STATE OF SOUTH CAROLINA

South Carolina Electric & Gas Company's Integrated Resource Plan (IRP)

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

COVER SHEET

DOCKET NUMBER: 2014 - ____ - E

(Please type or print)

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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 Certificatio
☐ Electric/Telecommunications	☐ Answer	☐ Motion	☐ Request for Investigatior
☐ 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	☒ Other:
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	Integrated Resource Plan
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

K. Chad Burgess
Associate General Counsel

chad.burgess@scana.com

February 28, 2014

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 2014 Integrated Resource Plan
Docket No. 2014-____-E

Dear Ms. Boyd:

In accordance with S.C. Code Ann. § 58-37-40 (Supp. 2013) and Order No. 98-502 enclosed you will find the 2014 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2014 IRP"). This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann § 58-33-340.

By copy of this letter, we are also serving the South Carolina Office of Regulatory Staff and the South Carolina Energy Office with a copy of the SCE&G 2014 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,

K. Chad Burgess

K. Chad Burgess

KCB/kms
cc: John W. Flitter
Jeffery M. Nelson, Esquire
Ashlie Lancaster
(all via electronic and U.S. First Class Mail)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2014-___-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 **2014 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:

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Karen M. Scruggs

Karen M. Scruggs

Cayce, South Carolina
This 28th day of February 2014

2014

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

Introduction

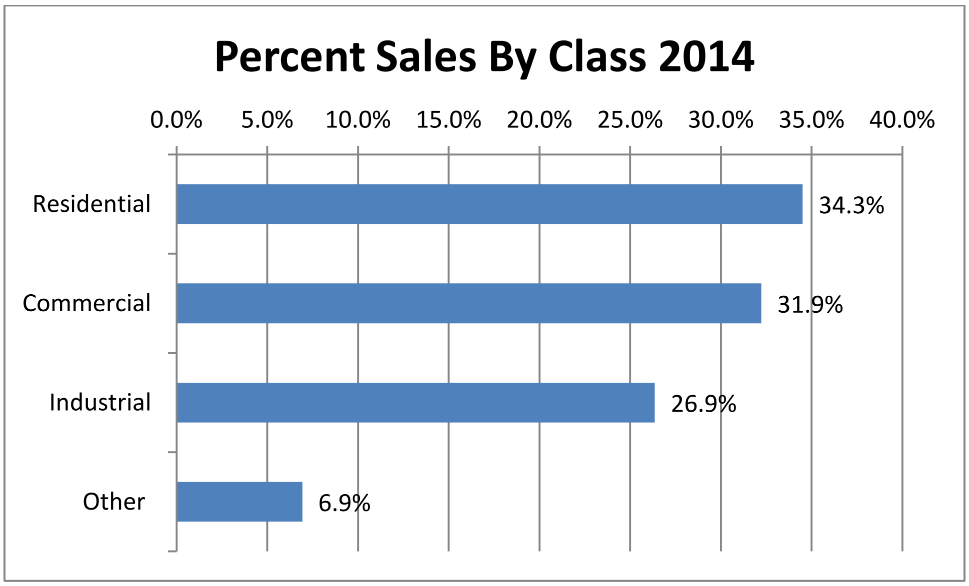
This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2014 through 2028. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (Supp. 2013) 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 (Supp. 2013). The objective of the Company's IRP is to develop a resource plan that will provide reliable and economically priced energy to its customers while complying with all environmental laws and regulations.

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2028

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 1.6% per year over the next 15 years, while firm territorial summer peak demand and winter peak demand will increase at 1.6% and 1.7% per year, respectively, over this forecast horizon. The table below contains these projected loads. By convention winter follows summer.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2014	4,786	4,496	22,648
2015	4,849	4,557	22,732
2016	4,968	4,632	22,944
2017	5,073	4,713	23,423
2018	5,166	4,814	23,765
2019	5,245	4,894	24,279
2020	5,319	4,967	24,683
2021	5,385	5,057	25,065
2022	5,458	5,152	25,533
2023	5,540	5,249	26,032
2024	5,623	5,349	26,514
2025	5,705	5,447	27,007
2026	5,789	5,541	27,481
2027	5,867	5,636	27,935
2028	5,943	5,731	28,397

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 just over 93% of our sales. The following bar chart shows the relative contribution to territorial sales made by each class. The "other" class in the chart below includes street lighting, other public authorities, municipalities and electric cooperatives.

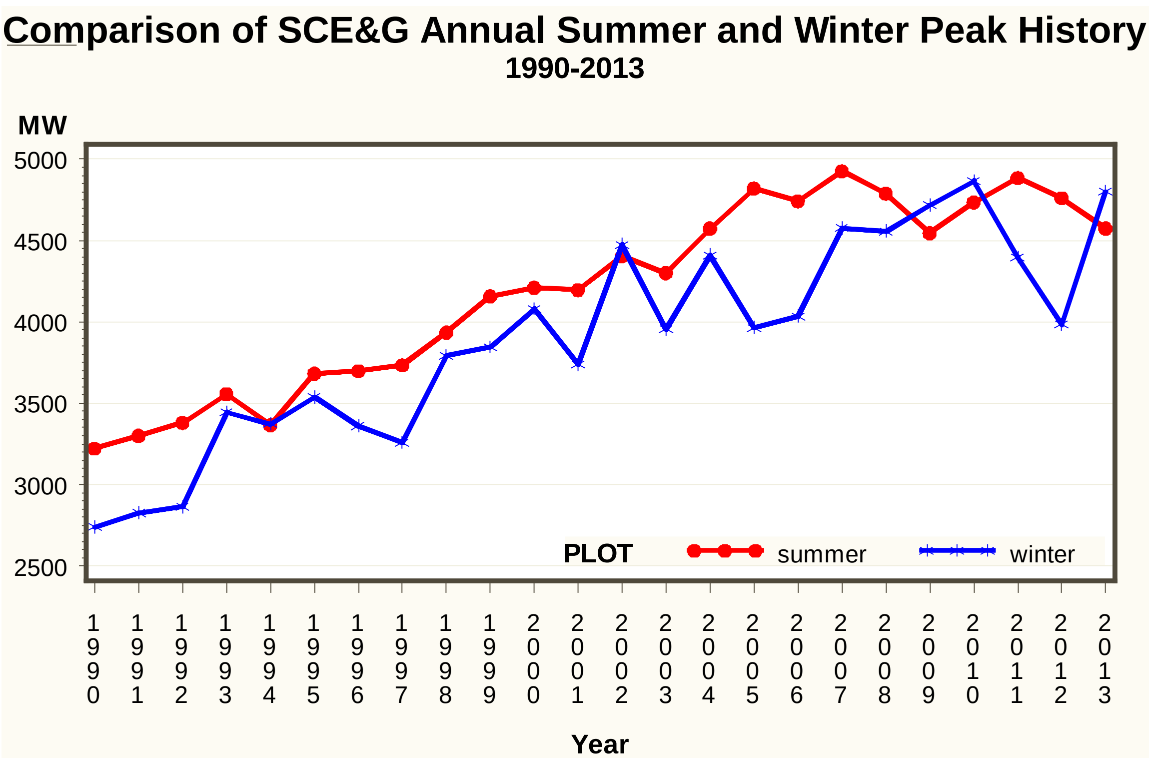


SCE&G's forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained in Appendix A of this report. Short-range is defined 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 for each group are based on statistical and econometric models derived from historical relationships.

1. System Peak Demand: Summer vs. Winter

SCE&G usually peaks in the summer as seen in the chart below. This is reasonable for several reasons. First, the climate in SCE&G's service area is generally hotter in the summer than colder in the winter relative to a given base temperature. Second, the penetration of air-conditioners among SCE&G's customers approaches 100% since there are no real substitutes for electric air-conditioners at present. Finally, a large number of residential and gas customers heat their homes and businesses with natural gas. Results of the peak demand forecast methodology used herein show that the general pattern of higher summer peaks relative to winter peaks will continue.

