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: 2015 - ____ - E**

(Please type or print)

Submitted by:	Matthew W. Gissendanner	**SC Bar Number:**	76027
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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	

SCANA® POWER FOR LIVING

Matthew W. Gissendanner
Assistant General Counsel

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February 27, 2015

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 2015 Integrated Resource Plan
Docket No. 2015-____-E

Dear Ms. Boyd:

In accordance with S.C. Code Ann. § 58-37-40 (Supp. 2014) and Order No. 98-502 enclosed you will find the 2015 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2015 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 2015 IRP and attached a certificate of service to that effect.

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

Very truly yours,

Matthew W. Gissendanner

Matthew W. Gissendanner

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

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2015-___-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 **2015 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 27th day of February 2015

2015

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

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Introduction

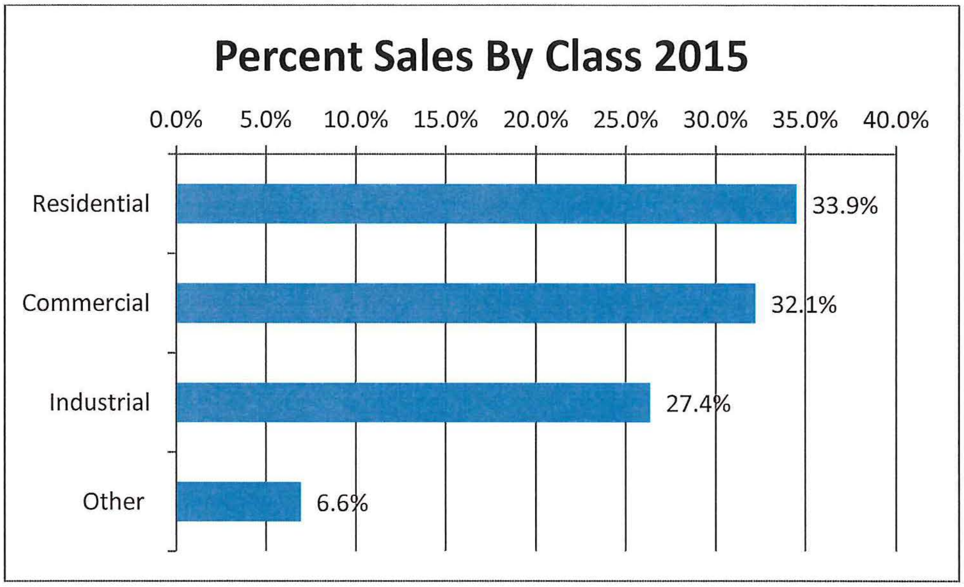
This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2015 through 2029. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (Supp. 2014) 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. 2014). 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 2029

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 1.4% per year over the next 15 years, while firm territorial summer peak demand and winter peak demand will increase at 1.8% and 1.4% per year, respectively, over this forecast horizon. The table below contains these projected loads. Note that by utility convention winter follows summer so that the 2015 winter refers to the 2015-2016 winter season.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2015	4,747	4,602	22,635
2016	4,822	4,664	22,770
2017	4,925	4,744	23,120
2018	5,033	4,862	23,412
2019	5,142	4,909	23,690
2020	5,256	4,978	24,093
2021	5,365	5,043	24,502
2022	5,464	5,108	24,803
2023	5,566	5,174	25,124
2024	5,659	5,241	25,505
2025	5,747	5,310	25,894
2026	5,837	5,380	26,283
2027	5,919	5,446	26,650
2028	5,996	5,514	26,028
2029	6,079	5,581	27,410

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 public street lighting, other public authorities, municipalities and electric cooperatives.

