STATE OF SOUTH CAROLINA

South Carolina Electric & Gas Company's Integrated Resource Plan

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

COVER SHEET

DOCKET NUMBER: 2012 - 9 - E

(Please type or print)

Submitted by:	**Matthew W. Gissendanner**	**SC Bar Number:**	**76027**
Address:	**SCANA Corp.**	**Telephone:**	**803-217-5359**
	220 Operation Way, MC-C222	**Fax:**	**803-217-7931**
	Cayce, SC 29033-3701	**Other:**	
		Email:	**matthew.gissendanner@scana.com**

NOTE: The cover sheet and information contained herein neither replaces nor supplements the filing and service of pleadings or other papers as required by law. This form is required for use by the Public Service Commission of South Carolina for the purpose of docketing and must be filled out completely.

DOCKETING INFORMATION (Check all that apply)

☐ **Emergency Relief demanded in petition** ☐ **Request for item to be placed on Commission's Agenda expeditiously**

☐ **Other:**

INDUSTRY (Check one)	**NATURE OF ACTION (Check all that apply)**		
☒ Electric	☐ Affidavit	☐ Letter	☒ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certification
☐ Electric/Telecommunications	☐ Answer	☐ Motion	☐ Request for Investigation
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☐ Tariff
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	☒ Other:
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	Integrated Resource Plan
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

Matthew W. Gissendanner
Senior Counsel

matthew.gissendanner@scana.com

May 30, 2012

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: South Carolina Electric & Gas Company's 2012 Integrated Resource Plan
Docket No. 2012-9-E

Dear Ms. Boyd:

In accordance with S.C. Code Ann. § 58-37-40 (1976, as amended) and Order No. 98-502 enclosed you will find the 2012 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2012 IRP"). This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann § 58-33-430.

By copy of this letter we are also serving the South Carolina Office of Regulatory Staff, the South Carolina Energy Office and counsel for the South Carolina Coastal Conservation League, the Southern Alliance for Clean Energy, and Upstate Forever with a copy of the SCE&G 2012 IRP and attach a certificate of service to that effect.

If you have any questions or concerns, please do not hesitate to contact us.

Very truly yours,

Matthew W. Gissendanner

MWG/kms
cc: John W. Flitter
Jeffrey M. Nelson, Esquire
Ashlie Lancaster
J. Blanding Holman IV, Esquire
(both via electronic mail and First Class U.S. Mail w/enclosure)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2012-9-E

IN RE:

South Carolina Electric & Gas Company's) Integrated Resource Plan)))	**CERTIFICATE OF SERVICE**

This is the certify that I have caused to be served this day one (1) copy of the **2012 Integrated Resource Plan of South Carolina Electric & Gas Company** via electronic mail and U.S. First Class Mail to the persons named below at the address set forth:

Jeffrey Nelson, Esquire
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jnelson@regstaff.sc.gov

John Flitter
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jflitter@regstaff.sc.gov

J. Blanding Holman IV, Esquire
Southern Environmental Law Center
43 Broad Street, Suite 300
Charleston, SC 29401
bholman@selcsc.org

Ashlie Lancaster
SC Energy Office
1200 Senate Street
408 Wade Hampton Building
Columbia, SC 29201
alancaster@energy.sc.gov

Karen M. Scruggs

Cayce, South Carolina

This 30th day of May 2012

2012

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

Introduction

This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2012 through 2026. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (1976, as amended) and Order No. 98-502 and also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430 (1976, as amended). The objective of the Company's IRP is to develop a resource plan that will provide reliable and economically priced energy to its customers.

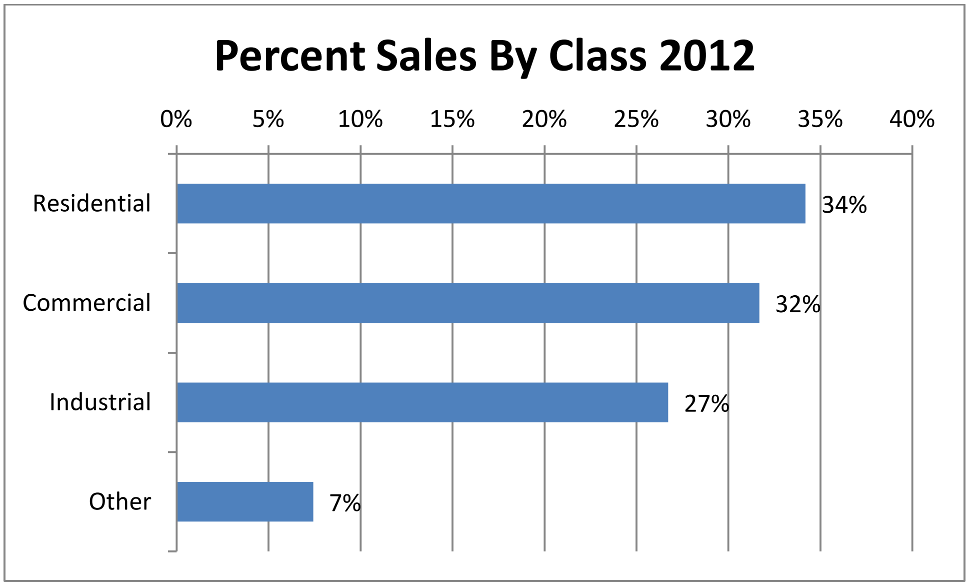
I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2026

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 1.2% per year over the next 15 years, while firm territorial summer peak demand and winter peak demand will increase at 1.4% and 1.3% per year, respectively, over this forecast horizon. The table below contains these projected loads.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2012	4,750	4,660	22,896
2013	4,772	4,703	22,963
2014	4,852	4,732	23,182
2015	4,929	4,782	23,378
2016	5,035	4,870	23,740
2017	5,119	4,960	24,095
2018	5,176	5,039	24,393
2019	5,239	5,110	24,695
2020	5,313	5,175	24,937
2021	5,368	5,235	25,157
2022	5,447	5,305	25,517
2023	5,529	5,381	25,875
2024	5,612	5,455	26,243
2025	5,691	5,528	26,607
2026	5,768	5,598	26,937

The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of our seven classes of customers. The three primary customer classes -

residential, commercial, and industrial - comprise about 93% of our sales. The following bar chart shows the relative contribution to territorial sales made by each class. Please note that the "other" class in the chart below includes street lighting, other public authorities, municipalities and electric cooperatives.



SCE&G's forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained in Appendix A of this report. Short-range is defined as the next two years. Appendix B contains similar information for the long-range methodology. Long range is defined as beyond two years. Sales projections to each group are based on statistical and econometric models derived from historical relationships.

Energy Efficiency Adjustments

Several adjustments were made to the baseline projections to incorporate significant impacts not reflected in historical experience. These were increased air-conditioning and heat pump efficiency standards and improved lighting efficiencies, both mandated by federal law, and the addition of SCE&G's new energy efficiency programs.

Since the baseline forecast is based on historical relationships between energy use and driver variables such as weather, economics, and customer behavior, it embodies changes which have occurred between them over time. For example, construction techniques which result in better insulated houses have had a dampening effect on energy use. Since this process happens with the addition of new houses and/or extensive home renovations, it occurs gradually. Over time this factor and others are captured in the forecast methodology. However, when significant events occur which will impact energy use but are not captured in the historical relationships, they must be accounted for outside the traditional model structure.

The first adjustment relates to federal mandates for air-conditioning units and heat pumps. In 2006, the minimum SEER (Seasonal Energy Efficiency Ratio) for newly manufactured appliances was raised from 10 to 13, which means that cooling loads for a house that replaced a 10 SEER unit with a 13 SEER unit would decrease by 30% assuming no change in other factors. The last mandated change to efficiencies like this took place in 1992, when the minimum SEER was raised from 8 to 10, a 25% increase in energy efficiency. Since then air-conditioner and heat pump manufacturers introduced much higher-efficiency units, and models are now available with SEERs up to 19. However, overall market production of heat pumps and air-conditioners is concentrated at the lower end of the SEER mandate. The new minimum SEER rating represented a significant change in energy use which would not be fully captured by statistical forecasting techniques based on historical relationships. For this reason an adjustment to the baseline was warranted.

A second reduction was made to the baseline energy projections beginning in 2012 for savings related to lighting. Mandated federal efficiencies as a result of the Energy Independence and Security Act of 2007 take effect in 2012 and will be phased in through 2014. Standard incandescent light bulbs are inexpensive and provide good illumination, but they are extremely inefficient. Compact fluorescent light bulbs (“CFLs”) have become increasingly popular over the past several years as substitutes. They last much longer and generally use about one-fourth the energy as that of standard light bulbs. However, CFLs are more expensive and still have some unpopular lighting characteristics, so their large-scale use as a result of market forces was not guaranteed. The new mandates will not force a complete switchover to CFLs, but they will impose efficiency standards that can only be met by them or newly developed high-efficiency incandescent light bulbs. Again, this shift in lighting represents a change in energy use which was not present in the historical data.

The final adjustment to the baseline forecast was to account for SCE&G’s new set of energy efficiency programs. These energy efficiency programs along with the others in SCE&G’s existing DSM portfolio are discussed later in the IRP.

The following table shows the baseline projection, the energy efficiency adjustments and the resulting forecast of territorial energy sales.

		Energy Efficiency			
	Baseline Sales (GWH)	**SCE&G DSM Programs (GWH)**	**Federal Mandates (GWH)**	**Total EE Impact (GWH)**	**Territorial Sales (GWH)**
2012	23,103	-69	-138	-207	22,896
2013	23,283	-146	-175	-321	22,962
2014	23,708	-230	-297	-527	23,181
2015	24,214	-323	-513	-836	23,378
2016	24,719	-423	-556	-979	23,740
2017	25,213	-519	-598	-1,117	24,096
2018	25,657	-625	-640	-1,265	24,392
2019	26,115	-739	-682	-1,421	24,694
2020	26,598	-863	-798	-1,661	24,937
2021	27,069	-996	-915	-1,911	25,158
2022	27,586	-1,131	-938	-2,069	25,517
2023	28,114	-1,278	-960	-2,238	25,876
2024	28,651	-1,424	-984	-2,408	26,243
2025	29,197	-1,582	-1,008	-2,590	26,607
2026	29,720	-1,752	-1,031	-2,783	26,937

Baseline sales are projected to grow at the rate of 1.8% per year. The impact of energy efficiency, both from SCE&G's DSM programs and from federal mandates, causes the ultimate territorial sales growth to fall to 1.2% per year as reported earlier.

The forecast of summer peak demand is developed using a load factor methodology. Load factors for each class of customer are associated with the corresponding forecasted energy to project a contribution to summer peak. The winter peak demand is projected through its correlation with annual energy sales and winter degree-day departures from normal. By industry convention, the winter period is assumed to follow the summer period.

Load Impact of Energy Efficiency and Demand Response Programs

The Company's energy efficiency programs ("EE") and its demand response programs ("DR") will reduce the need for additional generating capacity on the system. The EE programs implemented by our customers should lower not only their overall energy needs but also their power needs during peak periods. The DR programs serve more directly as a substitute for peaking capacity. The Company has two DR programs: an interruptible program for large customers and a standby generator program. These programs represent over 200 megawatts ("MW") on our system. The following table shows the impacts of EE from the Company's DSM programs and from federal mandates as well as the impact from the Company's DR programs on the firm peak demand projections.

Territorial Peak Demands (MWs)							
		Energy Efficiency					
Year	Baseline Trend	SCE&G Programs	Federal Mandates	Total EE Impact	System Peak Demand	Demand Response	Firm Peak Demand
2012	4,989	-15	-6	-21	4,968	-218	4,750
2013	5,030	-31	-6	-37	4,993	-221	4,772
2014	5,156	-48	-31	-79	5,077	-225	4,852
2015	5,268	-68	-43	-111	5,157	-228	4,929
2016	5,411	-89	-55	-144	5,267	-232	5,035
2017	5,531	-110	-67	-177	5,354	-235	5,119
2018	5,624	-132	-79	-211	5,413	-237	5,176
2019	5,725	-157	-90	-247	5,478	-239	5,239
2020	5,842	-183	-105	-288	5,554	-241	5,313
2021	5,946	-212	-122	-334	5,612	-244	5,368
2022	6,058	-241	-124	-365	5,693	-246	5,447
2023	6,177	-271	-129	-400	5,777	-248	5,529
2024	6,299	-304	-133	-437	5,862	-250	5,612
2025	6,419	-339	-137	-476	5,943	-252	5,691
2026	6,540	-377	-141	-518	6,022	-254	5,768

II. SCE&G's Program for Meeting Its Demand and Energy Forecasts in an Economic and Reliable Manner

A. Demand-Side Management

Generally speaking, Demand-Side Management ("DSM") encompasses a set of actions aimed at influencing the level and timing of the consumption of energy. There are two common subsets of Demand Side Management: Energy Efficiency and Load Management (also known as Demand Response). Energy Efficiency typically includes actions designed to increase efficiency by maintaining the same level of production or comfort, but using less energy in an economically efficient way. Load Management typically includes actions specifically designed to encourage customers to reduce usage during peak times or in the alternative, shift that usage to other times of the day.