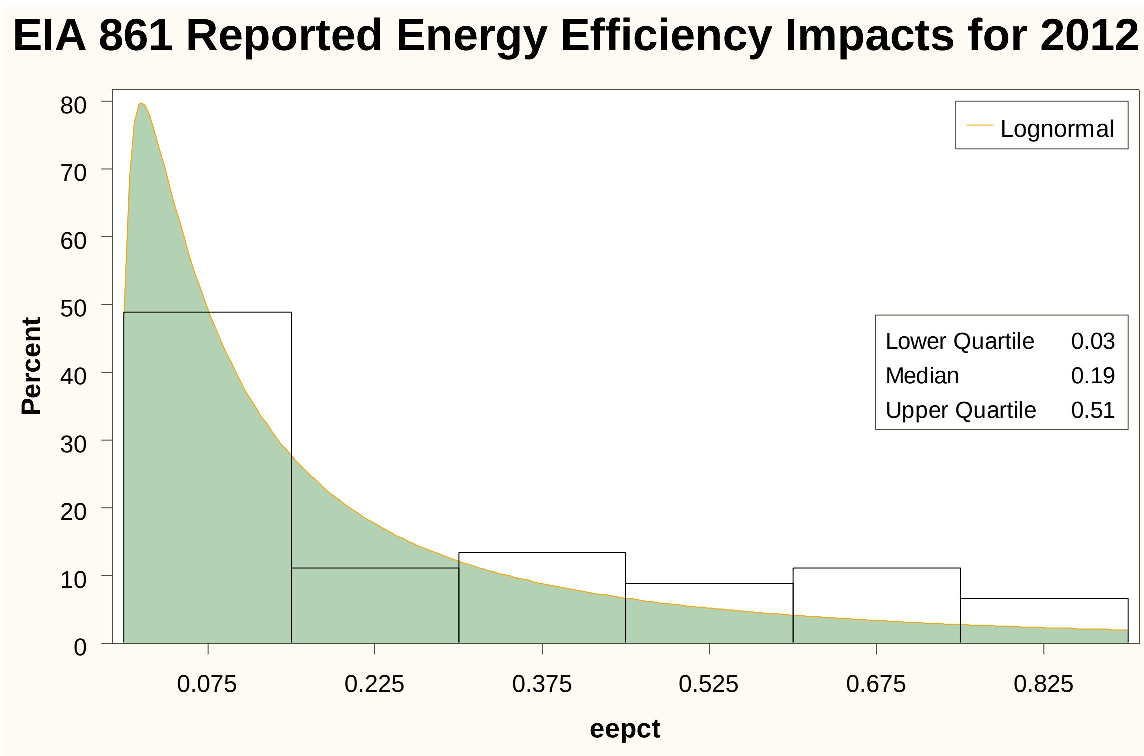
The following charts shows SCE&G's experience with summer versus winter peaking. By industry convention, the winter period is assumed to follow the summer period. In 19 of the past 24 years, SCE&G peaked in the summer. One other notable feature of the peak demand chart is the greater variability in winter peak demand.



The forecast of summer peak demand is developed by combining the load profile characteristics of each customer class collected in the Company's Load Research Program with forecasted energy. The winter peak demand is projected through its correlation with annual energy sales and winter degree-day departures from normal.

2. DSM Impact on Forecast

SCE&G expects its energy efficiency ("EE") programs to reduce retail sales in 2014 by 84,627 MWH or approximately 85 GWH. Retail sales after this EE impact are expected to be 22,035 GWH. Therefore, the EE programs are expected to reduce retail sales by 0.384% from what they would have been. To gauge how its EE programs compared to other companies in the Southeast, SCE&G analyzed the EE impacts filed with the U.S. Energy Information Administration ("EIA") in 2012, the latest year available. There were 47 companies filing from the Southeast, in particular, from the NERC regions of SERC and FRCC. Two companies were dropped from the analysis for bad data. The chart below shows graphically the distribution of reported results. The median EE impact was 0.19%. Thus half the companies showed results higher and half lower than this median value. SCE&G's expectation for 2014 is twice this median value placing it in the top half of the distribution and almost into the top quartile. Clearly SCE&G's EE programs compare favorably with other companies in the Southeast.



As part of the forecast development, the 0.38% EE savings was divided into a residential and commercial component. In addition, savings due to lighting efficiencies were removed from the class numbers and combined with lighting efficiency effects due to federally mandated measures. This was necessary to produce a consistent forecast of lighting efficiency effects. After this adjustment, the annual EE percentages used to produce the forecast were determined to be 0.31% and 0.13% for the residential and commercial sectors, respectively. The table below illustrates the calculation of the EE reductions. The far right-hand column labeled "Cumulative

Reductions" is the sum of the residential and commercial cumulative reductions and represents the "SCE&G DSM Programs" column shown in a subsequent forecast summary table.

Derivation of Annual EE Savings

	Baseline Residential (GWH)	Cumulative Reductions (GWH)	Incremental Reductions (GWH)	Inc. %	Baseline Commercial (GWH)	Cumulative Reductions (GWH)	Incremental Reductions (GWH)	Inc. %	Cumulative Reductions (GWH)
2014	7,883	-	-	-	7,247	-	-	-	-
2015	7,919	-	-	-	7,257	-	-	-	-
2016	8,053	-25	-25	-0.31	7,437	-10	-10	-0.13	-35
2017	8,192	-50	-25	-0.31	7,615	-20	-10	-0.13	-70
2018	8,318	-76	-26	-0.31	7,777	-30	-10	-0.13	-106
2019	8,511	-103	-26	-0.31	8,042	-40	-10	-0.13	-143
2020	8,697	-129	-27	-0.31	8,300	-51	-11	-0.13	-180
2021	8,877	-157	-28	-0.31	8,544	-62	-11	-0.13	-219
2022	9,054	-185	-28	-0.31	8,783	-73	-11	-0.13	-259
2023	9,242	-214	-29	-0.31	9,041	-85	-12	-0.13	-299
2024	9,420	-243	-29	-0.31	9,288	-97	-12	-0.13	-340
2025	9,602	-273	-30	-0.31	9,540	-110	-12	-0.13	-382
2026	9,777	-303	-30	-0.31	9,782	-122	-13	-0.13	-425
2027	9,947	-334	-31	-0.31	10,015	-135	-13	-0.13	-469
2028	10,120	-365	-31	-0.31	10,257	-149	-13	-0.13	-514

3. Energy Efficiency Adjustments

Several adjustments were made to the baseline projections to incorporate significant factors 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 energy efficiency programs. The following table shows the baseline projection, the energy efficiency adjustments and the resulting forecast of territorial energy sales.

	Baseline Sales (GWH)	Energy Efficiency SCE&G DSM Programs (GWH)	Federal Mandates (GWH)	Total EE Impact (GWH)	Territorial Sales (GWH)
2014	22,773	0	-125	-125	22,648
2015	22,919	0	-187	-187	22,732
2016	23,446	-35	-467	-502	22,944
2017	23,999	-70	-506	-576	23,423
2018	24,415	-106	-544	-650	23,765
2019	25,011	-143	-589	-732	24,279
2020	25,565	-180	-702	-882	24,683
2021	26,103	-219	-819	-1,038	25,065
2022	26,633	-259	-841	-1,100	25,533
2023	27,195	-299	-864	-1,163	26,032
2024	27,740	-340	-886	-1,226	26,514
2025	28,297	-382	-908	-1,290	27,007
2026	28,836	-425	-930	-1,355	27,481
2027	29,355	-469	-951	-1,420	27,935
2028	29,883	-514	-972	-1,486	28,397

Baseline sales are projected to grow at the rate of 2.0% 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 1.6% per year as reported earlier.

Since the baseline forecast utilizes 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. Because 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 that 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 Seasonal Energy Efficiency Ratio ("SEER") 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 over 20. However, overall market production of heat pumps and air-conditioners is concentrated at the lower end of the SEER mandate. The 2006 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 2013 for savings related to lighting. Mandated federal efficiencies as a result of the Energy Independence and Security Act of 2007 took effect in 2013 and will be phased in through 2015. 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 that incandescent light bulbs use. 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 fully reflected 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. In developing the forecast it was assumed that the impacts of these programs were captured in the baseline forecast for the next two years but thereafter had to be reflected in the forecast on an incremental basis.

4. 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 Summer Peak Demands (MWs)								
		Energy Efficiency						
Year	Baseline Trend	SCE&G Programs	Federal Mandates	Total EE Impact	System Peak Demand	Demand Response	Firm Peak Demand
2014	5,046	0	-3	-3	5,043	-257	4,786
2015	5,112	0	-4	-4	5,108	-260	4,848
2016	5,270	-11	-26	-37	5,233	-267	4,966
2017	5,406	-21	-38	-59	5,347	-275	5,072
2018	5,525	-33	-48	-81	5,444	-279	5,165
2019	5,631	-44	-59	-103	5,528	-283	5,245
2020	5,735	-55	-74	-129	5,606	-286	5,320
2021	5,829	-67	-89	-156	5,673	-289	5,384
2022	5,920	-79	-92	-171	5,749	-292	5,457
2023	6,021	-91	-96	-187	5,834	-296	5,538
2024	6,125	-104	-100	-204	5,921	-299	5,622
2025	6,228	-116	-103	-219	6,009	-303	5,706
2026	6,331	-129	-107	-236	6,095	-306	5,789
2027	6,429	-143	-110	-253	6,176	-310	5,866
2028	6,525	-157	-113	-270	6,255	-313	5,942

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

A. Demand Side Management

Demand Side Management (DSM) can be broadly defined as the set of actions that can be taken to influence 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 input in an economically efficient way. Load Management typically includes actions specifically designed to encourage customers to reduce usage during peak times or shift that usage to other times.

Energy Efficiency

SCE&G's Energy Efficiency programs include Customer Information Programs, Web-Based Information and Services Programs, Energy Conservation and the Demand Side Management 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 2013, 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, ongoing customer feedback is used 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 are integrated to ensure we are communicating in a consistent manner that customers will understand.