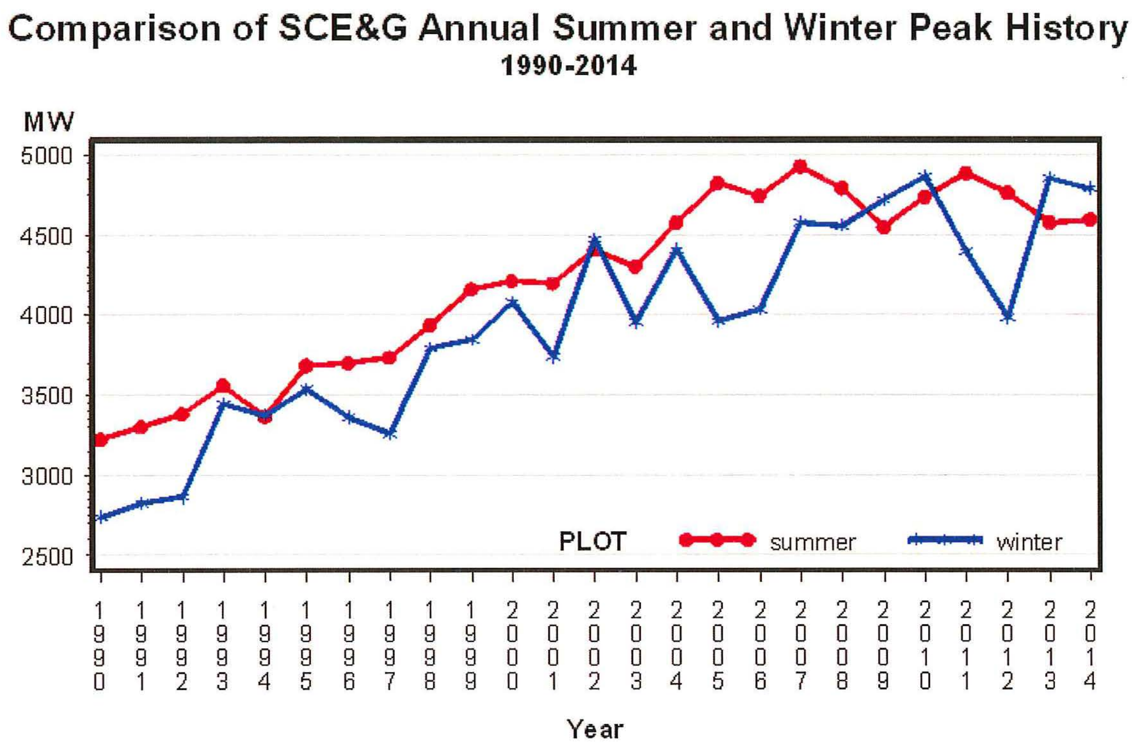


SCE&G's forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained in Appendix A of this report. Short-range is defined 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 following chart. 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 in the sense that kWh sales are about 15% higher in the summer than winter. 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 chart shows SCE&G's experience with summer versus winter peaking. By utility industry convention, the winter period is assumed to follow the summer period. In 6 of the past 25 years, SCE&G peaked in the winter. One other notable feature of the peak demand chart is the greater variability in winter peak demand.



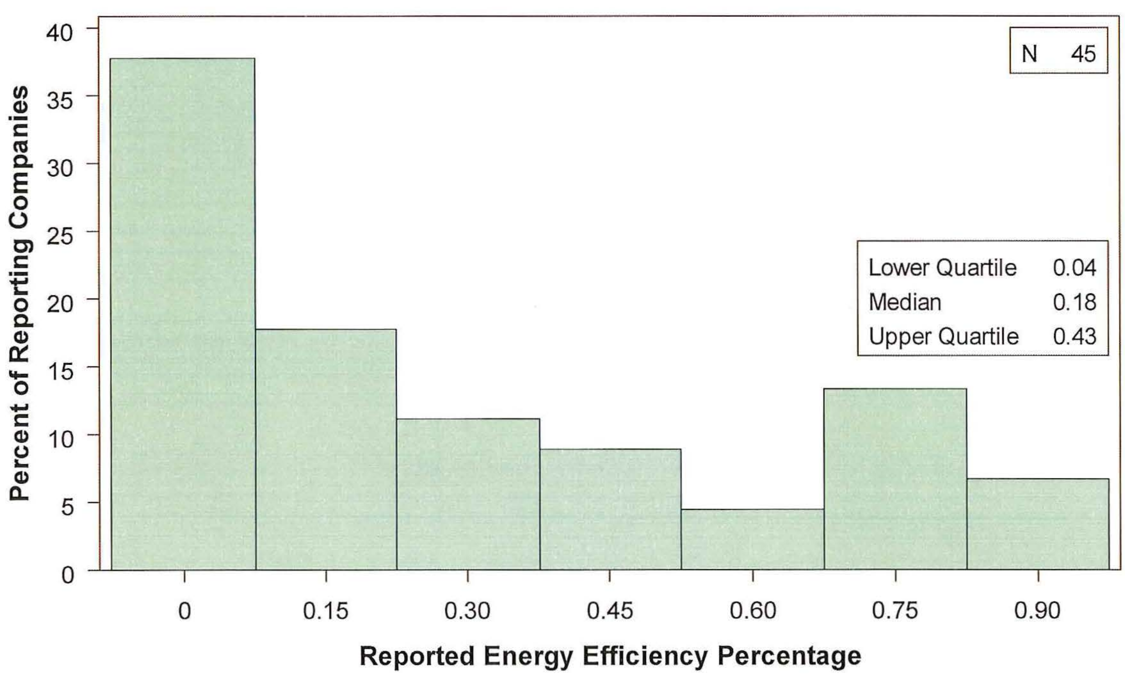
The forecast of summer peak demand is developed by combining the load profile characteristics of each customer class collected in the Company's Load Research Program with forecasted energy. The winter peak demand is projected through customer class equations which relate class winter peaks with weather variables and growth factors.