Energy Efficiency

SCE&G's Energy Efficiency programs include Customer Information Programs, Web-based information, Energy Conservation and the newly offered DSM programs. A description of each follows:

1. **Customer Information Programs:** SCE&G's customer information programs fall under two headings: the **Annual Energy Efficiency Campaigns** and **Web-based Information Initiatives**. The following is an overview of each.

   Annual Energy Efficiency Campaigns

   a. ***Customer Insights and Analysis:*** In 2011, SCE&G continued to proactively educate its customers and create awareness on issues related to energy efficiency and conservation. To help maximize the effectiveness of our campaigns, customer feedback was obtained to ensure marketing and communications efforts are consistent with what customers value most. Key insights gained through SCE&G's Brand Health Study and Voice of the Customer Panels were integral to ensure we are communicating in a consistent manner that customers will understand.

      As a result, SCE&G continues to highlight programs and services that reflect three main categories identified by our customers as offering the best opportunity to save energy and money. These areas include: (1) rebates and incentives; (2) in-home services; and (3) education.

b. ***Media/Channel Preferences:*** Placement of all marketing and advertising is carefully considered, taking into account media preferences customers have identified as preferred methods of communicating information about SCE&G's energy efficiency programs and services. Priority channels include television (local news and select cable stations); online banner advertising, radio, electronic/print newsletters, direct mail, bill inserts and newspaper (major dailies and weekly minority publications). SCE&G's 37 statewide business office locations also serve as a distribution point for sharing information with customers. In addition, SCE&G has also incorporated the use of social media to communicate with its customers.

   Key South Carolina markets covered with all marketing communications include Columbia, Charleston, Aiken and Beaufort.

   In 2011, 27,644,176 impressions were made through our marketing communications and advertising plan and channel mix (excluding social media).

c. ***Public Affairs/News Media/Speakers Bureau:*** SCE&G understands the value of public affairs as an integral part of a well-rounded, energy efficiency communication strategy and actively engages news media (broadcast and print) for coverage of key programs and services that will benefit our customers now and in the future. Public Affairs and marketing staff also provide support with securing company experts to address a variety of organizations through a formal Speakers' Bureau, extending our outreach to church groups, senior citizen and low-income housing communities, civic organizations, builder groups and homeowner associations.

d. ***Special Events:*** Another key component to SCE&G's annual marketing initiatives is participation in a variety of events that offer the opportunity to further extend customer education and outreach for energy information. SCE&G's 2011 schedule included a solid mix of special events to include the HBA Home Improvement Show and Tour of Homes in Columbia, Black Expos in Columbia and Charleston and sponsorship of Columbia Metropolitan Magazine's Dream Home. The company organized an Energy Day sponsorship with the

University of South Carolina and hosted live, on-air energy efficiency phone banks with WIS-TV (Columbia) and WCSC-TV (Charleston) – with SCE&G Energy Team members fielding customer calls during local evening news programming.

e. ***EnergyWise Communications:*** Brand positioning of SCE&G's energy efficiency programs and services with all marketing and advertising initiatives falls under the EnergyWise umbrella – an SCE&G registered trademark in South Carolina and encompassing **general awareness education** as well as **program specific offerings**.

   i. **General Awareness Education:** Last year's advertising included messaging on a wide range of topics such as year-round and seasonal energy efficiency tips that are practical for customers to manage on their own or that have a no-cost, low-cost factor to them. Examples include thermostat settings, checking air filters monthly, water heater settings and unplugging appliances that are sometimes perceived to be "energy vampires" (lights, TV's, computers, cell phone chargers, etc.).

   ii. **Program Specific Offerings:** In 2011, SCE&G launched several new rebate/incentive programs under its Demand Side Management department – many of which were featured in our general awareness advertising schedule. Specific programs included ENERGY STAR Lighting, our free Home Energy Check-up, Home Performance with ENERGY STAR and Heating & Cooling and Water Heating (new equipment and efficiency tune-ups).

2. Web-Based Information and Services Programs: SCE&G's online offerings can be broken into four components: Customer Awareness Information, the Energy Analyzer, free online Energy Audit and EnergyWise e-newsletter. Altogether, there have been more than 3.88 million visits to SCE&G's website in 2011 and feedback has been positive. Customers must be registered to use the interactive tools: Energy Analyzer and Energy Audit. There are over 299,000 customers registered for this access. Descriptions of the four categories listed above is as follows:

a. **Customer Awareness Information:** SCE&G's website supports all communication efforts to promote energy savings information – both general awareness tips and program-specific profiles, tools and resources – all through a section entitled, "Be EnergyWise and Save". Energy savings information includes detailed information on each of the new DSM programs for residential and commercial/industrial customers, as well as how-to videos on insulation, thermostats and door and windows. Details on the latest tax credits offered by the American Recovery and Reinvestment Act of 2009 is also available, including links to help customers explore and learn how they can take advantage of these credits.

b. **Energy Analyzer:** The Energy Analyzer, in use since 2004, is a 24-month bill analysis tool. It uses complex analytics to identify a customer's seasonal usages and target the best ways to reduce demand. This Web-based tool allows customers to access their current and historical consumption data and compare their energy usage month-to-month and year-to-year -- noting trends, temperature impact and spikes in their consumption. There were over 100,000 visits to the Energy Analyzer tool in 2011.

c. **Online Energy Audit:** The Online Energy Audit tool leads customers through the process of creating a complete inventory of their home's insulation and appliance efficiency. The tool allows customers to see the energy and financial savings of upgrades before making an investment. There were 5,063 customers who used the Energy Audit tool in 2011.

d. **SCE&G EnergyWise E-Newsletter:** SCE&G's web-based information and services included ongoing management of its EnergyWise e-newsletter to support customer demand for additional information on ways to help them save energy. A total of 3,100 customers registered for the e-newsletters in 2011.

3. Energy Conservation

Energy conservation is a term that has been used interchangeably with energy efficiency. However, energy conservation has the connotation of using less energy in order to save rather than using less energy to perform the same or better function more efficiently. The following is an overview of each SCE&G energy conservation offering:

a. **Energy Saver / Conservation Rate**: The Rate 6 (Energy Saver / Conservation) rewards homeowners and homebuilders who upgrade their existing homes or build their new homes to a high level of energy efficiency with a reduced electric rate. This reduced rate, combined with a significant reduction in energy usage, provides for considerable savings for our customers. Participation in the program is simple since the requirements are prescriptive, which is beneficial to all of our customers and trade allies. Homes built to this standard have improved comfort levels and increased re-sale value over homes built to the minimum building code standards, which is also a significant benefit to participants. Information on this program is available on our website and by brochure.
b. **Seasonal Rates**: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

4. Demand Side Management Programs

On July 15, 2010, SCE&G received an Order from the Commission approving its portfolio of DSM programs. The portfolio included nine programs, seven targeting SCE&G's residential customer classes and two targeting SCE&G's commercial and industrial customer classes. Implementation began in 4th quarter of 2010 with the free Home Energy Check-up and select Commercial and Industrial programs – followed by a phased-in approach that continued through 2nd quarter of 2011. A description of each program follows:

a. **Residential Home Energy Reports** (previously Benchmarking**)** provides customers with comparisons of their monthly energy consumption with benchmarks showing average energy consumption by similarly situated energy users. The monthly benchmarking information is provided free of charge to customers who elect to participate in the program.
b. **Residential Energy Information Display** provides customers with an in-home display that shows information from the customer's meter regarding a home's current energy use and cost, and the use and cost to date for the month. The displays are made available to customers at a discounted price. After review of the initial implementation phase, a second phase was implemented in 4th quarter

of 2011 to a select group of customers, with full rollout scheduled for 2nd quarter of 2012.

c. **Residential Home Energy Check-up and Home Performance with ENERGY STAR®** encourages customers to have an assessment done of the energy efficiency of their homes. It includes two tiers of home energy review and assessment.

   i. Beginning in October 2010, the **Home Energy Check-up** program was offered to customers. This visual checkup and "check-off" audit is performed by SCE&G staff at the customer's home. As a direct incentive for customers to participate in the program, customers are offered an energy efficiency kit containing simple measures, such as compact fluorescent light bulbs ("CFL"), water heater wraps and/or pipe insulation. The Home Energy Check-up is provided free of charge to all residential customers who elect to participate.

   ii. The **Home Performance with ENERGY STAR®** program goes a step further and provides a comprehensive audit with diagnostic testing of the energy efficiency of the home by trained contractors. SCE&G promotes these audits by independent providers and subsidizes the cost of the audit and specific measures undertaken by customers based on the audit findings.

d. **Residential ENERGY STAR® Lighting** program provides residential customers with incentives for purchasing and installing high-efficiency and ENERGY STAR® qualified lighting.

e. The **Residential Heating & Cooling and Water Heating Equipment** (previously New High Efficiency HVAC and Water Heater) program provides incentives for installing high efficiency HVAC units and water heaters in new and existing homes.

f. The **Residential Heating & Cooling Efficiency Improvements** (previously named Existing HVAC Efficiency) program provides residential customers with incentives for investing in efficiency tune-ups and other improvements to their HVAC systems.

g. Customers and builders willing to commit to overall high standards of energy efficiency in new construction may receive incentives under the **Residential ENERGY STAR® New Homes** program. This program provides incentives based on a comprehensive analysis of the energy efficiency of new homes reflecting both the construction techniques used and the appliances installed.

h. Beginning in October 2010, the **Commercial and Industrial Prescriptive** program began providing lighting incentives to non-residential customers to invest in high-efficiency lighting and fixtures. In the 1st quarter of 2011, SCE&G went beyond these incentives to include energy efficient measures like high efficiency motors and other equipment. To ensure simplicity, the program includes a master list of measures and incentive levels that are easily accessible to commercial and industrial customers on the website.

i. **Commercial and Industrial Custom** program provides tailored incentives to commercial and industrial customers based on the calculated efficiency benefits of their particular energy efficiency plans or construction proposals. This program applies to technologies and applications that are more complex and customer-specific. All aspects of this program fit within the parameters of both retrofit and new construction projects.

Load Management Programs

The primary goal of SCE&G's load management programs is to reduce the need for additional generating capacity. There are four load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows:

1. **Standby Generator Program:** The Standby Generator Program for retail customers was revamped in 2009 to serve as a load management tool. General guidelines authorize SCE&G to initiate a standby generator run request when reserve margins are stressed due to a temporary reduction in system generating capability or high customer demand. Through consumption avoidance, customers who own generators release capacity back to SCE&G where it is then used to satisfy system demand. Qualifying customers (able to defer a minimum of 200 kW) receive financial credits determined initially by recording the customer's demand during a load test. Future demand credits are based on what the customer actually delivers when SCE&G requests them to run their generator(s). This

program allows customers to reduce their monthly operating costs, as well as earn a return on their generating equipment investment. There is also a wholesale standby generator program that is similar to the retail programs. On March 3, 2010, the United States Environmental Protection Agency ("EPA") published regulations restricting the operation of certain reciprocating internal combustion engines ("RICE"). These RICE regulations threatened to restrict our retail standby generator program so much that much of its value to the system would be eliminated. However, in February 2011, the EPA asked for further comments on some of the restrictions and is expected to publish less restrictive regulations in 2012.

2. **Interruptible Load Program:** SCE&G has over 150 megawatts of interruptible customer load under contract. Participating customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity.
3. **Real Time Pricing ("RTP") Rate:** A number of customers receive power under our real time pricing rate. During peak usage periods throughout the year when capacity is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.
4. **Time of Use Rates:** Our time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All SCE&G customers have the option of purchasing electricity under a time of use rate.
5. **Demand Response Technologies:** With the retirement of coal capacity and the increased reserve margin target, both discussed later in this document, the Company's resource plan reflects that SCE&G will require additional capacity in order to continue providing reliable electric service to its customers. As SCE&G evaluates how to satisfy this need, the Company will consider, among other things, demand response technologies.

