

CHAPTER 8, NEED FOR POWER

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8.0 NEED FOR POWER

NRC has indicated that the environmental report should include consideration of the benefits of the proposed action [10 CFR 51.45(c)] and that it must assess the need for power to accurately characterize the benefits associated with the proposed action (NRC 2003).

Chapter 8 addresses the need for the power that the proposed action, construction and operation of VCSNS Units 2 and 3, would produce. Unit 2 would come on line in 2016 and Unit 3 would come on line 2019 (1,107 megawatts-electric net summer rating each). As indicated in Chapter 1, the proposed action is a joint project between SCE&G and Santee Cooper. SCE&G would receive 1,218 megawatts of the net electricity generated and Santee Cooper 996 megawatts. SCE&G is acting as Santee Cooper's agent for the purposes of securing licenses to operate.

NRC expects states and regions to prepare need-for-power evaluations that can be the bases for NRC evaluation if they are (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty (NRC 1999). In this chapter, SCE&G summarizes the state of South Carolina process for evaluating the need for power within public utility service areas and the SERC Reliability Corporation (SERC)^a regional process for evaluating need for power, and demonstrates how these processes satisfy NRC criteria.

The proposed project would be a traditionally regulated plant. SCE&G and Santee Cooper would have state-designated service territories; customers would have no choice of alternative electric service providers; and the state would have approval authority for the need for the electric power to be generated. However, SCE&G and Santee Cooper are subject to different South Carolina statutory and regulatory requirements. The following sections discuss utility-specific and regional need-for-power evaluations as follows:

- State Need-for-Power Planning – SCE&G ([Section 8.1](#))
- State Need-for-Power Planning – Santee Cooper ([Section 8.2](#))
- Regional Need-for-Power Planning ([Section 8.3](#))
- Satisfaction of NRC Criteria ([Section 8.4](#))
- Conclusion ([Section 8.5](#))

a. The former Southeastern Electric Reliability Council (SERC) is now incorporated as the SERC Reliability Corporation.

8.1 STATE NEED-FOR-POWER PLANNING – SCE&G

The South Carolina General Assembly has created the South Carolina Public Service Commission (PSC) and elects its members. The General Assembly has vested the PSC with the power and jurisdiction to supervise and regulate rates and service of South Carolina public utilities, including the establishment of service territories. In addition, the General Assembly has established the Office of Regulatory Staff to serve as a public interest advocate before the PSC and the South Carolina State Regulation of Public Utilities Review Committee to oversee PSC and Office of Regulatory Staff operations (SCCL 2007a, SCCL 2007b).

SCE&G is an investor-owned, integrated electric utility that generates, transmits, and distributes electric power. SCE&G is subject to PSC regulation as a traditional utility, meaning that SCE&G is responsible for providing electric power within a designated geographic area, called a service territory, and that customers within that area have no choice of alternative electric providers. SCE&G provides electric service to more than 623,000 customers in 24 of the state's 46 counties (SCE&G 2007a). **Figure 8.1-1** shows South Carolina regulated electric service territories. The SCE&G territory is shown in red and is further identified by the numeral 5.

South Carolina imposes on SCE&G a two-step process for evaluating the need for power. The first step involves preparing integrated resource plans and the second involves obtaining certificates of environmental compatibility and public convenience and necessity (CPCNs). The following subsections address these steps.

8.1.1 INTEGRATED RESOURCE PLANS

The PSC is a quasi-judicial body, with the authority to issue orders. In 1998, by order, the PSC established the current requirements for investor-owned electric utility integrated resource plans, requiring the following contents (PSC 1998; See also S.C. Code Ann. Section 58-37-40):

- Demand and energy forecast for at least a 15-year period
- Supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including demand-side and supply-side options
- Brief description and summary of cost-benefit analysis, if available, of each option which was considered, including those not selected
- Supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy services, and a description of the external environmental and economic consequences of the plan to the extent practicable

The integrated resource plan is a public document, providing disclosure to customers and the general public, the Office of Regulatory Staff, PSC, and Public Utilities Review Committee, and the General Assembly. The state does not perform a separate review of an integrated resource plan but, instead, uses it as a basis against which the PSC evaluates subsequent facility-specific evaluation of the need for power ([Section 8.1.2](#)).

SCE&G submits integrated resource plans to the PSC annually, with a copy to the Office of Regulatory Staff. The company's most recent integrated resource plan is dated 2007 (SCE&G 2007b) and contains information summarized in the following paragraphs.

8.1.1.1 Load Forecast

SCE&G is responsible to the state for generating or otherwise securing electric energy and distributing it to customers who use it. The amount of electric energy that SCE&G customers use is called the SCE&G load. There are two common measures of load. The first is the average amount of electricity used over time, generally referred to as "energy sales." The second is the maximum amount of electricity used at any one time, generally referred to as "peak demand." To be successful, SCE&G must be able to accurately forecast future loads so as to be able to cost-effectively and reliably plan for securing requisite electric energy. This subsection briefly summarizes the process that SCE&G uses to forecast its load.

SCE&G bases its load forecasts on the following:

- Historical Data – SCE&G maintains a database of historical energy sales and peak demand values and historical data for factors that influence sales and demand, such as:
 - Number and type of customers
 - Total population numbers and characteristics such as per capita income
 - Industrial production indices
 - 15-year weather measurements and calculated heating and cooling degree-days
 - Electricity prices

SCE&G updates this data annually to incorporate the past year's information, and reviews previous forecasting accuracy. On average, SCE&G forecasting error has been about 1.3% (SCANA 2007).

- Projections – Where available, SCE&G uses commercially generated projections of factors that influence sales and demand, such as economic and demographic variables from Global Insight, Inc. SCE&G makes its

own projections of other factors, such as weather, for which it has historical data.

- Modeling – SCE&G uses econometric modeling to establish the relationships between variables to be explained or forecasted (e.g., energy sales and peak demand) and other factors (e.g., population and economic growth and industrial development). The modeling enables SCE&G to use those relationships to predict energy sales and peak demand using projections of the factors that historically influence sales and demand. The modeling also enables SCE&G to perform analyses of the sensitivity of results to changes in model inputs such as fuel prices. SCE&G uses commercially developed software (from SAS Institute, Inc.) that incorporates regression analysis and various statistics to evaluate the success of the regression analyses.
- Professional Judgment – SCE&G uses in-house and outside expertise to adjust projections and modeling to take into account new or discontinued marketing programs, new industrial loads, contract expiration, economic factors (e.g., recessions), and input from SCE&G's largest industrial customers about potential changes in electricity usage.

SCE&G's forecast process is more detailed in the short range than over the long range. In the short range, two years of monthly forecasts for electric customers, average usage, and total usage were developed according to company class and rate structures, with industrial customers further classified into Standard Industrial Classification codes. Residential customers were classified by housing type (single family, multifamily, and mobile homes) and by whether or not they use electric space heating. For each forecasting group, the number of customers and either total usage or average usage were estimated for each month of the forecast period.

The long-range electric sales forecast was developed for seven classes of service: residential, commercial, industrial, street lighting, other public authorities, municipals, and cooperatives. These classes were disaggregated into appropriate subgroups where data was available and there were notable differences in the data patterns. The residential, commercial, and industrial classes are considered the major classes of service and account for over 90% of total territorial sales. A customer forecast was developed for each major class of service. For the residential class, forecasts were also produced for those customers with electric space heating and for those without electric space heating. They were further disaggregated into housing types of single family, multifamily and mobile homes. These subgroups were chosen based on available data and differences in the average usage levels and/or data patterns.

