Forecast Scenarios (MW)

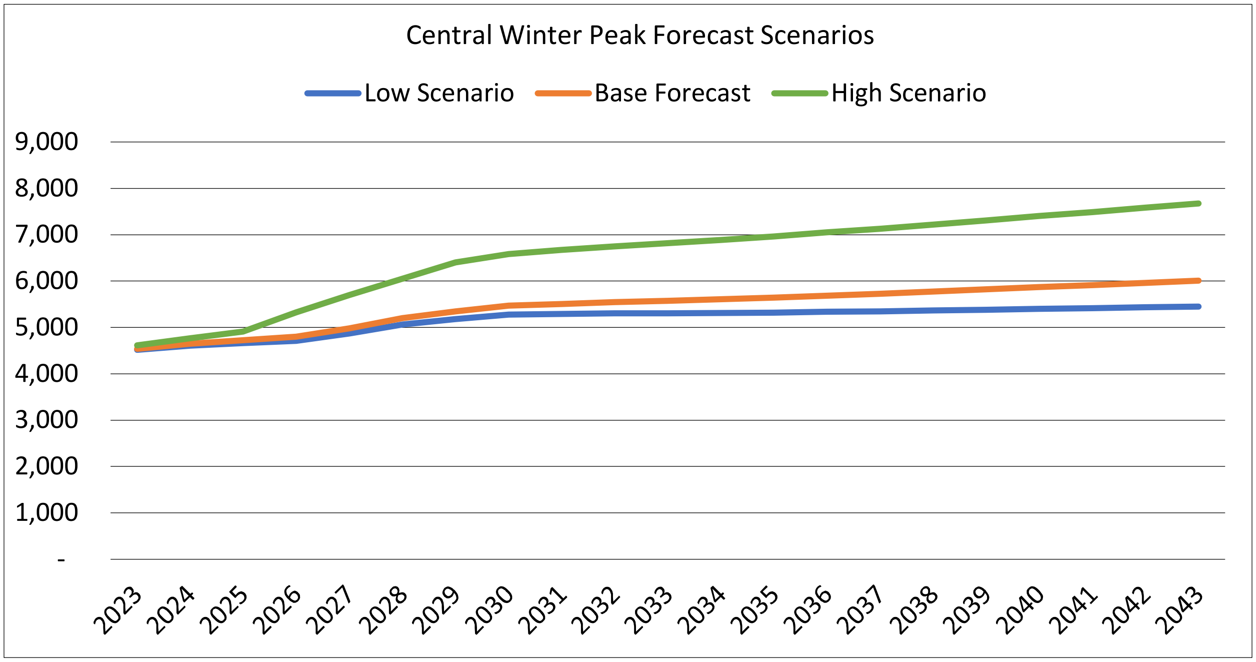


Figure 5-5: Summer Peak Forecast Scenarios (MW)

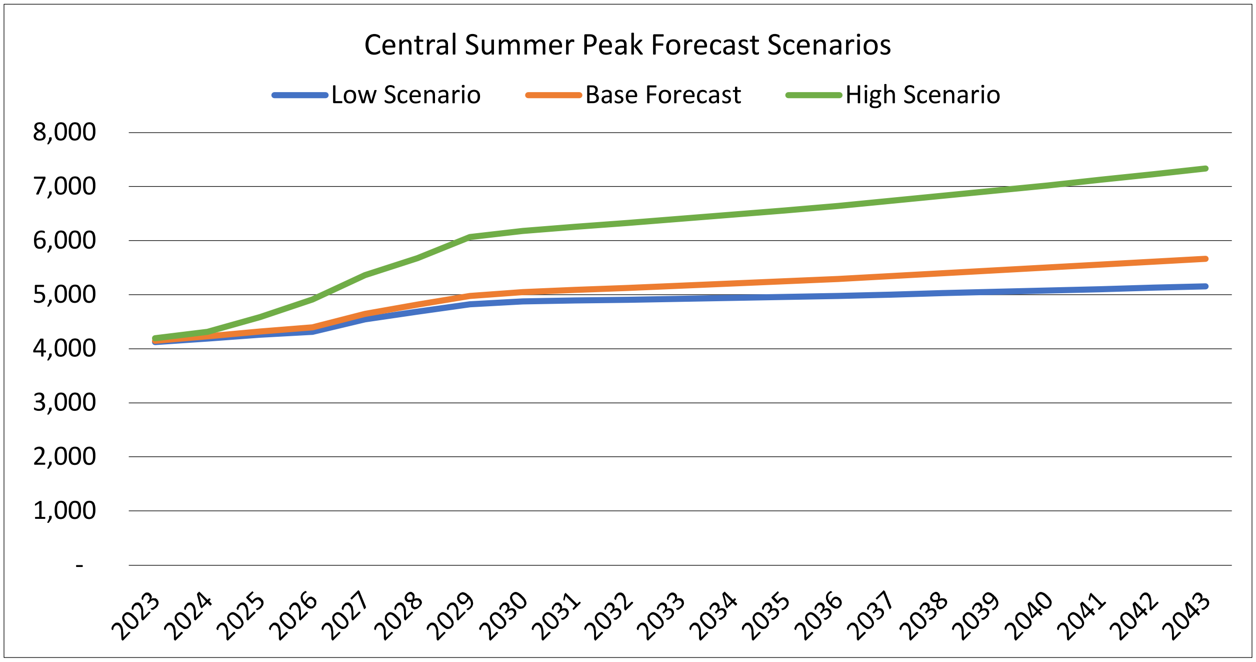


Table 5-4: Low Load Growth Scenario

Year	Summer (MW)	Winter (MW)	Energy (MWh)
2023	4,128	4,523	20,850,589
2024	4,188	4,608	21,439,573
2025	4,259	4,661	21,904,887
2026	4,317	4,717	22,538,745
2027	4,551	4,876	24,283,126
2028	4,702	5,074	25,624,373
2029	4,841	5,200	26,708,553
2030	4,895	5,299	27,129,166
2031	4,916	5,313	27,128,924
2032	4,931	5,328	27,293,671
2033	4,951	5,332	27,308,174
2034	4,968	5,341	27,309,817
2035	4,987	5,352	27,379,926
2036	5,007	5,372	27,567,596
2037	5,037	5,386	27,625,922
2038	5,066	5,406	27,678,462
2039	5,096	5,427	27,795,110
2040	5,122	5,449	28,008,314
2041	5,148	5,465	28,008,843
2042	5,179	5,487	28,072,594

Year	Summer (MW)	Winter (MW)	Energy (MWh)
2043	5,209	5,507	28,228,355
Growth Rate	1.17%	0.99%	1.53%

Table 5-5: High Load Growth Scenario

Year	Summer (MW)	Winter (MW)	Energy (MWh)
2023	4,194	4,615	21,095,324
2024	4,310	4,766	21,927,444
2025	4,584	4,910	22,999,183
2026	4,908	5,322	24,464,548
2027	5,359	5,697	28,104,370
2028	5,671	6,051	30,880,133
2029	6,065	6,406	33,204,697
2030	6,179	6,586	34,308,608
2031	6,256	6,672	34,577,803
2032	6,327	6,750	35,040,268
2033	6,404	6,815	35,318,501
2034	6,478	6,886	35,611,862
2035	6,557	6,962	35,987,323
2036	6,639	7,049	36,512,563
2037	6,734	7,130	36,864,833
2038	6,827	7,219	37,234,537
2039	6,925	7,310	37,681,613
2040	7,018	7,404	38,258,509
2041	7,122	7,488	38,649,662
2042	7,226	7,582	39,064,363
2043	7,332	7,677	39,553,320
Growth Rate	2.83%	2.58%	3.13%

DSM Penetration Scenarios

DSM penetration scenarios are explained in Section 4.

Renewable and Cogeneration Penetration Scenarios

Renewable and cogeneration penetration scenarios are explained in Section 6.

6 Resource Plan

6 Resource Plan

The portfolio of power supply contracts managed by Central is evolving. To better manage its own power supply needs and ensure efficient resource planning, Central negotiated changes to the CA in 2013 that effectively provide opt-out rights regarding Central's participation in future Santee Cooper generation procurement. Further, the pace of technological innovation in the power industry has accelerated, creating a number of powerful trends influencing Central's resource plan. The resource plan discussed in this section is focused on the Santee Cooper BAA. As previously mentioned, this IRP assumes Central will renew its all requirements contract with Duke Energy Carolinas. Therefore, Central's load in the Duke BAA will be served from Duke's network resources as described in Duke's 2023 IRP. The contractual provisions related to generation expansion planning in the 2013 CA Amendments give Central more extensive planning rights and obligations in the Santee Cooper BAA, and the resource plan in this IRP will guide Central's joint planning efforts.

While prices for RE have increased since 2020, prices are expected to return to their long-term trend of steadily decreasing and in the long run are expected to be priced lower than the cost of fossil generation. Additionally, energy storage is becoming an increasingly viable source of reliable capacity. The increasing affordability of RE and energy storage is leading a shift away from large, central station generation to smaller, distributed energy solutions. At the same time, dramatic increases in the supply of natural gas — as a result of improved hydraulic fracking techniques combined with more efficient CTs — have transformed modern natural gas CC plants into the lowest cost sources of traditional large-scale generation. It is in this environment that Central has an opportunity to evolve its resource mix into a blend of assets and power supply contracts that reduces the cost burden on cooperative member-owners while improving the sustainability of its resource portfolio.

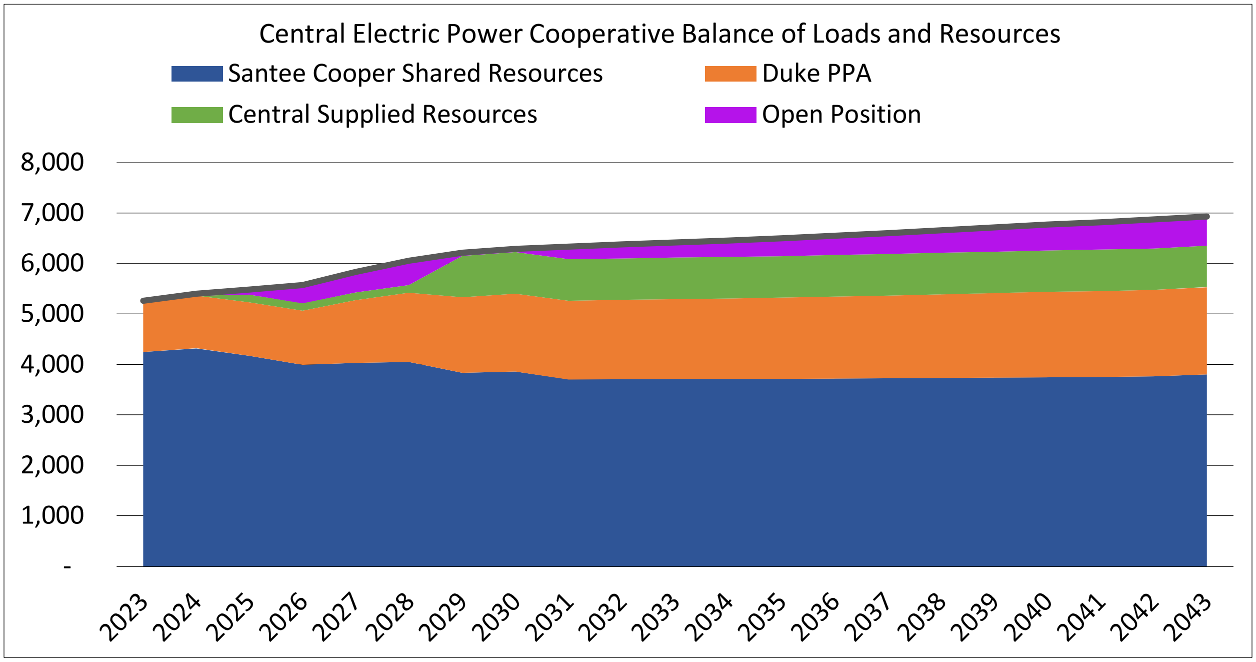
As noted in previous sections, Central's existing principal wholesale power supply contracts are the CA with Santee Cooper and the Duke PPA. While the Duke PPA is scheduled to phase out by the end of 2030, this IRP assumes that Central and Duke will successfully negotiate a contract extension. The CA with Santee Cooper terminates in 2058. However, the mix of resources used to serve load in the Santee Cooper BAA is not fixed. Per the CA, whenever a need for new capacity arises, Central and Santee Cooper will jointly develop a new generation expansion plan. This generation expansion plan will produce one or more proposed shared resources. These resources can be large central station generating units, PPAs, renewable resources, and/or demand-side management programs. The board of directors for each company will independently decide whether to opt into each proposed shared resource in the generation expansion plan. If one party declines to opt in for a resource, each party must independently develop a resource to provide the combined system with that party's load ratio share of the capacity shortfall that was identified in the generation expansion plan. As Central currently accounts for 69% of the Santee Cooper system's firm demand, Central would be required to provide the combined system with at least 69% of the identified capacity shortfall if a proposed shared resource is not jointly approved.