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

b. **Media/Channel Preferences:** Placement of all marketing and advertising is carefully reviewed, taking into consideration the customers' preferred methods of receiving 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 newspapers (major daily and weekly minority publications). SCE&G's statewide business office locations also serve as a distribution point for sharing information with customers. In addition, SCE&G has also incorporated social media, e.g. Twitter and Facebook, into its communications strategy. Key South Carolina markets covered, with all marketing communications, include Columbia, Charleston, Aiken and Beaufort.

c. **Public Affairs/News Media/Speakers Bureau:** Furthermore, 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 include participation in a variety of events that offer the opportunity to further extend customer education and outreach of energy information. SCE&G's 2013 schedule included a solid mix of special events to include the Home Builders Association ("HBA") Home Improvement Show and Tour of Homes in Columbia and Black Expos in Columbia and Charleston.

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 encompasses **general awareness education** as well as **program specific offerings**.

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.).

Program Specific Offerings: In 2013, SCE&G continued to heavily promote its portfolio of residential electric rebate/incentive programs under its Demand Side Management (DSM) 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 Residential Heating & Cooling and Water Heating Equipment.

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 5.1 million visits to SCE&G's website in 2013. Customers must be registered to use the interactive tools Energy Analyzer and Energy Audit. There are over 350,000 customers registered for this access. Descriptions of the four categories listed above follows:

    a. **Customer Awareness Information:** The SCE&G website, www.sceg.com, supports all communication efforts to promote energy savings information – both general awareness tips and program-specific overviews, tools and resources – all through a section called "Be EnergyWise and Save". Energy savings information includes detailed information on each of the Demand Side Management programs for residential and commercial/industrial customers, as well as how-to videos on insulation, thermostats and door and windows.

    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 a little over 106,000 visits to the Energy Analyzer tool in 2013.

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. Over 7,000 customers used the Energy Audit tool in 2013.

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 2,464 customers are registered for the e-newsletters distributed in 2013.

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 very easy as 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 standard, 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

In 2013, SCE&G completed a comprehensive evaluation of the existing DSM programs with the specific intention of updating programs and introducing new programs to the DSM portfolio. In May 2013, the Company presented the new portfolio to the Commission and received approval in November 2013. The Commission approved a suite of eleven (11) DSM programs, which includes nine programs targeting SCE&G's residential customer classes and two programs targeting SCE&G's commercial and industrial customer classes. A description of each program follows:

a. **Residential Home Energy Reports** provides customers with free monthly/bi-monthly reports comparing their energy usage to a peer group and providing information to help identify, analyze and act upon potential energy efficiency measures and behaviors.

b. **Residential Energy Information Display** provides customers with an in-home display that shows information from the customer's meter regarding current energy usage and cost, and the approximate use and cost to date for the month. The displays were distributed to targeted customers, upon their request, at a discounted price.

c. **Residential Home Energy Check-up** program provides customers with a visual energy assessment performed by SCE&G staff at the customer's home. At the completion of the visit, 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.

d. **Residential Home Performance with ENERGY STAR®** program promotes a comprehensive energy efficiency audit of the home by trained contractors. SCE&G provides incentives to customers for implementing specific measures based on the audit findings.

e. **Residential ENERGY STAR® Lighting** program incentivizes residential customers to purchase and install high-efficiency ENERGY STAR® qualified lighting products by providing discounts to the manufacturers and retailers.

f. **Residential Heating & Cooling and Water Heating Equipment** program provides incentives to customers for purchasing and installing high efficiency HVAC equipment and non-electric resistance water heaters in new and existing homes.

g. **Residential Heating & Cooling Efficiency Improvements** program provides residential customers with incentives to improve the efficiency of existing AC and heat pump systems through HVAC tune-ups (system optimizer), complete duct replacements, duct insulation and duct sealing. The system optimizer was discontinued in May 2013.

h. **Residential ENERGY STAR® New Homes** program provides incentives to customers and builders who are willing to commit to ENERGY STAR® standards in new home construction.

i. **Neighborhood Energy Efficiency Program (NEEP)**, approved by the Commission in April 2013, provides qualifying customers energy education, an on-site energy survey of the dwelling, and direct installation of low-cost energy saving measures at no additional cost to the customer. The program is delivered in a neighborhood door-to-door sweep approach and offers customers who are eligible and wish to participate a variety of direct installation energy efficiency measures.

j. **Commercial and Industrial Prescriptive** program provides incentives to non-residential customers to invest in high-efficiency lighting and fixtures, 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.

k. **Commercial and Industrial Custom** program provides custom 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.

5. 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:

a. **Standby Generator Program:** The Standby Generator Program for wholesale customers provides about 25 megawatts of peaking capacity that can be called upon when reserve capacity is low on the system. This capacity is owned by our wholesale customers and through a contractual arrangement is made available to SCE&G dispatchers. SCE&G has a retail version of its standby generator program in which SCE&G can call on 20 or more customers to run their emergency generators. This retail program provides about 17 MWs of additional capacity as needed.
b. **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.
c. **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.
d. **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.

SCE&G's resource plan shows the need for additional capacity in the future 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

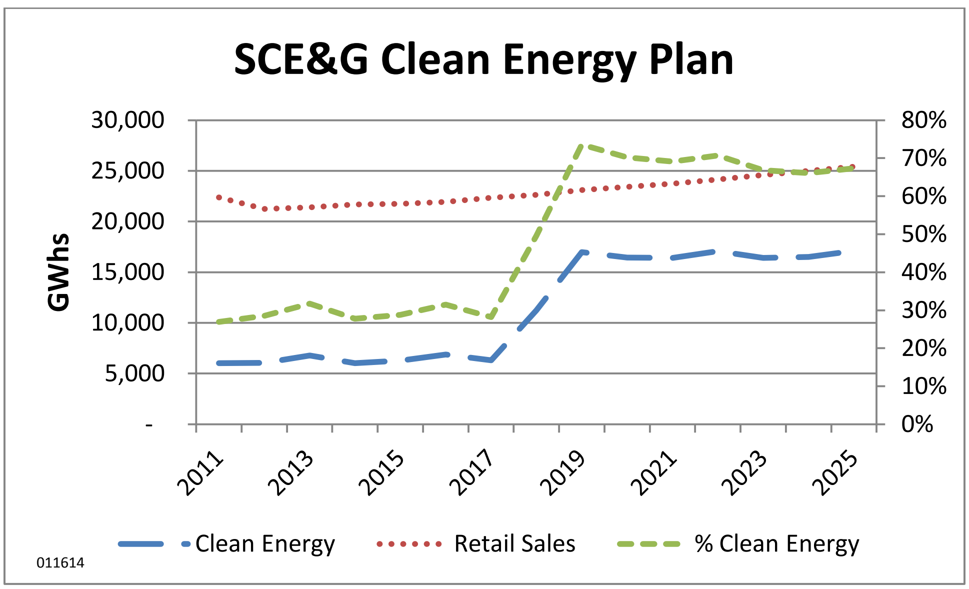
Clean Energy at SCE&G

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

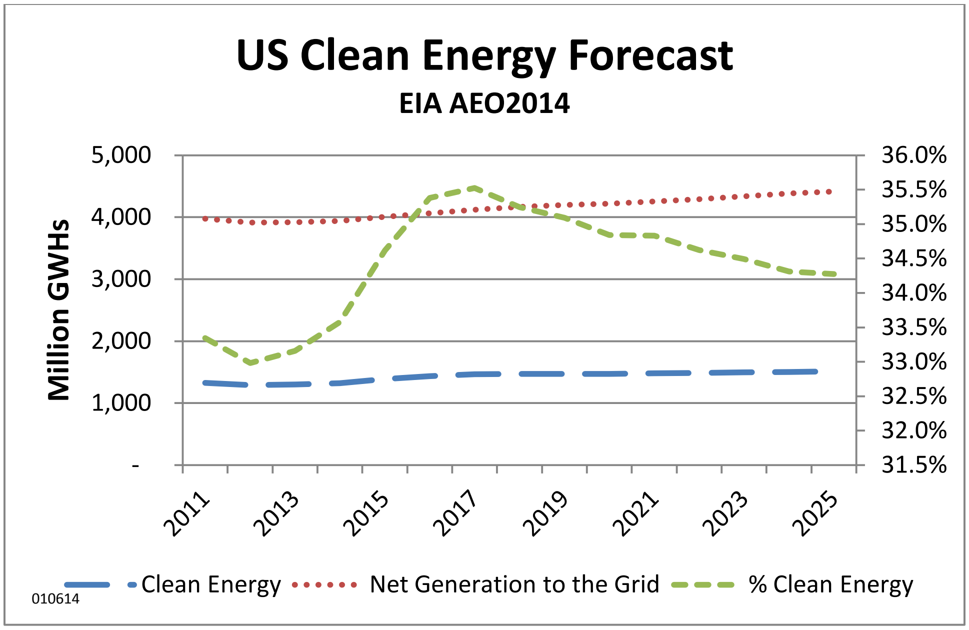
1. Existing Sources of Clean Energy

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.

a. 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 in GWH and as a percentage of retail sales.