The industrial class was disaggregated into two-digit Standard Industrial Classification code classification for the large general service customers, while smaller industrial customers were grouped into an "other" category. These subgroups were chosen to account for the differences in the industrial mix in the service territory. With the exception of the residential group, the forecast for sales

was estimated based on total usage in that class of service. The number of residential customers and average use per customer were estimated separately and total sales were calculated as a product of the two.

Historical data has demonstrated that SCE&G experiences a peak demand in the summer and a peak demand in the winter, with the first usually being the greater. SCE&G uses a load factor methodology to forecast summer peak demands by class of customer. A load factor is a value that can be used in a formula with historical energy sales values to approximate historical summer peak demands (Load Factor = Energy Sales ÷ [Peak Demand × 8,760 hours per year]). Applying the load factor against forecast energy sales results in forecast summer peak demand. For winter peak demand forecasting, SCE&G has correlated historical winter peak loads to historical energy sales and weather, with some lesser variables. Given an energy sales forecast and a weather projection, SCE&G can use the historical correlation to forecast winter peak demand.

The results of the SCE&G load forecasting for the next 15 years show energy sales predicted to grow at an approximate average of 2% per year. [Figure 8.1-2](#) illustrates this growth. [Table 8.1-1](#) shows the values used to create the figure, indicating an expected growth in energy sales from 23,741 gigawatt-hours in 2007 to 31,187 gigawatt-hours in 2021. For perspective, [Figure 8.1-2](#) and [Table 8.1-1](#) also show SCE&G energy sales for the past ten years, which represent a growth rate of a little more than 2% per year.

The SCE&G peak demand forecast shows summer and winter peak demands predicted to increase at 2% per year. [Figure 8.1-3](#) illustrates the peak summer load growth and [Table 8.1-1](#) shows the values used to create this figure. These indicate an expected growth in peak demand from 5,173 MW in 2007 to 6,355 MW in 2021, an average growth rate of approximately 84 MW per year after having subtracted the effect of demand side management. Variations in the peak demand growth curve are the result of variations in capacity caused by expirations of sales contracts (SCE&G 2007b).

8.1.1.2 Demand-Side Management

The integrated resource plan presents the three components that comprise the SCE&G demand-side management program—customer information programs, energy conservation programs, and load management programs. Customer information programs involve presenting to customers educational materials designed to create an awareness of issues related to energy and energy conservation. SCE&G uses bill inserts and other mailings to customers, brochures and other printed materials available in business offices, a web site, community appearances, and interviews and press releases to print and broadcast media in order to contact customers and others.

SCE&G energy conservation programs include visiting customer homes and discussing benefits of energy conservation in purchasing energy-related equipment and materials, including rebates for insulation and storm windows.

Customers who upgrade to meet higher energy efficiency levels receive reduced electric rates.

SCE&G's load management programs include the following:

- Standby Generator Program – Customers having large standby generators agree with SCE&G to run their generators during times of reserve margin stress due to system problems or high customer demand. Standby generator operation reduces system stress in exchange for credits that reduce subsequent operating costs.
- Interruptible Load Program – Participating customers receive electric rate discounts for agreeing to shed load when SCE&G is short of capacity.
- Real Time Pricing Rate – During peak usage periods when system capacity is low, SCE&G sends a high-price signal to participating customers to encourage conservation and load shifting. In exchange, during low usage periods, the customer's rates are lower.
- Time of Use Rates – Rates during daily peaks in demand are higher, to encourage conservation and load shifting during these periods.

SCE&G's load management program reliably reduces the system's peak demand by approximately 250 MW of capacity. SCE&G uses this figure to reduce its system peak demand forecasts to produce a firm peak demand for planning purposes. Subsection 9.2.1.3 provides additional detail about SCE&G demand side management. (SCE&G 2007b)

8.1.1.3 Existing Capacity and Energy Sales

At the end of 2006, SCE&G had a generating capacity of 5,808 MW consisting of (SCE&G 2007b):

- Coal-fired plants (2,566 MW, or 44% of capacity)
- Two-thirds ownership of one nuclear plant (644 MW, or 11% of capacity)
- Oil- and gas-fired plants (1,717 MW or 30% of capacity)
- Hydroelectric plants (823 MW, or 14% of capacity)
- Long-term power purchases (58 MW, or 1% of capacity)

Coal produced approximately 62% of the system's energy, nuclear 20%, gas 13%, and hydro 5%. The loss of 11 MW of Southeastern Electric Power Administration capacity related to a wholesale contract is projected for 2010. **Figure 8.1-3** shows the growth in capacity that SCE&G projects through 2020, with **Table 8.1-1** showing the values used to create the figure. This data indicates an expected growth in capacity from 5,808 MW in 2007 to 7,197 MW in 2021. Variations in the

capacity growth curve are the result of variations in expectations for firm annual purchases, retirements, and assumed additions to capacity. The projection for 2021 assumes the addition of 200 MW of peaking or intermediate load capacity and 1,200 MW of baseload generation. The baseload additions represent the addition of the SCE&G portions of Unit 2 in 2016 and Unit 3 in 2019. During intervening years, SCE&G will purchase power as needed to maintain the reserve margin.(SCE&G 2007b)

8.1.1.4 Reserve Margin

Reserve margin is the supply capacity that a company maintains in excess of anticipated demand. This excess helps the company maintain reliable load regardless of unanticipated interruptions in supply (generation or transmission capacity) or increases in demand. Reserve margins are typically established to maintain the risk of unscheduled interruptions to between 1 day in 10 years and 1 day in 1 year.

SCE&G is a member of the Virginia-Carolinas Reliability Group, a subregion of the SERC Reliability Corporation (see [Section 8.3](#) for discussion of the corporation). Operating agreements between the Virginia-Carolinas Reliability Group companies establish the subregion's daily reserve margin. SCE&G's annual prorata share of this capacity is approximately 200 MW. Failure to maintain this reserve margin could result in loss of membership in the Virginia — Carolinas Reliability Group. This would mean that SCE&G would have to meet SERC requirements of having operating reserves to cover the largest unit on the system (*i.e.*, 644 MW).

In addition to this requirement, SCE&G has planned for reserve needed to balance supply and demand risk. SCE&G accounts for uncertainty in developing its planning reserve margin, which captures the impact of forecast error and extreme weather as well as risks related to supply (e.g., plants off line because of hurricanes) (SCE&G 2007c). SCE&G has a minimum reserve margin of 12%, which is sufficient to handle the demand-side risk related to forecast error and extreme weather as well as much of the supply-side risk usually encountered.

[Figure 8.1-3](#) shows the SCE&G capacity and demand forecast as separate lines on the same graph. Generally, the space between these lines represents reserve margin.

8.1.1.5 Need for Power

Technologies for generating electricity are often categorized as baseload, which operates the most; intermediate, and peaking, which operates the least amount of time. Baseload capacity is generally coal-fired or nuclear, is the most expensive to build, takes the most time to start up and shut down, and is the least expensive to operate for extended periods of time. Peaking units are generally gas-fired turbines and are the least expensive to build, can be quickly started or stopped, and are the most expensive to operate for extended periods. Characteristics of intermediate capacity fall between the other two ([Figure 8.1-3](#)).