B. Supply Side Management

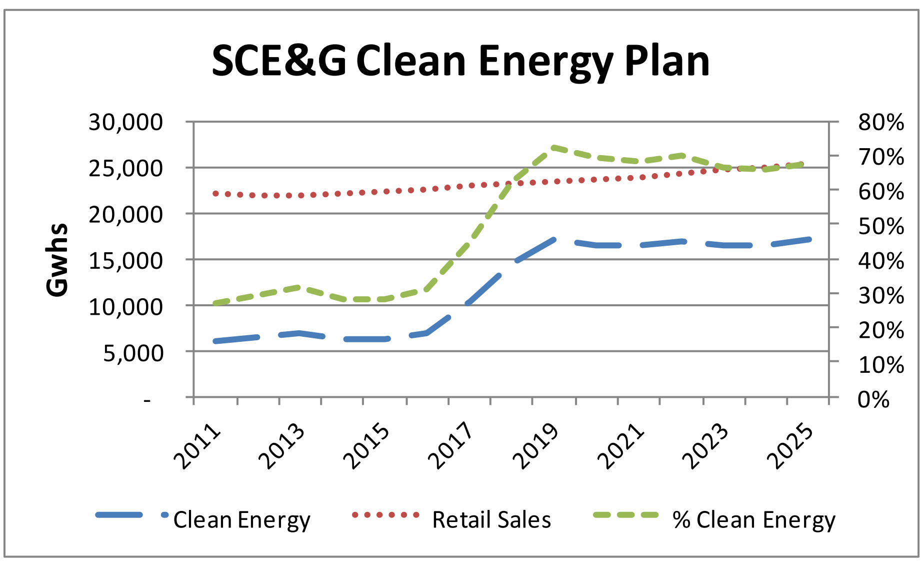
1. Clean Energy at SCE&G

Clean energy includes energy efficiency and clean energy supply options like nuclear power, hydro power, combined heat and power as well as renewable energy.

Existing Sources of Clean Energy

SCE&G is committed to generating more of its power from clean energy sources. This commitment is reflected: in the amount of current and projected generation coming from clean sources, in the certified renewable energy credits that the Company generates each year, in the Company's net metering program, and in the Company's support for Palmetto Clean Energy, Inc. Below is a discussion of each of these topics.

1. **Current Generation:** SCE&G currently generates clean energy from hydro, nuclear, solar and biomass. The following chart shows the current and expected amounts of clean energy by GWh and as a percentage of retail sales.



As seen in the chart, SCE&G currently generates nearly 30% of its retail sales from clean energy sources and by 2019 expects to generate about 72%.

2. **Renewable Energy Credits:** The SCE&G-owned electric generator, located at the KapStone Charleston Kraft LLC facility, generates electricity using a mixture of coal and

biomass. KapStone Charleston Kraft, LLC, produces black liquor through its kraft pulping process and produces and purchases biomass fuels. These fuels which are used to produce renewable energy and the electricity generated qualify for Renewable Energy Certificates as approved by Green-e Energy, a leading national independent certification and verification program for renewable energy administered by the Center for Resource Solutions, a nonprofit company based in San Francisco, California. Over the last five years SCE&G generated the following amounts of renewable energy from the Kapstone generator, formerly known as the Cogen South generator:

Year	MWH	% of Retail Sales
2007	371,573	1.7%
2008	369,780	1.7%
2009	351,614	1.7%
2010	346,190	1.5%
2011	336,604	1.5%

3. **Boeing Solar Generator:** In 2011, SCE&G installed approximately 10 acres of thin-film laminate panels (18,095 individual panels) on the roof of Boeing's North Charleston assembly plant. The PV system, having an alternating current peak output of 2.35 MW, began generating in October 2011. All RECs and energy generated by the roof top solar system will be provided to Boeing for onsite use. At the time of completion this was the largest roof-top solar generator in the Southeast.
4. **Net Metering Rates and the PR-1 Rate:** Protecting the environment includes encouraging and helping our customers to take steps to do the same. Net metering provides a way for residential and commercial customers interested in generating their own renewable electricity to power their homes or businesses and sell the excess energy back to SCE&G. For residential customers, the generator output capacity cannot exceed the annual maximum household demand or 20 KW, whichever is less. For small commercial customers, the generator output capacity cannot exceed the annual maximum demand of the business or 100 KW, whichever is less. Under its PR-1 rate for qualifying facilities, the Company will pay the qualifying customer for any power generated and transmitted to the SCE&G system. The PR-1 rate is developed using SCE&G's avoided costs.

5. **Palmetto Clean Energy, Inc.:** Palmetto Clean Energy, Inc. ("PaCE") is a non-profit, tax exempt organization formed by SCE&G, Duke Energy, Progress Energy, the South Carolina Office of Regulatory Staff ("ORS") and the SC Energy Office for the purpose of subsidizing renewable power in South Carolina. Customers make a tax deductible payment to PaCE and PaCE uses the funds collected to pay renewable generators a supplemental fee for their power.

Future Clean Energy

SCE&G is participating in activities whose goal is to advance renewable technologies in the future. Specifically the Company is involved with off-shore wind activities in the state, co-firing with biomass fuels, studying smart grid opportunities and distribution automation. These activities are set forth in more detail below.

1. **Off-Shore Wind Activities:** SCE&G currently participates in the Regulatory Task Force for Coastal Clean Energy. This task force was established with a 2008 grant from the U.S. Department of Energy. The goal is to identify and overcome existing barriers for coastal clean energy development for wind, wave and tidal energy projects in South Carolina. Efforts include an offshore wind transmission study; a wind, wave & ocean current study; and creation of a Regulatory Task Force. The mission of the Regulatory Task Force is to foster a regulatory environment conducive to wind, wave and tidal energy development in state waters. The Regulatory Task Force is comprised of state and federal regulatory and resource protection agencies, universities, private industry and utility companies.
2. **Co-firing with Biomass:** In 2010, SCE&G began a project to investigate and evaluate the co-firing of biomass and other engineered waste products in our existing coal burning facilities. The goal of the project is to determine the operational practicality as well as the economic and fuel supply implications of co-firing in existing coal units. Co-firing of biomass fuel in our existing units represents an opportunity to include additional renewable fuels in our production mix without having to build new facilities or spend significant capital on existing facilities.

   The Company has purchased and set up mobile fuel handling equipment to facilitate testing of different types of biomass and other waste materials at multiple facilities. Tests with different forms of biomass material are ongoing and the results are being evaluated by the Fossil Hydro department to determine a future course of action.

3. **New Renewable Projects:** SCE&G has met with several companies that are considering developing renewable facilities in South Carolina and who wish to sell power to SCE&G through a long term purchased power agreement. SCE&G evaluates all power proposals to determine if the power is needed and can be supplied at a price that is competitive with other supply alternatives. The Company will continue to evaluate opportunities in the renewable market sector, but the power must be economical for our customers.

   SCE&G also continues to monitor state and federal bills that, if enacted, would mandate a federal or state renewable portfolio standard ("RPS"). One of the primary purposes of an RPS is to increase the amount of clean energy produced in the U.S. The bills proposed, but not passed, in 2010 required 15-20% of utilities' retail sales to come from renewable sources by year 2020. Qualified renewable sources include wind, solar, geothermal, biomass, qualified hydro-power, and marine and hydrokinetic renewable energy. The most viable renewable energy source in SC is woody biomass. Off-shore wind energy and solar energy are available but are uneconomic today. SCE&G will follow the development of these technologies and will include them in its resource mix when appropriate.

4. **Smart Grid Activities:** SCE&G currently has approximately 10,000 electric meters that are not supported by our "drive by" Automated Meter Reading ("AMR") system. These meters are predominately located on our medium to large commercial customers as well as our smaller industrial customers and must be manually read each month. We are currently installing SmartSynch AMI (Advanced Metering Infrastructure) meters on the applications referenced above, which will provide full two way communication to these meters. Other applications for this technology include all time-of-use meters and accounts with customer generation (net metering). Installation began in March 2011, and will be completed in July 2012. This capability is particularly important to this class of customer because it will allow real time outage notification and power quality monitoring as well as making load profile data available to the customer enabling better management of its energy consumption. This technology will also enable more sophisticated DSM offerings that may be attractive to a variety of customer classes.

5. **Distribution Automation:** SCE&G is continuing to expand the penetration of automated Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the system. We have over 700 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing the number of affected customers. Some of these isolating switches can communicate with each other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. In order to more fully utilize the new technology being deployed, we are researching Distribution Management Systems that would work in conjunction with our Outage Management System to better synthesize the information coming back from our SCADA switches with other system operating information. Bringing this information together will enable us to operate the system in a more reliable and efficient manner.

Environmental Mitigation Activities

In order to reduce NO_X emissions and to meet its compliance requirements, SCE&G installed Selective Catalytic Reduction ("SCR") equipment at its Cope Station in the fall of 2008. The SCR began full time operation on January 1, 2009, and has run well since that time. It is capable of reducing NO_X emissions at the Cope Station by approximately 90%. SCE&G is also utilizing the existing SCRs at Williams and Wateree Station along with previously installed low NO_X burners at the other coal-fired units to meet the Clean Air Interstate Rule ("CAIR") requirements for NO_X which are in effect while the Cross State Air Pollution Rule is under a court-ordered stay.

Additionally, SCE&G has installed flue gas desulfurization ("FGD") equipment, commonly known as wet scrubbers, at Wateree and Williams Station to reduce SO_2 emissions. The in-service date for Williams and Wateree Stations were February 25, 2010, and October 12, 2010, respectively. Scrubber performance tests at both stations met the SO_2 designed removal rate of 98%.

During 2010, SCE&G worked with a contractor to test a Chem-Mod fuel additive that was expected to reduce SO_2, NO_X and mercury at Urquhart 3, Canadys, and McMeekin units. Test results through a third party indicate emissions reductions of more than 30% Mercury, more than 7% NO_X, and a 2 – 3% SO_2 reduction. SCE&G recently received a SCDHEC permit for on-going use of Chem-Mod at McMeekin, Canadys and Urquhart Stations.

Through recent testing, reduction in mercury is occurring as a result of the SCR and the wet scrubber installations. SCE&G is currently quantifying the removal efficiency of mercury through third party testing. Any reductions in emissions resulting from the use of the Chem-Mod fuel additive will be a benefit to the environment of South Carolina.

Summary of Proposed and Recently Finalized Regulations

There are five new regulations that are either proposed or have been recently finalized plus one modification. These are Cross-State Air Pollution Rule ("CSAPR"), Mercury and Air Toxics Standards ("MATS"), Greenhouse Gases, Cooling Water Intake Structures, and Coal Combustion Residuals, and a new 1-hour sulfur dioxide National Ambient Air Quality Standard ("NAAQS").

1. **Cross-State Air Pollution Rule ("CSAPR")**

   Finalized in July 2011 under the Clean Air Act, this rule affects 27 states including South Carolina, requiring reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions beginning in 2012, with stricter reductions in 2014. The rule establishes an emissions cap for SO_2 and NO_X and limits the trading region for emission allowances by separating affected states into two groups with no trading between the groups. It replaces CAIR. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued a stay delaying implementation of CSAPR pending the outcome of a legal appeal. The federal court ordered the EPA to continue administering the previously promulgated CAIR until a final decision can be made on the merits of the rule, likely this summer or fall.

2. **Mercury and Air Toxics Standards ("MATS")**

   Proposed under the Clean Air Act, this rule sets numeric emission limits for mercury, particulate matter as a surrogate for toxic metals, and hydrogen chloride as a surrogate for acid gases. The final rule also revises new source performance standards for power plants to address emissions of particulate matter, sulfur dioxide and nitrogen oxides. The rule would replace the court-vacated Clean Air Mercury Rule. MATS was proposed in May 2011, and the final rule was issued on December 21, 2011.

   The rule became effective on April 16, 2012. Compliance with MATS is required within three years. A 1-year extension may be granted if additional time is needed for units that are required to run for reliability purposes that (A) would otherwise be deactivated, or

(B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay. It is expected that coal-fired generators will need to have a combination of flue gas desulfurization, selective catalytic reduction and fabric filters in order to comply with the standards. A second year of extension may also be possible for reliability critical units that qualify for an Administrative Order at the end of the 1-year extension. All extension requests must be supported by the written concurrence of the appropriate Planning Authority and will be considered by EPA on a case-by-case basis, supplemented with consultation of FERC and/or other entities with relevant reliability expertise as appropriate.

3. Greenhouse Gases

This rule, to be proposed under the Clean Air Act, would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. The first part of this rule, related to new generation sources, was released in April 2012. The part related to existing generation sources is expected later in 2012. The Draft Rule essentially requires all new fossil fuel-fired power plants to meet the carbon dioxide (CO_2) emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal plants can be constructed without carbon capture and sequestration ("CCS") capabilities.

4. Cooling Water Intake Structures

Proposed under section §316(b) of the Clean Water Act, this rule is intended to reduce damage to aquatic life through impingement, when organisms are trapped against inlet screens, or entrainment, when they are drawn into the generator's cooling water system. Facilities that withdraw at least 2 million gallons per day would be subject to a limit on the number of fish that can be killed through impingement. Facilities that withdraw at least 125 million gallons per day and new units at existing facilities may be subject to more stringent restrictions. The rule was proposed in April 2011, with comments accepted until August 2011. A final rule is expected in July 2012.