In the Preferred Plan of its 2023 IRP, Santee Cooper declared its intention to retire Winyah Generating Station by the end of 2030. This retirement will reduce system capacity by 1,150 MW (winter), creating a need for new capacity. In November 2021, Santee Cooper issued a proposed shared resource in the form of a 2x1 natural gas-fired CC at Winyah. Central carefully evaluated this proposal, with significant emphasis placed on the cost and risks involved in building natural gas pipeline infrastructure to the Winyah location. Central's Board determined that there were viable alternatives to the Winyah 2x1 with lower risk. Consequently, in April 2022, Central's Board issued an opt-out notice to Santee Cooper. Per the CA, Central had 180 days to identify an alternative resource plan to fulfill its obligation to bring net dependable capacity to the system in an amount at least equivalent to its load share ratio of the capacity shortfall that would have been filled by the Winyah 2x1 CC. After a thorough analysis of more than 60 alternative portfolios, Central's Board determined that the least cost, risk adjusted path forward was the Diversified Resource Portfolio. This portfolio, the components of which were discussed in Section 3, consists of 150 MW of baseload capacity and energy from the Catawba Nuclear Station, 215-230 MW of intermediate capacity and energy from the Santa Rosa CC, 292 MW of peaking capacity from the Sandersville CTs, 150 MW of 4-hour Battery Energy Storage Systems (BESS), increased adoption of utility-scale solar generation, and 25 MW of DSM. Central's Board also expressed interest in participating in a multiparty CC project in South Carolina. Since this decision was made in October 2022, Central executed contracts for the existing generation units, submitted transmission service requests for the existing units, conducted an RFP for BESS, and entered the BESS into Santee Cooper's interconnection queue. More information regarding Central's plans for DSM activities is included in Section 4 of this report.

Santee Cooper's plans to fulfill its obligation to supply at least 338 MW of non-shared capacity to the system are less clear at the time of publication. At the end of the 180-day period, Santee Cooper presented to its Board a plan to build a 1x1 CCGT in Hampton County, South Carolina. Since that time, Santee Cooper filed its 2023 IRP. The Adjusted Preferred Plan in that IRP does not assume the Hampton CCGT will be built, instead it includes 1,020 MW CC as part of a joint project with DESC. For most scenarios evaluated in this IRP, Central respects Santee Cooper's CA declaration of a Hampton 1x1 CC. Central has also built a scenario that hardcodes the 1,000 MW joint CC build, and a scenario that does not add any Santee Cooper non-shared capacity until 2031, when the model is allowed to optimize. In all scenarios evaluated, Santee Cooper takes 522 MW of CC capacity in 2031 as its NSR. The scenarios vary based on the other resources selected beyond Santee Cooper's NSR.

Central is a winter peaking system, so planning for the winter peak will always be a key driver of Central's and its member-cooperatives' capacity needs. In Figure 6-1, Central's balance of loads and resources shows the member-cooperatives' winter capacity needs and the expected sources of that capacity, primarily Santee Cooper, Duke, and the open position.

Figure 6-1: Central's Balance of Loads and Resources (MW)



Central is currently working with Santee Cooper on a short-term resource plan to fill the open position for 2024 through 2028. The recent purchase of Cherokee Cogeneration, a 98 MW CC in Gaffney, South Carolina, by Santee Cooper was the first step in that process. Central anticipates execution of additional short-term PPAs in the near future that will significantly fill the short-term open position. The resource plans detailed in this IRP are designed to fill the long-term open position. Central intends to develop a blended portfolio of DSM, renewable resources, conventional central station generation, and PPAs to create a portfolio of resources capable of serving Central's member-cooperatives with reliable, low-cost power on a risk adjusted basis. Central's continuing mission will be to manage this portfolio of resources in the best interests of its member-cooperatives.

6.1 Southeast Regional Transmission Organization Potential

The adaptation of emerging technology, economic efficiencies, and regulatory initiatives refocuses attention toward achieving more affordable, reliable, safe, and sustainable electricity. Regional Transmission Organizations (RTO) and other Independent System Operators (ISO) operate the transmission delivery network and facilitate the buying and selling of power. Each market and region has a distinct design and structure through which customer value can be derived. An important function of an RTO is to dispatch generating plants on a lowest cost basis across a wider pool, creating savings for customers.

The majority of the electricity users in the United States are serviced by seven ISOs or RTOs, while the Southeast region of the country operates without an organized wholesale electricity market. In recent years, there have been studies and discussions on the impacts of forming an organized market in the Southeast. The formation of an organized market in the Southeast could facilitate greater competition and transparency for energy, capacity, and ancillary services transactions, which could result in net economic savings and fewer concerns with building new generators that may become stranded assets.

In 2022, utilities throughout the Southeast joined to create the Southeastern Energy Exchange Market (SEEM). SEEM is a platform for utilities to engage in bilateral non-firm trades in 15-minute increments. By reducing barriers to short-term trades, SEEM allows market participants to operate their systems more efficiently while reducing costs to consumers. There are currently 23 utilities in 12 states with more than 200,000 MW winter capacity participating in SEEM.[6] Central is not currently a member of SEEM, but Santee Cooper and Duke are members, and Central's member-cooperatives benefit from their SEEM transactions.

The South Carolina legislature created an Electric Market Reform Measures Study Committee in 2020. This committee commissioned The Brattle Group to perform an analysis of the South Carolina electricity market to determine if changes to the market structure would produce benefits to the State. The Brattle report identified changes that could potentially produce lower rates for electric consumers. The legislature has not yet taken action on the Brattle report. Central supports the legislature's efforts to evaluate South Carolina's electric market structure.

6.2 Reliability Considerations

The overarching objective of Central's IRP is to meet forecasted annual peak demand and energy reliably and economically and to establish reserves in excess of the shortfalls demonstrated in the previous sections. Reliability implications differ between a large 2 x 1 CCGT and multiple generators that equal the same capacity. Large generating units within a system can contribute a significant portion of an area's capacity reserves, but load-serving capability diminishes rapidly when a large unit is forced offline or taken out of service. The loss of a single or multiple large unit(s) would reduce reserves in an instant and may potentially compromise reliability. The loss probability of one large unit versus multiple units differs significantly and must be considered when planning future resources.

Planning Reserve Margin

The planning reserve margin (PRM) is a metric that represents the amount of generation capacity available to meet the forecasted load in the planning period. Alternatively stated, PRM is the percentage difference in projected resource availability over and above the net demand. Projected PRMs can be determined with probabilistic models that measure the uncertainty of resource delivery compared to net demand. "Net demand" is the total internal demand minus dispatchable, controllable demand used to reduce load, such as loads participating in DR programs. This measurement indicates the capacity available in excess of the uncertainty in demand for the planning horizon. This measurement is capacity-based and does not provide an indication of energy adequacy. As part of its 2023 IRP, Santee Cooper hired the independent consulting firm Astrape Consulting to perform a Reserve Margin Study Report. This report is publicly available through Santee Cooper's IRP stakeholder website. Central participated in the analysis and

[6] Source: Southeastenergymarket.com

supports its conclusion that the winter reserve margin for the Santee Cooper system needs to be increased from 12% to 17% by 2026. The report recommends maintaining the 15% summer reserve margin requirement. In early 2023, Central opted into Santee Cooper's proposed purchase of the 98 MW Cherokee County Cogeneration CC near Gaffney, South Carolina. Central and Santee Cooper believe this new generator will provide valuable capacity that will enhance system reliability. Duke Energy Carolinas is recommending a winter PRM of 22% in its 2023 IRP. Recent severe winter weather events have shown the value of strong reserves for maintaining system reliability.

Effective Load Carrying Capability

The Effective Load Carrying Capability (ELCC) of a generating resource represents its probabilistic capacity contribution as a percentage of its nameplate capacity. Most thermal generators are attributed to a high percentage ELCC due to their likely availability to generate when called upon, typical of the unit's capacity and forced outage rate. Solar and wind generators are attributed ELCC based on their time of delivery due to their variable and intermittent nature. Their contribution to utility peak demand is dependent on the uncontrollable factor of sunshine and wind. ELCC decreases as variable generation increases, shifting the impact to peak demand, diminishing the overall capacity value of the resource. The same Astrape report that establishes the new PRM requirements also identifies the ELCC for solar and storage assets in the Santee Cooper BAA. The report shows that solar provides minimal capacity value during the winter, but it produces meaningful capacity during summer peaks. The combination of solar plus 4-hour BESS systems produces a very high ELCC in both seasons. Central expects that solar plus storage will be an important component of all future resource plans.

Probabilistic Loss of Load

Loss of Load Probability (LOLP) is a metric of resource adequacy that can be calculated with the use of a detailed model that measures the hourly risk of load not being served. The measurement considers hourly projected load and compares it to generation capacity and the generation forced outage rate. LOLP measures the risk associated with insufficient generation to meet hourly load requirements. LOLP does not measure the amount of unmet demand or the duration that the demand is not met.

Loss of Load Expectation (LOLE) is a reliability metric that seeks to determine the amount of capacity needed to operate a reliable system without numerous shortages. LOLE is an annual measure of resource adequacy converted from the product of hourly LOLP. To calculate LOLE, the generators of a given system are analyzed by combining their capacity profiles, scheduled outages, and the probability of generator forced outages to determine how many days in a year a shortage could occur. The historically accepted industry target for LOLE is to remain below 1 day in 10 years. The Reserve Margin and Effective Load Carrying Capability Study Report performed by Astrape for Santee Cooper and referenced throughout this section used a 1 day in 10 years LOLE target for its recommendation to increase the system PRM.

In a survey of load-serving entities, the North American Electric Reliability Corporation (NERC) observed that most entities in North America performed resource adequacy studies primarily using LOLE. While it has been a matter of judgement between regions and assessment areas as to the methodology used to measure adequacy, the trend is that most recognize that emerging reliability issues may be assessed with probabilistic models. The LOLE of any system can be reduced by managing and reducing forced outage rates. The replacement of larger units, equal in capacity, with smaller, flexible, and reliable generating units will maintain PRM while reducing LOLE. In a wider interconnected system, additional reliability gains can be measured through the accounting of neighboring utility support. These reserve sharing programs serve to minimize LOLP resulting in increased reliability. Santee Cooper, Duke Energy Carolinas, Duke Energy Progress, and Dominion Energy South Carolina are part of a joint reserves sharing group that enables each utility to achieve a higher level of reliability than they could reach independently.

IRP Reserve Margin

As previously explained, important measures of reliability are PRM and LOLE, and the relationship between them should be noted when assessing system reliability. NERC references 15% and 10% PRM to mostly thermal and mostly hydro-electric systems, respectively, when regional and sub-regional specific margin calculations are not provided. Coupled with probabilistic analysis, the PRM is a standard used by planners to measure adequacy. NERC guidance is provided to the SERC Reliability Corporation (SERC) and the other Regional Reliability Organizations (RRO). The individual RROs provide further guidance and/or requirements to the BAs.

Consistent with Santee Cooper's application of planning reserves, this IRP targets PRMs of 17% and 15% for the winter and summer months, respectively, in the Santee Cooper BAA. Due to the all-requirements nature of Central's PPA with Duke, modeling Duke's reserve margins is not relevant to this IRP. Central recommends that anyone interested in Duke's reserve margin requirements read Duke's 2023 IRP.

6.3 Santee Cooper Balancing Authority

If Central declines to opt into a proposed shared resource resulting from the Santee Cooper-led joint generation expansion process or if Santee Cooper rejects Central's request to participate in a proposed shared resource, Central is obligated to provide capacity to the Santee Cooper system if existing resources are insufficient to maintain the required reserve margins. Table 6-1 shows the capacity shortfall in the Santee Cooper BAA that this IRP attempts to resolve. The table assumes Central supplies its Diversified Resource Portfolio in 2029, Winyah Station retires as scheduled at the end of 2030, and Santee Cooper supplies capacity equivalent to a 1x1 CC in 2031. Central anticipates that Central and Santee Cooper will develop a joint generation expansion plan guided by the two companies' IRPs to identify pathways to close this shortfall.

Table 6-1: Santee Cooper BAA Capacity Needs

	Santee Cooper BAA Capacity Needs (MW)		
Year	Base Case	High Load	Low Load
2023	-	-	-
2024	50	165	18
2025	57	178	-
2026	427	861	284
2027	502	1,020	335

Year	Santee Cooper BAA Capacity Needs (MW) Base Case	High Load	Low Load
2028	599	1,187	409
2029	-	392	-
2030	-	474	-
2031	266	1,064	5
2032	306	1,137	20
2033	334	1,199	26
2034	367	1,267	36
2035	405	1,341	49
2036	450	1,424	69
2037	490	1,500	84
2038	536	1,584	103
2039	583	1,670	124
2040	632	1,757	146
2041	674	1,836	162
2042	722	1,923	184
2043	771	2,010	205

6.4 Duke Balancing Authority

Although Central and Duke are negotiating a PPA extension, this IRP assumes that Duke will continue to serve the cooperative load within its BAA. Table 6-2 shows the forecasts for this load under base, high, and low scenarios.