Baseload capacity typically operates in excess of 70% of the time. Currently, approximately 56% of SCE&G's generation capacity is baseload. As SCE&G's load continues to grow, so does its need for baseload capacity. The integrated resource plan identifies a need for an addition of 1,200 MW of SCE&G baseload capacity by 2020 and indicates SCE&G and Santee Cooper are planning to build nuclear capacity to meet baseload capacity needs.

8.1.1.6 Role of Purchased Power

SCE&G anticipates making several firm annual purchases between 2009 and 2015. SCE&G constantly monitors markets for electric energy and, at times, is an active purchaser and seller. Currently, SCE&G is a net seller, with firm contract sales of 250 MW through 2012.

8.1.1.7 Transmission Planning

Subsection 2.2.2 describes the VCSNS transmission lines. The SCE&G transmission system is interconnected with those of Progress Energy, Duke Power, Santee Cooper, Georgia Power Company, and SEPA. SCE&G participates in regional computer modeling to produce an integrated electrical network. SCE&G is a member of SERC Reliability Corporation ([Section 8.3](#)). SCE&G tests and designs its transmission system to be compliant with reliability standards of the North American Electric Reliability Corporation and maintains a 10-year schedule of modifications and additions to its network. SERC maintains information about interties between SERC subregions (SERC 2006a).

8.1.2 CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY

As required by the PSC, an integrated resource plan presents the results of analyzing the need for power on a system-wide basis. Before construction, a facility-specific statement explaining the need for power is developed (SCCL 2007c). At this stage, the statement of need in the application is expanded upon by direct testimony and exhibits. As an example, a recent SCE&G application to the PSC for a CPCN for Jasper County Generating Facility (SCE&G 2001) contained a summary statement of the need and detailed testimony. The summary statement identified the system capacity, forecast need, forecast date of additional need, and SCE&G's plan for meeting the need. The detailed testimony included:

- Qualifications of the testifier
- Discussion of how SCE&G's peak demand has grown
- Discussion of SCE&G's projected capacity needs
- Description of how firm peak demand was forecasted
- Identification of major assumptions used in the forecast

- Description of SCE&G's existing supply system
- Identification of demand-side resource availability
- Discussion of SCE&G's conservation and efficiency-based demand side management programs
- Identification and explanation of SCE&G's prudent reserve margin range
- Discussion of the process that led from the need for capacity to the specific project proposed
- Discussion of the effects of changing assumptions in the project analysis
- Discussion of how proposal provides lowest cost to customers
- Discussion of sensitivity of analysis to higher gas prices

The PSC held a hearing on the application, took testimony, and made findings of fact and conclusions (PSC 2002). One finding was that the testimony was consistent with the SCE&G's integrated resource plans, with the related conclusion that SCE&G had established the need for the facility.

SCE&G plans to submit to the PSC its application for a CPCN for Units 2 and 3 during the first quarter of 2008 and expects to have a final PSC order by December 2008. If SCE&G were to fail to adequately demonstrate a need for the units, the PSC would refuse to issue the CPCN and SCE&G would not begin construction.

8.1.3 RELEVANCE TO NRC REVIEW

NRC's review of need for power is to support its accurate characterization of the benefits of the proposed action. This would enable NRC to weigh the likely benefits against the environmental impacts of constructing and operating Units 2 and 3. One such benefit is the electricity that the units would produce. The NRC is not supplanting the role of the state, which is responsible for assessing the need for power facilities and their economic feasibility and for regulating rates and services. The state process for evaluating the need for Units 2 and 3 has begun with SCE&G's inclusion of the units in its integrated resource plan and will culminate in a PSC order expected by December 2008. Review of this evaluative process gives NRC a reasonable basis for relying on realization of the need for power as a benefit while acknowledging the state's primacy in evaluating whether the power is needed. NRC's review can determine that the state evaluation meets NRC criteria for being systematic, comprehensive, subject to confirmation, and responsive to forecasting uncertainty. **Section 8.4** analyses how the state evaluation satisfies each criterion.

**Table 8.1-1
SCE&G Energy Sales, Capacity, and Peak Demand**

Year	Energy Sales (gigawatt- hours)	Capacity (MW)	Peak Demand (MW)
Historical			
1997	17,969		
1998	19,709		
1999	20,018		
2000	21,253		
2001	20,948		
2002	22,275		
2003	22,044		
2004	23,232		
2005	23,300		
2006	23,091		
Forecast^(a)			
2007	23,741	5,808	5,173
2008	24,277	5,808	5,170
2009	24,790	5,898	5,262
2010	24,994	5,997	5,310
2011	25,482	6,067	5,418
2012	25,956	6,187	5,520
2013	26,457	6,022	5,375
2014	27,006	6,157	5,493
2015	27,588	6,287	5,615
2016	28,157	6,597	5,732
2017	28,734	6,597	5,855
2018	29,323	6,697	5,976
2019	29,927	7,197	6,099
2020	30,599	7,197	6,228
2021	31,187	7,197	6,355

a) Source: SCE&G (2007b). Capacity includes addition of Unit 2 in 2016 and Unit 3 in 2019. Other capacity changes are the net result of expiration of an existing sales contract and additional purchases.