There is considerable uncertainty regarding when the regulations would be effective and the steps that would have to be taken in order to meet them. Facilities must comply with Best Available Technology standards within 8 years, but many required submittals are due much earlier, as early as six months after rule promulgation. Compliance actions range from enhancing screening and reconfiguring of water intake systems to reducing flow rate by installing cooling towers. On SCE&G's system Jasper, Cope, Canadys and Wateree Stations have closed cycle cooling towers installed and should not be significantly affected by these regulations.

5. Coal Combustion Residuals

In response to concerns over the potential structural failure of coal ash impoundment facilities instigated by the December 2008 failure that occurred at a Tennessee Valley Authority facility, EPA has proposed changing the classification of coal combustion residuals from its current status of an exempt waste. Two options were proposed under the Resource Conservation and Recovery Act: (1) list residuals as special hazardous wastes when destined for disposal in landfills or surface impoundments and (2) regulate as a non-hazardous waste. The proposed rule was released in June 2010 and comments were received through November 2010. EPA has indicated the release of the final rule will occur at the end of 2012. The effective date is believed to be dependent on which option is selected. If coal combustion residuals are classified as non-hazardous wastes, the compliance date is expected to be around 2018. A special hazardous waste designation would likely push compliance out until about 2020.

On January 18, 2012, several environmental groups, led by Earthjustice, filed a notice of intent to sue the EPA to force the agency to finalize its proposed rule determining how coal combustion residuals (commonly referred to as "coal ash") will be categorized.

6. NAAQS 1-hour SO2

In June 2010, EPA revised the primary SO_2 standard by establishing a new 1-hour standard at a level of 75 parts per billion ("ppb"). The Agency revoked the two existing primary standards of 140 ppb evaluated over 24-hours, and 30 ppb evaluated over an entire year. The new form is the 3-year average of the 99th percentile of the annual distribution of daily maximum 1-hour average concentrations. EPA also required states to install new monitors by January 1, 2013. Compliance requires both monitoring and refined dispersion modeling of SO_2 sources to meet the new standard.

The new 1-hour national ambient air quality standard ("NAAQS") for SO_2 presents new challenges and is driving strategic planning for large SO_2 emitters around the country. For this new standard, EPA is requiring the unusual step of using air quality modeling for criteria pollutant attainment designations. EPA recently released its draft guidance for this

State Implementation Plan ("SIP") modeling and now the states are gearing up for their designation modeling efforts.

Historically, ambient air monitoring data has provided the basis for attainment designations. The shift to using models instead of ambient data poses significant challenges:

- Due to the stringent nature of the short term SO_2 standards, the conservative nature of the models and use of conservative inputs in the model (short-term emission limits) the results can significantly overstate reality.
- There are likely to be surprises for historically grandfathered sources or even new well-controlled sources.

The results will produce a public record of how each individual company and facility impacts SO_2 attainment, making it very important to be aware of the state's approach and to develop a strategy to ensure that the correct inputs are used and that a source's impacts are properly characterized.

2. Supply Side Resources at SCE&G

Existing Supply Resources

SCE&G owns and operates ten (10) coal-fired fossil fuel units (2,434 MW), eight (8) combined cycle gas turbine/steam generator units (gas/oil fired, 1,327 MW), sixteen (16) peaking turbine units (355 MW), three (3) hydroelectric generating plants (218 MW), and one Pumped Storage Facility (576 MW). In addition, SCE&G receives an output of 85 MW from a cogeneration facility. The total net non-nuclear summer generating capability rating of these facilities is 4,995 MW. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer season. When SCE&G's nuclear capacity (644 MW), a long term capacity purchase (25 MW) and additional capacity (22 MW) provided through a contract with the Southeastern Power Administration are added, SCE&G's total supply capacity is 5,686 MW. This is summarized in the table on the following page.

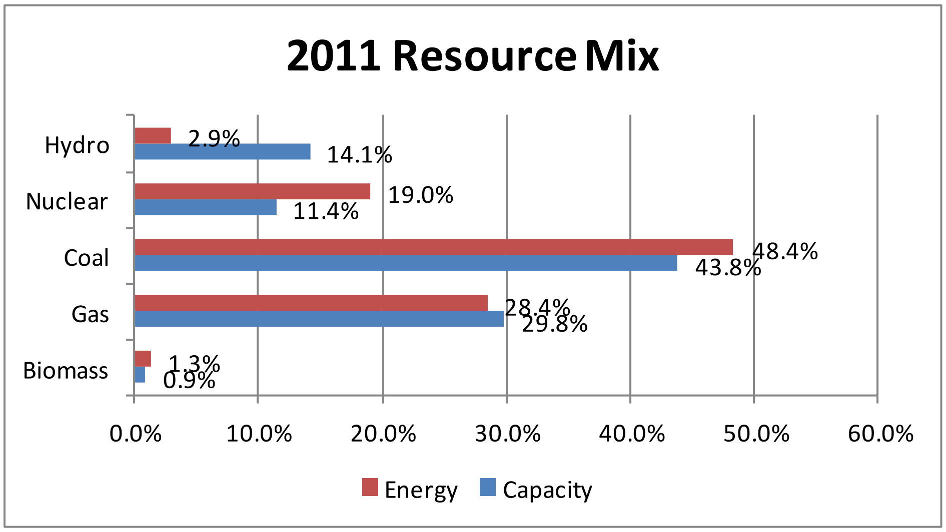
Existing Long Term Supply Resources

The following table shows the generating capacity that is available to SCE&G in the summer of 2012.

	In-Service Date	Summer (MW)
Coal-Fired Steam:		
Urquhart – Beech Island, SC	1953	95
McMeekin – Near Irmo, SC	1958	250
Canadys - Canadys, SC	1962	385
Wateree – Eastover, SC	1970	684
*Williams – Goose Creek, SC	1973	605
Cope - Cope, SC	1996	415
Kapstone – Charleston, SC	1999	85
Total Coal-Fired Steam Capacity		2,519
Nuclear:		
V. C. Summer - Parr, SC	1984	644
I. C. Turbines:		
Hardeeville, SC	1968	12
Urquhart – Beech Island, SC	1969	39
Coit – Columbia, SC	1969	28
Parr, SC	1970	60
Williams – Goose Creek, SC	1972	40
Hagood – Charleston, SC	1991	128
Urquhart No. 4 – Beech Island, SC	1999	48
Urquhart Combined Cycle – Beech Island, SC	2002	458
Jasper Combined Cycle – Jasper, SC	2004	869
Total I. C. Turbines Capacity		1,682
Hydro:		
Neal Shoals – Carlisle, SC	1905	3
Parr Shoals – Parr, SC	1914	7
Stevens Creek - Near Martinez, GA	1914	8
Saluda - Near Irmo, SC	1930	200
Fairfield Pumped Storage - Parr, SC	1978	576
Total Hydro Capacity		794
Other: Long-Term Purchases		25
SEPA		22
Grand Total:		5,686

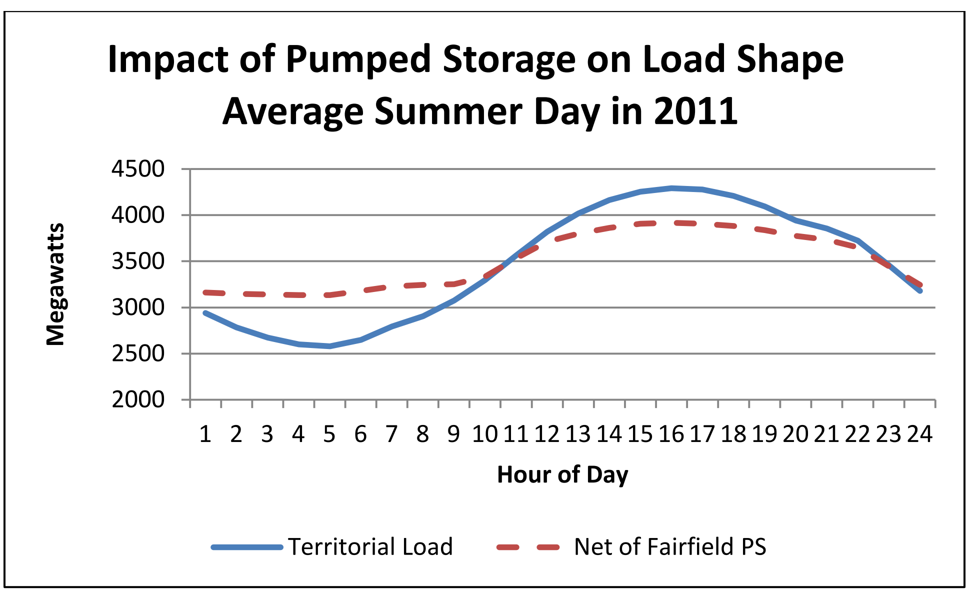
* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and is operated by SCE&G. Not reflected in the table is a solar PV generator owned by SCE&G with a nominal direct current rating of 2.6 MWs.

The bar chart below shows the actual 2011 relative energy generation and the relative capacity by fuel source.



DSM From the Supply Side

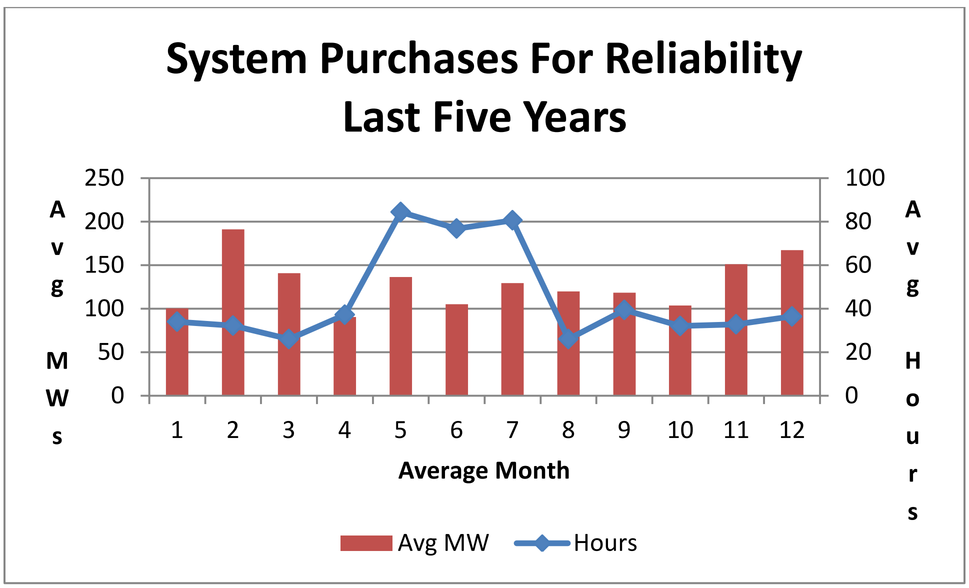
SCE&G is able to achieve a DSM-like impact from the supply side using its Fairfield Pumped Storage Plant. The Company uses off-peak energy to pump water uphill into the Monticello Reservoir and then displaces on-peak generation by releasing the water and generating power. This accomplishes the same goal as many DSM programs, namely, shifting use to off-peak periods and lowering demands during high cost, on-peak periods. The following graph shows the impact that Fairfield Pumped Storage had on a typical summer weekday.



In effect the Fairfield Pumped Storage Plant shaved about 350MWs from the daily peak times of 2:00pm through 6:00pm and moved about 3.3% of customer's daily energy needs to the off peak. Because of this valuable supply side capability, a similar capability on the demand side, such as a time of use rate, would be less valuable on SCE&G's system than on many other utility systems.

Planning Reserve Margin and Operating Reserves

The Company provides for the reliability of its electric service by maintaining an adequate reserve margin of supply capacity. The appropriate level of reserve capacity for SCE&G is in the range of 14 to 20 percent of its firm peak demand. For the past several years, the Company has used a lower range of reserve margins, i.e., 12 to 18 percent, but this lower range would require the Company to rely on an increasingly tight and risky market for power purchases to support the system. The following chart shows the average number of hours and the average MWs that the Company has purchased for reliability reasons over the last five years summarized by month.



As seen in the chart the Company purchased about 100 to 150 MWs for a number of hours each month on average. This suggests the need to increase the Company's reserve margin by about 100 MWs or 2%. The Company therefore increased the reserve margin target range to 14%-20%. This range of reserves will allow SCE&G to have adequate daily operating reserves and to have reserves to cover two primary sources of risk: supply risk and demand risk. Mitigation of these two types of risk is discussed below.

Supply reserves are needed to balance the "supply risk" that some SCE&G generation capacity may be forced out of service or its capacity reduced on any particular day because of mechanical failures, fuel related problems, environmental limitations or other force majeure/unforeseen events. The amount of capacity forced-out or down-rated will vary from day-to-day. SCE&G's reserve margin range is designed to cover most of these days as well as the outage of any one of our generating units.