2. DSM Impact on Forecast

SCE&G expects its energy efficiency ("EE") programs to reduce retail sales in 2015 by 71,307 MWH or approximately 71 GWH. Retail sales after this EE impact are expected to be 21,853 GWH. Therefore, the EE programs are expected to reduce retail sales by about 0.33%

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 2013, the latest year available. There were 52 companies filing from the Southeast, in particular, from the North American Electric Reliability Corporation (NERC) regions of the SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC). Three companies were dropped from the analysis for bad data, and the Tennessee Valley Authority reporting in four states was dropped as well. The chart below shows graphically the distribution of reported results. The median EE impact was 0.18%. Thus, half the companies reported results higher and half lower than this median value. SCE&G's expectation for 2015 places it in the top half of the distribution. Clearly SCE&G's EE programs compare favorably with other companies in the Southeast.

EIA 861 Reported Energy Efficiency Impacts for 2013



As part of the forecast development, the 0.33% 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 0.28% and 0.10% for the residential and commercial sectors, respectively. The table below illustrates the calculation of the EE reductions. The far right-hand column labeled "Total 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. %	Total Cumulative Reductions (GWH)
2015	7,783	-	-	-	7,271	-	-	-	-
2016	7,840	-	-	-	7,314	-	-	-	-
2017	7,996	-22	-22	-0.28	7,431	-7	-7	-0.10	-29
2018	8,130	-45	-23	-0.28	7,532	-15	-8	-0.10	-60
2019	8,234	-68	-23	-0.28	7,704	-23	-8	-0.10	-91
2020	8,415	-91	-24	-0.28	7,932	-31	-8	-0.10	-122
2021	8,591	-115	-24	-0.28	8,159	-39	-8	-0.10	-154
2022	8,708	-140	-24	-0.28	8,331	-47	-8	-0.10	-187
2023	8,831	-165	-25	-0.28	8,514	-56	-9	-0.10	-221
2024	8,989	-191	-25	-0.28	8,721	-64	-9	-0.10	-255
2025	9,152	-216	-26	-0.28	8,935	-73	-9	-0.10	-289
2026	9,319	-242	-26	-0.28	9,145	-82	-9	-0.10	-324
2027	9,483	-268	-27	-0.28	9,339	-92	-9	-0.10	-360
2028	9,649	-295	-27	-0.28	9,541	-101	-10	-0.10	-396
2029	9,814	-323	-27	-0.28	9,745	-111	-10	-0.10	-434

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, heat pump, and water heater efficiency standards, plus improved lighting efficiencies, all 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.

		Energy Efficiency			
	Baseline Sales (GWH)	SCE&G DSM Programs (GWH)	Federal Mandates (GWH)	Total EE Impact (GWH)	Territorial Sales (GWH)
2015	22,766	0	-131	-131	22,635
2016	22,947	0	-177	-176	22,770
2017	23,418	-29	-269	-259	23,120
2018	23,840	-60	-368	-348	23,412
2019	24,220	-91	-439	-410	23,690
2020	24,732	-122	-517	-479	24,093
2021	25,233	-154	-577	-532	24,502
2022	25,620	-187	-630	-577	24,803
2023	26,028	-221	-683	-625	25,124
2024	26,495	-255	-735	-670	25,505
2025	26,977	-289	-794	-723	25,894
2026	27,459	-324	-852	-775	26,283
2027	27,918	-360	-908	-827	26,650
2028	28,388	-396	-1,964	-880	26,028
2029	28,861	-434	-1,017	-931	27,410

Baseline sales are projected to grow at the rate of 1.71% 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 1.38% 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 which 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 2015 the minimum Seasonal Energy Efficiency Ratio ("SEER") will increase from 13 to 14 for South Carolina and other regions of the United States. This was the first change in SEER ratings since 2006, when the minimum SEER for newly manufactured appliances was raised from 10 to 13. The cooling load 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 first 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 2015 minimum SEER rating represented another 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.