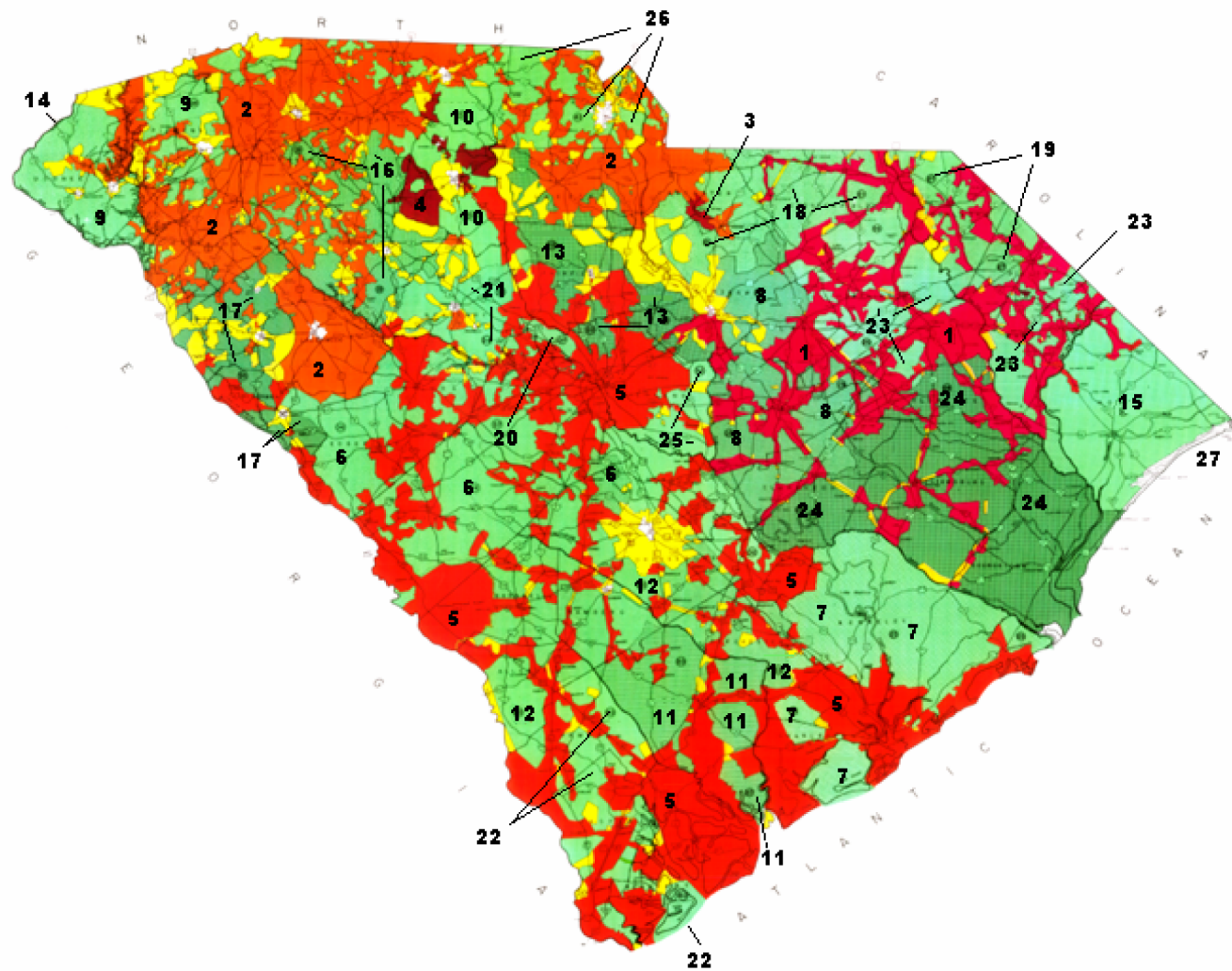
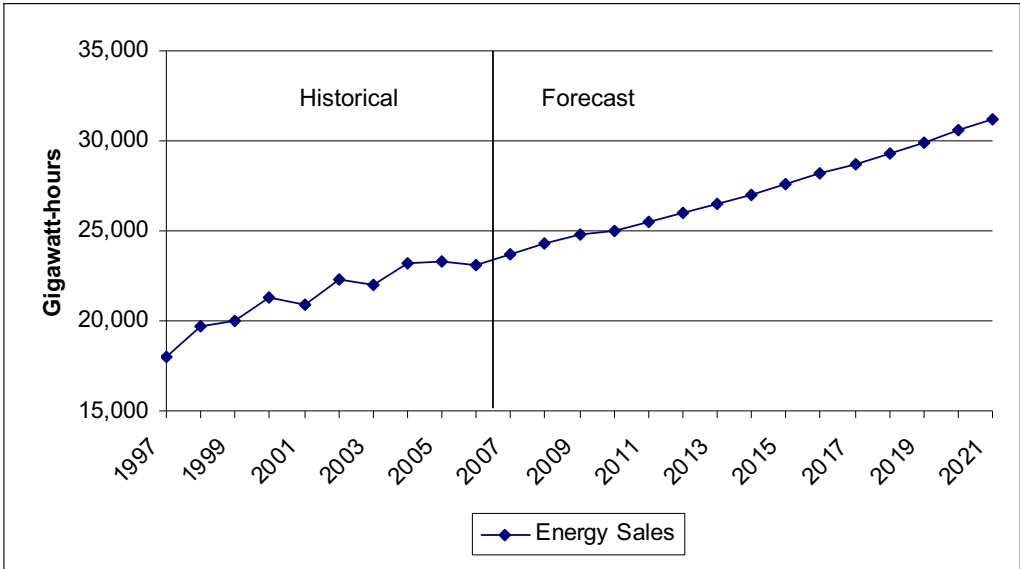


Figure 8.1-1. South Carolina Regulated Electric Service Territories (Sheet 1 of 2)

Legend

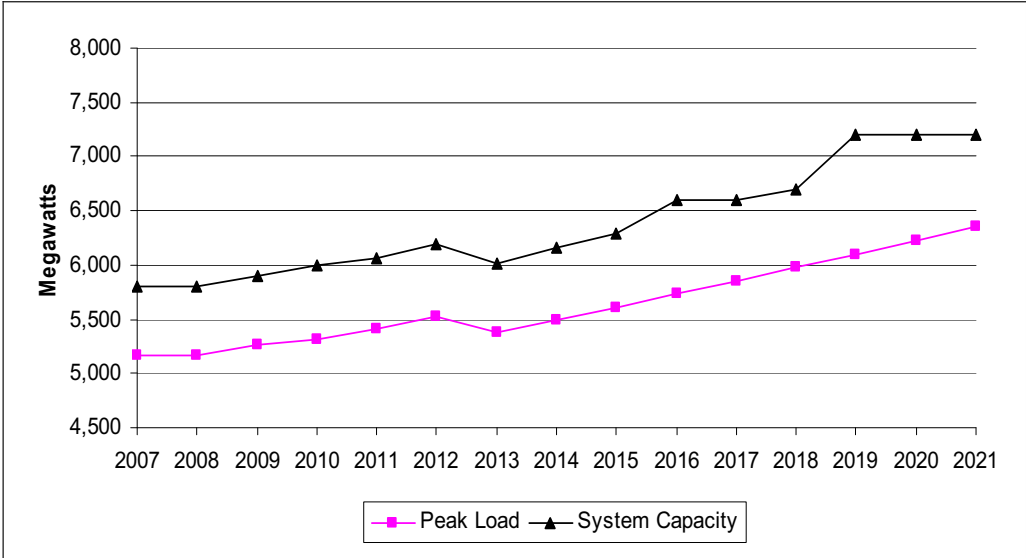
- | | |
|--|---|
| 1 Progress Energy | 16 Laurens Electric Cooperative |
| 2 Duke Power Company | 17 Little River Electric Cooperative |
| 3 Heath Springs Light & Power | 18 Lynches Electric Cooperative |
| 4 Lockhart Power Company | 19 Marlboro Electric Cooperative |
| 5 South Carolina Electric & Gas Company | 20 Mid-Carolina Electric Cooperative |
| 6 Aiken Electric Cooperative | 21 Newberry Electric Cooperative |
| 7 Berkeley Electric Cooperative | 22 Palmetto Electric Cooperative |
| 8 Black River Electric Cooperative | 23 Pee Dee Electric Cooperative |
| 9 Blue Ridge Electric Cooperative | 24 Santee Electric Cooperative |
| 10 Broad River Electric Cooperative | 25 Tri-County Electric Cooperative |
| 11 Coastal Electric Cooperative | 26 York Electric Cooperative |
| 12 Edisto Electric Cooperative | Unassigned Area |
| 13 Fairfield Electric Cooperative | 27 South Carolina Public Service Authority |
| 14 Haywood Electric Cooperative | Municipally Owned Electric System |
| 15 Horry Electric Cooperative | |

**Figure 8.1-1. South Carolina Regulated Electric Service Territories
(Sheet 2 of 2)**



Source: Data from Table 8.1-1.

Figure 8.1-2. SCE&G Energy Sales



Source: Data from Table 8.1-1. Capacity includes addition of VCSNS Unit 2 in 2016 and Unit 3 in 2019.