Another component of reserve margin is the demand reserve. This is needed to cover "demand risk" related to unexpected increases in customer load above our peak demand forecast. This can be the result of extreme weather conditions or other unexpected events.

The level of daily operating reserves required by the SCE&G system is dictated by operating agreements with other VACAR companies. VACAR is the organization of utilities serving customers in the Virginia-Carolinas region of the country who have entered into a reserve sharing agreement. These utilities are members of the SERC Reliability Corporation, a nonprofit corporation responsible for promoting and improving the reliability of the bulk power transmission system in much of the southeastern United States. VACAR has set the group's reserve need at 150% of the largest unit in the group. While it can vary by a few megawatts each year, SCE&G's pro-rata share of this capacity is always around 200 megawatts.

By maintaining a reserve margin in the 14 to 20 percent range, the Company addresses the uncertainties related to load and to the availability of generation on its system. It also allows the Company to meet its VACAR obligation. SCE&G will monitor its reserve margin policy in light of the changing power markets and its system needs and will make changes to the policy as warranted.

New Nuclear Capacity

On May 30, 2008, SCE&G filed with the Commission a Combined Application for a Certificate of Environmental and Compatibility and Necessity and for a Base Load Review Order for the construction and operation of two 1,117 net MW nuclear units to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina. Following a full hearing on the Combined Application, the Commission issued Order No. 2009-104(A) granting SCE&G, among other things, a Certificate of Environmental Compatibility and Necessity.

On March 30, 2012, the United States Nuclear Regulatory Commission issued a combined Construction and Operation License ("COL") to SCE&G for each unit. Both units will have the Westinghouse AP1000 design and use passive safety systems to enhance the safety of the units. The first unit is expected to come online in 2017 and the second in 2018. SCE&G will own 55% of the units (614 MWs each) while Santee Cooper will own 45%.

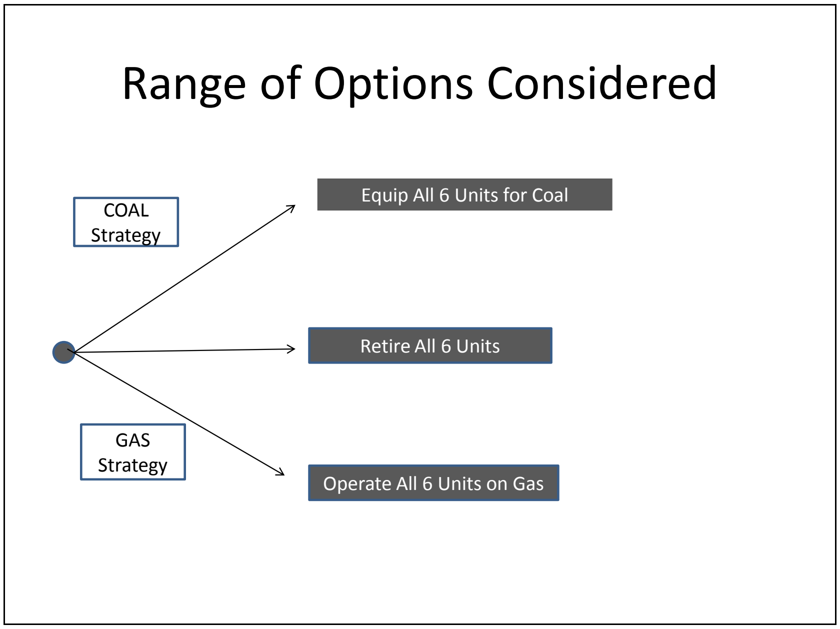
Retirement of Coal Plants

SCE&G has six small coal-fired units in its fleet totaling 730 MWs that range in age from 45 to 57 years. These units are listed in the table below. Under the existing environmental regulations, the Company does not anticipate that it will be able to continue to operate these six units using coal as the fuel source unless the Company installs pollution control equipment.

Plant Name	Capacity (MW)	Commercialization Date
Canadys 1	90	April 1962
Canadys 2	115	May 1964
Canadys 3	180	June 1967
Urquhart 3	95	November 1955
McMeekin 1	125	July 1958
McMeekin 2	125	December 1958

For its current resource plan, SCE&G has analyzed its options from the perspectives of two planning horizons: the long run and the short run. The long run perspective analyzes the value of these plants after the new nuclear capacity is added while the short run identifies economic steps to be taken prior to 2017 which help implement the long range strategy.

Long Range Perspective: The long range analysis considered a set of options bounded by three extremes: 1) equip all 6 units with pollution control equipment; 2) retire all 6 units; or 3) operate all 6 units on natural gas. Today, three of the coal units can operate on natural gas, while the other three units can be made to do so with some effort and investment. The following diagram displays the analytical structure of the issue in graphical form.



In the long run analysis, SCE&G wanted to determine the most economical disposition of these six coal units in a long-run least cost resource plan under existing environmental regulations. The analysis calculated the incremental revenue requirements of many possible plans beginning in 2017. Eleven combinations of the 3 basic strategies are shown in the following table.

Scenario	Strategy	Description	Revenue Requirements 25 year Levelized ($000) Change from Lowest Cost
7		**Retire All**	**-**
9	Gas	U3, M1-2 on gas, Retire C1-3	**$134**
8	Gas	U3 on gas, Retire C1-3, M1-2	**$3,050**
10	Gas	U3, M1-2, C1-2 on gas, Retire C3	**$5,776**
5	Coal	Scrub M2, Retire C1-3, U3, M1	**$11,326**
11	Gas	All on Gas	**$11,419**
4	Coal	Scrub M1-2, Retire C1-3, U3	**$21,630**
6	Combo	Scrub M1-2, Retire C1-3 , U3 on gas	**$29,595**
3	Coal	Scrub C3, M1-2, Retire C1-2, U3	**$45,505**
2	Coal	Scrub C3, U3, M1-2, Retire C1-2	**$64,923**
1	Coal	Scrub All	**$99,309**

NOTE: In the above table, U3 refers to Urquhart Unit 3; M1-M2 refers to the McMeekin Units 1 and 2 and C1, C2, C3 refers to the Canadys Units 1, 2 and 3.

Retiring all six units in 2017 has the smallest levelized incremental revenue requirement over the 25 year study horizon. This is listed as Scenario 7 in the table above. A close second alternative, listed above as Scenario 9, is to operate Urquhart Unit 3 and both McMeekin Units 1 and 2 using natural gas and retiring Canadys Units 1, 2 and 3. Based on these results and the existing environmental regulations, the Company's reference resource plan calls for the retirement of the three Canadys units with the commercial operation of V.C. Summer Unit #2 and the retirement of the three remaining coal-fired units with the commercial operation of V.C. Summer Unit #3 in 2018. Although today's reference resource plan calls for the retirement of the six coal-fired units, the Company will continue to monitor, among other things, developments in environmental regulation and will continue to analyze its options and modify the plan as needed to benefit its customers.

Short Range Perspective: The Company also evaluated possible steps to be taken in the short term as a result of the existing environmental regulations and the Company's long-range reference resource plan as described above. SCE&G has identified three short-term steps that it believes will benefit its customers and support the Company's long-range reference resource plan. Those steps are described in more detail below.

STEP 1: SCE&G intends to retire the coal handling facilities at Urquhart Station and commit to operating Unit 3 at Urquhart Station exclusively on natural gas by the end of 2012. SCE&G projects that fixed O&M costs will be reduced by about $2 million per year and that the Company will save about $3 million in capital costs, which is a benefit to its customers. Additionally, SCE&G anticipates that operating Unit 3 at Urquhart Station exclusively on natural gas will provide environmental benefits in terms of reductions in air emissions and coal combustion waste. As a result of operating Unit 3 exclusively on natural gas, over the next five years SCE&G anticipates generating about 317 million kWh more with natural gas and 359 million kWh less with coal which would result in emission reductions of about 5,000 tons of SO_2, 420 tons of NO_X and almost 190,000 tons of CO_2 as well as reducing coal ash by about 14,000 tons.

STEP 2: SCE&G also intends to retire Unit 1 at Canadys Station by the end of 2012. SCE&G projects that fixed O&M costs will be reduced by about $1.5 million and that the Company will save about $21 million in avoided capital expenditures. As a result of the retirement of Unit 1 at Canadys Station, over the next five years SCE&G anticipates generating about 615 million kWh more with natural gas and 679 million kWh less with coal which would result in emission reductions of almost 12,000 tons of SO_2, 1,200 tons of NO_X and over 500,000 tons of CO_2 as well as reducing coal ash by about 30,000 tons. The retirement of the 90-MW Unit 1 at Canadys Station will increase the reserve margin deficit prior to the addition of V.C. Summer Unit #2; however, filling this capacity deficit should cost significantly less than the $28.5 million in anticipated savings.

STEP 3: The EPA's MATS rule requires compliance in three years, by April 2015. The rule offers the potential of a one-year waiver which the EPA indicated would be liberally granted. A waiver for a second one-year extension is also available to preserve reliability, but the EPA does not expect to grant many of these waivers. Although SCE&G is considering applying for these waivers, it cannot assume that the waivers will be granted and has therefore begun analyzing the possibility of operating Units 2 and 3 at Canadys Station and Units 1 and 2 at McMeekin Station exclusively on natural gas by April 2015. The deliverability of natural gas to these units appears to be the most critical uncertainty.

In conclusion, these short range steps support the Company's long-range reference resource plan. These steps significantly reduce emissions and allow the Company to achieve compliance with existing environmental regulations in a manner that provides an economic benefit to its customers.

As stated above, the Company will continue to monitor, among other things, developments in environmental regulation and will continue to analyze its options and modify both its short- and long-range plans as needed to benefit its customers.

Scenario Planning and Risk

There is considerable uncertainty associated with planning for the future. Two principle sources of uncertainty are the economy and the state of federal environmental regulations. The economy has been officially out of recession since June 2009, but growth since then has been slow. Economists look to the unrest in the Middle East and to the economic troubles of the European Union and conclude that there could be another recession coming. On the other hand, it is possible that those matters could resolve themselves and the U.S. economy could re-ignite producing strong economic growth resulting in increased sales growth for the Company. On the regulatory front there is also considerable uncertainty. As discussed previously the CSAPR rules are under a court injunction, the MATS regulations have been finalized but are being challenged, the 316(b) water regulations and the coal ash regulations have not been finalized yet and the greenhouse gas regulations for new units are out but existing units may get caught by them through new source review standards if significant maintenance is performed. Electric and gas utilities and their customers are currently benefiting from a depressed natural gas market price caused principally by the new technology called “fracking”. This technique has its detractors in the environmental community and the EPA expects to report the results of its investigation next year. Regardless of the outcome, if the emission of CO_2 into the atmosphere continues to be a concern, then utilities should expect at some point in the future more regulations on the burning of natural gas not unlike those being promulgated for the burning of coal.

While there is considerable uncertainty in the future, SCE&G is in the enviable position of having a robust resource plan to serve its electric customers. Having made the commitment to a nuclear strategy several years ago, the Company has significantly mitigated the environmental and cost risks associated with a reliance on fossil fuels. With two new nuclear units in its fleet of generators, SCE&G will lower its emissions of CO_2, SO_X, NO_X and particulates as well as avoid the creation of a significant amount of coal ash. If the U.S. Congress passes a Clean Energy Bill, then the Company’s resource plan is most likely already in compliance. However, the Company’s resource plan will not meet a Renewable Portfolio Standard (“RPS”) that excludes nuclear power. Currently, renewable power is more costly than conventional alternatives so an RPS would result in higher costs for our customers. However the Department of Energy has established cost effectiveness goals for solar power and for off-shore wind. These goals are summarized in the following table.

	Year	Goal
Offshore Wind	2020	10 c/KWh
Offshore Wind	2030	7 c/KWh
PV Solar	2017	$1.00/Watt

The off-shore wind goals were set jointly by the U. S. Department of Energy and the U. S. Department of the Interior. The solar cost goal, which is to reduce the current cost by 75%, is part of the DOE’s SunShot Initiative. If the DOE can accomplish these goals, then renewable energy would be more cost competitive as a supply resource. The 2020 time frame is good for SCE&G’s resource plans because by this time the new nuclear units will be online and SCE&G will be looking for additional capacity to serve the growing load on its system.

Risk Analysis: Because of the many unknown factors described above and because of other factors described below, the Company feels that the level of uncertainty about the future is particularly acute at the present time. Below are a few more sources of uncertainty directly affecting the load forecast that should be considered.