All electric water heaters manufactured after April 2015 will also be subject to higher efficiency standards. The level of increase varies according to the size of the water heater, but for a 40-gallon water heater the energy factor will rise by 3.4%. While high-efficiency water heaters have been available in the market for some time, it is still expected that a considerable percentage of residential customers will be impacted by the new standards. Therefore, reductions were made to the baseline energy projections to incorporate this effect.

A third 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 2012 and will be phased in through 2014. Standard incandescent light bulbs are inexpensive and provide good illumination, but they are extremely inefficient. Compact fluorescent light bulbs ("CFLs") have become increasingly popular over the past several years as substitutes. They last much longer and generally use about one-fourth the energy 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.

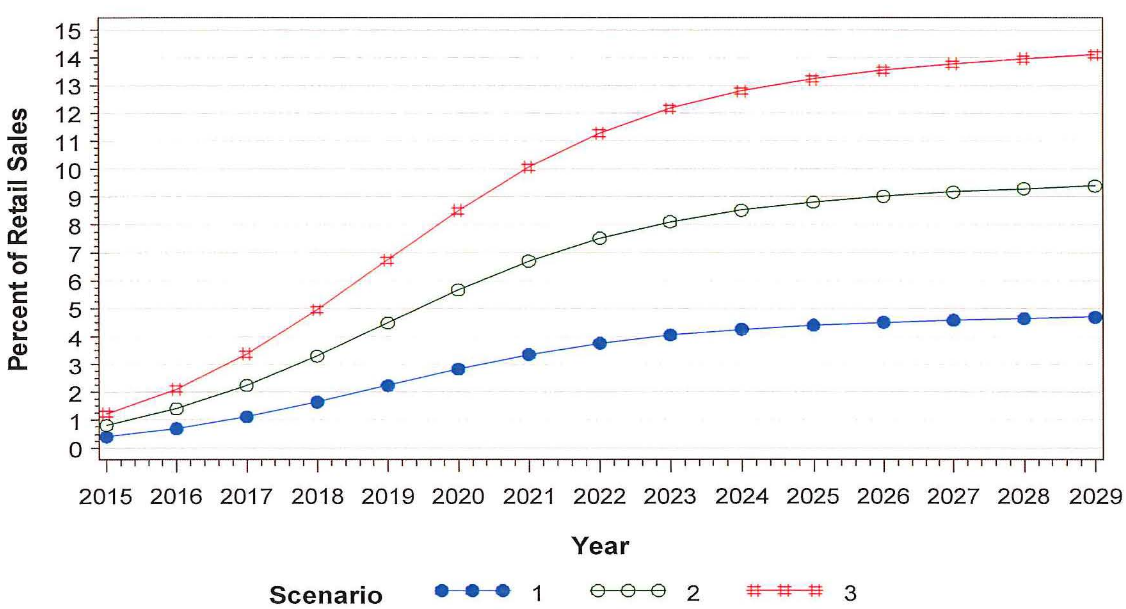
Territorial Peak Demands (MWs)							
		Energy Efficiency					
Year	Baseline Trend	SCE&G Programs	Federal Mandates	Total EE Impact	System Peak Demand	Demand Response	Firm Peak Demand
2015	5,007	0	-4	-4	5,003	-256	4,747
2016	5,089	0	-8	-8	5,081	-259	4,822
2017	5,211	-9	-13	-22	5,189	-265	4,924
2018	5,341	-18	-18	-36	5,305	-272	5,033
2019	5,466	-29	-21	-50	5,416	-275	5,141
2020	5,595	-38	-23	-61	5,534	-277	5,257
2021	5,719	-48	-25	-73	5,646	-280	5,366
2022	5,833	-59	-27	-86	5,747	-283	5,464
2023	5,951	-69	-29	-98	5,853	-286	5,567
2024	6,059	-80	-31	-111	5,948	-289	5,659
2025	6,162	-90	-33	-123	6,039	-292	5,747
2026	6,268	-101	-35	-136	6,132	-295	5,837
2027	6,366	-112	-37	-149	6,217	-298	5,919
2028	6,460	-124	-39	-163	6,297	-301	5,996
2029	6,559	-134	-41	-175	6,384	-304	6,080