As seen in the chart above, SCE&G currently generates a little over 30% of its retail sales from clean energy sources but by 2019 it expects to generate about 74% from clean energy. According to the EIA, the U.S. as a nation currently generates about 33% of its retail sales as clean energy and it expects this percentage to increase slightly over the next ten years or so. The following chart graphs EIA's forecast for US clean energy.



SCE&G compares very favorably to the nation in its clean energy plans since by 2019 it should be meeting about twice as much of its retail sales with clean energy on a relative basis compared to the nation.

b. 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 ("REC") 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. The nearby table shows the MWHs of renewable energy generated by 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%
2012	414,047	1.9%
2013	385,202	1.8%

c. 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 are provided to

Boeing for onsite use. At the time of completion this was the largest roof-top solar generator in the Southeast. Over the last two years the Boeing solar plant has generated the following amounts of energy:

Year	MWh
2012	3,513
2013	3,410

d. 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 partially 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.

e. 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 S.C. Energy Office for the purpose of promoting the development of renewable power in South Carolina. Customers make a tax deductible contribution to PaCE and PaCE uses the funds collected to pay renewable generators a financial incentive for their power.

2. Future Clean Energy

SCE&G is participating in activities seeking 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, building solar generation, studying smart grid opportunities and distribution automation. These activities are set forth in more detail below.

a. New Renewable Projects: SCE&G's customers and other South Carolina stakeholders have expressed a desire for solar energy in the State, and SCE&G is looking for ways to integrate additional solar into the system in the most economical way possible while beginning to grow a new energy economy in South Carolina based on a diverse portfolio of generation. SCE&G currently has approximately 4 megawatts of solar generation on the system, and plans to build new solar farms that will add up to 20 megawatts of renewable energy to our system. We have created an experienced team focused on research, design, and implementation of renewable energy resources (solar, wind, and biomass). In 2014-2016, we plan to install several solar farms on the system. These solar farms will be built in various locations throughout the system and will include opportunities for research, education, and expansion of the energy economy in S.C.

b. Off-Shore Wind Activities: SCANA/SCE&G is a founding member of the Southeastern Coastal Wind Coalition and participates in the Utility Advisory Group of that organization. The mission of Southeastern Coastal Wind Coalition is to advance the coastal and offshore wind industry in ways that result in net economic benefits to industry, utilities, ratepayers, and citizens of the Southeast. The focus is three fold:

1. Research and Analysis – objective, transparent, data-driven, and focused on economics.
2. Policy / Market Making – exploring multistate collaborative efforts and working with utilities, not against them.
3. Education and Outreach – website, communications, and targeted outreach.

SCE&G participated 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 included an offshore wind transmission study; a wind, wave and ocean current study; and creation of a Regulatory Task Force. The mission of the Regulatory Task Force was to foster a regulatory environment conducive to wind, wave and tidal energy development in state waters. The Regulatory Task Force was comprised of state and federal regulatory and resource protection agencies, universities, private industry and utility companies.

SCANA/SCE&G participated in discussions to locate a 40 MW demonstration wind farm off the coast of Georgetown. This effort, known as Palmetto Wind, includes Clemson University's Restoration Institute, Coastal Carolina University, Santee Cooper, the S.C. Energy

Office and various utilities. Palmetto Wind has been put on hold due to the high cost of the project.

SCE&G invested $3.5 million in the Clemson University Restoration Institute's wind turbine drive train testing facility at the Clemson campus in North Charleston. This new facility is dedicated to groundbreaking research, education, and innovation with the world's most advanced wind turbine drive train testing facility capable of full-scale highly accelerated mechanical and electrical testing of advanced drive train systems for wind turbines.

c. Co-firing with Biomass: SCE&G continues 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. Results are evaluated by the Fossil Hydro department to determine the feasibility for a future course of action.

d. Smart Grid Activities: SCE&G currently has approximately 9,300 AMI meters that are installed predominately on our medium to large commercial customers as well as our smaller industrial customers. Other applications where this technology is deployed include all time-of-use accounts and all accounts with customer generation (net metering). These meters utilize public wireless networks as the communication backbone and have full two-way communication capability. Register readings and load profile data are remotely collected daily from all AMI meters. In addition to traditional metering functions, the technology also provides real-time monitoring capability including power outage/restoration, meter/site diagnostics, and power quality monitoring. Load profile data is provided to customers daily via web applications enabling these customers to have quick access to energy usage allowing better management of their energy consumption. Moving forward, this technology will also enable more sophisticated DSM offerings that may be attractive to a variety of customer classes.

e. 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 approximately 850 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. We are continuing to evaluate systems that will help these automated devices communicate with each other and safely reconfigure the system in a fully automated fashion.

f. Environmental Mitigation Activities: In order to reduce NO_X emissions and to meet compliance requirements, SCE&G installed Selective Catalytic Reduction ("SCR") equipment at 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 Cope Station by approximately 90%. SCE&G is also utilizing the existing SCRs at Williams and Wateree Stations 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 Williams and Wateree Stations to reduce SO_2 emissions. The in-service dates 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%. Mercury emission control has also been realized in the industry via the operation of FGD equipment. Consequently, the continued operation of the FGD equipment will contribute to SCE&G's strategy for meeting the impending requirements of the US EPA's Mercury and Air Toxics Standard ("*MATS*") that will become effective on April 16, 2015. The Chem-Mod fuel additive being used at McMeekin Station, Cope Station, and Williams Station will similarly contribute to SCE&G's efforts in stack emission control for mercury, as well as for NO_X and SO_2.

In response to the US EPA's impending *MATS*, the last coal-fired boiler at Urquhart Station, Unit 3, was converted to natural gas. Decommissioning of the plant's former coal handling facilities is in progress. Also in response to MATS Canadys Station ceased operations on November 6, 2013, and decommissioning efforts are in progress.

In an effort to cease bottom ash sluicing to the Wateree Station's ash ponds, SCE&G installed two remote submerged flight conveyors that dewater boiler bottom ash sluice and recycle the overflow back to the boiler for reuse. This retrofit was completed for Units 1 and 2 during October 2012. The bottom ash is then marketed as an ingredient in the manufacture of pre-stressed concrete products.

g. Nuclear Power in the Future – Small and Modular: Small Modular Reactor ("SMR") technology continues to be developed. DOE has awarded two grants, totaling $452 million, for SMR development. At about a third, or less, of the size of current nuclear power plants, SMRs could make available, for a smaller capital investment, a modular design for specific generation needs. SCE&G will continue to evaluate this technology as it develops.

3. Summary of Proposed and Recently Finalized Regulations

The EPA has either proposed or recently finalized 6 regulations and modified one additional regulation. These are Cross-State Air Pollution Rule ("CSAPR"), Mercury and Air Toxics Standards ("MATS"), Greenhouse Gases, Cooling Water Intake Structures, Coal Combustion Residuals, Effluent Limitation Guidelines, and a new 1-hour sulfur dioxide National Ambient Air Quality Standard ("NAAQS").

a. Cross-State Air Pollution Rule ("CSAPR")

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. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR and left CAIR in place. The federal court ordered the EPA to continue administering the previously promulgated CAIR. On October 5, 2012, the EPA filed a petition for rehearing of the order. On January 24, 2013, the United States Court of Appeals for the D.C. Circuit denied EPA's petition for rehearing. The Court ordered EPA to continue to enforce the 2005 CAIR until CSAPR could be re-issued. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013, the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G has already completed have allowed the Company to comply with the reinstated CAIR and will also allow it to comply with CSAPR if reinstated.

CSAPR, which was intended to replace CAIR, was initially finalized in July 2011 under the Clean Air Act and would affect 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 established an emissions cap for SO_2 and NO_X and limited the trading region for emission allowances by separating affected states into two groups with no trading between the groups.

SCE&G Fossil Hydro generation is in compliance with emission limits set by CSAPR and CAIR.

b. 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 by the state permitting authorities if additional time is needed for units that are required to run for reliability purposes which would otherwise be deactivated, or which, 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 by consultation with FERC and/or other entities with relevant reliability expertise as appropriate.

SCE&G applied for and received a 1-year extension from DHEC for both McMeekin and Canadys. With the retirement of Canadys in the 4^{th} quarter of 2013, only McMeekin has a waiver that will allow the continued use of coal until April 2016.