Table 6-2: Duke BAA Capacity Position

Year	Duke PPA Coverage	Duke BAA Forecast (MW)		
		Base Case	High Load	Low Load
2023	100%	1,022	1,030	1,015
2024	100%	1,043	1,059	1,031
2025	100%	1,060	1,082	1,043
2026	100%	1,074	1,182	1,052
2027	100%	1,244	1,480	1,217
2028	100%	1,370	1,693	1,339
2029	100%	1,493	1,930	1,457
2030	100%	1,544	1,983	1,502
2031	100%	1,558	2,005	1,510
2032	100%	1,569	2,025	1,516
2033	100%	1,583	2,047	1,524
2034	100%	1,595	2,068	1,530
2035	100%	1,609	2,090	1,538
2036	100%	1,623	2,113	1,545

Year	Duke PPA Coverage	Duke BAA Forecast (MW)		
		Base Case	High Load	Low Load
2037	100%	1,640	2,140	1,556
2038	100%	1,657	2,166	1,566
2039	100%	1,674	2,193	1,576
2040	100%	1,689	2,219	1,584
2041	100%	1,698	2,247	1,587
2042	100%	1,714	2,276	1,596
2043	100%	1,728	2,305	1,602

6.5 Central Resource Planning Process

Central designed a process for its IRP analyses to determine the most cost-effective resource portfolios for the 20-year study period. The key steps were as follows:

1. Inputs and assumptions were developed that define important variables.
2. Capacity expansion modeling was performed to identify lowest cost portfolios under different sets of resource constraints and with variations in key inputs and assumptions.
3. Production cost modeling was conducted on the remaining portfolios for detailed cost, operational, and sensitivity analysis.
4. The top portfolios were selected. These represent a diverse set of cost-effective portfolios.

6.6 Study Inputs and Assumptions

The first step in resource planning is to identify study inputs and assumptions with an emphasis on those that impact the cost-effectiveness of resource portfolios. For example, the projected price of natural gas is an important input assumption that affects the cost-effectiveness of potential future resources. Central categorized input assumptions into the following categories:

- New Generation Resources (Cost and Operational Performance)
    - Thermal Generation Options
    - Renewable Generation and Energy Storage Options
- Electric Transmission Investments
- Power Purchase Options
- Load
- Fuel (Commodity Prices and Transportation Costs)
- Renewables Integration
- Demand-Side Management
- Environmental Regulations

- Financial Assumptions

In addition to the base case assumptions for these inputs, the analysis included sensitivities or variations in the assumptions, such as a high natural gas price and a low natural gas price. The following sections highlight the input assumptions used for capacity expansion scenarios and sensitivities.

Technical Assessment of New Generation Resources

Technology assumptions for new resources are a critical component of a capacity expansion plan. A typical assessment is comprised of planning-level assumptions for cost (capital, operations, and maintenance) and performance characteristics. The assessment for new resources to satisfy future capacity and energy needs in this expansion plan was split into two main technology categories: thermal and renewable. The thermal unit technology assessments were performed for various peaking and CC technologies. Peaking generation is designed to produce power for relatively brief periods of time. CC generators are baseload generation, which are expected to operate around the clock. The renewable technologies consisted of wind, solar, and battery storage.

Thermal Generation Technology

The thermal unit technology assessments were separated into two main groups: peaking and CC technologies. Due to the lead time before a resource is needed, this IRP focuses on a single technology configuration for CC and peaking resources. New CC resources were assumed to be 600 MW units, which could be a 2x1 F-frame setup or a 1x1 H-class configuration. The model was given the option to build two 600 MW units, effectively creating a 1,200 MW 2x1 H-class unit. New peaking natural gas resources were modeled as 300 MW units with parameters closer to an F-frame turbine. Specific technology decisions will be made based on the IRP analysis.

Simple cycle gas turbine (SCGT) technology produces power in a natural gas turbine generator and is typically used for peaking power due to fast load ramp rates and relatively low capital costs. These units have high heat rates compared to CC technologies. Heat rate is a measure of efficiency; it relates the amount of thermal energy consumed to the amount of electricity generated. All peaking technology assessed is fueled by natural gas. The assessed technologies are shown in Table 6-3 with the associated capacity and capital cost.

The basic principle of a CCGT plant is to use natural gas to produce power in a natural gas turbine that can be converted to electric power by a coupled generator. The hot exhaust gases from the natural gas turbine are then used to produce steam in a heat recovery steam generator (HRSG). This steam is used to drive a steam turbine and generator to produce electric power. The use of both natural gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and lower emissions. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing. CC facilities can be designed with multiple CTs connected to a single steam turbine. These technologies are called 2x1 (two by one) CCGTs to indicate that there are two CTs and one steam turbine. A CC with only one CT is called a 1x1 CCGT.

Table 6-3: Thermal Technology Options

	CC	CT
Cost		
Capital Cost [2031 COD] (2031 $/kW)	$1,327	$1,134
Fixed O&M (2031 $/kW-Year)	$36.74	$25.59
Variable O&M (2031 $/MWh)	$2.62	$6.09
Annual Cost Escalation	2.50%	2.50%
Capacity and Operation		
Installed Capacity (MW)	600	300
Forced Outage Rate (%)	5.0%	2.5%
Economic Maximum (MW)	600	300
Economic Minimum (MW)	240	120
Heat Rate at Maximum Load (Btu/kWh)	6,300	10,500
Emission Rates		
SO_2 (lbs./MMBtu)	0.0019	0.0009
NO_X (lbs./MMBtu)	0.0000	0.0036
CO_2 (lbs./MMBtu)	118	118

Renewable Technology

Inflation Reduction Act

The Inflation Reduction Act (IRA), passed in 2022, contains significant investments to promote decarbonization in the United States. The IRA could help stimulate a reduction of between 32% and 42% (from 2005 levels) in net emissions by 2030, whereas BAU would have resulted in a reduction of between 24% and 35%.[7] Hailed as the largest investment in climate by the United States to date, the United States will invest at least $369 billion over the next decade on climate initiatives.[8] The majority of the investment will be expended through tax credits. IRA tax credits now include the option for Direct Pay, which allows tax exempt entities like Central to receive tax credits for clean energy investments. Previously, tax exempt entities had to partner with entities with tax appetites in order to take advantage of the previously existing credits, reducing the benefits to consumer rates.

The IRA extends and modifies the investment tax credit (ITC) and production tax credit (PTC). With the ITC, the credit received is a percentage of the cost of a project. The PTC is similar to the ITC, but the amount compensated depends on energy production versus project cost.

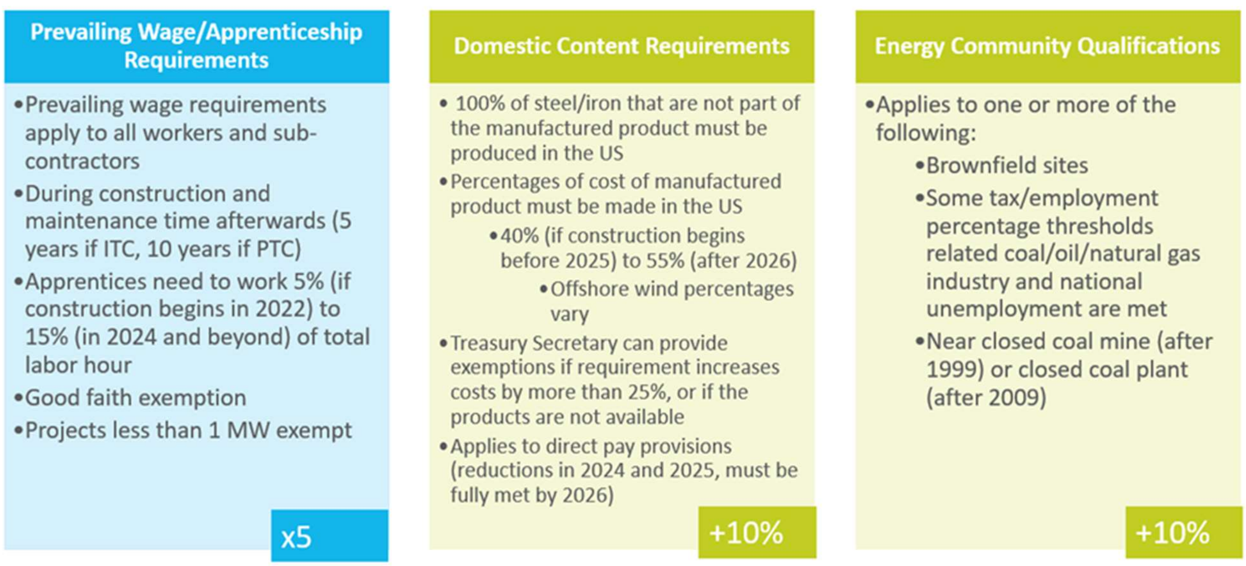
The ITC and PTC have been in place for decades in the U.S. and have helped encourage development of renewable generation. Eligibility for the ITC and PTC was limited to certain technologies; however, under

[7] https://rhg.com/research/climate-clean-energy-inflation-reduction-act/
[8] https://www.cohnreznick.com/insights/inflation-reduction-act-renewable-energy-tax-incentives

the IRA, the ITC and PTC become new, technology-neutral incentives beginning in 2025. To qualify for the technology-neutral PTC under the new Section 45Y of the United States Code, resources must emit zero emissions based on a lifecycle assessment.

Energy storage now qualifies for the technology-neutral ITC under the new Section 48D. Previously, storage had to charge from a renewable resource to be eligible. The 2023 IRP assumes that storage, wind, and solar will leverage IRA tax credits. The federal government revamped the ITC and PTC to support United States labor and supply chains. Generally, there is a base ITC and a base PTC. These base credits are multiplied by a factor of five if developers meet prevailing wage and apprenticeship requirements. There are additional 10% adders if domestic content requirements are met, or if the project is located in an energy community. Details on these multipliers are shown in Figure 6-2.[9] The general tax credits are shown in Figure 6-3.[10] There are also grants, loans, and loan financing available under the IRA. Central will investigate and pursue opportunities that will reduce rates for its member-cooperatives.

Figure 6-2: Bonus Credits in Inflation Reduction Act



[9] Jenkins, Jesse D.; Farbes, Jamil; Jones, Ryan; and Mayfield, Erin N. (2022), "REPEAT Project Section-by-Section Summary of Energy and Climate Policies in the 117th Congress," B23 REPEAT Project, http://bit.ly/REPEAT-Policies. doi: 10.5281/zenodo.6993118; https://docs.google.com/spreadsheets/d/1X2PORZp5JzP2yWbdUSbXphElIGPEOlJNI-T12gz7n1s/edit#gid=1108881515

[10] Jenkins, Jesse D.; Farbes, Jamil; Jones, Ryan; and Mayfield, Erin N. (2022), "REPEAT Project Section-by-Section Summary of Energy and Climate Policies in the 117th Congress," B23 REPEAT Project, http://bit.ly/REPEAT-Policies. doi: 10.5281/zenodo.6993118; https://docs.google.com/spreadsheets/d/1X2PORZp5JzP2yWbdUSbXphElIGPEOlJNI-T12gz7n1s/edit#gid=1108881515

Figure 6-3: Inflation Reduction Act Tax Credits

	Clean Electricity ITC, Section 48D		Clean Electricity PTC, Section 45Y	
	If GHG emissions are zero		*Does not apply to storage*	
	Meet prevailing wage for construction + 1st 5 years of operation	Miss prevailing wage for construction + 1st 5 years of operation	Meet prevailing wage for construction + 1st 10 years of operation	Miss prevailing wage for construction + 1st 10 years of operation
Base Credit	30% ITC	6% ITC	$27.60/MWh (in 2025 $) PTC	$5.52/MWh (in 2025 $) PTC
AND Meet domestic content requirements, or located in an energy community	40% ITC	8% ITC	$30.35/MWh (in 2025 $) PTC	$6.07/MWh (in 2025 $) PTC
OR Meet both	50% ITC	10% ITC	$33.39/MWh (in 2025 $) PTC	$6.62/MWh (in 2025 $) PTC

Credits phase out (100%, 75%, 50%) in following three years when annual greenhouse gas emissions from electricity are 25% of 2022 values, or 2032 (whichever year is later)

Renewable Technologies Modeled

Renewable and storage technology cost curves were developed using a blended approach of near-term market pricing with long-term learning curves from the Department of Energy's National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB). The NREL 2022 ATB was the most current ATB published at the time the assumptions in this IRP were developed. Central developed high and low ranges based on recent market bids for projects and other publicly available information related to recent increases in PPA prices.

Table 6-4 shows the renewable technology types studied with size and cost information for a 2031 start date. Wind and solar costs are shown as levelized cost of energy (LCOE), and storage costs are shown as levelized cost of storage (LCOS).

Table 6-4: Renewable and Storage Resources in 2023 IRP

	Generic Project Size (MW)	Annual Capacity Factor (%)	LCOE (2031 $/MWh)	LCOS (2031 $/kW-Month)
Land-Based Wind	50	25%	$61.01	-
Offshore Wind	50	43%	$123.34	-
Utility-Scale Solar	50	30%	$36.27	-
4-Hour Battery Storage	50 MW/200 MWh	16.67%	-	$13.08

Wind Technology

Wind turbines convert the kinetic energy of wind into mechanical energy, which can be used to generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into the following two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground

More than 95% of turbines over 100 kW are configured as horizontal axis. Subsystems for either configuration typically include a blade/rotor assembly to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. The power generated by a turbine is proportional to the cube of the prevailing wind; that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital. According to NREL, Class 3 wind areas (average wind speeds of 14.5 mph) are generally considered to be suitable for wind generation development. South Carolina's offshore areas demonstrate wind speeds higher than 16.8 mph. Offshore wind typically has more consistent and stronger wind patterns than onshore wind. Utility-scale land-based wind turbines are typically 80 meters to 140 meters in height; onshore wind resources are challenged in South Carolina, as wind speeds average below 14.5 mph. Offshore wind technology is still gaining momentum in the United States and can often be cost prohibitive while technology and construction advancements continue to catch up with onshore wind.