5. Potential for New Solar Generation

While it is difficult to predict the amount and timing of solar generation on the SCE&G system, it is informative to postulate a few scenarios. If the cost of solar panels continues to fall at a rate comparable to its recent past, then there should be a significant amount of solar generation added to the system by SCE&G's customers. Here we consider three scenarios. Under scenario 1, it is assumed that 25% of new residential customers in both single family and multi-family homes have solar panels added to their houses, that 10% of the existing residential market adds solar panels and 10% of the commercial square footage on the system has solar panels installed. In scenarios 2 and 3, the saturation percentages are respectively double and triple those in scenario 1. It is assumed that these market percentages are reached in 10 to 15 years following the pattern of a typical saturation S-curve. These assumptions are summarized in the nearby table. It is estimated that residential homes install a 5 kW solar system producing about 6,242 kWh per year and that commercial solar panels produce about 15.8 kWh per square foot per year. The following shows the results of these assumptions under each scenario as a percent of SCE&G's retail sales.

	Percent Saturation with Solar (%)		
Scenario	New Residential Customers	Existing Residential Customers	Commercial Square Footage
1	25	10	10
2	50	20	20
3	75	30	30

Solar Generation as a Percent of Retail Sales



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 Education and Outreach, Energy Conservation and the Demand Side Management programs. A description of each follows:

1. **Customer Education and Outreach:** SCE&G's customer education and outreach includes a wide variety of communication vehicles to help customers become more energy efficient. Two key components, customer insights/analysis and media/channel placement, are summarized below:
    a. **Customer Insights and Analysis:** Key insights gained through SCE&G's annual Voice of the Customer panels and customer perception surveys are carefully evaluated to ensure customer communications are consistent, easy to understand and include information about what they value most – rebates/incentives, education and in-home services.
    b. **Media/Channel Placement:** SCE&G is committed to customer education about available programs and services designed to help them be more energy efficient. To reach as many customers as possible, a diverse mix of channels is used, including both paid and earned media. Direct mail, bill inserts, TV, radio, online and community events continue to prove successful with engaging customers. In 2014, SCE&G launched a new website designed to give customers easier access to the many tools and resources available to manage their energy use. Extensive outreach via social media continues to provide maximum coverage and the opportunity to

inform customers. A steady increase in customer engagement with Facebook and Twitter has resulted in nearly 30,000 likes and about 5,200 followers respectively. Year-round news coverage is equally important and is consistently integrated into the media mix, particularly during peak winter and summer months when usage is high.

2. **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**: Rate 6 (Energy Saver/Conservation) rewards homeowners and homebuilders with a reduced electric rate when they upgrade existing homes or build new homes to a high level of energy efficiency. This reduced rate, combined with a significant reduction in energy usage, provides for considerable savings to customers. Participation in the program is easy as the requirements are prescriptive which is beneficial to all customers and trade allies.

   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.

3. **Demand Side Management Programs**

In 2014, the Demand Side Management portfolio of programs included nine (9) programs targeting SCE&G's residential customer classes and two programs targeting 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 Home Energy Check-up** 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.

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

d. **Residential Heating & Cooling and Water Heating Equipment** provides incentives to customers for purchasing and installing high efficiency HVAC equipment and non-electric resistance water heaters in new and existing homes. Additionally, the program provides residential customers with incentives to improve the efficiency of existing AC and heat pump systems through complete duct replacements, duct insulation and duct sealing. During 2014, SCE&G discontinued offering residential customers incentives for non-electric resistance water heaters.

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

f. **Neighborhood Energy Efficiency Program (NEEP)** provides income qualified customers energy efficiency education, an in-home energy assessment and direct installation of low-cost energy saving measures as part of a neighborhood door-to-door sweep approach. In 2014, neighborhoods in Aiken, Columbia, Charleston and Beaufort have taken part in the program.

g. **Appliance Recycling Program,** first offered to electric customers in 2014, provides incentives for allowing SCE&G to collect and recycle less-efficient, but operable, secondary refrigerators, and/or standalone freezers, permanently removing the units from service.

h. **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. During 2014, pursuant to Commission Order, SCE&G discontinued this program.

i. **Residential Home Performance with ENERGY STAR®** 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. During 2014, pursuant to Commission Order, SCE&G discontinued this program.

j. **EnergyWise For Your Business 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 prescriptive measures and incentive levels that are easily accessible to commercial and industrial customers on the website. Additionally, a custom path provides 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.

k. **Small Business Energy Solutions Program** is a turnkey program, tailored to help owners of small businesses manage energy costs by providing incentives for energy efficiency lighting, electric water heaters and refrigeration upgrades. The program is available to SCE&G's small business and small nonprofit customers with an annual energy use of 100,000 kWh or less, and five or fewer SCE&G electric accounts.