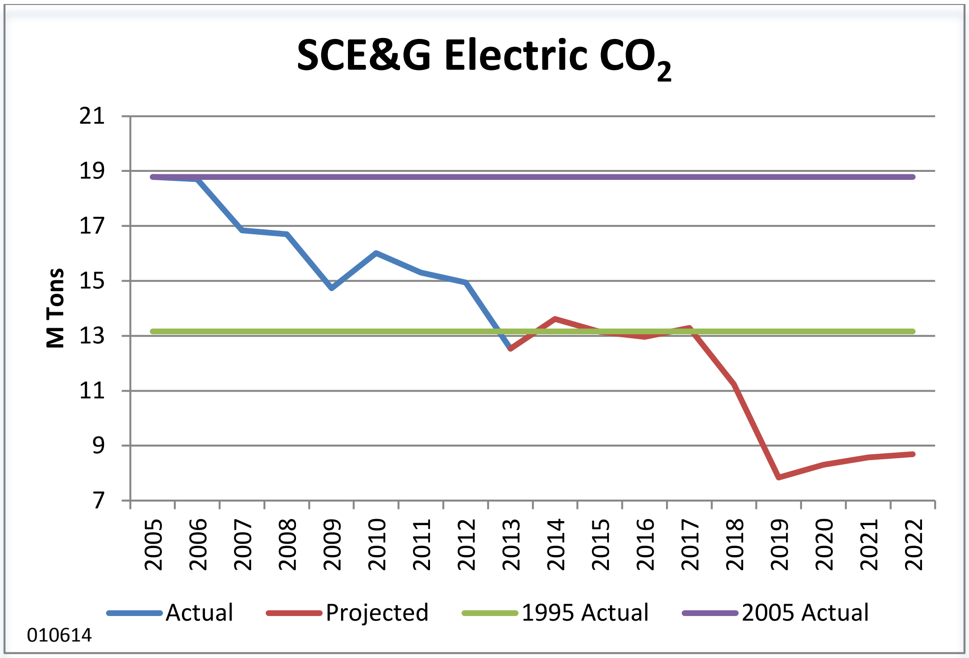
c. Greenhouse Gases

The EPA's rule addressing the emission of greenhouse gases was proposed under the Clean Air Act and would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. This action will amend the new source performance standards ("NSPS") for electric generating units ("EGU") and will establish the first NSPS for greenhouse gas ("GHG") emissions. The 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. The first part of this rule, related to new generation sources, was released in April 2012 and was expected to become final in March 2013.

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA issued a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The April 2012 rule was withdrawn by EPA and the new rule, which became final on January 8, 2014, still requires all new fossil fuel-fired power plants to meet the carbon dioxide 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 fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal fired units in the near future.

The Presidential Memorandum also directed EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. The Company also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on the Company, if any.

SCE&G's new nuclear generation will mitigate CO_2 concerns going forward. The following chart shows that SCE&G's CO_2 emissions will fall well below its 1995 level after the next several years.



d. 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, and 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, and a final rule is now expected by April 17, 2014.

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 enhanced screening and reconfiguration of water intake systems to installation of cooling towers to reduce the flow rate. On SCE&G's system, Jasper, Cope and Wateree Stations have closed cycle cooling towers installed and should not be significantly affected by these regulations. The Company is currently conducting studies and is developing or implementing compliance plans for these initiatives.

e. 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 or (2) regulate as a non-hazardous waste. The proposed rule was released in June 2010 and comments were received through November 2010. EPA has not issued the rule as yet and has not specified when a final rule will be issued. The effective date is believed to be dependent on which option is selected. If coal combustion residuals are classified as non-hazardous wastes, the rule would be effective six months after promulgation. A special hazardous waste designation would likely push compliance out until about 2021 when the state adopts the rule. Timing will vary from state to state.

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. On January 22, 2013, the Court in the coal combustion residuals ("CCR") deadline litigation postponed the status conference in the case until April 26, 2013. On October 29, a federal district judge ordered EPA to file by December 29, 2013, a timeline for the completion of this rule. However, because environmental groups and coal ash recyclers are in settlement negotiations concerning the timeline, in December, the district court accepted a motion to give EPA additional time (until late January) to file the timeline. In January, a consent decree was filed that sets forth EPA's obligation to sign, by December 19, 2014, a notice for publication in the Federal Register taking final action on the Agency's rule for CCR.

The final CCR rule may require the closure of ash ponds. SCE&G has three generating facilities that have employed ash storage ponds, and all of these ponds have either been closed after all ash was removed or are part of an ash pond closure project that includes complete removal of the ash prior to closure. The electric generating facilities which continue to be coal-fired have dry ash handling, and the ash ponds undergoing closure have a detailed dam safety inspection conducted at least quarterly.

f. Effluent Limitation Guidelines

The Clean Water Act ("CWA") establishes the basic structure for regulating discharges of pollutants into the waters of the United States. It provides EPA and the States with a variety of programs and tools to protect and restore the nation's waters. These programs and tools generally rely either on water quality-based controls, such as water quality standards and water quality-based permit limitations, or technology-based controls such as effluent guidelines and technology-based permit limitations. The EPA is currently developing a proposed rule to amend the effluent guidelines and standards for the Steam Electric Power Generating category. Once issued, the Steam Electric effluent guidelines and standards will be incorporated into State administered wastewater permits known as National Pollutant Discharge Elimination System ("NPDES") permits. EPA's decision to proceed with a rulemaking was announced on September 15, 2009, following completion of a preliminary study.

EPA reviewed wastewater discharges from power plants and the treatment technologies available to reduce pollutant discharges. EPA believes that the current regulations, which were last updated in 1982, do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades. EPA's main reason for this concern is that the air pollution control technologies that have been retrofitted to power plants in order to reduce air emissions put a majority of those contaminants into the wastewater discharge. In 2010, EPA submitted an Information Collection Request ("ICR") to all electric utilities to aid in their review of plant operations, pollution control technologies, and current wastewater discharges. Consequently, SCE&G expended considerable time and resources to answer a 213-page questionnaire for each of its electric generating facilities.

Under the CWA, compliance with applicable limitations is achieved under State-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every 5 years) any new effluent limitations would be incorporated. New federal effluent limitation guidelines for steam electric generating units (the ELG Rule) were published in the Federal Register on June 7, 2013. Comments were due by September 20, 2013, and the rule is expected to be finalized May 22, 2014. EPA expects compliance as soon as possible after July 2017 but no later than July 2020. Once the rule becomes effective, the State environmental regulators will modify the NPDES permits to match more restrictive standards thus requiring utilities to retrofit each facility with new wastewater treatment technologies. Based on the proposed rule, SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree at a minimum.

g. NAAQS 1-hour SO_2

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 EPA revoked the two existing primary standards of 140 ppb evaluated over 24-hours, and 30 ppb per hour averaged 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 released its draft guidance for this State Implementation Plan ("SIP") modeling and the states prepared for designation modeling efforts. However, later guidance issued during June 2012 indicated that EPA would back off of the modeling requirement.

Historically, ambient air monitoring data has provided the basis for attainment designations. The shift to using models instead of ambient data poses significant challenges. For example, 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. Also there are likely to be surprises for historically grandfathered sources or even new well-controlled sources.

During 2013, EPA deferred designations for South Carolina for future action. On January 7, 2014, EPA made available two updated draft documents that provide technical assistance for states implementing the 2010 health-based, sulfur dioxide (SO_2) standard. These documents provide technical advice on the use of modeling and monitoring to determine if an area meets the 2010 SO_2 air quality standard. In a future rule expected in 2014, the EPA will establish requirements for characterizing SO_2 air quality in priority areas, focusing on areas with sources that have emissions higher than a threshold amount. The EPA expects to establish these thresholds taking population into account. States will have the flexibility to characterize air quality using modeling of actual emissions or using appropriately sited existing and new monitors. These data would be used in two future rounds of designations in 2017 (based on modeling) and 2020 (based on new monitoring). EPA expects to issue a Data Requirements Rule for implementing the 1-Hour SO_2 standard during 2014. Air quality control installations that SCE&G and GENCO have already completed and planned retirements of older coal-fired units are expected to allow the Company to comply with the 1-Hour SO_2 standard.

4. Supply Side Resources at SCE&G

a. Existing Supply Resources

SCE&G owns and operates six (6) coal-fired fossil fuel units, one (1) gas-fired steam unit, eight (8) combined cycle gas turbine/steam generator units (gas/oil fired), sixteen (16) peaking turbine units, four (4) hydroelectric generating plants, and one Pumped Storage Facility. In addition, SCE&G receives the output of 85 MWs from a cogeneration facility. The total net non-nuclear summer generating capability rating of these facilities is 4,590 MWs in summer and 4,764 MWs in winter. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer and winter seasons. When SCE&G's nuclear capacity (647 MWs in summer and 661 MWs in winter), a long term capacity purchase (25 MWs) and additional capacity (20 MWs) provided through a contract with the Southeastern Power Administration are added, SCE&G's total supply capacity is 5,282 MWs in summer[1] and 5,470 MWs in winter. This is summarized in the table on the following page.

[1] This supply capacity does not include the Company's solar generator with a DC nominal rating of 2.6 MWs which lies behind a customer's meter.