Figure 6-4 and Figure 6-5 contain base, high, and low LCOE curves from the IRP compared to NREL published cost curves for land-based and offshore wind. Near-term (2025 to 2027) market ranges are blended into the NREL curve. Beginning in 2035 and through the rest of the study period, the solar LCOEs match the NREL cases for base, high, and low.

Figure 6-4: Land-Based Wind Levelized Cost of Energy

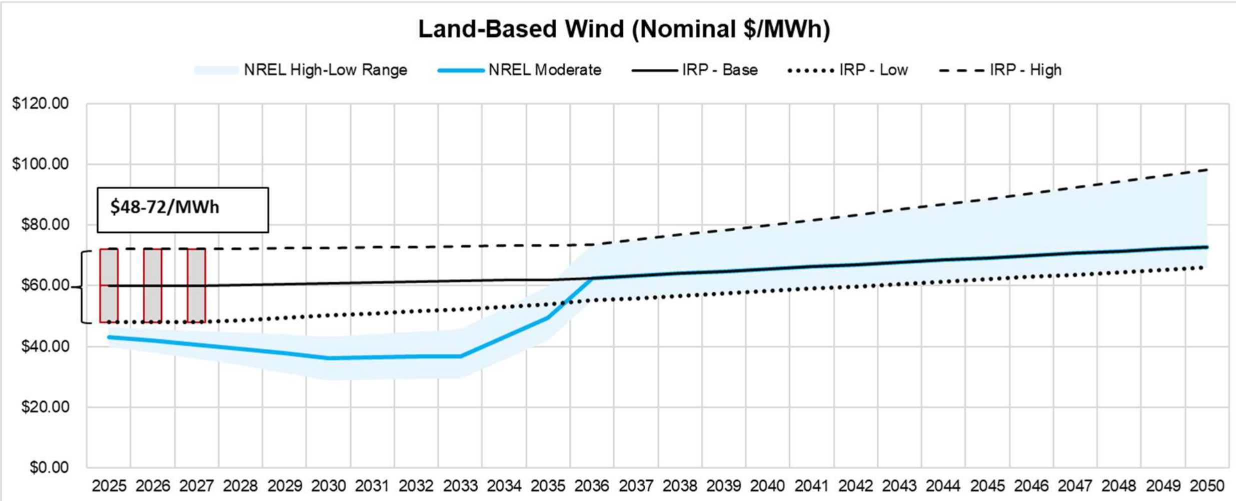
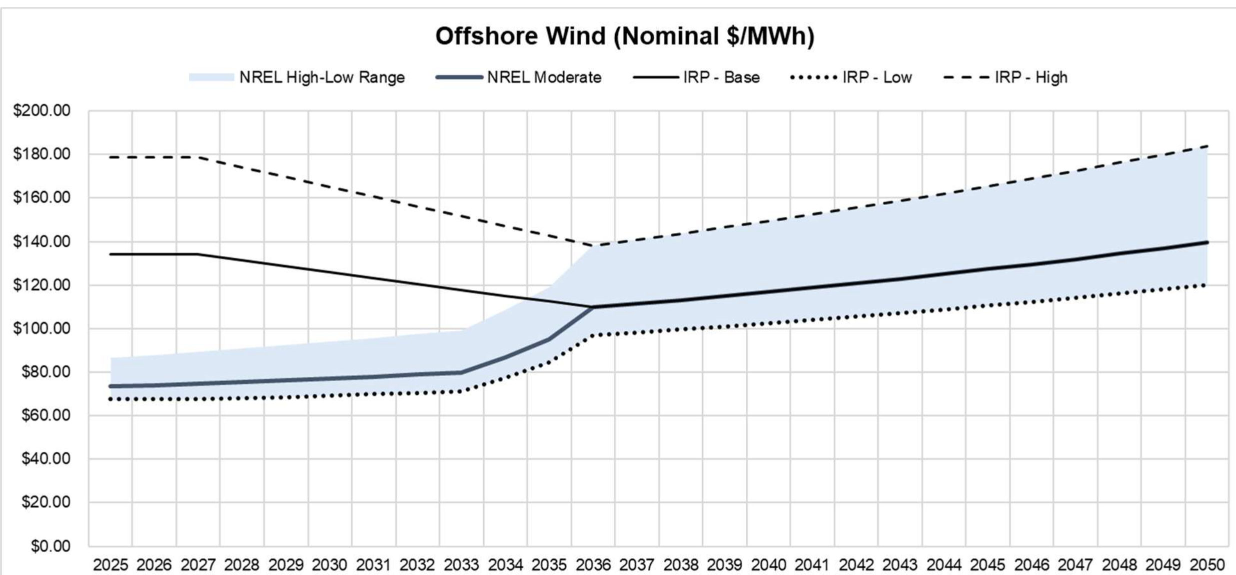


Figure 6-5: Offshore Wind Levelized Cost of Energy

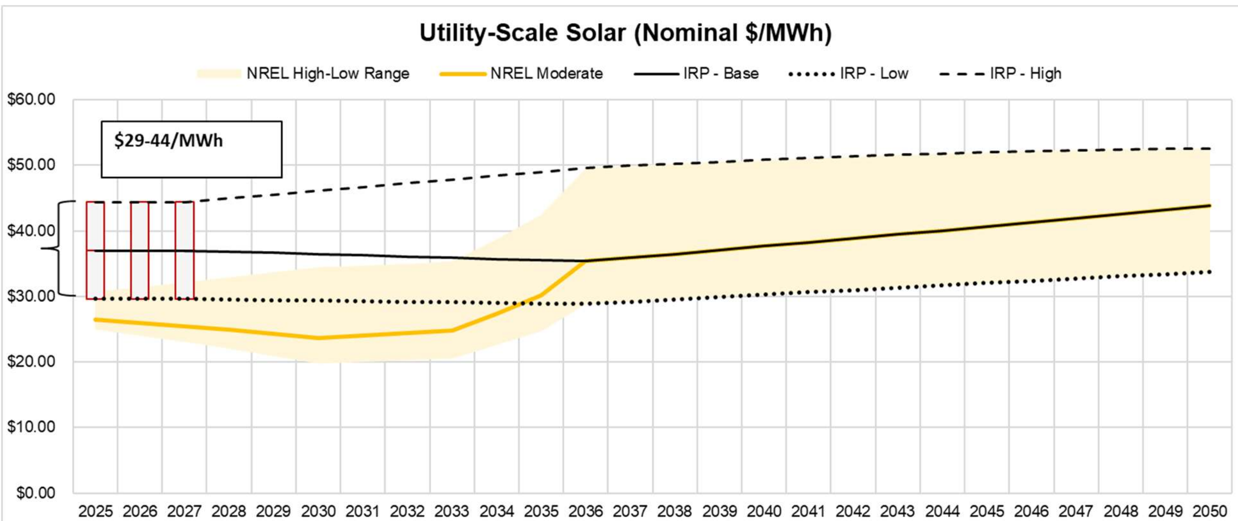


Single Axis Tracking Photovoltaic Technology

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is developing into a diverse mix of technological designs. PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured by wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15% of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of approximately 2% in the first year and 0.5% per year thereafter. At the end of a typical 30-year period, the conversion efficiency of the cell will be approximately 80% of its initial efficiency. Single axis tracking was utilized in this assessment and is commonly used in utility-scale applications. Single axis tracking means that the solar panels are mounted on structures with one axis of rotation. Motors mechanically rotate the panels along the horizon. The panels are oriented north to south, to face east with the sunrise, and track west until sundown.

Figure 6-6 contains base, high, and low LCOE curves from the IRP compared to NREL published cost curves. Near-term (2025 to 2027) market ranges are blended into the NREL curve. Beginning in 2035 and through the rest of the study period, the solar LCOEs match the NREL cases for base, high, and low.

Figure 6-6: Utility-Scale Solar Levelized Cost of Energy



Battery Storage

Electrochemical technology is becoming one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Central recently received a Department of Energy grant to install a 3.6 MW 14.4 MWh long-duration flow battery at a member-cooperative substation. This pilot will provide Central with operational experience with a long-duration battery and a greater understanding of the uses, costs, and benefits of long-duration batteries. Findings from this pilot will be used for Central's next IRP. For this IRP, 4-hour lithium-ion batteries are the only form of BESS that was considered for the optimization.

Lithium-ion (Li-ion) batteries contain graphite and metal-oxide electrodes, and lithium ions dissolve within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion battery technology has recently experienced a resurgence of development due to its high energy density, low self-discharge, and cycling tolerance. Many Li-ion battery manufacturers currently offer 15-year warranties or performance guarantees. Consequently, Li-ion batteries have gained traction in several markets including the utility and automotive industries. Li-ion battery prices are decreasing, and continued development and investment by manufacturers is expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, Li-ion batteries are anticipated to expand their reach into the utility sector.

Flow batteries use an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system, in which the cells can be stacked in series to achieve the desired voltage difference. The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary. In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

The key cost elements of a battery system are the inverter, the battery cells, the interconnection, and the installation. Capital costs include engineering, procurement, and construction (EPC) costs plus owner's costs, which reflect recent trends for capacity overbuild to account for short-term degradation. It is also assumed that the system will be co-located with an existing asset or in close proximity to existing infrastructure.

Figure 6-7 contains base, high, and low cost curves for battery storage used in this analysis. Battery storage is primarily a capacity resource, so a metric of LCOS is used instead of LCOE. LCOS levelizes the capital cost and fixed O&M, which includes augmentation, over the lifetime of the project. Developers typically quote this cost in $/kW-month when looking at PPAs or tolling agreements from storage projects.

Figure 6-7: 4-Hour Battery Storage Levelized Cost of Storage

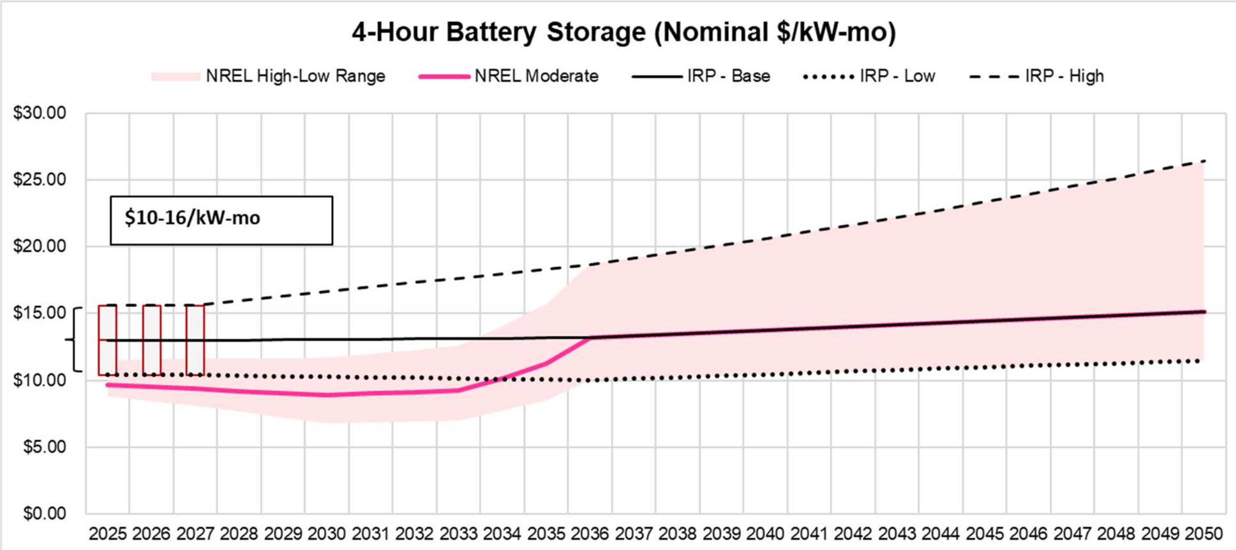


Table 6-5: 4-Hour Battery Storage: Key Assumptions

New Battery Storage Resource Summary
Modeled Generic Resource Size: 50 MW/200 MWh
Usable Storage Limits: 180 MWh Max Stored Energy; 20 MWh Min Stored Energy
Cycling Limitations: Annual Capacity Factor limit of 16.67% (equivalent to 365 full cycles per year)
Capacity Value/ELCC: Dynamic based on Santee Cooper's ELCC Study
Round-Trip Efficiency: 85% (equivalent to 117% Payback Required in model)
Degradation: 0%; augmentation cost included in Fixed O&M
Tax Credit Eligibility: 30% ITC
Hybrid Storage: 5% capital cost discount

Transmission System

Central's transmission system consists of more than 850 miles of transmission lines at 44 kilovolts (kV), 46 kV, 69 kV, 100 kV, and 115 kV. Central currently has physical interconnections with the following utilities:

- Santee Cooper
- Duke
- DESC

The member-cooperatives' systems' power requirements are delivered to Central's delivery points through a combination of these interconnections and Central's transmission facilities.

Central's system currently includes two transmission stations, and all 582 wholesale distribution delivery points that serve the member-cooperative systems are owned by Central's member-cooperatives. Central owns the metering associated with Central's member-cooperatives' load within the Duke transmission system, and Santee Cooper owns the metering within the Santee Cooper/Central shared transmission system.

Transmission Access

Central is not a NERC-registered Transmission Service Provider (TSP). Central's transmission service needs within the Santee Cooper/Central shared transmission system are managed through the CA. Central is a wholesale customer of Duke and requests transmission service through the Duke Open Access Transmission Tariff (OATT) process. For transmission service needs outside of Duke and Santee Cooper areas, Central must coordinate with the respective TSP through their OATT process.