1. The nation and SCE&G's service territory are still recovering from the Great Recession. It is unclear among economists and others whether the slow pace of recovery will continue or be replaced by a more robust growth pattern.
2. Electric (and gas) customers throughout the country have implemented conservation measures to reduce their energy consumption and associated bills largely in response to economic conditions but also in response to a national consciousness of the issue. It is unclear whether this will be a short-lived phenomenon or one that will become a more permanent aspect of customer behavior.
3. The federal government is channeling large sums of money to state and local governments to stimulate energy efficiency programs. The impact of the resulting programs is difficult to quantify.
4. SCE&G has implemented a new set of energy efficiency programs among its customer base providing information and monetary incentives to encourage customers to implement energy efficiency and conservation measures. The effectiveness of these programs depends on customer acceptance which is difficult to predict. The energy impacts in the short run and the persistence of these impacts in the long run provide a source of significant uncertainty.
5. SCE&G is following the development of electric vehicles in the market place. Over the next several years these vehicles are not likely to put a significant load on our generators but they will have a localized impact on our distribution system. With the recently enacted $2,000 tax credit in South Carolina available up to a statewide limit of $200,000 annually through 2017 along with the federal tax credit of up to $7,500 available to a maximum of 200,000 vehicles per manufacturer, the deployment of a certain number of electric vehicles in the SCE&G service area is assured.
6. In 1978, the federal National Energy Act was signed into law and began more than 30 years of programs and regulations to increase energy efficiency in the country. While these efforts have raised awareness and encouraged or mandated energy efficiency, the need for power nevertheless continued to grow. Based on this experience, SCE&G looks

to the future with uncertainty when it considers the proliferation of electronic devices such as large screen TVs and electronic billboards and the possible development of a large market for electric vehicles.

Due to the uncertainty described above and that highlighted by consideration of possible future scenarios, it is particularly important to develop a range of possible forecast outcomes. By developing a resource plan to meet a reference, a high and a low forecast, the Company will highlight future risks and can better plan to meet the energy needs of its customers. When generating forecast scenarios, it is important to determine a reasonable methodology to derive alternative energy and peak demand growth patterns. A scenario based on an unreasonably high or low forecast would not be useful. The approach chosen is to review the historical record of SCE&G's energy sales, by class, over the past forty years, and then establish "high" and "low" growth rates from that sample. This offers several advantages. First, determination of growth rates by class should give a better estimate of territorial sales since the estimate is based on a higher level of detail. For example, residential growth percentages were developed by examination of customer growth and average use changes over time. Secondly, the future growth prospects of the major customer classes will vary, and it is possible to explicitly capture the impact of the different growth rates on total sales. Finally, a review of historical data allows one to see the major events which have occurred in the past and their impact on SCE&G's electric sales, and then to incorporate those patterns into the growth scenarios.

The nearby table shows the 15-year annual compound growth rate in sales that result from the reference forecasting methodology for major customer classes. The "reference" growth rate is compared to the "high load" scenario and the "low load" scenario. The table also shows the historical growth in sales to these customer classes for the pre-recession period 1990-2005.

Assumptions For High and Low Sales Scenarios				
	15-Year Projection of Annual Percent Growth			
	Reference Forecast	High Load Scenario	Low Load Scenario	Pre-Recession History
Residential	0.8	1.5	0.0	2.7
Commercial	1.4	2.0	0.5	3.2
Industrial	1.3	2.3	0.6	2.6
Territorial	1.2	1.9	0.4	2.8

The high load scenario also assumes that the impact of energy efficiency will be 75% of that reflected in the base forecast while, for the low load scenario, it was assumed that the energy efficiency impact of SCE&G's new energy efficiency programs would be 25% more effective. If SCE&G's service territory recovers from the recession quickly and growth returns to more normal levels as experienced historically, then the high load scenario may be more reflective of SCE&G's future load growth. On the other hand, if the recovery from the recession continues to be slow with long lasting effects, then the low load scenario may be a better representation of future growth.

The following table compares the territorial firm peak demand forecast under the low, reference and high scenarios.

Firm Peak Demand Scenarios (MWs)					
Year	Low Scenario	Delta	Reference Scenario	Delta	High Scenario
2012	4,750	0	4,750	0	4,750
2013	4,772	0	4,772	0	4,772
2014	4,752	-100	4,852	115	4,967
2015	4,796	-133	4,929	186	5,115
2016	4,871	-164	5,035	210	5,245
2017	4,919	-200	5,119	228	5,347
2018	4,947	-229	5,176	251	5,427
2019	4,975	-264	5,239	274	5,513
2020	5,016	-297	5,313	302	5,615
2021	5,040	-328	5,368	328	5,696
2022	5,085	-362	5,447	353	5,800
2023	5,135	-394	5,529	378	5,907
2024	5,181	-431	5,612	400	6,012
2025	5,224	-467	5,691	423	6,114
2026	5,268	-500	5,768	450	6,218

If SCE&G's territory experiences growth comparable to pre-recession levels, then the firm peak demand on the system will be more like that of the high scenario, adding as much as 451 MWs to the demand in 2026. On the other hand if the slow pace of the current recovery continues, then the peak demand is likely to be as much as 499 MWs less than in the reference scenario.

Projected Loads and Resources

SCE&G's resource plan for the next 15 years is shown in the table labeled "SCE&G Forecast Loads and Resources – 2012 IRP – Reference Scenario" on a subsequent page. The resource plan shows the need for additional capacity and identifies, on a preliminary basis, whether the need is for peaking/intermediate capacity or base load capacity.

On line 11 the resource plan shows decreases in capacity which relate to the retirement of coal units as previously discussed. The resource plan shows the addition of peaking capacity on line 9 and the addition of a firm one year capacity purchase on line 13, both as needed to maintain the reserve margin within the target range.

Two additional resource plans are shown in the following pages: one for the high load growth scenario and one for the low load scenario. Under both these scenarios SCE&G is able to adjust its retirement strategy to maintain system reliability.

The Company believes that its supply plan, summarized in the following table, will be as benign to the environment as possible because of the Company's continuing efforts to utilize state-of-the-art emission reduction technology in compliance with state and federal laws and regulations. The supply plan will also help SCE&G keep its cost of energy service at a minimum since the generating units being added are competitive with alternatives in the market.

SCE&G Forecast of Summer Loads and Resources - 2012 IRP (Reference Scenario)

	YEAR	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Forecast																
1	Baseline Trend	4989	5030	5156	5268	5411	5531	5624	5725	5842	5946	6058	6177	6299	6419	6540
2	EE Impact	-21	-37	-79	-111	-144	-177	-211	-247	-288	-334	-365	-400	-437	-476	-518
3	Gross Territorial Peak	4968	4993	5077	5157	5267	5354	5413	5478	5554	5612	5693	5777	5862	5943	6022
4	Demand Response	-218	-221	-225	-228	-232	-235	-237	-239	-241	-244	-246	-248	-250	-252	-254
5	Net Territorial Peak	4750	4772	4852	4929	5035	5119	5176	5239	5313	5368	5447	5529	5612	5691	5768
6	Firm Contract Sales	250														
7	Total Firm Obligation	5000	4772	4852	4929	5035	5119	5176	5239	5313	5368	5447	5529	5612	5691	5768
System Capacity																
8	Existing	5689	5689	5599	5599	5599	5599	5918	6187	6187	6187	6187	6280	6373	6466	6559
	Additions															
9	Peaking/Intermediate											93	93	93	93	93
10	Baseload						614	614								
11	Other		-90				-295	-345								
12	Total System Capacity	5689	5599	5599	5599	5599	5918	6187	6187	6187	6187	6280	6373	6466	6559	6652
13	Firm Annual Purchase				25	150										
14	Total Production Capability	5689	5599	5599	5624	5749	5918	6187	6187	6187	6187	6280	6373	6466	6559	6652
Reserves																
15	Margin (L14-L7)	689	827	747	695	714	799	1011	948	874	819	833	844	854	868	884
16	% Reserve Margin (L15/L7)	13.8%	17.3%	15.4%	14.1%	14.2%	15.6%	19.5%	18.1%	16.5%	15.3%	15.3%	15.3%	15.2%	15.3%	15.3%
17	% NERC Res.Mrgn L15/(L7-L4)	13.2%	16.6%	14.7%	13.5%	13.6%	14.9%	18.7%	17.3%	15.7%	14.6%	14.6%	14.6%	14.6%	14.6%	14.7%

Note: L17 shows the reserve margin calculated according to NERC's new definition. See the following link for details:
http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf

SCE&G Forecast of Summer Loads and Resources - 2012 IRP (High Load Scenario)

	YEAR	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Forecast																
1	Baseline Trend	4989	5030	5279	5464	5634	5776	5896	6022	6172	6304	6443	6592	6738	6884	7034
2	EE Impact	-21	-37	-83	-116	-150	-184	-218	-256	-299	-345	-378	-413	-450	-490	-532
3	Gross Territorial Peak	4968	4993	5196	5348	5484	5592	5678	5766	5873	5959	6065	6179	6288	6394	6502
4	Demand Response	-218	-221	-228	-233	-239	-244	-249	-253	-258	-263	-267	-272	-276	-280	-284
5	Net Territorial Peak	4750	4772	4968	5115	5245	5348	5429	5513	5615	5696	5798	5907	6012	6114	6218
6	Firm Contract Sales	250														
7	Total Firm Obligation	5000	4772	4968	5115	5245	5348	5429	5513	5615	5696	5798	5907	6012	6114	6218
System Capacity																
8	Existing	5689	5689	5599	5599	5599	5599	5918	6187	6280	6466	6559	6652	6745	6931	7024
	Additions															
9	Peaking/Intermediate								93	186	93	93	93	186	93	93
10	Baseload						614	614								
11	Other		-90				-295	-345								
12	Total System Capacity	5689	5599	5599	5599	5599	5918	6187	6280	6466	6559	6652	6745	6931	7024	7117
13	Firm Annual Purchase			75	250	375	175									
14	Total Production Capability	5689	5599	5674	5849	5974	6093	6187	6280	6466	6559	6652	6745	6931	7024	7117
Reserves																
15	Margin (L14-L7)	689	827	706	734	729	745	758	767	851	863	854	838	919	910	899
16	% Reserve Margin (L15/L7)	13.8%	17.3%	14.2%	14.3%	13.9%	13.9%	14.0%	13.9%	15.2%	15.2%	14.7%	14.2%	15.3%	14.9%	14.5%
17	% NERC Res.Mrgn L15/(L7-L4)	13.2%	16.6%	13.6%	13.7%	13.3%	13.3%	13.3%	13.3%	14.5%	14.5%	14.1%	13.6%	14.6%	14.2%	13.8%

	SCE&G Forecast of Summer Loads and Resources - 2012 IRP (Low Load Scenario)														
	YEAR	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Load Forecast																
1	Baseline Trend	4989	5030	5052	5128	5236	5317	5378	5444	5525	5593	5669	5752	5836	5918	6003
2	EE Impact	-21	-37	-76	-107	-138	-169	-203	-238	-278	-322	-353	-386	-422	-460	-501
3	Gross Territorial Peak	4968	4993	4976	5021	5098	5148	5175	5206	5247	5271	5316	5366	5414	5458	5502
4	Demand Response	-218	-221	-223	-225	-227	-229	-229	-230	-230	-231	-231	-232	-233	-233	-234
5	Net Territorial Peak	4750	4772	4753	4796	4871	4919	4946	4976	5017	5040	5085	5134	5181	5225	5268
6	Firm Contract Sales	250														
7	Total Firm Obligation	5000	4772	4753	4796	4871	4919	4946	4976	5017	5040	5085	5134	5181	5225	5268
System Capacity																
8	Existing	5689	5689	5599	5599	5599	5599	5918	6187	6187	6187	6187	6187	6187	6187	6187
	Additions															
9	Peaking/Intermediate															
10	Baseload						614	614								
11	Other		-90				-295	-345								
12	Total System Capacity	5689	5599	5599	5599	5599	5918	6187	6187	6187	6187	6187	6187	6187	6187	6187
13	Firm Annual Purchase															
14	Total Production Capability	5689	5599	5599	5599	5599	5918	6187	6187	6187	6187	6187	6187	6187	6187	6187
Reserves																
15	Margin (L14-L7)	689	827	846	803	728	999	1241	1211	1170	1147	1102	1053	1006	962	919
16	% Reserve Margin (L15/L7)	13.8%	17.3%	17.8%	16.7%	14.9%	20.3%	25.1%	24.3%	23.3%	22.8%	21.7%	20.5%	19.4%	18.4%	17.4%
17	% NERC Res.Mrgn L15/(L7-L4)	13.2%	16.6%	17.0%	16.0%	14.3%	19.4%	24.0%	23.3%	22.3%	21.8%	20.7%	19.6%	18.6%	17.6%	16.7%

THIS PAGE INTENTIONALLY LEFT BLANK

V. Transmission System Assessment and Planning

SCE&G's transmission planning practices develop and coordinate a program that provides for timely modifications to the SCE&G transmission system to ensure a reliable and economical delivery of power. This program includes the determination of the current capability of the electrical network and a ten-year schedule of future additions and modifications to the system. These additions and modifications are required to support customer growth, provide emergency assistance and maintain economic opportunities for our customers while meeting SCE&G and industry transmission performance standards.