Figure 8.1-3. SCE&G Capacity and Demand Forecasts

8.2 STATE NEED-FOR-POWER PLANNING – SANTEE COOPER

Santee Cooper is a state-owned public utility created by the South Carolina General Assembly. The South Carolina Governor appoints the Santee Cooper Board of Directors with the advice and consent of the Senate. The General Assembly has created an advisory board to oversee Santee Cooper operations. The advisory board is composed of the Governor, Attorney General, State Treasurer, Comptroller General, and Secretary of State (SCCL 2007d).

Santee Cooper provides electric service directly to more than 155,000 residential, commercial, and industrial customers. In addition, Santee Cooper is the primary source of power distributed by 20 of the state's electric cooperatives to over 665,000 customers located in all of the state's 46 counties (Santee Cooper 2005). **Figure 8.1-1** shows South Carolina regulated electric service territories. The Santee Cooper direct service territory is shown in cross-hatched white and is further identified by the numeral 27 (identified in the legend as South Carolina Public Service Authority). The electric cooperative service territories are shown in green and are further identified as numerals 6 through 13 and 15 through 26.

South Carolina statutes require Santee Cooper to submit an integrated resource plan triennially, with annual updates during intervening years, to the State Energy Office (SCCL 2007e). The statutorily required contents are the same as those imposed by the PSC on SCE&G, that is:

- Demand and energy forecast for at least a 15-year period
- Supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including demand-side and supply-side options
- Brief description and summary of cost-benefit analysis, if available, of each option which was considered, including those not selected
- Supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy services, and a description of the external environmental and economic consequences of the plan to the extent practicable

The integrated resource plan is a public document, providing disclosure to customers and the general public, the advisory committee, and the General Assembly. Santee Cooper's most recent integrated resource plan is dated 2004 (Santee Cooper 2005) and the most recent update was in 2006 (Santee Cooper 2006). These contain information summarized in the following paragraphs.

8.2.1 LOAD FORECAST

The Santee Cooper integrated resource plan contains forecasts of energy sales, summer peak demand, and winter peak demand. Santee Cooper works with GDS Associates, Inc., to perform annual updates of its load forecast database to

include the most recent historical data, including electric system data (e.g., number of customers, energy sales, revenues by customer class), economic data, and weather data. Santee Cooper bases historical values on data available from the Census Bureau, Department of Labor, and Bureau of Economic Analysis, and on Santee Cooper's own records. Most recent historical records have shown that Santee Cooper's winter peak demand is greater than its summer peak demand.

Santee Cooper then forecasts growth trends for key economic and demographic factors, including population, employment, personal income, retail sales, and inflation. Between 1997 and 2005, after weather adjustment, the Santee Cooper average annual forecasting error was less than 1%. Projected values are based on information obtained from Woods & Poole Economics, Economy.com, and the University of South Carolina (Division of Research, Moore School of Business).

The Santee Cooper service area is composed of three independent electric systems that have differing geographic, demographic, economic, and weather characteristics. Santee Cooper prepares separate economic outlooks and forecasts for each area and combines them for total territorial energy sales and peak demand forecasts.

Santee Cooper develops forecasts of monthly energy sales and peak demand requirements for the 20-year period. For energy sales forecasting, Santee Cooper uses econometric modeling for weather-sensitive components (residential and commercial classifications) and historical trends and customer input for non-weather-sensitive components (industrial classifications). For peak demand forecasting, Santee Cooper uses econometric modeling based on temperatures on historical peak days.

Santee Cooper accounts for uncertainties in the forecasting process by using model simulations for energy sales and peak demand. Santee Cooper uses temperature distribution to develop a probability distribution of temperature at the time of the territorial peak. The results provide peak demand estimates for given temperatures and the probabilities that load requirements will rise or fall to specified levels around the base case forecast (Santee Cooper 2005).

Figure 8.2-1 illustrates the results of the Santee Cooper energy sales forecast and **Table 8.2-1** identifies the values used to create the figure. As shown, Santee Cooper expects its energy sales to grow approximately 2% per year for the next 15 years, rising from 28,383 gigawatt-hours in 2007 to 37,291 gigawatt-hours in 2021. In large part, this growth is attributable to Santee Cooper directly serving one of the state's fastest growing areas, Myrtle Beach. Santee Cooper's growth rate in its direct service area has averaged 3.5% over the past 5 years (Santee Cooper 2007). For overall perspective, **Figure 8.2-1** and **Table 8.2-1** also include Santee Cooper historical energy sales for the past 10 years.

8.2.2 DEMAND-SIDE MANAGEMENT

Santee Cooper provides energy conservation options for residential and commercial customers, giving reduced rates for homes and buildings built or

upgraded to high energy efficiency standards. This includes standards for heating and air conditioning equipment, water heaters, weather stripping and storm windows and doors, attic insulation, and major electric appliances. Customers can also obtain low-interest loans for purchasing these items, and commercial customers may be eligible for up-front rebates (Santee Cooper 2005).

Curtailable, interruptible, and economy power pricing rates are available for commercial and industrial customers. Time-of-use pricing encourages electricity usage during off-peak times and discourages usage during peak loads (Santee Cooper 2005).

Subsection 9.2.1.3 provides additional detail about Santee Cooper demand side management.

8.2.3 EXISTING CAPACITY AND ENERGY SALES

At the end of 2006, Santee Cooper had a summer peak generating capacity of 4,509 MW. The summer generation capacity mix included (Santee Cooper 2006):

- Coal-fired plants (2,791 megawatts, or 62% of capacity)
- Oil- and gas-fired plants (1,270 MW, or 28% of capacity)
- Hydroelectric plants (130 MW, or 3% of capacity)
- Partial ownership in Unit 1 (318 MW, or 7% of capacity)

In 2006, coal provided approximately 77% of the energy sales, nuclear 10%, oil, natural gas, and landfill gas 8%, and hydro 1% (Santee Cooper 2007). [Figure 8.2-2](#) shows the growth in capacity that Santee Cooper projects through 2021, with [Table 8.2-1](#) showing the values used to create the figure. This data indicates an expected growth in capacity from 5,765 MW in 2007 to 7,962 MW in 2021.

8.2.4 RESERVE MARGIN

Santee Cooper operates using planning reserve targets of 10% and 13% for winter and summer months, respectively. This includes Santee Cooper obligations as part of Virginia-Carolinas Reliability Group. As noted in [Subsection 8.1.1.4](#), failure to maintain reserve margins would increase operating reserves required by SERC. The space between the graphs of capacity and demand forecast on [Figure 8.2-2](#) generally represents reserve margin.

8.2.5 NEED FOR POWER

At the end of 2006, Santee Cooper had under construction two 600 MW coal-fired units (Cross 3 & 4) scheduled for commercial operation January 2007 and 2009, respectively. In addition, Santee Cooper generation planning has identified the following as necessary to meet projected demand:

- 168 MW simple cycle combustion turbine for commercial operation in 2018
- Various firm purchased power amounts
- 600 MW-class supercritical pulverized coal unit for commercial operation in 2012 (Pee Dee)
- 45% ownership share of two 1,107 MW nuclear units located at the VCSNS site

Currently, approximately 65% of Santee Cooper's generation fleet is baseload.

8.2.6 PURCHASED POWER

During 2006, Santee Cooper met 3% (net) of its energy requirements using power purchases. Capacity purchases supplied 8% of demand requirements. Santee Cooper is projecting interim shortfalls in capacity and reserve requirements that it will meet using firm purchases as necessary.