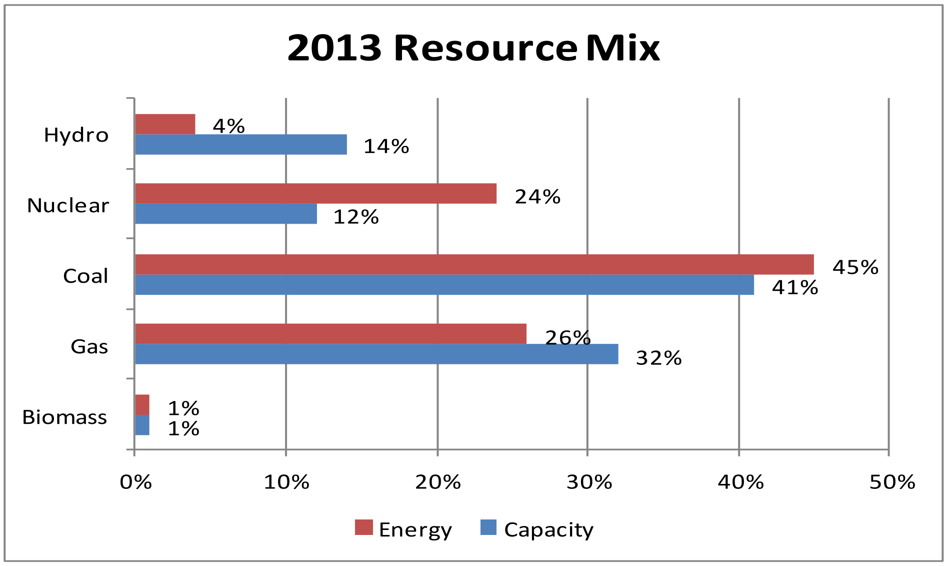
Existing Long Term Supply Resources

The following table shows the generating capacity that is available to SCE&G in 2014.

	In-Service Date	Summer (MW)	Winter (MW)
Coal-Fired Steam:			
McMeekin – Near Irmo, SC	1958	250	250
Wateree – Eastover, SC	1970	684	684
*Williams – Goose Creek, SC	1973	605	610
Cope - Cope, SC	1996	415	415
Kapstone – Charleston, SC	1999	85	85
Total Coal-Fired Steam Capacity		2,039	2,044
Gas-Fired Steam:			
Urquhart – Beech Island, SC	1953	95	96
Nuclear:			
V. C. Summer - Parr, SC	1984	647	661
I. C. Turbines:			
Hardeeville, SC	1968	9	9
Urquhart – Beech Island, SC	1969	39	48
Coit – Columbia, SC	1969	28	38
Parr, SC	1970	60	73
Williams – Goose Creek, SC	1972	40	52
Hagood – Charleston, SC	1991	128	145
Urquhart No. 4 – Beech Island, SC	1999	48	49
Urquhart Combined Cycle – Beech Island, SC	2002	458	484
Jasper Combined Cycle – Jasper, SC	2004	852	924
Total I. C. Turbines Capacity		1,662	1,822
Hydro:			
Neal Shoals – Carlisle, SC	1905	3	4
Parr Shoals – Parr, SC	1914	7	12
Stevens Creek - Near Martinez, GA	1914	8	10
Saluda - Near Irmo, SC	1930	200	200
Fairfield Pumped Storage - Parr, SC	1978	576	576
Total Hydro Capacity		794	802
Other: Long-Term Purchases		25	25
SEPA		20	20
Grand Total:		5,282	5,470

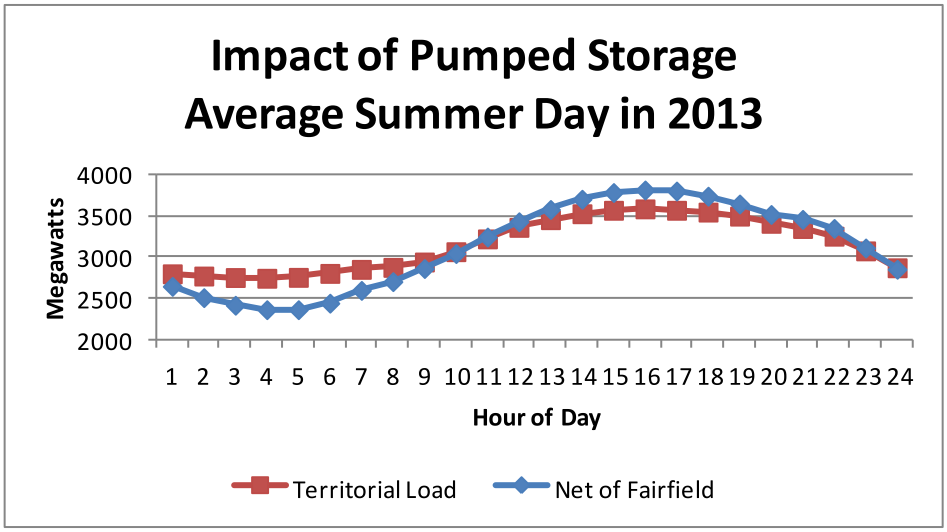
* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and is operated by SCE&G. Not reflected in the table is a solar PV generator owned by SCE&G with a nominal direct current rating of 2.6 MWs nor a purchase of 300 MWs of firm capacity for the years 2014-2015.

The bar chart below shows SCE&G's actual 2013 relative energy generation and relative capacity by fuel source.



b. 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 was used to shave about 218 MWs from the daily peak times of 2:00pm through 6:00pm and to move about 2.4% of customer's daily energy needs 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.

c. 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. 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.

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. While it can vary by a few megawatts each year, SCE&G's pro-rata share of this capacity is always around 200 megawatts.

To analyze these three components of reserve and establish a reserve margin target range, SCE&G employs three methodologies: 1) the component method which analyzes separately each of the three components mentioned above; 2) the traditional and industry standard technique of "Loss of Load Probability," or LOLP, using a range of LOLP from 1 day per year to

1 day in 10 years; and 3) the largest unit out method. The results of this analysis are summarized in the following table and support a reserve margin target range of 14% to 20%.

	Low MWs	Low %	High MWs	High %
Component Method	766	16.0%	1016	21.3%
LOLP	721	14.4%	1171	23.5%
Largest Unit	644	13.5%	966	20.2%
	644		1171	
Reserve Policy		14.0%		20.0%

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.

d. New Nuclear Capacity

On May 30, 2008, SCE&G filed with the Commission a Combined Application for a Certificate of Environmental Compatibility and Public Convenience 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 Public Convenience 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.

On January 27, 2014, SCE&G and Santee Cooper agreed to increase SCE&G's ownership share from 55% to 60% in three stages. SCE&G will acquire an additional 1% of the 2,234 MWs of capacity when Unit #2 achieves commercial operation which is expected around December 2017 or the first quarter of 2018. An additional 2% will go to SCE&G one year later and another 2% one year after that. By December 2019 or the first quarter of 2020, SCE&G will own 60% of both units (670 MWs each) while Santee Cooper will own 40%.

e. Retirement of Coal Plants

When the EPA promulgated its Mercury and Air Toxics Standards ("MATS") on December 21, 2011, SCE&G had six small coal-fired units in its fleet totaling 730 MWs ranging in age from 45 to 57 years that could not meet the emission standards without further modifications to the units. Those six units are displayed in the following table.

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

After a thorough retirement analysis, the Company decided that these six units would be retired when the addition of new nuclear capacity was available as a replacement.[2] As part of this retirement plan the Company has retired Canadys' Units #1, 2 and 3 and has converted Urquhart #3 to be fired with natural gas while dismantling the coal handling facilities at this unit. The capacity (250 MWs) of the remaining two coal-fired units, McMeekin 1&2, is required to maintain system reliability until the new nuclear capacity is available. Under the MATS regulations but with a one year waiver granted by South Carolina Department of Health and Environmental Control ("SCDHEC") these units cannot run on coal after April 15, 2016. The Company is currently looking at ways to bridge, with dispatchable resources, the gap between the MATS compliance date and the availability of the new nuclear capacity.

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[2] In announcing its plans to retire the units in its 2012 Integrated Resource Plan, the Company was careful to note that its retirement plans were subject to change if circumstances changed. <u>See</u> SCE&G's 2012 Integrated Resource Plan, at 29 (May 30, 2012) ("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.").