SCE&G has an ongoing process to determine the current and future performance level of the SCE&G transmission system. Numerous internal studies are undertaken that address the service needs of our customers. These needs include: 1) distributed load growth of existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers and 3) customers who use only transmission services on the SCE&G system.

SCE&G has developed and adheres to a set of internal <u>Long Range Planning Criteria</u> which can be summarized as follows:

> *The requirements of the SCE&G "LONG RANGE PLANNING CRITERIA" will be satisfied if the system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.*
>
> *a. Loss of any bus and associated facilities operating at a voltage level of 115kV or above*
> *b. Loss of any line operating at a voltage level of 115kV or above*
> *c. Loss of entire generating capability in any one plant*
> *d. Loss of all circuits on a common structure*
> *e. Loss of any transmission transformer*
> *f. Loss of any generating unit simultaneous with the loss of a single transmission line*
>
> *Outages more severe are considered acceptable if they will not cause equipment damage or result in uncontrolled cascading outside the local area.*

Furthermore, SCE&G subscribes to the set of mandatory Electric Reliability Organization ("ERO"), also known as the North American Electric Reliability Corporation ("NERC"), Reliability Standards for Transmission Planning, as approved by the NERC Board of Trustees and the Federal Energy Regulatory Commission ("FERC"). SCE&G assesses and designs its transmission system to be compliant with the requirements as set forth in these standards. A copy of the NERC Reliability Standards is available at the NERC website http://www.nerc.com/.

The SCE&G transmission system is interconnected with Progress Energy – Carolinas, Duke Energy, South Carolina Public Service Authority ("Santee Cooper"), Georgia Power ("Southern Company") and the Southeastern Electric Power Administration ("SEPA") systems. Because of these interconnections with neighboring systems, system conditions on other systems can affect the capabilities of the SCE&G transmission system and also system conditions on the SCE&G transmission system can affect other systems. SCE&G participates with other transmission planners throughout the southeast to develop current and future power flow and stability models of the integrated transmission grid for the NERC Eastern Interconnection. All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, SCE&G evaluates its current and future transmission system for compliance with the SCE&G Long Range Planning Criteria and the NERC Reliability Standards.

To ensure the reliability of the SCE&G transmission system while considering conditions on other systems and to assess the reliability of the integrated transmission grid, SCE&G participates in assessment studies with neighboring transmission planners in South Carolina, North Carolina and Georgia. Also, SCE&G on a periodic and ongoing basis participates with other transmission planners throughout the southeast to assess the reliability of the southeastern integrated transmission grid for the long-term horizon (up to 10 years) and for upcoming seasonal (summer and winter) system conditions.

The following is a list of joint studies with neighboring transmission owners completed over the past year:

1. 2011 January OASIS Study
2. 2011 April OASIS Study
3. 2011 July OASIS Study
4. 2011 October OASIS Study
5. SERC NTSG Reliability 2011 Summer Study
6. SERC NTSG Reliability 2011/2012 Winter Study
7. SERC LTSG 2017 Summer Future Year Study
8. CTCA 2015/2018 Summer Study
9. SERC East/RFC/NPCC 2011 Summer Study
10. SERC East/RFC/NPCC 2020 Summer Study
11. SCE&G-Duke Tie Line Study

12. SCE&G-Santee Cooper-Southern Tie Line Study

where the acronyms used above have the following reference:

OASIS – Open Access Same-time Information System
SERC – SERC Reliability Corporation
NTSG – Near Term Study Group of SERC
LTSG – Long Term Study Group of SERC
CTCA – Carolinas Transmission Coordination Arrangement
RFC – Reliability First Corporation
NPCC – Northeast Power Coordination Council

These activities, as discussed above, provide for a reliable and cost effective transmission system for SCE&G customers.

Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative ("EIPC") was initiated by a coalition of regional Planning Authorities. These Planning Authorities are entities listed on the NERC compliance registry as Planning Authorities and represent the entire Eastern Interconnection. The EIPC was founded to be a broad-based, transparent collaborative process among all interested stakeholders:

- State and Federal policy makers
- Consumer and environmental interests
- Transmission Planning Authorities
- Market participants generating, transmitting or consuming electricity within the Eastern Interconnection

The EIPC provides a grass-roots approach which builds upon the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities. This approach provides coordinated interregional analysis for the entire Eastern Interconnection guided by the consensus input of an open and transparent stakeholder process.

The EIPC represents a first-of-its-kind effort, to involve Planning Authorities in the Eastern Interconnection to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. This work builds upon, rather than replaces, the current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the entire Eastern Interconnection. Those processes are informed by the EIPC analysis efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options.

FERC Order 1000 – Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order 1000 – Transmission Planning and Cost Allocation by Transmission Owning and Operating Utilities. With respect to transmission planning, this Final Rule: (1) requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) requires that each public utility transmission provider amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; (3) removes from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improves coordination between neighboring transmission planning regions for new interregional transmission facilities. Also, this Final Rule requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule. Each cost allocation method must satisfy six cost allocation principles.

SCE&G is working with Santee Cooper to develop processes, procedures and systems to achieve compliance with the regional requirements, which must be implemented by October 2012 and working with other neighboring transmission operators to achieve compliance with the interregional requirements, which must be implemented by April 2013.

Appendix A

Short Range Methodology

This section presents the development of the short-range electric sales forecasts for the Company. 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 SIC (Standard Industrial Classification) codes. Residential customers were classified by housing type (single family, multi-family, and mobile homes), rate, and by a statistical estimate of weather sensitivity. For each forecasting group, the number of customers and either total usage or average usage was estimated for each month of the forecast period.

The short-range methodologies used to develop these models were determined primarily by available data, both historical and forecast. Monthly sales data by class and rate are generally available historically. Daily heating and cooling degree data for Columbia and Charleston are also available historically, and were projected using a 15-year average of the daily values. Industrial production indices are also available by SIC on a quarterly basis, and can be transformed to a monthly series. Therefore, sales, weather, industrial production indices, and time dependent variables were used in the short range forecast. In general, the forecast groups fall into two classifications, weather sensitive and non-weather sensitive. For the weather sensitive classes, regression analysis was the methodology used, while for the non-weather sensitive classes regression analysis or time series models based on the autoregressive integrated moving average (ARIMA) approach of Box-Jenkins were used.

The short range forecast developed from these methodologies was also adjusted for DSM programs, new industrial loads, terminated contracts, or economic factors as discussed in Section 3.

Regression Models

Regression analysis is a method of developing an equation which relates one variable, such as usage, to one or more other variables which help explain fluctuations and trends in the first. This method is mathematically constructed so that the resulting combination of explanatory variables produces the smallest squared error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. Several statistics which indicate the success of the regression analysis fit are shown for each model. Several of these indicators are R^2, Root Mean Squared Error, Durbin-Watson Statistic, F-Statistic, and the T-Statistics of the Coefficient. PROC REG of SAS[1] was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

Two variables were used extensively in developing weather sensitive average use models: heating degree days ("HDD") and cooling degree days ("CDD"). The values for HDD and CDD are the average of the values for Charleston and Columbia. The base for HDD was 60^o and for CDD was 75^o. In order to account for cycle billing, the degree day values for each day were weighted by the number of billing cycles which included that day for the current month's billing. The daily weighted degree day values were summed to obtain monthly degree day values. Billing sales for a calendar month may actually reflect consumption that occurred in the previous month based on weather conditions in that period and also consumption occurring in the current month. Therefore, this method should more accurately reflect the impact of weather variations on the consumption data.

The development of average use models began with plots of the HDD and CDD data versus average use by month. This process led to the grouping of months with similar average use patterns. Summer and winter groups were chosen, with the summer models including the months of May through October, and the winter models including the months of November through April. For each of the groups, an average use model was developed. Total usage models were developed with a similar methodology for the municipal and cooperative customers. For these customers, HDD and CDD were weighted based on Cycle 20 distributions. This is the last reading date for bills in any given month, and is generally used for larger customers.

Simple plots of average use over time revealed significant changes in average use for some customer groups. Three types of variables were used to measure the effect of time on average use:

1. Number of months since a base period;
2. Dummy variable indicating before or after a specific point in time; and,
3. Dummy variable for a specific month or months.

Some models revealed a decreasing trend in average use, which is consistent with conservation efforts and improvements in energy efficiency. However, other models showed an increasing average use over time. This could be the result of larger houses, increasing appliance saturations, lower real electricity prices, and/or higher real incomes.

ARIMA Models

Autoregressive integrated moving average ("ARIMA") procedures were used in developing the short range forecasts. For various class/rate groups, they were used to develop customer estimates, average use estimates, or total use estimates.

ARIMA procedures were developed for the analysis of time series data, i.e., sets of observations generated sequentially in time. This Box-Jenkins approach is based on the assumption that the behavior of a time series is due to one or more identifiable influences. This method recognizes three effects that a particular observation may have on subsequent values in the series:

1. A decaying effect leads to the inclusion of autoregressive (AR) terms;
2. A long-term or permanent effect leads to integrated (I) terms; and,
3. A temporary or limited effect leads to moving average (MA) terms.

Seasonal effects may also be explained by adding additional terms of each type (AR, I, or MA).

The ARIMA procedure models the behavior of a variable that forms an equally spaced time series with no missing values. The mathematical model is written:

$$Z_t = u + Y_i \ (B)\ X_{i,t} \ + \ q\ (B) / f\ (B)\ a_t$$

This model expresses the data as a combination of past values of the random shocks and past values of the other series, where:

t indexes time

B is the backshift operator, that is $B\ (X_t) = X_{t-1}$

Z_t is the original data or a difference of the original data

f(B) is the autoregressive operator, $f(B) = 1 – f_1 B - \ldots - f_1 B^p$

u is the constant term

q(B) is the moving average operator, $q\ (B) = 1 - q_1\ B - ... - q_q\ B^q$

a_t is the independent disturbance, also called the random error

$X_{i,t}$ is the ith input time series

$y_i(B)$ is the transfer function weights for the ith input series (modeled as a ratio of polynomials)

$y_i(B)$ is equal to $w_i\ (B) / d_i\ (B)$, where $w_i\ (B)$ and $d_i\ (B)$ are polynomials in B.

The Box-Jenkins approach is most noted for its three-step iterative process of identification, estimation, and diagnostic checking to determine the order of a time series. The autocorrelation and partial autocorrelation functions are used to identify a tentative model for univariate time series. This tentative model is estimated. After the tentative model has been fitted to the data, various checks are performed to see if the model is appropriate. These checks involve analysis of the residual series created by the estimation process and often lead to refinements in the tentative model. The iterative process is repeated until a satisfactory model is found.

Many computer packages perform this iterative analysis. PROC ARIMA of (SAS/ETS)[2] was used in developing the ARIMA models contained herein. The attractiveness of ARIMA models comes from data requirements. ARIMA models utilize data about past energy use or customers to forecast future energy use or customers. Past history on energy use and customers serves as a proxy for all the measures of factors underlying energy use and customers when other variables were not available. Univariate ARIMA models were used to forecast average use or total usage when weather-related variables did not significantly affect energy use or alternative independent explanatory variables were not available.

Footnotes

1. SAS Institute, Inc., SAS/STAT[tm] Guide for Personal Computers, Version 6 Edition. Cary, NC: SAS Institute, Inc., 1987.

2. SAS Institute, Inc., SAS/ETS User's Guide, Version 6, First Edition. Cary, NC: SAS Institute, Inc., 1988.

Electric Sales Assumptions

For short-term forecasting, over 30 forecasting groups were defined using the Company's customer class and rate structures. Industrial (Class 30) Rate 23 was further divided using SIC codes. In addition, twenty-nine large industrial customers were individually projected. The residential class was disaggregated into several sub-groups, starting first with rate. Next, a regression analysis was done to separate customers into two categories, “more weather-sensitive” and “less weather sensitive”. Generally speaking, the former group is associated with electric space heating, and the latter those without electric space heating. Finally, these categories were divided by housing type (single family, multi-family, and mobile homes). Each municipal and cooperative account represents a forecasting group and was also individually forecast. Discussions were held with Industrial Marketing and Economic Development representatives within the Company regarding prospects for industrial expansions or new customers, and adjustments made to customer, rate, or account projections where appropriate. Table 1 contains the definition for each group and Table 2 identifies the methodology used and the values forecasted by forecasting groups.

The forecast for Company Use is based on historic trends and adjusted for Summer nuclear plant outages. Unaccounted energy, which is the difference between generation and sales and represents for the most part system losses, is usually about 4.6% of total territorial sales. The monthly allocations for unaccounted for were based on a regression model using normal total degree-days for the calendar month and total degree-days weighted by cycle billing. Adding Company use and unaccounted energy to monthly territorial sales produces electric generation requirements.