The following is a list of the challenges that Santee Cooper investigated during the generation planning process with regards to the purchase of long-term power from the wholesale market.

- There is a lack of excess baseload capacity within the region. For example, Santee Cooper issued an RFP during the generation planning process in 2005 and there were no bids. Duke, Progress, and SCE&G are also in need of capacity in this timeframe. Many utilities in the region are also tight on capacity and are attempting to build/permit new units.
- Purchased power leads to higher costs than self-build options. During the generation planning process, there were two utilities that were willing to discuss build-to-buy, although this is not attractive because these utilities have to issue taxable debt and have to realize a profit on sales, thereby increasing the cost to Santee Cooper.
- There are currently limited transmission paths into Santee Cooper that can, or are reliably able to, bring in power in the 600 MW range.
- A long-term power purchase deal introduces counterparty risk. There is the risk that the company remains viable and able to deliver the required energy and capacity, and there is the risk that the company can continue to purchase fuel required and provide any liquidated damages that may be written into any contracts.

8.2.7 TRANSMISSION PLANNING

Subsection 2.2.2 describes the VCSNS transmission lines. The Santee Cooper transmission system is interconnected with those of Progress Energy, Duke, SCE&G, Southern Company, and the Southeastern Power Administration. Santee

Cooper participates in regional computer modeling to produce an integrated electrical network. Like SCE&G, Santee Cooper is a member of the SERC Reliability Corporation, tests and designs its transmission system to be compliant with reliability standards of the North American Electric Reliability Corporation, and maintains a 10-year schedule of modifications and additions to its network.

8.2.8 RELEVANCE TO NRC REVIEW

See [Subsection 8.1.3](#) for general information about the purpose of the NRC review for need-for-power. Santee Cooper is different from SCE&G in that Santee Cooper is a state-owned public utility. Thus, the Santee Cooper need-for-power analysis in its integrated resource plan is the state's evaluation. [Section 8.4](#) analyzes how the State evaluation satisfies each NRC review criterion.

**Table 8.2-1
Santee Cooper Energy Sales, Capacity, and Peak Demand**

Year	Energy Sales (gigawatt- hours)	Capacity (megawatts)	Peak Demand (megawatts)
Historical^(a)			
1997	18,437		
1998	19,466		
1999	20,286		
2000	22,139		
2001	22,400		
2002	24,121		
2003	24,060		
2004	24,451		
2005	25,064		
2006 ^(b)	25,422		
Forecast^(c)			
2007	28,383	5,765	5,165
2008	29,011	5,906	5,295
2009	29,619	6,156	5,435
2010	30,232	6,243	5,567
2011	30,846	6,390	5,700
2012	31,465	6,770	5,833
2013	32,089	6,770	5,968
2014	32,720	6,850	6,104
2015	33,356	7,005	6,242
2016	33,998	7,260	6,381
2017	34,646	7,320	6,520
2018	35,299	7,476	6,661
2019	35,957	7,897	6,803
2020	36,621	7,897	6,947
2021	37,291	7,962	7,092

a) Source: Santee Cooper (2006). Note: Data does not include distribution losses.

b) Source: Santee Cooper (2007). Note: Data does not include distribution losses.

c) Forecast energy sales include distribution losses. Capacity and peak demand data are summer values. Peak demand data are firm demand only. Capacity includes additional coal units in 2007, 2009, and 2012, several landfill gas units between 2007 and 2012, VCSNS Unit 2 in 2016, natural gas unit in 2018, VCSNS Unit 3 in 2019, and various purchases.

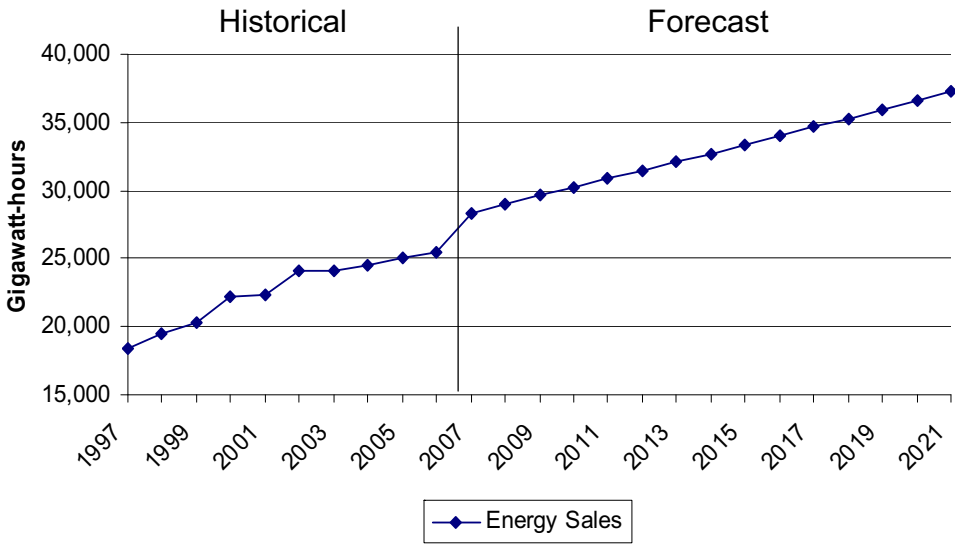
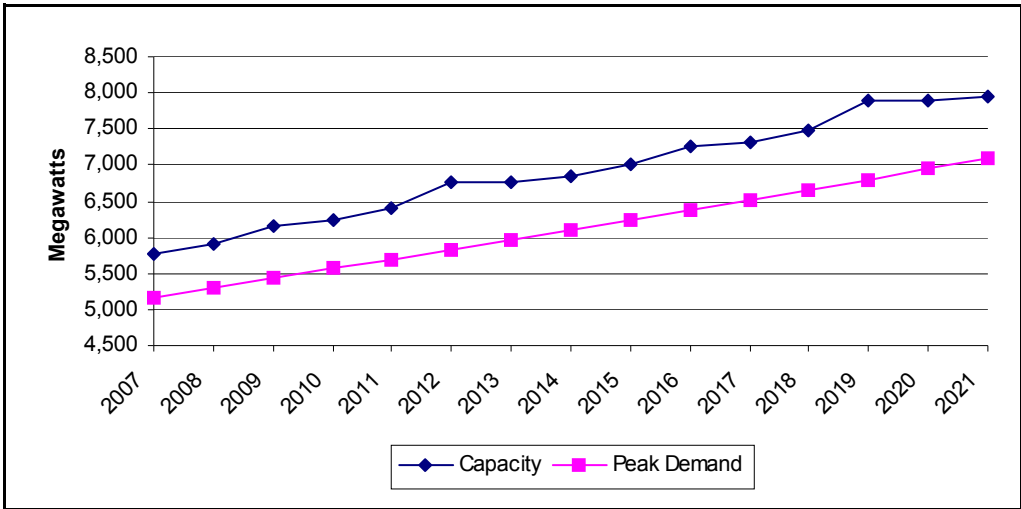