Load Management Programs

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

1. **Standby Generator Program:** The Standby Generator Program for 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 participants to run their emergency generators. This retail program provides about 17 megawatts of additional capacity as needed.

2. **Interruptible Load Program:** SCE&G has over 150 megawatts of interruptible customer load under contract. Participating customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity.
3. **Real Time Pricing ("RTP") Rate:** A number of customers receive power under our real time pricing rate. During peak usage periods throughout the year when capacity is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.
4. **Time of Use Rates:** Our time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All SCE&G customers have the option of purchasing electricity under a time of use rate.

B. Supply Side Management

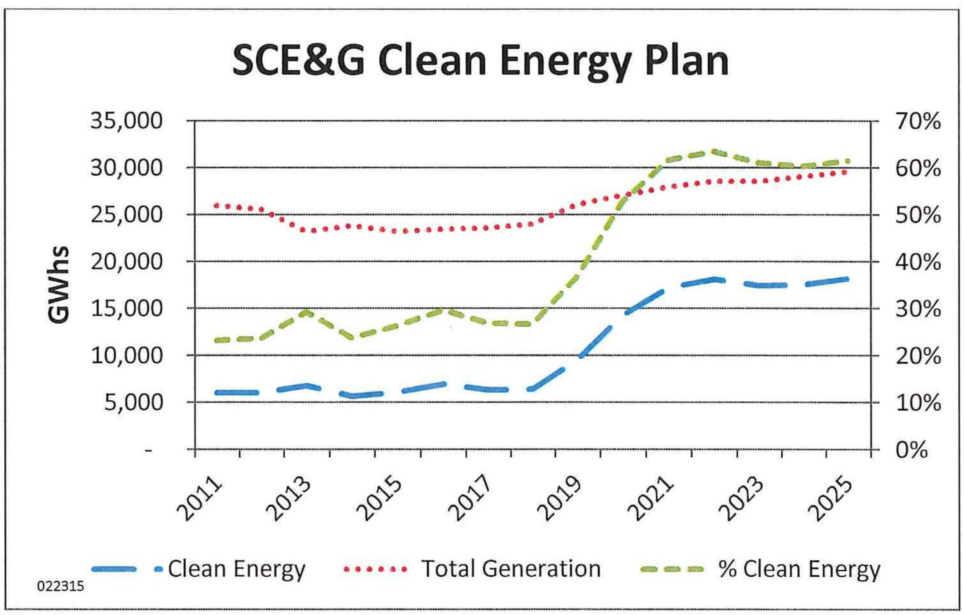
Clean Energy at SCE&G

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

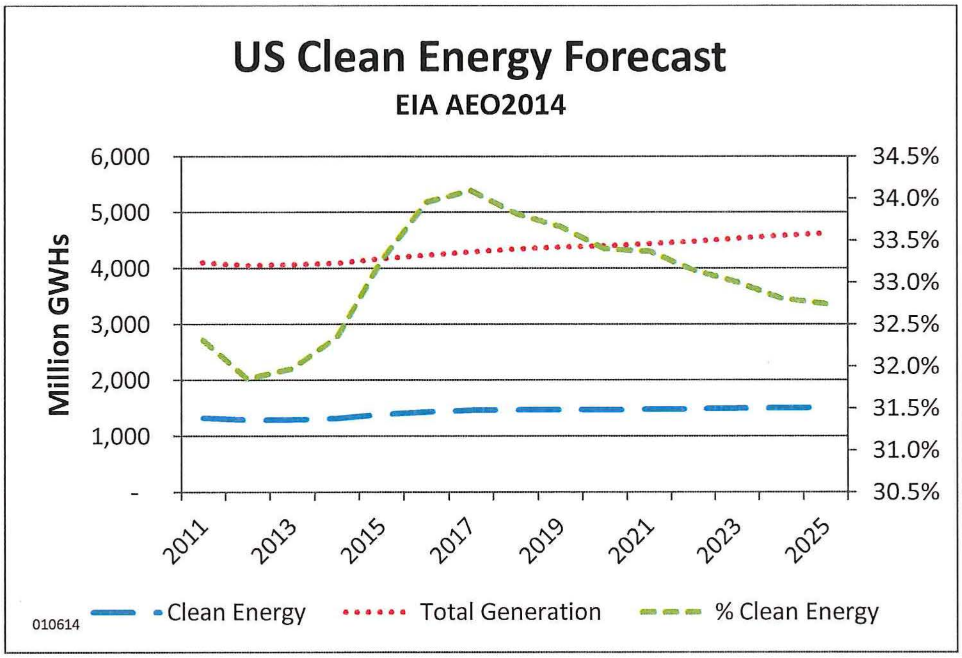
1. Existing Sources of Clean Energy

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 total generation.