TABLE 1
Short-Term Forecasting Groups

Class Number	Class Name	Rate/SIC Designation	Comment
10	Residential Non-Space Heating	Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
		Multi Family	67, 68, 69
910	Residential Space Heating	Mobile Homes	
20	Commercial Non-Space Heating	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other Rates	1, 3, 10, 11, 14, 16, 17, 18, 24, 25, 26, 27, 29, 62, 67, 69
920	Commercial Space Heating	Rate 9	Small General Service
30	Industrial Non-Space Heating	Rate 9	Small General Service
		Rate 20, 21	Medium General Service
		Rate 23, SIC 22	Textile Mill Products
		Rate 23, SIC 24	Lumber, Wood Products, Furniture and Fixtures (SIC Codes 24 and 25)
		Rate 23, SIC 26	Paper and Allied Products
		Rate 23, SIC 28	Chemical and Allied Products
		Rate 23, SIC 30	Rubber and Miscellaneous Products
		Rate 23, SIC 32	Stone, Clay, Glass, and Concrete
		Rate 23, SIC 33	Primary Metal Industries; Fabricated Metal Products; Machinery; Electric and Electronic Machinery, Equipment and Supplies; and Transportation Equipment (SIC Codes 33-37)
		Rate 23, SIC 99	Other or Unknown SIC Code*
		Rate 24, 27, 60	Large General Service
		Other	Rates 18, 25, and 26
60	Street Lighting	Rates 3, 9, 13, 17, 18, 25, 26, 29, and 69	
70	Other Public Authority	Rates 3, 9, 20, 21, 25, 26, 29, 65 and 66	
92	Municipal	Rate 60, 61	Three Individual Accounts
97	Cooperative	Rate 60	One Account

*Includes small industrial customers from all SIC classifications that were not previously forecasted individually. Industrial Rate 23 also includes Rate 24. Commercial Rate 24 also includes Rate 23.

TABLE 2

Summary of Methodologies Used To Produce
The Short Range Forecast

Value Forecasted	Methodology	Forecasting Groups
Average Use	Regression	Class 10, All Groups
		Class 910, All Groups
		Class 20, Rates 9, 12, 20, 22, 24, 99
		Class 920, Rate 9
		Class 70, Rate 3
Total Usage	ARIMA/ Regression	Class 30, Rates 9, 20, 99, and 23, for SIC = 91 and 99
		Class 930, Rate 9
		Class 60
		Class 70, Rates 65, 66
	Regression	Class 92, All Accounts
		Class 97, All Accounts
Customers	ARIMA	Class 10, All Groups
		Class 910, All Groups
		Class 20, All Rates
		Class 920, Rate 9
		Class 30, All Rates Except 60, 99, and 23 for SIC = 22, 24, 26, 28, 30, 32, 33, and 91
		Class 930, Rate 9
		Class 60
		Class 70, Rate 3

Appendix B

Long Range Sales Forecast

Electric Sales Forecast

This section presents the development of the long-range electric sales forecast for the Company. The long-range electric sales forecast was developed for seven classes of service: residential, commercial, industrial, street lighting, other public authorities, municipal 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, multi-family and mobile homes. In addition, two residential classes and residential street lighting were evaluated separately. 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 SIC 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 usage per customer were estimated separately and total sales were calculated as a product of the two.

The forecast for each class of service was developed utilizing an econometric approach. The structure of the econometric model was based upon the relationship between the variable to be forecasted and the economic environment, weather, conservation, and/or price.

Forecast Methodology

Development of the models for long-term forecasting was econometric in approach and used the technique of regression analysis. Regression analysis is a method of developing an equation, which relates one variable, such as sales or customers, to one or more other variables that are statistically correlated with the first, such as weather, personal income or population growth. Generally, the goal is to find the combination of explanatory variables producing the smallest error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. In the equation, the variable being explained equals the sum of the explanatory variables each multiplied by an estimated coefficient. Various statistics, which indicate the success of the regression analysis fit, were used to evaluate each model. The indicators were R^2, mean squared Error of the Regression, Durbin-Watson Statistic and the T-Statistics of the Coefficient. PROC REG and PROC AUTOREG of SAS were used to estimate all regression models. PROC REG was used for preliminary model specification, elimination of insignificant variables, and also for the final model specifications. Model development also included residual analysis for incorporating dummy variables and an analysis of how well the models fit the historical data, plus checks for any statistical problems such as autocorrelation or multicollinearity. PROC AUTOREG was used if autocorrelation was present as indicated by the Durbin-Watson statistic.

Prior to developing the long-range models, certain design decisions were made:

- The multiplicative or double log model form was chosen. This form allows forecasting based on growth rates, since elasticities with respect to each explanatory variable are given directly by their respective regression coefficients. Elasticity explains the responsiveness of changes in one variable (e.g. sales) to changes in any other variable (e.g. price). Thus, the elasticity coefficient can be applied to the forecasted growth rate of the explanatory variable to obtain a forecasted growth rate for a dependent variable. These forecasted growth rates were then applied to the last year of the short range forecast to obtain the forecast level for customers or sales for the long range forecast. This is a constant elasticity model, therefore, it is important to evaluate the reasonableness of the model coefficients.

- One way to incorporate conservation effects on electricity is through real prices, or time trend variables. Models selected for the major classes would include these variables, if they were statistically significant.
- The remaining variables to be included in the models for the major classes would come from four categories:
  1. Demographic variables - Population.
  2. Measures of economic well-being or activity: real personal income, real per capita income, employment variables, and industrial production indices.
  3. Weather variables - average summer/winter temperature or heating and cooling degree-days.
  4. Variables identified through residual analysis or knowledge of political changes, major economics events, etc. (e.g., gas price spike in 2005 and recession versus non-recession years).

Standard statistical procedures (all possible regressions, stepwise regression) were used to obtain preliminary specifications for the models. Model parameters were then estimated using historical data and competitive models were evaluated on the basis of:

- Residual analysis and traditional "goodness of fit" measures to determine how well these models fit the historical data and whether there were any statistical problems such as autocorrelation or multicollinearity.
- An examination of the model results for the most recently completed full year.

- An analysis of the reasonableness of the long-term trend generated by the models. The major criteria here was the presence of any obvious problems, such as the forecasts exceeding all rational expectations based on historical trends and current industry expectations.
- An analysis of the reasonableness of the elasticity coefficient for each explanatory variable. Over the years a host of studies have been conducted on various elasticities relating to electricity sales. Therefore, one check was to see if the estimated coefficients from Company models were in-line with others. As a result of the evaluative procedure, final models were obtained for each class.
- The drivers for the long-range electric forecast included the following variables.

Service Area Population
Service Area Real Per Capita Income
Service Area Real Personal Income
State Industrial Production Indices
Real Price of Electricity
Average Summer Temperature
Average Winter Temperature
Heating Degree Days
Cooling Degree Days

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties, which account for the vast majority of total territorial electric sales. Service area historic data and projections were used for all classes with the exception of the industrial class. Industrial productions indices were only available on a statewide basis, so forecasting relationships were developed using that data. Since industry patterns are generally based on regional and national economic patterns, this linking of Company industrial sales to a larger geographic index was appropriate.

Economic Assumptions

In order to generate the electric sales forecast, forecasts must be available for the independent variables. The forecasts for the economic and demographic variables were obtained from Global Insight, Inc. and the forecasts for the price and weather variables were based on historical data. The trend projection developed by Global Insight is characterized by slow, steady growth, representing the mean of all possible paths that the economy could follow if subject to no major disruptions, such as substantial oil price shocks, untoward swings in policy, or excessively rapid increases in demand.

Average summer temperature or CDD (Average of June, July, and August temperature) and average winter temperature or HDD (Average of December (previous year), January and February temperature) were assumed to be equal to the normal values used in the short range forecast.

Peak Demand Forecast

This section describes the procedures used to create the long-range summer and winter peak demand forecasts. It also describes the methodology used to forecast monthly peak demands. Development of summer peak demands will be discussed initially, followed by the construction of winter peaks.

Summer Peak Demand

The forecast of summer peak demands was developed with a load factor methodology. This methodology may be characterized as a building-block approach because class, rate, and some individual customer peaks are separately determined and then summed to derive the territorial peak.

Briefly, the following steps were used to develop the summer peak demand projections. Load factors for selected classes and rates were first calculated from historical data and then used to estimate peak demands from the projected energy consumption among these categories. Next, planning peaks were determined for a number of large industrial customers. The demands of these customers were forecasted individually. Summing these class, rate, and individual customer demands provided the forecast of summer territorial peak demand. Next, savings identified from SCE&G's demand-side management programs were removed. Finally, the incremental reductions in demand resulting from the Company's standby generator and interruptible programs were subtracted from the peak demand forecast. This calculation gave the firm summer territorial peak demand, which was used for planning purposes.

Load Factor Development

As mentioned above, load factors are required to calculate KW demands from KWH energy. This can be seen from the following equation, which shows the relationship between annual load factors, energy, and demand:

Load Factor = Energy/(Demand x 8760)

The load factor is thus seen to be a ratio of total energy consumption relative to what it might have been if the customer had maintained demand at its peak level throughout the year. The value of a system coincident load factor will usually range between 0 and 1, with lower values indicating more variation in a customer's consumption patterns, as typified by residential users with relatively large space-conditioning loads. Conversely, higher values result from more level demand patterns throughout the year, such as those seen in the industrial sector.

Rearrangement of the above equation makes it possible to calculate peak demand, given energy and a corresponding load factor. This form of the equation is used to project peak demand herein. The question then becomes one of determining an appropriate load factor to apply to projected energy sales.

The load factors used for the peak demand forecast were not based on one-hour coincident peaks. Instead, it was determined that use of a 4-hour average class peak was more appropriate for forecasting purposes. This was true for two primary reasons. First, analysis of territorial peaks showed that all of the summer peaks had occurred between the hours of 2 and 6 PM. However, the distribution of these peaks between those four hours was fairly evenly spread. It was thus concluded that while the annual peak would occur during the 4-hour band, it would not be possible to say with a high degree of confidence during which hour it would happen.

Second, the coincident peak demand of the residential and commercial classes depended on the hour of the peak's occurrence. This was due to the former tending to increase over the 4-hour band, while the latter declined. Thus, load factors based on peaks occurring at, say, 2 PM, would be quite different from those developed for a 5 PM peak. It should also be noted that the class contribution to peak is quite stable for groups other than residential and commercial. This means that the 4-hour average class demand, for say, municipals, was within 2% of the 1-hour coincident peak. Consequently, since the hourly probability of occurrence was roughly equal for peak demand, it was decided that a 4-hour average demand was most appropriate for forecasting purposes.

The effect of system line losses were embedded into the class load factors so they could be applied directly to customer level sales and produce generation level demands. This was a convenient way of incorporating line losses into the peak demand projections.

Energy Projections

For those categories whose peak demand was to be projected from KWH sales, the next requirement was a forecast of applicable sales on an annual basis. These projections were utilized in the peak demand forecast construction. In addition, street light sales were excluded from forecast sales levels when required, since there is no contribution to peak demand from this type of sale.

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The large industrial customers whose peak demands were developed separately were also added to this forecast.

Derivation of the planning peak required that the impact of demand reduction programs be subtracted from the unadjusted peak demand forecast. This is true because the capacity expansion plan is sized to meet the firm peak demand, which includes the reductions attributable to such programs.

Winter Peak Demand

To project winter peaks actual winter peak demands were correlated with three primary explanatory variables, total territorial energy, customers, and weather during the day of the winter peak's occurrence. Other dummy variables were also tested for inclusion in the model to account for unusual events, such as recessions or extremely cold winters, but the final model utilized the two variables named above.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in total territorial load is correlated with economic growth and activity in SCE&G's service area, and as such may be used as a proxy variable for those economic factors, which cause winter peak demand to change. It should be noted that the winter peak for any given year by industry convention is defined as occurring after the summer peak for that year. The winter period for each year is December of that year, along with January and February of the following year. For example, the winter peak in 1968 of 962 MW occurred on December 11, 1968, while the winter peak for 1969 of 1,126 MW took place on January 8, 1970. In addition to economic factors, weather also causes winter peak demand to fluctuate, so the impact of this element was measured by two variables: the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston and the minimum temperature on the peak day. The presence of a weather variable reduces the bias which would exist in the other explanatory variables' coefficients if weather were excluded from the regression model, given that the weather variable should be included. When the actual forecast of winter peak demand was calculated, the normal value of heating degree-days over the sample period was used. Although the ratio of winter to summer peak demands fluctuated over the sample period, it did show an increase over time. A primary cause for this increasing ratio was growth in the number of electric space heating customers. Due to the introduction and rapid acceptance of heat pumps over the past three decades, space-heating residential customers increased from less than 5,000 in 1965 to almost 217,000 in 2004, a 10.2% annual growth rate. However, this growth slowed dramatically in the 1990's, so the expectation is that the ratio of summer to winter peaks will change slowly in the future.