Capital Asset Management

Capital asset management is focused on ensuring required maintenance is performed and necessary investments are made to economically maintain the long-term safety, security, adequacy, and reliability of Central's assets. The current rate of asset replacement via annual system inspections is sufficient to maintain reliability. Central, through its operations and maintenance providers, performs annual asset inspections to determine which assets require replacement before substantial degradation or failure affects reliability. Ongoing inspections, supplemented with asset-specific in-depth inspections, will continue to guide sustainable asset replacement strategies.

Santee Cooper performs operations and maintenance of the Santee Cooper/Central shared transmission system under the CA. Santee Cooper has transmission crews stationed in the following locations in South Carolina: Conway, Moncks Corner, Hemingway, Pinewood, Darlington, Blythewood, Batesburg, Aiken, Orangeburg, Varnville, and Bluffton. New Horizon Electric Cooperative (NHEC) performs operation and maintenance for Central's radial transmission assets interconnected to the Duke transmission system through an operations and maintenance service agreement, and has a crew located in Laurens, South Carolina.

Transmission Facilities

Central prepares a Long-Range Transmission Plan (Plan) to serve as a guide for developing its system to meet the current and future needs of its consumers. This Plan is updated on a 10-year cycle or as the result of a significant change to the transmission system, whichever is sooner. The purpose of the Plan is to study the current system, including asset health projections, identify system shortfalls, and develop system mitigation measures that will provide the most practical and economical means of serving future loads.

The Plan is developed to examine the ability of Central's system to serve the projected load levels for the near term (Year 0 to Year 5) and longer term (Year 6 to Year 10) planning horizons. Central is a winter peaking system; the summer peak, light load, and winter peak loading conditions are evaluated. In addition to the ability to serve projected load, the health of existing assets is considered in the Plan.

Results from the most recent transmission studies, which were conducted in 2023, show there was no loading in the base case above 100%. Overloads were observed during certain contingency conditions.

The overloads can be mitigated with operational procedures, so other mitigation measures are not required for the Plan.

Central continuously monitors the need for additional transmission facilities. At the time the need for additional facilities is identified, the timing, type, and approximate costs of additional facilities will be developed.

Central participates in the South Carolina Regional Transmission Planning (SCRTP) group, which includes DESC and Santee Cooper, and the Carolina Transmission Planning Collaborative (CTPC), which includes the Duke BAs in the Carolinas, planning processes as a stakeholder. These meetings consist of quarterly forums and periodic assessments of the regional transmission system function and reliability. These processes identify long-term regional transmission requirements and identify a portfolio of projects designed to maintain grid reliability and address congestion issues.

Table 6-6: Future Transmission System Investment through 2032

Year	Miles	Cost Projections
2023	35.2	$57,252,511
2024	35.4	$59,973,267
2025	35.4	$70,809,389
2026	45.1	$97,562,050
2027	124.9	$216,614,390
2028	13.1	$24,651,547
2029	12.8	$27,228,684
2030	46.8	$95,786,685
2031	13.0	$25,618,323
2032	15.4	$40,220,236

Power Purchase Agreements

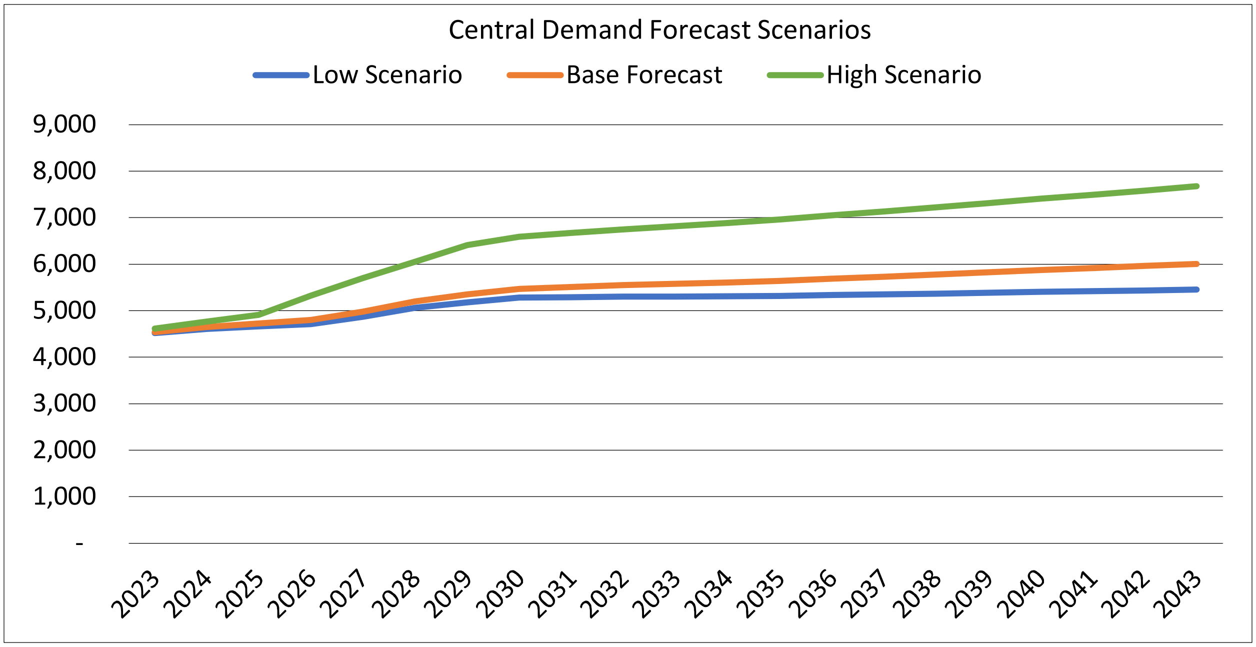
During the process of evaluating alternatives to Santee Cooper's Winyah proposed shared resource, Central solicited and received PPA offers from multiple entities. The PPAs received varied in options from unit contingent power to full-requirement options. The three selected PPAs are described in Section 3 of this report.

Load

Due to variations in economic growth, changing consumption patterns, and changing electrification trends, there is uncertainty in future electric load growth. To account for the variations in potential load growth, two load sensitivities were developed in addition to the base load forecast. Section 5 details the load projections for base, high, and low load growth. The projected capacity surplus and deficiencies are discussed in Sections 6.3 and 6.4.

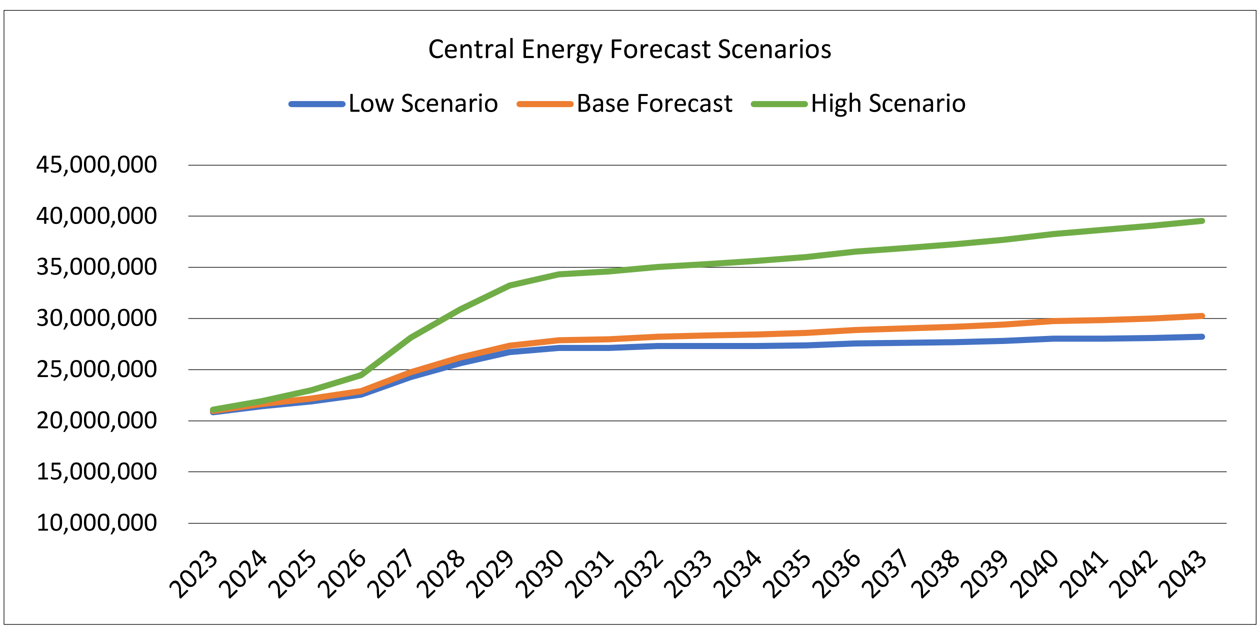
The base load forecast and the high and low sensitivities were developed by Central. All three load forecasts were modeled in EnCompass to create resource portfolios optimized to each load forecast. The peak demand for the base forecast and the high and low sensitivities are shown in Figure 6-8.

Figure 6-8: Peak Load Growth (MW)



The energy forecast for the base assumptions and high/low sensitivities is shown in Figure 6-9.

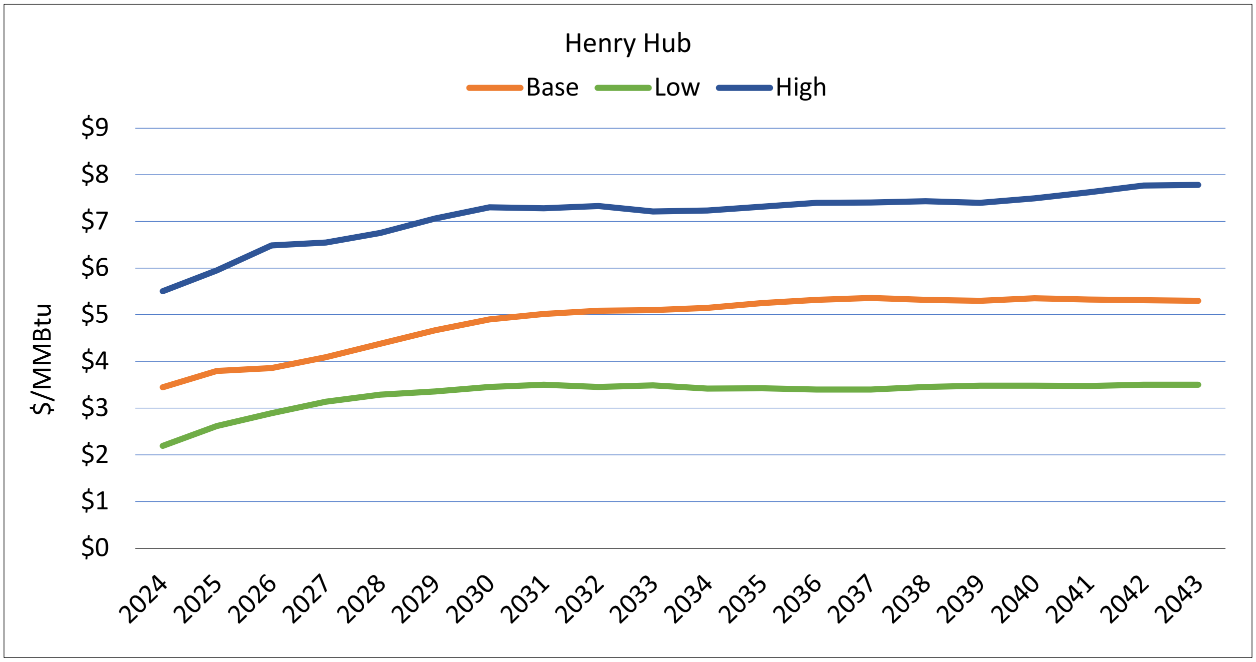
Figure 6-9: Energy Growth (MWh)



Fuel

New York Mercantile Exchange (NYMEX) Henry Hub was assumed to be the source of the natural gas pricing. Historically, natural gas prices have experienced volatility that is often difficult to predict. To account for the volatility that may exist over the study period, two sensitivities were developed beyond the base scenario. Stochastic distributions for the natural gas prices were developed and were used to frame the high and low natural gas prices sensitivities. Figure 6-10 shows an annual average commodity price that was modeled for the base natural gas forecast and the high and low sensitivities.

Figure 6-10: Natural Gas Commodity Price Forecast



Renewables Integration

Renewable energy has been rapidly advancing and has gathered support due its competitive pricing and lower environmental impact relative to thermal energy generators. The generatation expansion modeling performed for this IRP indicates that increasing renewable penetration reduces system energy costs. All portfolios under consideration sharply increase renewable penetration in South Carolina compared to the status quo. The intermittant nature of renewables makes it challenging to bring substantial amounts of one type of renewable resource online in a single year. Consequently, the modeling limits the amount of solar that can come online each year to allow a gradual implementation. As older, slower moving coal units are replaced with more flexible resources, renewable implementation challenges should decrease. Central's desire to minimize the power costs of its member-cooperatives, along with the sustainability objectives of commercial member-owners, drives Central to strongly support increasing the solar generation on the system. While the IRP modeling limits the solar capacity that can be brought online in any year, this should not be seen as a limitation on Central's ability to add generation when it is in the best interest of its member-cooperatives. For example, the Reference Case portfolio has 800 MW of incremental solar capacity brought online in 200 MW incremements beginning in 2028. If Central has the opportunity to add solar in 400 MW increments and doing so reduces power costs, it will add solar generation more quickly than projected in the Reference Case modeling. In an attempt to capture the impact that changes in renewable price projections have on resource plan results, two renewable sensitivities were developed beyond the base case. The two sensitivities, referred to as High Technology Cost and Low Technology Cost, vary the costs of solar generation, wind generation, and BESS.