As seen in the chart above, SCE&G currently produces approximately 25% of its total generation from clean energy sources but by 2021 it expects to generate over 60% from clean energy. According to the EIA, the U.S. as a nation currently produces about 33% of its total generation from clean sources, and it expects this percentage to decrease slightly over the next ten years or so. The following chart graphs EIA's forecast for US clean energy.



SCE&G compares favorably to the nation in its clean energy plans. By 2021 it should be producing about twice as much of its generation 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 are used to produce renewable energy which qualifies 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%
2014	404,526	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 with a nameplate rating of 2.6 MW DC began generating in October 2011 and has a peak output of about 2.35 MW AC. 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
2014	3,337

d. Net Energy Metering ("NEM") 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 under the current NEM rider, 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. The NEM rider provides that each kWh generated by the customer will offset one kWh of consumption by the customer. This is referred to as 1:1 kWh. Customer-generator capacity under the current NEM program is limited to 0.2% of the Company's retail peak demand.

The Company anticipates offering its customers another NEM rate that will allow customer-generators to be as large as 1,000 kW. The Company also anticipates applying a Net Metering Incentive, funded through a Distributed Energy Resource Program, to customer-generators receiving service under this NEM rate prior to January 1, 2021, in order to make such customer-generators' bills equal to the bills they would have received if the power generated by the distributed energy resource facilities were valued at the 1:1 Rate. Customer-generator capacity under this NEM rate is capped at 2.0% of the five-year average of the Company's retail peak demand. A hearing on the methodology to establish this NEM rate was held before the Commission on February 3, 2015, in Docket No. 2014-246-E where a settlement agreement, signed by most parties of record and not objected to by any, was presented to the Commission for approval. Under the settlement agreement, customers will be offered the new NEM rate until January 1, 2021, and those customers taking service under the new NEM rate will receive the Net Metering Incentive described above until December 31, 2025, or until they take service under a different rate, whichever occurs first. Customers taking service under the existing NEM rider may continue to do so until December 31, 2020. A Commission order is expected in the near future.

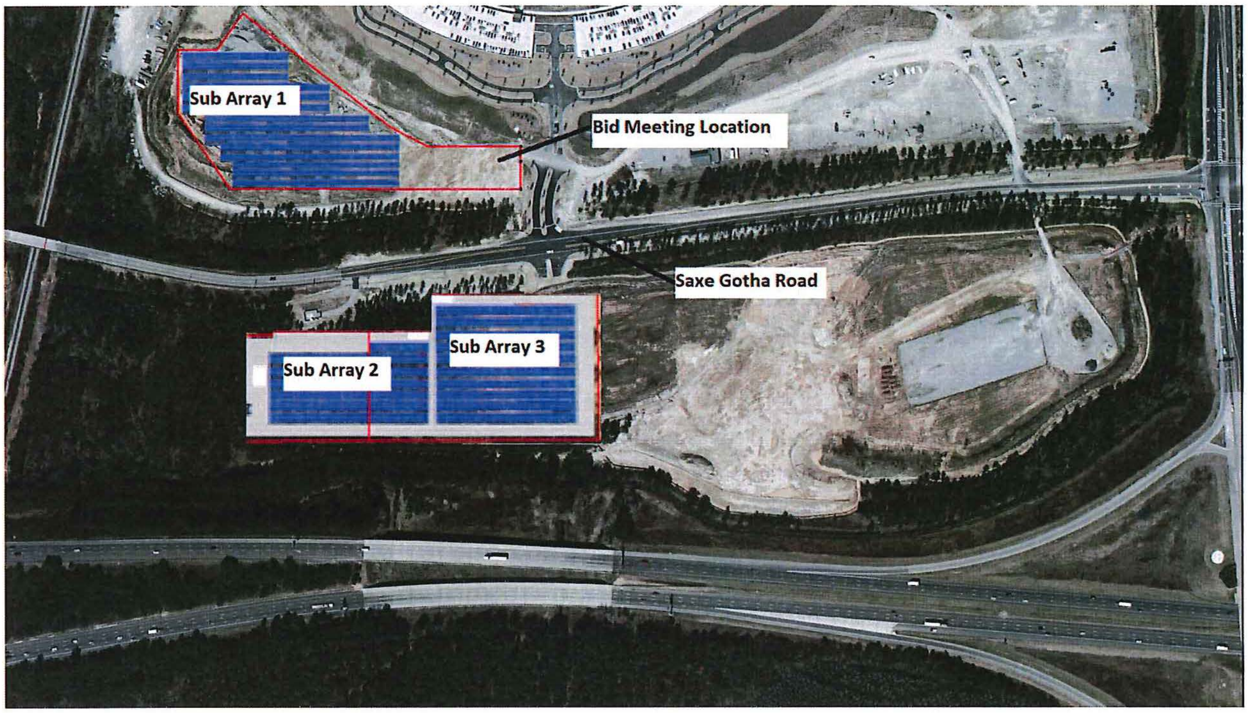
Under its PR-1 rate for qualifying facilities, the Company will pay the qualifying customer for any power generated and transmitted to the SCE&G system. The PR-1 rate is developed using SCE&G's avoided costs.