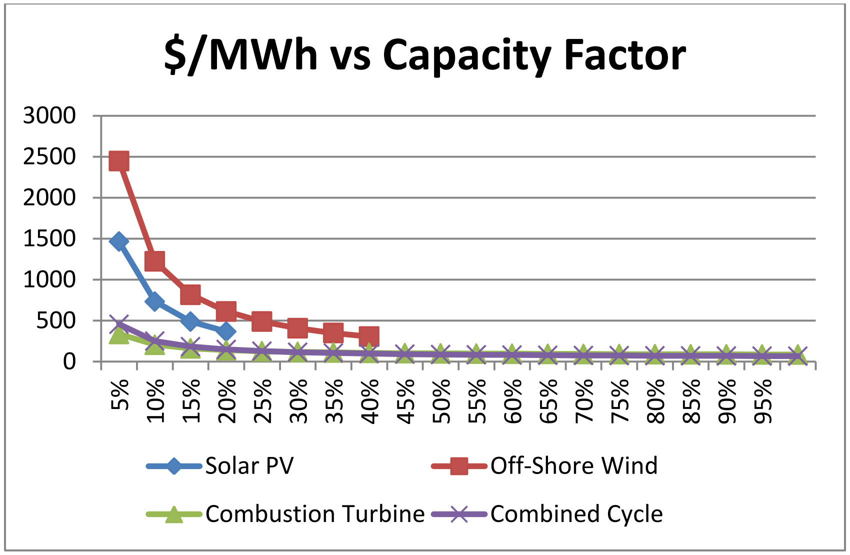
f. Renewable Resources

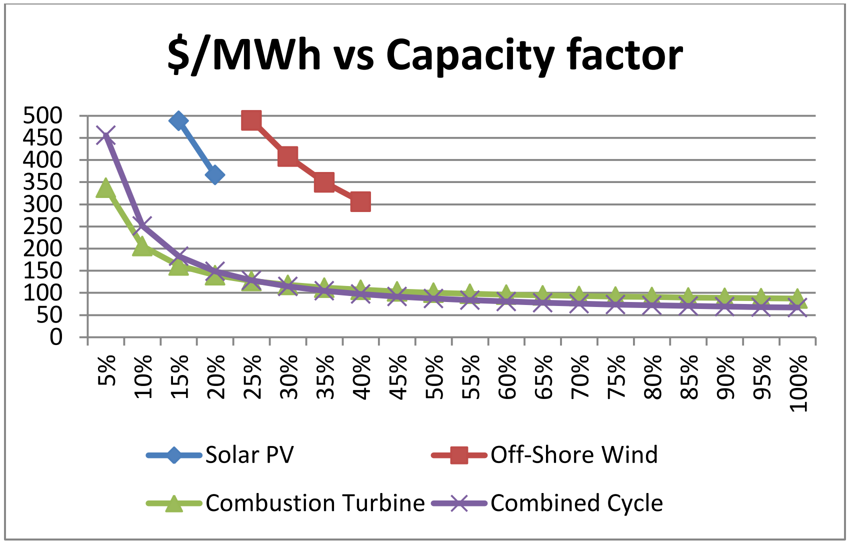
SCE&G continues to monitor the development of renewable sources of energy and looks for economic opportunities to include them in its resource plan.

1. Busbar Costs of Renewable Resources

The following charts show the busbar cost of renewable resources compared to other potential resource additions. The busbar cost is shown in terms of $/MWh at various capacity factors. It is assumed that the overnight capital costs of solar PV and off-shore wind are $3,873 per KW and $6,230 per KW respectively. The capital cost for a combined cycle facility and a combustion turbine facility are $1,023 per KW and $676 per KW respectively. Solar PV and off shore wind can be seen as more costly than traditional sources of power.

There are four charts shown on the next page. The two charts on the left side of the page show the busbar costs with and without the federal investment tax credit (“ITC”). As an approximation it is assumed that the ITC will reduce the capital cost of solar and wind by 30%. The two charts on the right side of the page show the same information but with the vertical axis truncated at $500/MWh thereby displaying more granularity at higher capacity factors.


$/MWh vs Capacity Factor
3000
2500
2000
1500
1000
500
0
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
Solar PV
Off-Shore Wind
Combustion Turbine
Combined Cycle


$/MWh vs Capacity factor
500
450
400
350
300
250
200
150
100
50
0
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
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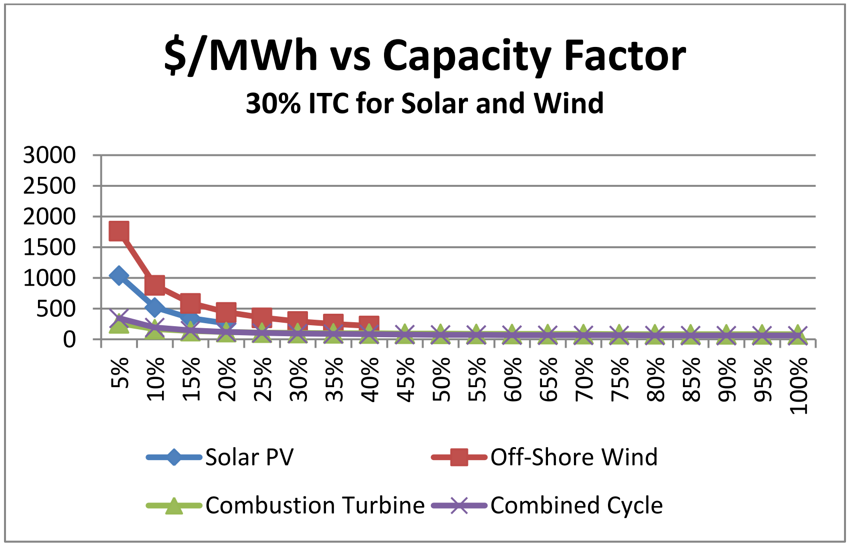
Solar PV
Off-Shore Wind
Combustion Turbine
Combined Cycle


$/MWh vs Capacity Factor
30% ITC for Solar and Wind
3000
2500
2000
1500
1000
500
0
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
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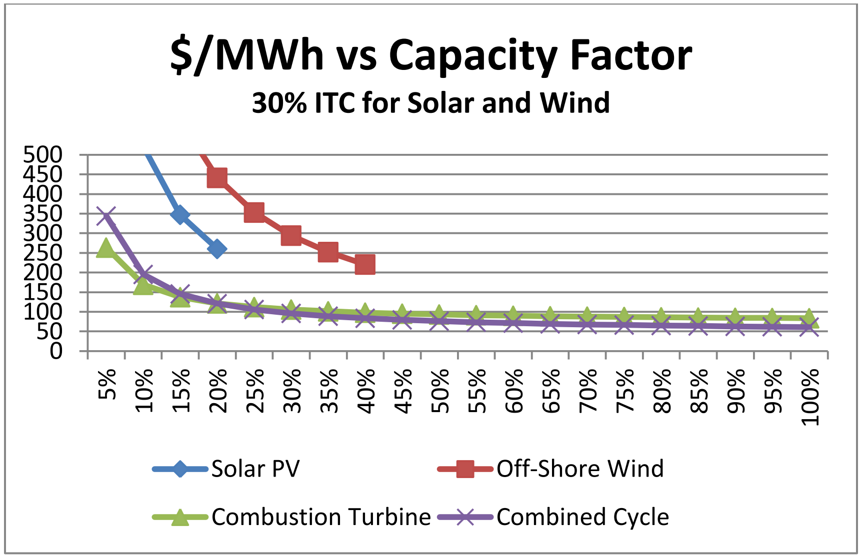
80%
85%
90%
95%
100%
Solar PV
Off-Shore Wind
Combustion Turbine
Combined Cycle


$/MWh vs Capacity Factor
30% ITC for Solar and Wind
500
450
400
350
300
250
200
150
100
50
0
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
Solar PV
Off-Shore Wind
Combustion Turbine
Combined Cycle

2. CO_2 Emissions and Renewable Resources

The following table compares several types of generation to SCE&G's new nuclear capacity in terms of CO_2 output, both emitted and avoided, assuming that half gas and half coal generation is being displaced.

Equivalent Avoided CO_2 Emissions to SCE&G's New Nuclear Capacity				
Type	**Avoided CO_2 Emissions**	**Output MWh**	**Capacity MW**	**CO_2 Emissions Tons**
New Nuclear	6,756,327	10,564,560	1,340	0
Solar PV	6,756,327	10,564,560	7,354	0
Offshore Wind	6,756,327	10,564,560	3,260	0
Combined Cycle	6,756,327	25,316,685	3,613	9,434,389

To avoid the same number of tons of CO_2 as 1,340 MWs of nuclear capacity, you would need more than 5 times that capacity in solar PV capacity or almost 2.5 times that capacity in off shore wind capacity or more than 2.5 times that capacity in gas fired combined cycle capacity.

3. The Projected Cost of Distributed Solar Photovoltaic Energy

The National Renewable Energy Laboratory ("NREL") has produced and made available to the public a financial calculator to evaluate renewable technologies. The NREL model known as the System Advisor Model ("SAM") was used to estimate the level cost of solar energy ("LCOE") in South Carolina under several scenarios. See https://sam.nrel.gov for more information on the SAM model. The following table shows the LCOE for a commercial customer seeking a power purchase agreement ("PPA"). The LCOE is reduced by both a federal and a state investment tax credit ("ITC") and by the use of accelerated depreciation, in particular, 5 year MACRS. It assumes the project is financed with 80% debt at 7% interest with a target internal rate of return ("IRR") of 15%. Since the capital cost of a solar PV installation are size and site specific and since the costs continue to change each year, the LCOE is shown for several levels of capital cost.

Levelized Cost of Solar Energy for a Commercial Installation			
Size 2000 KW		Size 200 KW	
Capital Cost $/watt	L.C.O.E. $/MWh	Capital Cost $/watt	L.C.O.E. $/MWh
$3.00	$102.50	$4.00	$121.80
$2.50	$88.30	$3.00	$93.40
$2.00	$74.00	$2.50	$79.20

The following table shows similar results for a residential installation.