Figure 6-11 shows the cumulative additions of renewable technology in the Reference Case, High Technology Cost, and Low Technology Cost scenarios. Varying the cost of solar has minimal impact on implementation, with installed solar capacity ranging from 1,600 MW in the High Technology Cost scenario to 1,900 MW in the Low Technology Cost scenario. BESS are more responsive to changes in cost, with installed BESS ranging from 0 MW in the High Technology Cost scenario to 400 MW in the Low Technology Cost scenario.

Figure 6-11: Cumulative Additions of Renewable Technology (MW)

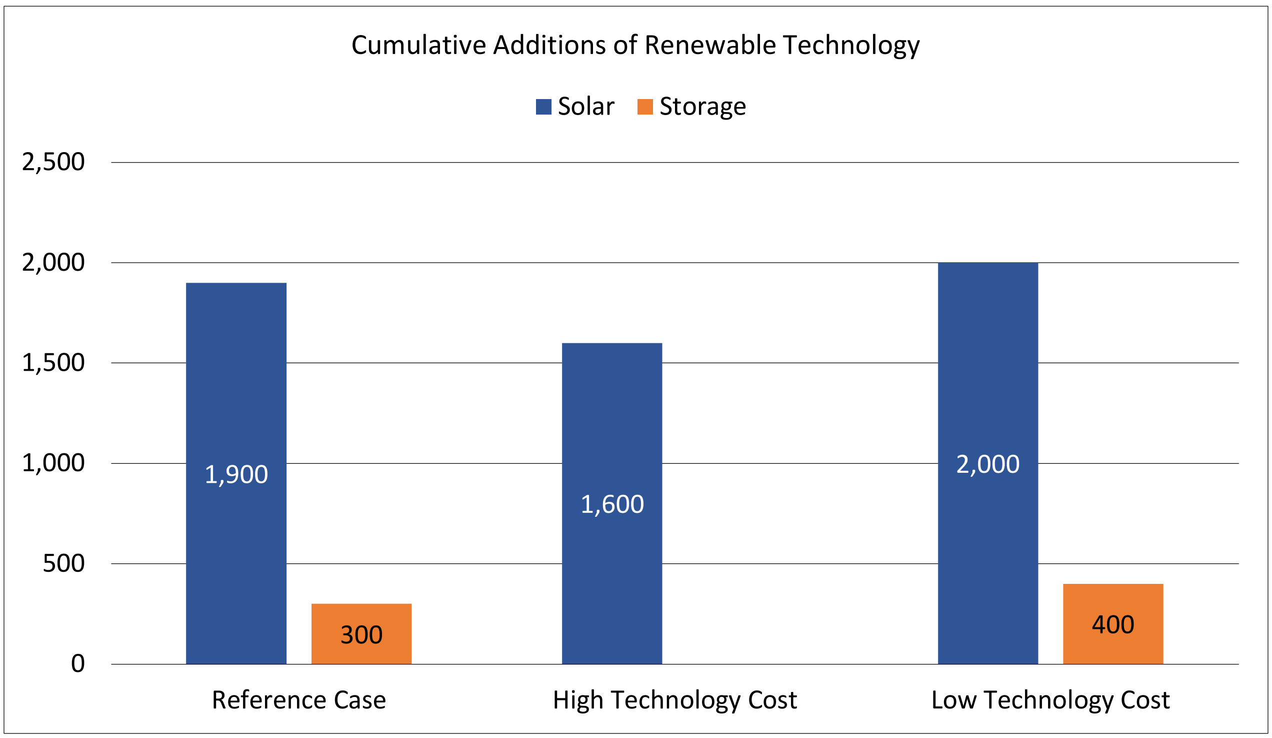


Table 6-7 shows the percentage of load in the Santee Cooper BAA served by renewables over three representative years of the study period for each of the 13 capacity expansion portfolios. All solar, hydro, and wind resources are included in the renewable totals. Renewables account for 8% of load in 2024 in each of the scenarios, while renewable penetration ranges from 23% of load in the Fuel Down scenario to 49% of load in the No New Fossil scenario in 2043.

Table 6-7: Total Renewable Energy by Year

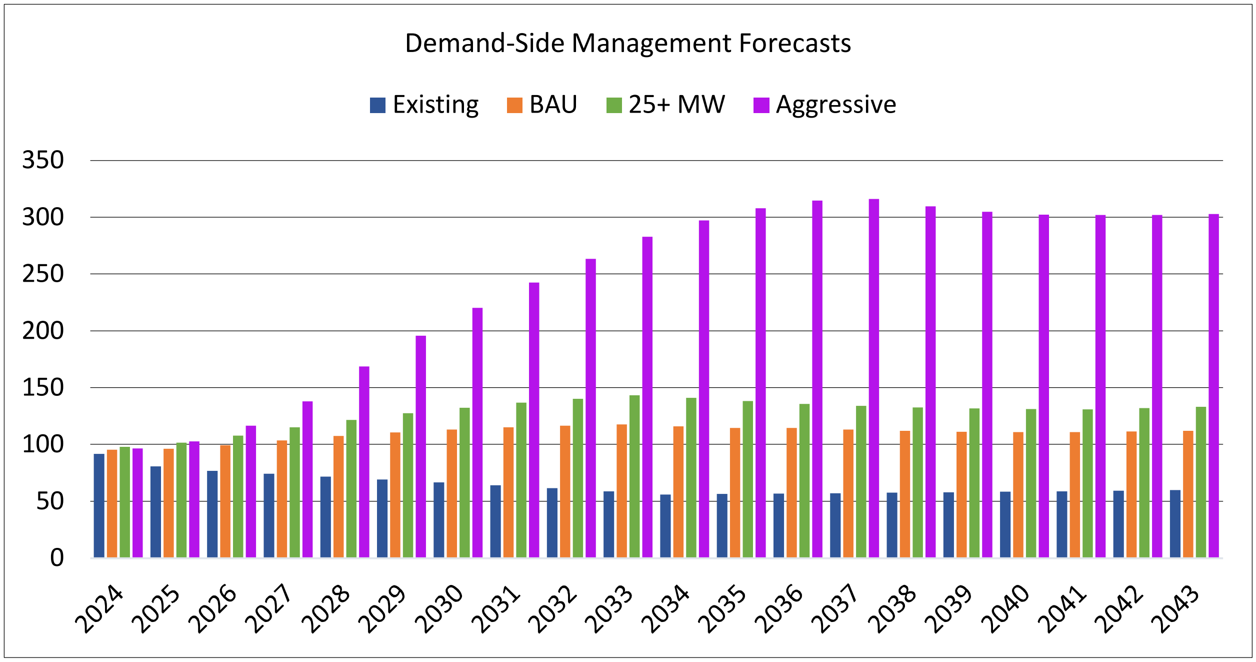
Portfolios	Renewable Energy % of Load in 2024	Renewable Energy % of Load in 2033	Renewable Energy % of Load in 2043
Reference Case	8%	20%	28%
Load Up	8%	17%	31%
Load Down	8%	19%	25%
Low DSM	8%	19%	28%
High DSM	8%	19%	27%
Fuel Up	8%	24%	33%
Fuel Down	8%	12%	23%
High Technology Cost	8%	18%	24%
Low Technology Cost	8%	21%	30%
Santee Cooper Resources	8%	20%	30%
No New Fossil Resources	8%	31%	49%
No Hampton CC	8%	19%	28%
EPA 111b Compliant	8%	20%	32%

Demand-Side Management

DSM allows electric utilities to reduce future energy requirements and peak demand through methods such as time-of-use rates, peak shaving, and smart thermostats. The reduction of future resource needs provides an opportunity for cost savings through avoided generation expansion. The BAU DSM forecast includes existing DSM plus continued incremental DSM deployment. The BAU case assumes DSM investments remain similar to current levels and forecasts an incremental addition of approximately 52 MW of DSM capacity resources by the end of the study period.

Given the uncertainty around DSM program savings and costs, two additional DSM scenarios were evaluated (25+ MW and Aggressive). The 25+ MW scenario is detailed in Section 4.5. The Aggressive DSM scenario is detailed in Section 4.6. The 25+ MW scenario is designed to achieve at least 25 MW of additional DR savings by 2029, above and beyond current 2023 DR levels. The Aggressive DSM assumption is designed to test the capacity expansion selection process. The Aggressive scenario assumes increased investments in DSM compared to current levels, and it forecasts an incremental addition of approximately 233 MW of DSM capacity resources by the end of the study period. The Existing DSM forecast shows the impact of no new incremental additions in DSM in excess of existing programs and resources.

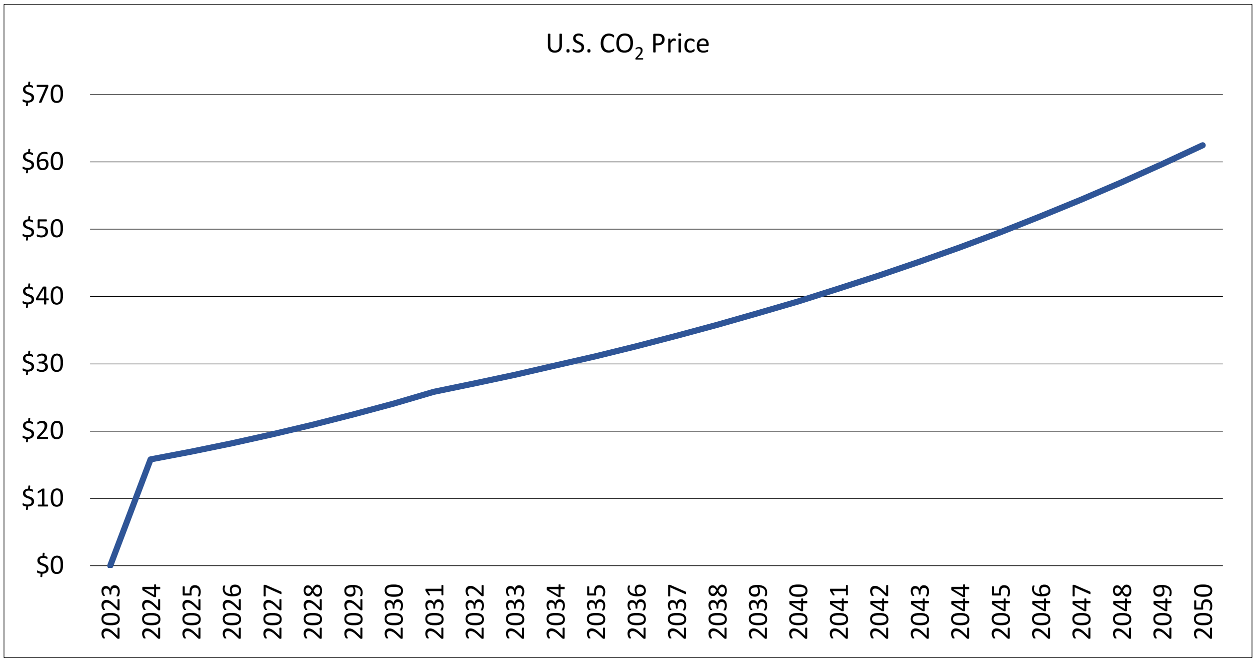
Figure 6-12: Demand-Side Management Forecasts (MW)



Carbon Policy

National regulation of carbon emissions in the United States has been shifting constantly over the past decade due to court decisions and changing presidential administrations. The Obama Administration proposed the Clean Power Plan, which was stayed by the Supreme Court before being repealed by the Trump Administration. The Trump Administration replaced the Clean Power Plan with the Affordable Clean Energy rule, which has also been repealed. Most recently, the Biden Administration proposed new regulations using Section 111 of the Clean Air Act to reduce carbon emissions by the power sector. The proposed Section 111 rules seek to require owners of large traditional fossil burning units to adopt a Best System of Emissions Reduction (BSER), which the EPA defines as carbon capture and sequestration or burning clean hydrogen. Units that cannot or will not adopt the BSER must be retired. Central is not in a position to comment on the impact of this rule on Santee Cooper's or Duke's existing resources. Interested parties should contact those utilities directly for more information regarding their compliance plans. The PPAs for existing resources contained in Central's Diversified Resource Portfolio are for units that either do not produce carbon emissions or fall below the size restrictions of the draft 111 proposal. One of the resource plans created for this IRP requires compliance with the proposed Section 111 proposal for all new resources. The portion of the draft Section 111 proposal relating to new resources is called 111b. South Carolina does not have a state policy limiting or otherwise placing an explicit price on carbon emissions from power generation. However, the potential remains for enactment of such a policy at the national or state level over the study period. To account for this, a carbon tax sensitivity was created. The carbon tax sensitivity assumed the implementation of a carbon tax beginning January 1, 2024. This tax was set at less than $20 per ton and escalates annually over the forecast period, as shown in Figure 6-13.