Figure 8.2-1. Santee Cooper Energy Sales



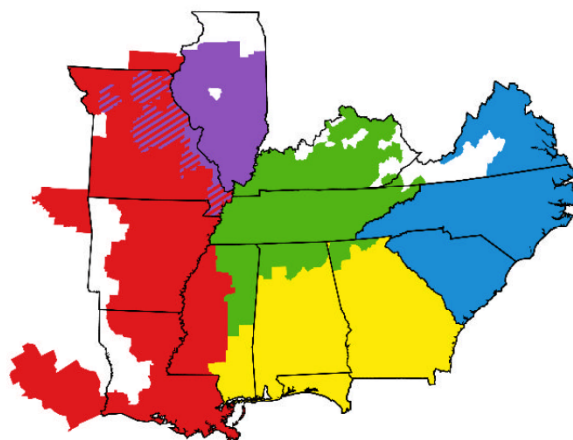
Source: Data from Table 8.2-1. See table for explanatory notes.
Figure 8.2-2. Santee Cooper Capacity and Demand Forecasts

8.3 REGIONAL NEED-FOR-POWER PLANNING

The North American Electric Reliability Corporation (NERC) was established by the electric power industry as a self-regulatory organization to ensure that the bulk electric system in North America is reliable, adequate, and secure. NERC is composed of eight regional reliability corporations, whose memberships include electricity producers, such as investor-owned utilities and merchant generators, and transmission owners. Annually, member electricity producers and transmission owners submit to their regional corporations information that the Energy Information Administration (EIA), U. S. Department of Energy, requests on Form EIA-411. Submitted information is as follows (EIA 2004):

- Historical and projected peak demand and energy
- Existing capacity
- Historical and projected demand and capacity
- Historical and projected capacity purchases, sales, and transfers
- Bulk electric transmission system description
- Projected changes to bulk electric transmission system

Member methodologies must be documented and are subject to audit by the regional councils. The regional councils compile the information into a regional composite that is submitted to NERC, which prepares national composite information and submits the regional and national composites to EIA. EIA organizes the information, adds its own analyses, and prepares annual reports for public dissemination (e.g., EIA 2006).



SERC Geographic Coverage

The SERC Reliability Corporation (SERC) is one of the NERC regional corporations. SERC has more than 50 members, which are investor-owned utilities; municipal, cooperative, state, and federal systems; merchant generators; and power marketers in 16 states (SERC 2006a). SERC is divided into 5 subregions, one of which is the Virginia-Carolinas Region (VACAR). VCSNS is located within the

SERC and VACAR geographic coverage, and VCSNS owners, SCE&G and Santee Cooper, are corporation members. SERC provides member data in its

annual EIA-411 reports to NERC (e.g., SERC 2006b). In addition, the corporation has provided to NERC the results of a regional self-assessment that NERC has compiled with other regional self-assessments into a national self-assessment (NERC 2006). SCE&G used both of these sources in providing this regional planning information.

Figure 8.3-1 shows southeast regional composite peak demand and capacity estimates for the report's current year (2005) and projections for the next 10 years. **Table 8.3-1** shows the data used to create **Figure 8.3-1**. The average annual growth rate is projected to be approximately 2.1% over the next 10 years (SERC 2006a). This is slightly higher than the historical growth rate of 1.9% over the last 5 years. These data take into account interruptible demand, load management, and other significant demand-side management programs.

Figure 8.3-1 shows two capacity values for each year. The first (Total capacity) includes capacity for which interconnection service has been requested but there is no commitment to provide the capacity. This is frequently the case for merchant generation facilities. While this could be a significant amount of capacity (e.g., estimated to be approximately 39,000 MW by the year 2015), because there is no commitment to serve the regional load, it is not included in reserve margin assessment.

The second capacity value shown in **Figure 8.3-1** (Committed capacity) excludes uncommitted capacity and is the one used in comparison to demand projections to calculate reserve capacity. For the year 2015, the capacity projection of 259,482 MW assumes the addition of almost 40,000 MW of committed capacity between 2005 and 2015. This capacity would exceed the demand projection of 222,083 MW by 37,399 MW, which is slightly more than a 14% capacity reserve.

In addition to the instantaneous peak demand shown in **Figure 8.3-1**, an area's need for electricity can be expressed as an annual net energy for load, which is a measure of electricity usage over time. **Figure 8.3-2** shows annual net energy loads for SERC and **Table 8.3-1** shows data used to create the figure. As illustrated, energy used in the region during 2005 was 962,054 gigawatt-hours, a value that members project will grow to 1,134,210 gigawatt-hours by the year 2015.

SERC data are relevant to the NRC review by providing an independent need-for-power evaluation against which NRC can compare the VCSNS Units 2 and 3 evaluation. SERC data are a composite of evaluations from more than 50 electric generators, giving regional values that would average out outliers in the form of lower- or higher-than normal evaluations. In this manner, the SERC average annual growth projection of approximately 2.1% for the next 10 years compares favorably with the SCE&G and Santee Cooper projections of approximately 2% for the next 15 years.

**Table 8.3-1
SERC Capacity, Demand, Energy Forecast**

Year	Total Capacity (MW)	Committed Capacity (MW)	Peak Demand (MW)	Energy (gigawatt- hours)
2005	247,803	219,749	186,049	962,054
2006	249,550	221,246	183,783	973,215
2007	252,907	223,103	187,982	991,874
2008	260,424	226,119	193,706	1,013,167
2009	265,960	230,978	197,248	1,029,412
2010	273,400	236,518	201,233	1,045,180
2011	279,768	242,176	204,992	1,059,158
2012	283,739	246,262	209,782	1,076,198
2013	287,839	250,402	214,100	1,094,208
2014	291,949	254,587	218,537	1,113,886
2015	298,483	259,482	222,083	1,134,210

Source: SERC (2006b).