Levelized Cost of Solar Energy for a Residential Installation	
Size 5 KW	
Capital Cost $/Watt	L.C.O.E. $/MWh
$6.00	$193.70
$5.00	$155.00
$4.00	$116.30
$3.00	$77.50

4. Potential Impact of Solar PV on the Resource Plan

It is difficult to pinpoint how much and how fast solar photovoltaic energy resources will develop in SCE&G's service territory, but it is evident that these resources will play a role in SCE&G's energy supply in the coming years. The cost of solar panels and associated equipment has been decreasing over the past years. Much of the ongoing and future cost reduction of solar farms is likely to be driven by efficiencies in design and construction, and the pace of reductions is likely to slow, but how far and how fast the costs will drop in the future is not certain. Federal and state tax incentives encourage the installation of solar facilities, but the level of support is likely to change in the future. Finally solar development is encouraged through the policy of net energy metering ("NEM") whereby all solar energy generated at a customer's site is valued at the customer's retail rate. Since much of the utility's fixed costs are recovered through a volumetric, per kWh charge, utilities generally claim that this policy is not sustainable. Conversely, particular solar installations may bring value to the system that is unaccounted for under current rate designs. SCE&G is working to better understand the costs and benefits of solar energy resources on its system so that costs and value are appropriately accounted for. The following table shows the impact of solar generation when its DC capacity is set to 2% of SCE&G's firm system peak. Approximately 56% of the DC rating of solar capacity will be generating on a summer afternoon and contribute to reducing the summer peak demand. There will be no solar generation at the time of SCE&G's winter peak demand which usually occurs between 7 and 8 am.

Impact When Solar DC Capacity Set to 2% of System Peak						
Year	System Peak MW	Solar DC MW @1%	Summer Peak Impact	Winter Peak Impact	Solar Energy MWH	Percent of Retail Sales
2014	4,786	96	54	0	134,161	0.6%
2015	4,849	97	54	0	135,927	0.6%
2016	4,968	99	56	0	139,263	0.6%
2017	5,074	101	57	0	142,234	0.6%
2018	5,166	103	58	0	144,813	0.6%
2019	5,246	105	59	0	147,056	0.6%
2020	5,319	106	60	0	149,102	0.6%
2021	5,385	108	60	0	150,952	0.6%
2022	5,458	109	61	0	152,999	0.6%
2023	5,540	111	62	0	155,297	0.6%
2024	5,623	112	63	0	157,624	0.6%
2025	5,704	114	64	0	159,895	0.6%
2026	5,790	116	65	0	162,305	0.6%
2027	5,867	117	66	0	164,464	0.6%
2028	5,942	119	67	0	166,566	0.6%

g. 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 - 2014 IRP " 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 10 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 8 and the need for any firm one year capacity purchases on line 12. The Company has secured the purchase of 300MWs in the years 2014 through 2016. Capacity is added to maintain the SCE&G's planning reserve margin within the target range of 14% to 20%. The resource plan thus constructed represents one possible way to meet the increasing demand of our customers. Before the Company commits to adding a new resource, it will perform a study to determine what type resource will best serve our customers.

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 - 2014 IRP

	YEAR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Load Forecast																
1	Baseline Trend	5046	5113	5272	5407	5525	5632	5734	5830	5921	6023	6125	6227	6332	6430	6525
2	EE Impact	-3	-4	-37	-58	-80	-103	-129	-156	-171	-187	-203	-220	-236	-253	-270
3	Gross Territorial Peak	5043	5109	5235	5349	5445	5529	5605	5674	5750	5836	5922	6007	6096	6177	6255
4	Demand Response	-257	-260	-267	-275	-279	-283	-286	-289	-292	-296	-299	-303	-306	-310	-313
5	Net Territorial Peak	4786	4849	4968	5074	5166	5246	5319	5385	5458	5540	5623	5704	5790	5867	5942
System Capacity																
6	Existing	5282	5287	5290	5293	5293	5918	6242	6288	6288	6288	6381	6474	6567	6660	6753
	Additions															
7	Solar Plant (20 MWs DC)	5	3	3												
8	Peaking/Intermediate										93	93	93	93	93	93
9	Baseload					625	669	46								
10	Retirements						-345									
11	Total System Capacity	5287	5290	5293	5293	5918	6242	6288	6288	6288	6381	6474	6567	6660	6753	6846
12	Firm Annual Purchase	300	300	375	500											
13	Total Production Capability	5587	5590	5668	5793	5918	6242	6288	6288	6288	6381	6474	6567	6660	6753	6846
Reserves																
14	Margin (L13-L5)	801	741	700	719	752	996	969	903	830	841	851	863	870	886	904
15	% Reserve Margin (L14/L5)	16.7%	15.3%	14.1%	14.2%	14.6%	19.0%	18.2%	16.8%	15.2%	15.2%	15.1%	15.1%	15.0%	15.1%	15.2%
16	% NERC Res.Mrgn L14/(L5-L4)	15.9%	14.5%	13.4%	13.4%	13.8%	18.0%	17.3%	15.9%	14.4%	14.4%	14.4%	14.4%	14.3%	14.3%	14.5%

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

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III. 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 Duke Energy Progress, Duke Energy Carolinas, 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. SERC NTSG Reliability 2013 Summer Study
2. SERC NTSG Reliability 2013/2014 Winter Study
3. SERC LTSG 2017 Summer Peak Study
4. SERC NTSG OASIS 2013 January Studies (13Q1)
5. SERC NTSG OASIS 2013 April Studies (13Q2)
6. SERC NTSG OASIS 2013 July Studies (13Q3)
7. SERC NTSG OASIS 2013 October Studies (13Q4)
8. SERC DSG 2014 Summer Peak/Shoulder/Light Load/Winter Peak, 2015 Summer Peak, and 2019 Summer Peak/Light Load/Winter Peak Dynamics Studies

9. ERAG 2018 Summer Transmission System Assessment
10. CTCA 2019 Summer Study
11. CTCA 2024 Carolinas Wind Study
12. SCRTP 2014 Summer Peak, 2013/2014 Winter Peak, 2018 Summer Peak, and 2023 Summer Peak Transfer Studies
13. EIPC 2018 & 2023 Roll-Up Integration Studies

where the acronyms used above have the following reference:

SERC - SERC Reliability Corporation
NTSG - Near Term Study Group of SERC
LTSG - Long Term Study Group of SERC
OASIS - Open Access Same-time Information System
DSG - Dynamics Study Group
ERAG - Eastern Interconnection Reliability Assessment Group
CTCA - Carolinas Transmission Coordination Arrangement
SCRTP - South Carolina Regional Transmission Planning
EIPC - Eastern Interconnection Planning Collaborative

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 purpose is 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 FERC-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 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.

On October 11, 2012, SCE&G filed with the FERC its proposed actions to achieve compliance with the Regional requirements of Order 1000. On April 18, 2013, FERC conditionally accepted SCE&G's filing subject to SCE&G providing more clarity and adding greater detail to SCE&G's compliance plans. On October 15, 2013, SCE&G submitted a second filing addressing these points. FERC is currently reviewing SCE&G's second filing. SCE&G worked with its neighboring planning region (Southeastern Regional Transmission Planning "SERTP") to develop actions to achieve compliance with the interregional requirements of Order 1000. On July 10, 2013, SCE&G filed with the FERC its proposed actions to achieve compliance with the Interregional requirements of Order 1000. FERC is currently reviewing SCE&G's Interregional compliance filing.

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 federally mandated lighting 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 more accurately reflects 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 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-eight 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 higher average use per customer in winter months relative to the latter group. Finally, these categories were divided by housing type (single family, multi-family, and mobile homes). Each municipal 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 1 nuclear plant outages. Unaccounted energy, which is the difference between generation and sales and represents for the most part system losses, is usually between 4-5% of total territorial sales. The average annual loss for the three previous years was 4.6%, and this value was assumed throughout the forecast. The monthly allocations for unaccounted use 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 Less Weather-Sensitive	Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
		Multi Family	67, 68, 69
910	Residential More Weather-Sensitive	Mobile Homes	
20	Commercial Less Weather-Sensitive	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other Rates	3, 10, 11, 14, 16, 18, 25, 26 29, 62, 67, 69
920	Commercial Space Heating More Weather-Sensitive	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 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

*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, One Account
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 six classes of service: residential, commercial, industrial, street lighting, other public authorities, and municipals. 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 93% 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 categorized into two groups, more and less weather-sensitive. 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 projected 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., the gas price spike in 2005 attributable to Hurricane Katrina and recession versus non-recession years).

Standard statistical procedures 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 Housing Starts
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.

After the trend econometric forecasts were completed, reductions were made to account for higher air-conditioning efficiencies, DSM programs, and the replacement of incandescent light bulbs with more efficient CFL or LED light bulbs. Industrial sales were increased if new customers are anticipated or if there are expansions among existing customers not contained in the short-term projections.

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:

$$\textit{Load Factor} = \textit{Energy}/(\textit{Demand} \times 8760)$$

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 factors: total territorial energy, customers, and weather during the day of the winter peak's occurrence. Other dummy variables were also included in the model to account for unusual events, such as recessions or extremely cold winters.

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.