Figure 6-13: CO_2 Price ($/ton)



Financial Assumptions

The capacity expansion evaluation required baseline assumptions and constraints applicable to Central. The following financial assumptions and parameters were assumed:

- The 20-year study period covers 2024 through 2043
- The study results are presented in calendar years
- The discount rate is assumed to be 5.0%
- The cost escalation rate assumed for future years is 2.5%

6.7 Capacity Expansion Modeling

Once inputs and assumptions are finalized, the next critical step of the IRP process is initiated. The purpose of the capacity expansion modeling process is to identify cost-effective resource portfolios to meet the capacity and energy system requirements. Load growth and increased reserve margins have created a large open position in the Santee Cooper BA. This shortfall of capacity and energy will need to be filled with new generation resource options that could include PPAs.

The capacity expansion modeling process utilizes the EnCompass power planning software model, which is becoming widely used in South Carolina IRPs. The capacity expansion model is an energy portfolio management software solution, which, under a given set of assumptions, considers multiple resource combinations to minimize cost over a time horizon while covering all system energy and capacity needs. The model identifies resource portfolios that have the lowest present value of revenue requirements (PVRR) for consumers. PVRR, a proxy for end-user cost, captures the discounted present value of future costs. The costs for new resources, including capital investment and production expenses such as fuel, are estimated in the PVRR for each portfolio. Ongoing costs for existing plants and any credit from off-system sales are included, as well. PVRR is evaluated over the full 20-year IRP study period.

Initial capacity expansion modeling was performed using base input assumptions and without constraining the types or combinations of resources that could be selected. For example, the model can choose from resources such as CC units, individual simple cycle CT units, renewable resources, and BESS to create a portfolio that minimizes PVRR for a given set of input assumptions. The results demonstrate a preference for quickly adding utility-scale solar, with a 1x1 CC and 100 MW of solar plus storage coming online in 2031. After 2031, the Reference Case model adds solar plus storage to meet all future capacity needs with additional utility-scale solar for energy production.

Table 6-8: Reference Case: Resource Additions (Installed Capacity, MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Planned Resource Additions										
4-Hour Battery Storage						150	150	150	150	150
Signed Solar PPAs	300	300	300	300	300	300	300	300	300	300
Santa Rosa CC						230	230	230	230	230
Sandersville CT						292	292	292	292	292
Catawba Baseload Nuclear						150	150	150	150	150
Subtotal: Planned Additions	300	300	300	300	300	1,122	1,122	1,122	1,122	1,122
Capacity Expansion Additions										
Natural Gas CC								600	600	600
Utility-Scale Solar					200	400	600	800	1,000	1,200
Hybrid Solar								100	200	200
Hybrid 4-Hour Storage								100	200	200
Subtotal: Optimized Additions	0	0	0	0	200	400	600	1,600	2,000	2,200
Grand Total: Resource Additions	**300**	**300**	**300**	**300**	**500**	**1,522**	**1,722**	**2,722**	**3,122**	**3,322**

Scenario and Sensitivity Matrix

Scenarios, which included varied input assumptions, as well as forced resource decisions, created a set of different portfolios or resource mixes specific to the given assumptions. All portfolios include a Santee Cooper 522 MW CC NSR. Unless stated otherwise, the optimizer was allowed to freely select from all the resource options available. Once the portfolios were established, those portfolios were locked and exposed to a set of sensitivities to evaluate how they performed across a range of varying assumptions. The following 13 capacity expansion portfolios were produced as part of the IRP modeling:

1. Reference Case

   a. Base assumptions were used for all inputs, such as load forecast, fuel prices, and renewable technology prices.
   b. The model is allowed to fully optimize new resources.

2. Load Up
   a. Central load demand is higher than forecasted, approximately 1,550 MW higher than the Base forecast by 2043.

3. Load Down
   a. Central load demand is lower than forecasted, approximately 550 MW lower than the Base forecast by 2043.

4. High DSM
   a. DSM is implemented according to the Aggressive Scenario, reaching a total peak reduction of 300 MW by 2043.

5. Low DSM
   a. DSM is incorporated at current levels with no incremental DSM. Total peak reduction decreases to just below 50 MW by 2043.

6. Fuel Up
   a. Henry Hub natural gas prices remain higher than the base price forecast and are slightly higher than $7.75/MMBtu by 2043.

7. Fuel Down
   a. Henry Hub natural gas prices remain lower than the base price forecast and level off near $3.50/MMBtu by 2043.

8. High Technology Cost
   a. High-cost curves were used for wind, solar, and battery storage.

9. Low Technology Cost
   a. Low-cost curves were used for wind, solar, and battery storage.

10. No New Fossil Resources
    a. The optimization can only select wind, solar, and battery storage as new resource options.

11. No Hampton CC
    a. The Santee Cooper 1x1 CC NSR is not hardcoded into the model.
    b. The model is allowed to optimize without it, and Santee Cooper is allocated 522 MW of the optimized CC as its NSR.

12. Santee Cooper 2031 Resources
    a. Santee Cooper's 2031 CC from the Adjusted Preferred Plan from its 2031 IRP is hardcoded into the model.
    b. The model optimizes later resources.

13. EPA 111b Compliant

a. All new resources selected must be compliant with draft EPA 111 regulations regarding carbon emissions.
b. This scenario does not attempt to comply with EPA 111d regulations on existing units.

Sensitivities

Each of the scenarios described above produced a specific portfolio, which is a set of resources selected based on that scenario's criteria to serve system load at the lowest price. Most of these portfolios were then run through sensitivities. A sensitivity takes the portfolio that was created during the scenario phase and varies a set of inputs to see how the portfolio reacts to the change. For example, the High Load sensitivity tests all the evaluated portfolios to see how they would fare if the High load forecast were to come true. The Reference Case, Load Up, Load Down, and Santee Cooper Resources portfolios were all tested against the High Load sensitivity. The list below identifies which portfolios were run through which sensitivities.

- Reference Case
    - This portfolio was stressed against changing load, DSM levels, fuel prices, new resource technology costs, and carbon tax.
- DSM Portfolios
    - The two additional DSM portfolios were run across three levels of DSM (base, low, high).
- Fuel Portfolios
    - The Fuel Up and Fuel Down portfolios were run across three levels of fuel prices (base, low, high).
- Technology Cost Portfolios
    - High and Low Technology Cost portfolios were run against base, high, and low-cost curves for wind, solar, and storage.
- Santee Cooper Resources Portfolio
    - This portfolio was stressed against changing load, DSM levels, fuel prices, new resource technology costs, and carbon tax.
- The No Hampton CC and EPA 111b Compliant Portfolios were only optimized and run through the Reference Case.

Figure 6-14 shows the resulting matrix of scenarios and sensitivities performed for Central's 2023 IRP.

Figure 6-14: Scenario and Sensitivity Matrix

Portfolios ↓	Sensitivities → Reference Case	High Load	Low Load	Low DSM	High DSM	High Fuel	Low Fuel	High Tech. Cost	Low Tech. Cost	Carbon Tax
Reference Case	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Load Up	✓	✓	✓	-	-	-	-	-	-	-
Load Down	✓	✓	✓	-	-	-	-	-	-	-
Low DSM	✓	-	-	✓	✓	-	-	-	-	-
High DSM	✓	-	-	✓	✓	-	-	-	-	-
Fuel Up	✓	-	-	-	-	✓	✓	-	-	-
Fuel Down	✓	-	-	-	-	✓	✓	-	-	-
High Technology Cost	✓	-	-	-	-	-	-	✓	✓	-
Low Technology Cost	✓	-	-	-	-	-	-	✓	✓	-
Santee Cooper Resources	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
No New Fossil	✓	-	-	-	-	-	-	-	-	-
No Hampton CC	✓	-	-	-	-	-	-	-	-	-
EPA 111b Compliant	✓	-	-	-	-	-	-	-	-	-

Capacity Expansion Results

Capacity expansion modeling was conducted on each of the 13 capacity expansion scenarios. A summary of the cumulative installed capacity additions for each portfolio is shown in Figure 6-15.

In the Reference Case, the model selects a new 600 MW CC resource in 2031, along with a significant amount of utility-scale solar beginning in 2028. Hybrid solar plus storage, sized at a 1:1 ratio of installed capacity, comes online in 2030.

The Load Up scenario provides insight into the resources that would be most economic if the load forecast increases higher than expected over time. The Load Down scenario shows how resource selections will change if loads are lower than currently projected. In the Load Up scenario, additional firm capacity is required, most notably an additional 600 MW CC and a 300 MW CT are added by 2035. The Load Down portfolio is similar to the Reference Case, with the same amount of CC added in 2031, but less hybrid solar and storage.

The High and Low DSM scenarios provide a similar resource mix as the Reference Case, with the only difference being the varying levels of hybrid solar and storage.

The Fuel Up and Fuel Down scenarios have a greater impact on the resulting portfolios compared to the Load Up and Load Down scenarios. In the Fuel Up scenarios, a CC is not selected in 2031, and peaking CTs combined with solar, storage, and wind serve as the replacement capacity. In the Fuel Down scenario, low natural gas prices make the low heat rate CC resources more attractive, and 1,200 MW of CC is added in combination with utility-scale solar. Fuel Down does not add any BESS.

The High Technology Cost and Low Technology Cost scenarios are useful for evaluating uncertainty around the cost of wind, solar, and storage projects in the future. If the costs for these technologies continue to increase because of supply chain issues, labor issues, and high demand, less hybrid solar and storage is selected, as shown in the High Technology Cost scenario. A 300 MW CT is selected to replace the firm capacity contribution of the storage. In the Low Technology scenario, the CT is displaced by lower cost storage in the form of solar plus storage hybrid projects. Solar costs have much less impact on the selections than BESS costs.

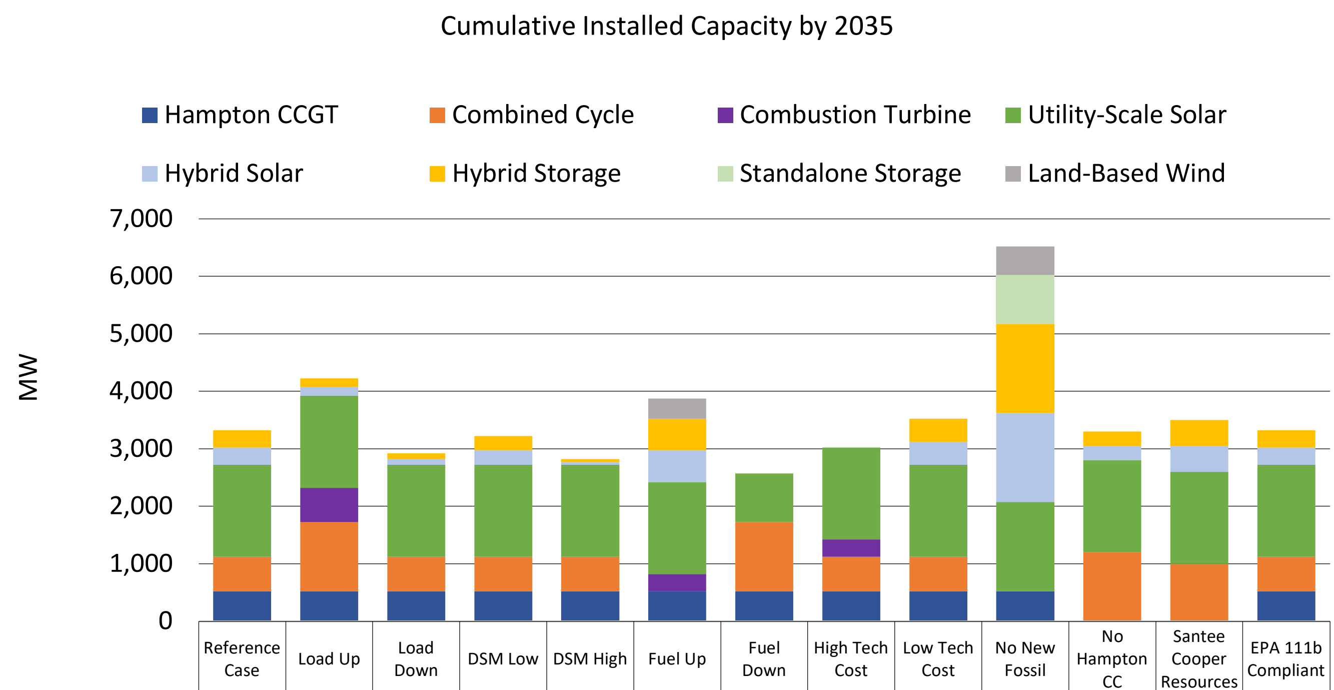
In the No New Fossil Resources scenario, the ability for the model to build new natural gas resources is removed, thus the model builds a significant amount of wind, solar, and storage. The total new installed capacity volume is double the volume in the Reference Case through 2035, with battery storage making up the majority of the winter firm capacity.

The Santee Cooper Resources portfolio forces 1,000 MW of CC in 2031, consistent with the Adjusted Preferred Plan in Santee Cooper's 2023 IRP, and the model then optimizes around the remaining open capacity position. Consistent with how Central has addressed Santee Cooper's NSR obligations in all scenarios, Santee Cooper is assumed to have 522 MW of NSR capacity out of the 1,000 MW CC. The remainder of the CC capacity, and all other resources, are jointly held. The IRP does not attempt to put new resources through CA cost allocation. A combination of utility-scale solar and hybrid solar plus storage are selected to fill the remaining capacity needs through 2035.