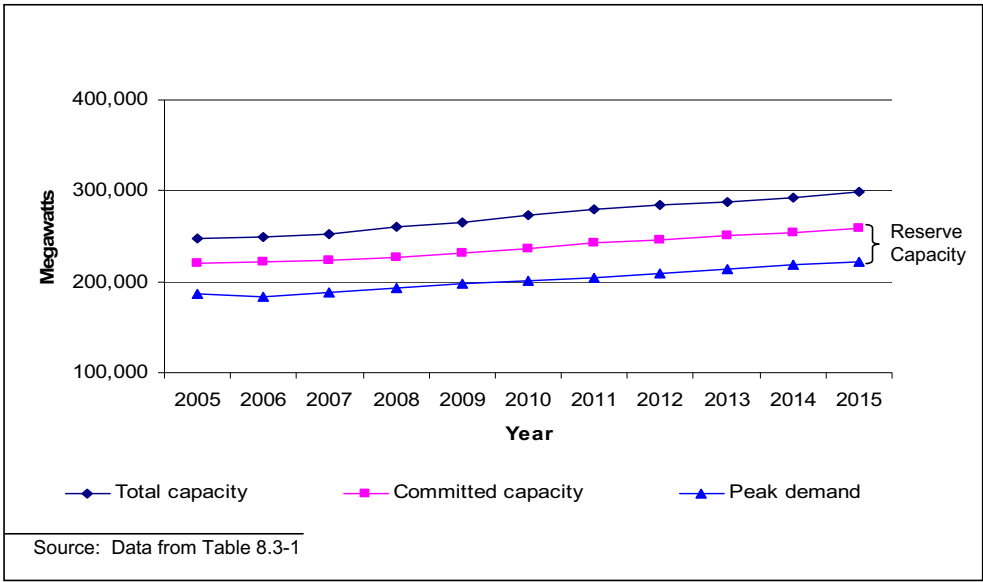


Figure 8.3-1. SERC Capacity and Demand Forecast

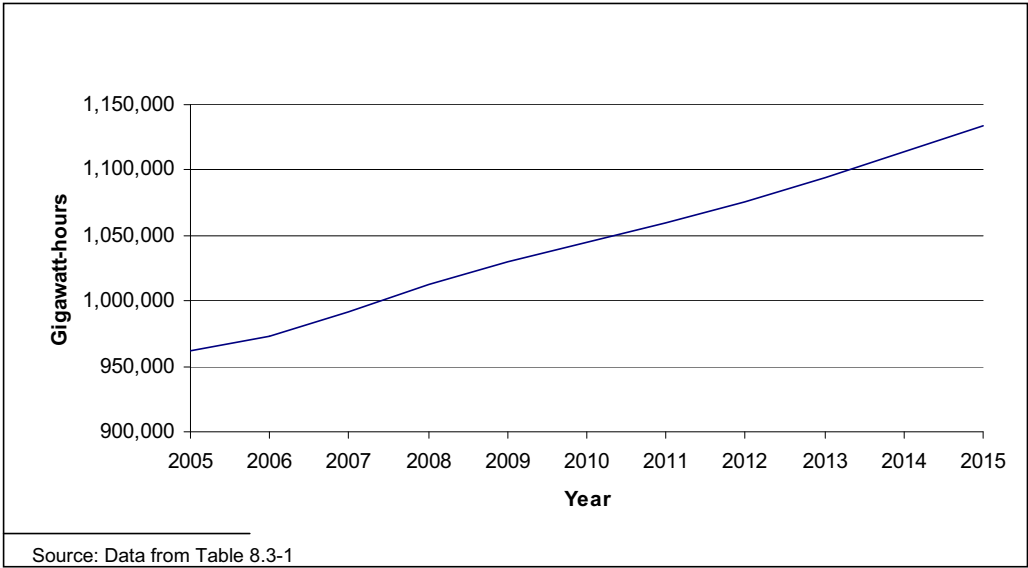


Figure 8.3-2. SERC Energy Forecast

8.4 SATISFACTION OF NRC CRITERIA

As introduced at the beginning of Chapter 8, NRC expects states and regions to prepare need-for-power evaluations that can be the bases for NRC evaluation if they are 1) systematic, 2) comprehensive, 3) subject to confirmation, and 4) responsive to forecasting uncertainty. The following subsections discuss how state and regional evaluations satisfy these NRC criteria for VCSNS Units 2 and 3.

8.4.1 SYSTEMATIC

The state of South Carolina and the SERC Reliability Corporation (SERC) approaches to determining need for power include processes that are systematic. The state of South Carolina has established its processes by statute, creating the Public Service Commission (PSC) to oversee need-for-power planning by public utilities such as SCE&G, the Office of Regulatory Staff to serve as public interest advocate before the PSC, and the Public Utilities Review Committee to oversee PSC and Office of Regulatory Staff operations. Also by statute, South Carolina has established Santee Cooper as a state-owned public utility and an advisory board to oversee Santee Cooper operations. The Santee Cooper Board of Directors is appointed by the Governor of South Carolina. The state has also designated the State Energy Office to review Santee Cooper need-for-power planning. Need-for-power planning must be reflected in annually updated integrated resource plans, and for SCE&G, is subjected to a second, more detailed analysis at the CPCN stage.

SERC follows a process set up by the North American Electric Reliability Corporation to comply with the Energy Information Administration data-gathering requirements. The corporation gathers the data on an annual basis, compiles it, and submits it to the North American Electric Reliability Corporation as a region-specific composite. The North American Electric Reliability Corporation submits the data to the Energy Information Administration as a national composite together with region-specific information.

SCE&G has concluded that the statutory, regulatory, and administrative requirements that make up the South Carolina and SERC processes comprise methodical state and regional processes for systematically reviewing the need for power that SCE&G and Santee Cooper are responsible for satisfying.

8.4.2 COMPREHENSIVE

South Carolina imposes similar requirements on SCE&G and Santee Cooper for annual comprehensive integrated resource planning that includes:

- Demand and energy forecast for at least a 15-year period
- Supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including demand-side and supply-side options

- Brief description and summary of cost-benefit analysis, if available, of each option which was considered, including those not selected
- Supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy services, and a description of the external environmental and economic consequences of the plan to the extent practicable

SCE&G and Santee Cooper follow similar industry practices in performing their integrated resource planning, breaking their analyses down by types of customers, identifying economic inputs to modeling, performing more-detailed analyses for short term forecasts, and accounting for supply and demand uncertainties. SCE&G goes through a second, more detailed planning evaluation at the CPCN stage.

SERC regional planning includes the following elements:

- Historical and projected peak demand and energy
- Existing capacity
- Historical and projected demand and capacity
- Historical and projected capacity purchases, sales, and transfers
- Bulk electric transmission system description
- Projected changes to bulk electric transmission system

SCE&G has concluded that the South Carolina and SERC need-for-power planning processes comprise comprehensive state and regional processes that encompass all of the components that NRC would cover if NRC had to perform a detailed review, covering the subject completely.

8.4.3 SUBJECT TO CONFIRMATION

SCE&G need-for-power planning is subject to PSC and Office of Regulatory Staff review at the integrated resource plan and CPCN stages, with the Office of Regulatory Staff acting as an advocate for the public interest. Santee Cooper planning is subject to review by its Board of Directors and advisory board. The SCE&G and Santee Cooper processes each result in publicly reviewable data and forecasts in integrated resource plans.

The South Carolina need-for-power planning processes are also confirmable by comparing SCE&G and Santee Cooper forecasts to SERC composite forecasts. Although the SCE&G and Santee Cooper forecasts are included in the SERC regional composite, the regional composite includes forecasts by many other generators and suppliers. The SCE&G and Santee Cooper capacities, 5,808 MW and 4,509 MW, respectively, are not sufficiently large to unduly influence analyses

at the level of a region that has a capacity that is well in excess of 200,000 MW. The SCE&G and Santee Cooper projections of approximately 2% annual growth rate compare favorably to the SERC regional annual growth rate of approximately 2.1%. Similarly, SERC projections are comparable to those of other regions in the Energy Information Administration national data.

SCE&G concludes that South Carolina and SERC need-for-power analyses are subject to corroboration at the level of the generator or supplier (e.g., SCE&G and Santee Cooper) and, by way of comparison, to overall regional data.

8.4.4 RESPONSIVE TO FORECASTING UNCERTAINTY

Both SCE&G and Santee Cooper use commercially developed software to perform uncertainty analyses to account for forecasting uncertainty. Each uses econometric modeling that enables them to perform analyses of the sensitivity of results to changes in model inputs and to create high- and low-range forecasts. Uncertainty analysis is also used in establishing planning reserve margins, themselves an acknowledgement of uncertainty.

8.5 CONCLUSION

SCE&G concludes that South Carolina, having opted to retain traditional regulation of its investor-owned utility (SCE&G) and its state-owned utility (Santee Cooper), has the kind of need-for-power planning process that meets the NRC criteria for an acceptable state need-for-power analysis. Similarly, SCE&G concludes that the SERC process for gathering need-for-power data provides further satisfaction of NRC criteria at the regional level. At the state and regional levels, growth projections support the need for the power that Units 2 and 3 would produce.

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