The No Hampton CC portfolio does not force a Santee Cooper NSR in 2031. Rather, it optimizes the system to determine what should be brought online in 2031 based only on economics. EnCompass chooses a 1,200 MW 2x1 CC in 2031. To ensure consistency with all other evaluated portfolios, 522 MW of the 2031 CC is a Santee Cooper NSR. After the 2031 CC, the No Hampton CC scenario brings utility-scale solar and hybrid solar plus storage online similar to the Reference Case.

The EPA 111b Compliant portfolio complies with the EPA's draft 111b portfolio. Central does not assume that carbon capture and sequestration or clean hydrogen are available in South Carolina during the IRP period. EPA's draft 111b is only concerned with new units; 111d is the portion of the regulation that focuses on existing units. This IRP does not attempt to model a system that is compliant with both 111b and 111d. The costs of doing so would likely be significant, and there are serious concerns about the stability and reliability of a system that attempts to meet both regulations. The EPA 111b Compliant portfolio still builds a new 600 MW CC in 2031 in addition to Santee Cooper's 522 MW Hampton CC, but those two units exist primarily for capacity, as they are restricted to running at low capacity factors. Most of the energy on the system is provided by existing units or by solar.

Figure 6-15: Cumulative Installed Capacity by 2035 for All Portfolios



	Reference Case	Load Up	Load Down	DSM Low	DSM High	Fuel Up	Fuel Down	High Tech Cost	Low Tech Cost	No New Fossil	No Hampton CC	Santee Cooper Resources	EPA 111b Compliant
Land-Based Wind						350				500			
Standalone Storage										850			
Hybrid Storage	300	150	100	250	50	550			400	1,550	250	450	300
Hybrid Solar	300	150	100	250	50	550			400	1,550	250	450	300
Utility-Scale Solar	1,600	1,600	1,600	1,600	1,600	1,600	850	1,600	1,600	1,550	1,600	1,600	1,600
Combustion Turbine		600				300		300					
Combined Cycle	600	1,200	600	600	600		1,200	600	600		1,200	1,000	600
Hampton CCGT	522	522	522	522	522	522	522	522	522	522			522

6.8 Production Cost Results

The 13 portfolios that resulted from the capacity expansion modeling process are then modeled and evaluated in hourly detail using EnCompass. Production cost modeling software is used to conduct a more detailed cost and operational analysis of the portfolios.

In capacity expansion modeling, assumptions and resource options are the inputs, and portfolios are the outputs. In production cost modeling, a single set of assumptions and a single portfolio are the inputs. The output is total cost, which is summarized in this report as PVRR. The production cost model is run for each portfolio under each set of assumptions identified in the sensitivity analysis. Production cost modeling allows the evaluation of a single portfolio under a wide range of assumptions for comparison to other portfolios under the same sets of assumptions. Table 6-9 contains 20-year portfolio cost metrics for each of the 13 capacity expansion portfolios with the Reference Case assumptions along with the initial 12-year build plan for each portfolio.

Table 6-9: PVRR Using Reference Case Inputs for Each Portfolio

Scenario	PVRR (2024 $MM)	Cumulative Additions Through 2035					
		Hampton CC (MW)	Natural Gas CC (MW)	Natural Gas CT (MW)	Solar (MW)	Storage (MW)	Wind (MW)
Reference Case	$16,360	522	600	-	1,900	300	-
Load Up	$17,478	522	1,200	600	1,750	150	-
Load Down	$16,214	522	600	-	1,700	100	-
Low DSM	$16,362	522	600	-	1,850	250	-
High DSM	$16,267	522	600	-	1,650	50	-
Fuel Up	$16,753	522	-	300	2,150	550	350
Fuel Down	$16,789	522	1,200	-	850	-	-
High Technology Cost	$16,580	522	600	300	1,600	-	-
Low Technology Cost	$16,441	522	600	-	2,000	400	-
No New Fossil Resources	$19,052	522	-	-	3,100	2,400	500
No Hampton CC	$16,313	-	1,200	-	1,850	250	-
Santee Cooper Resources	$16,394	-	1,000	-	2,050	450	-
EPA 111b Compliant	$16,904	522	600	-	1,900	300	-

Table 6-10: Full Scenario and Sensitivity Matrix with Results

Portfolios ↓	Sensitivities									
	Reference Case	Load Up	Load Down	Low DSM	High DSM	High Fuel	Low Fuel	High Tech. Cost	Low Tech. Cost	Carbon Tax
Reference Case	$16,360	$21,403	$16,054	$16,421	$16,569	$18,535	$14,166	$16,930	$16,024	$21,045
Load Up	$17,478	$21,308	$17,172							
Load Down	$16,214	$21,449	$15,836							
Low DSM	$16,362			$16,409	$16,548					
High DSM	$16,267			$16,296	$16,440					
Fuel Up	$16,753					$18,727	$14,747			
Fuel Down	$16,789					$19,097	$14,271			
High Technology Cost	$16,580							$16,929	$16,354	
Low Technology Cost	$16,441							$17,037	$16,034	
No New Fossil Resources	$19,052									
No Hampton CC	$16,313									
Santee Cooper Resources	$16,394	$20,970	$16,053	$16,426	$16,562	$18,524	$14,246	$17,030	$15,995	$21,940
EPA 111b Compliant	$16,904									

7 Conclusion

7 Conclusion

Central is using this IRP as a foundation to work with its member-cooperatives to address Central's open position and determine the best path forward. Filling this open position is an opportunity for Central to support its member-cooperatives in meeting the needs of member-owners for reliable, low-cost electricity and to create a more diversified portfolio. A diversified portfolio allows greater flexibility and opportunities for Central's member-cooperatives. The various resource plans identified in this report provide reliable capacity to meet the needs of member-owners, as identified in the current load forecast.

Central's Diversified Resource Portfolio, developed as a response to the announced retirement of the coal-fired Winyah Generation Station, will provide Central and the Santee Cooper system with reliable, environmentally responsible capacity. By diversifying among a variety of different resource types, primarily nuclear, CTs, CCs, BESS, solar, and DSM, Central mitigated the risk that an issue related to any one resource could inflict severe harm on Central's member-cooperatives. For example, while the Sandersville CTs and the Santa Rosa CC are natural gas-fired units, they are located on different pipelines, mitigating the harm to Central if one pipeline has supply issues. The BESS and utility-scale solar will be located in multiple locations throughout the Santee Cooper BAA. The Catawba nuclear unit is located in the Duke BAA, and it is part of a reliability exchange with other Duke managed nuclear units. All resources involve risk; the key is diversifying the portfolio to minimize the impact that any one variable will have on Central's member-cooperatives. The Diversified Resource Portfolio, along with Santee Cooper's system and Duke's system, will protect Central's member-cooperatives from outsized risk, and the foundation provided by these combined systems is the starting point from which long-term resource planning begins.

There is an open position in the Santee Cooper BAA as a result of load growth and increasing winter reserve margin requirements. Central has been collaborating with Santee Cooper to identify resources to fill the short-term open position. This work has resulted in Central opting into Santee Cooper's purchase of the 98 MW Cherokee County CC. Central anticipates collaborating with Santee Cooper through the joint generation expansion process described in the CA to develop a new long-term resource plan. This IRP will provide Central with an understanding of the options available to fill the open position and the risks involved in various resource plans. This knowledge will guide Central's joint planning efforts.

Central is a winter peaking system, which typically occurs early in the morning when solar resources are not available. All top 13 portfolios, except the No New Fossil Resources portfolio, involve investment in new natural gas capacity to serve peak demand. This capacity can come in the form of full ownership, joint ownership with or through Santee Cooper, or PPAs. Natural gas CC generation is economical and 50% less carbon intensive than coal generation. Battery storage can be used to shift the timing of solar power into hours when demand is highest. Battery storage options are becoming increasingly economic. After 2031, the top 13 portfolios use BESS as the sole source of firm capacity.

Central is committed to serving its member-cooperatives by procuring low-cost power for its member-owners. Central and its member-cooperatives must understand and evaluate the risks involved in every portfolio. Several portfolios are dependent on natural gas-fired generation. The future of natural gas prices and delivery is uncertain. Resource plans with high capital investment create the possibility for stranded costs if the environment shifts against that type of generation. The EPA's proposed Section 111 proposal could dramatically shift the operating costs of all fossil fuel powered units. Changes in technology can make an existing or planned generating unit less attractive. The development of an organized market in the Southeast could fundamentally alter the economic structure of the electric utility business in South Carolina. Advances in energy storage can reduce the integration costs of intermittent RE. Reductions in the variable integration costs of solar will provide Central and its member-cooperatives the ability to commission solar beyond the levels evaluated in this report.

As a part of the production cost modeling process, varying levels of DSM and renewable implementation were assessed. The results consistently showed that resource plans high in DSM, specifically DR and EE, and renewables outperformed plans with lower implementation levels across all evaluated risk scenarios. The analysis in this report indicates that replacing energy purchases from fossil fuel plants with the development of solar energy resources reduces power costs. Although solar provides minimal winter capacity benefit, Central and its member-cooperatives will continue working to expand access for member-owners to low-cost RE.

Central's strength has always been in the diversity of its member-cooperatives and their shared commitment to reliable, low-cost power. Each of the 20 member-cooperatives brings experience, understanding, and resources that produce a system that serves member-owners better than each member-cooperative working independently. Central will use this same philosophy as it builds a system to serve its member-cooperatives in the future.

This IRP is the foundation upon which Central and its member-cooperatives can build a more diversified portfolio to serve the energy needs of the people of South Carolina for years to come. The electric industry is changing, and the portfolio of resources that Central manages will need to evolve, as well. A holistic approach that combines RE, DSM, energy storage, efficient central station generation, and PPAs will likely produce a superior risk-adjusted outcome compared to a portfolio that ignores one of these components.

8 Appendices

8 Appendices

8.1 Existing Resources

Summer Resources																				
Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DLC AC Thermostat - Summer Only	1.3	1.2	1.0	0.9	0.8	0.6	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DLC AC Thermostat - All Seasons	3.9	3.5	3.1	2.7	2.3	1.9	1.5	1.2	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DLC AC Switch	8.0	8.0	7.0	6.0	5.0	4.0	3.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DLC Water Heaters AMI	11.5	10.5	9.4	8.4	7.3	6.1	4.9	3.8	2.5	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DLC Water Heaters RF	4.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electric Vehicle Charging	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Beat the Peak	4.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Generator DR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
On-bill Weatherization	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial EE	1.9	1.7	1.5	1.2	1.0	0.9	0.8	0.7	0.7	0.6	0.5	0.4	0.3	0.2	0.2	0.1	0.0	0.0	0.0	0.0
Residential electrification	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pilots	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Electrification	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable	14.7	14.6	14.6	14.5	14.4	14.3	14.3	14.2	14.1	14.1	14.0	13.9	13.8	13.8	13.7	13.6	13.6	13.5	13.4	13.4
CVR	59.7	60.2	60.7	61.3	61.8	62.4	63.0	63.5	64.1	64.7	65.3	65.8	66.4	67.0	67.6	68.2	68.9	69.5	70.1	70.7
Total	109.4	101.0	97.7	95.3	92.9	90.6	88.3	86.0	83.6	81.3	79.9	80.3	80.7	81.1	81.5	82.0	82.4	83.0	83.5	84.1

Winter Resources																				
Resource	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
DLC AC Thermostat - All Seasons	5.4	4.8	4.3	3.8	3.2	2.7	2.1	1.6	1.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DLC Water Heaters AMI	23.0	21.0	18.9	16.7	14.5	12.2	9.9	7.5	5.1	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DLC Water Heaters RF	6.0	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electric Vehicle Charging	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Beat the Peak	4.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Generator DR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
On-bill Weatherization	1.0	1.0	0.9	0.8	0.7	0.7	0.6	0.5	0.5	0.4	0.3	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Commercial EE	1.3	1.1	0.9	0.7	0.5	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Residential electrification	-0.3	-0.3	-0.3	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pilots	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Electrification	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7
CVR	48.2	48.6	49.1	49.5	49.9	50.4	50.8	51.3	51.8	52.2	52.7	53.2	53.7	54.1	54.6	55.1	55.6	56.1	56.6	57.1
Total	91.6	80.6	76.6	74.1	71.6	69.1	66.6	64.0	61.4	58.7	56.0	56.3	56.7	57.1	57.5	57.9	58.3	58.8	59.3	59.8

8.2 Community Causes

Blue Ridge Electric Cooperative	
Volunteer Services/Community Development Initiatives	Blue Ridge Employees can take part in a mentorship program with the Pickens County YMCA
	Many Blue Ridge Employees are involved and active leaders in local chambers of commerce and local organizations
	Encourage employees to take part in local leadership programs
Sponsorships of Charities and Local Organizations	Sponsorships for numerous local events and charity events (chamber events, charity balls, The Dream Center in Pickens County, local school initiatives, etc.)
	Helped the local career center with equipment needed for electrical/linemen training
	We have donated money to local agencies that help members on hard times pay their electric bills
	Sponsored a local school's security upgrade and helped them purchase walkie talkies for teachers
	Donated a bucket truck to the local technical college to assist with their linemen training program
	Sponsored a field trip to Roper Mountain Science Center in Greenville for two elementary schools that we serve
Fundraisers for Specific Community Causes	Blue Ridge holds Upcountry Fiber Foundation Concert Event that raises money for charities
	We hold an annual fundraiser with employees for all our local United Ways in each county we serve