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 a) distributed energy resources, b) off-shore wind activities in the state, c) co-firing with biomass fuels, d) smart grid opportunities, e) distribution automation, f) environmental mitigation activities, and g) nuclear power in the future. These activities are set forth in more detail below.

a. Distributed Energy Resource ("DER") Program: 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 clean 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. As part of its new DER Program, which was filed with the Commission on February 9, 2015, SCE&G plans to add up to almost 100 megawatts of renewable energy to its system by 2021. SCE&G has created an experienced team focused on research, design, and implementation of renewable energy resources (solar, wind, and biomass). In 2015 SCE&G plans to install approximately 14 MWs of solar generation on its system. The first two solar farms will be a 3.8 MW solar farm constructed along Saxe Gotha Road in Cayce and a 0.5 MW solar farm will be constructed at Leeds Avenue in Charleston. See pictures below. These solar farms will include opportunities for research, education, and expansion of the clean 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 was 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, included 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.

In an effort to promote wind turbine research, 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 9,600 AMI (Advanced Metering Infrastructure) 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.

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 900 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 enable these automated devices to communicate with each other and safely reconfigure the system in a fully automated fashion, let operators know exactly where the faulted section of a line is and monitor the status of the system as it is affected by outages, switching, and customer generation (solar).

f. Environmental Mitigation Activities: On January 1, 2015, the Clean Air Interstate Rule (CAIR) was replaced by the Cross State Air Pollution Rule (CSAPR), which set new emission limits for Annual and Seasonal NO_X and also for Annual SO_2. In addition the existing Acid Rain Program (ARP) continues in effect for annual SO_2 emissions.

To meet the compliance requirements for NO_X, SCE&G (& Genco) has installed Selective Catalytic Reduction equipment (SCRs) at Wateree, Cope and Williams Stations. Also all coal-fired units have previously installed low NO_X burners.

To meet the compliance requirements for SO_2, Williams and Wateree Stations have installed flue gas desulfurization ("FGD") equipment, commonly known as wet scrubbers. Cope Station has FGD equipment in the form of a dry scrubber, which was part of the original equipment of that plant.

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 U.S. 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, Cope, and Williams Stations 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 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 was completed in 2014. Also in response to MATS, Canadys Station ceased operations on November 6, 2013, and decommissioning efforts are still 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 Environmental Regulations

The EPA has either proposed or recently finalized 6 regulations and modified one additional regulation. These are: a) Cross-State Air Pollution Rule ("CSAPR"); b) Mercury and Air Toxics Standards ("MATS"): c) Greenhouse Gases; d) Cooling Water Intake Structures; e) Coal Combustion Residuals; f) Effluent Limitation Guidelines; and g) a new 1-hour sulfur dioxide National Ambient Air Quality Standard ("NAAQS"). A discussion of these proposed and finalized regulations follows.

a. Cross-State Air Pollution Rule ("CSAPR") On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the U.S. Court of Appeals for the D.C. Circuit issued an order granting a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR rule text with the revised court-ordered schedule, thus delaying the implementation dates to 2015 for Phase 1 implementation and to 2017 for Phase 2.

CSAPR replaces the Clean Air Interstate Rule (CAIR) and requires a total of 28 states to reduce annual SO_2 emissions, annual NO_X emissions and/or ozone season NO_X emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). The rule establishes an emissions cap for SO_2 and NO_X and limits the trading region for emission allowances by separating affected states into two groups with no trading between the groups.

SCE&G generation is in compliance with the allowances set by CSAPR. Air quality control installations that SCE&G has already completed have positioned the Company to comply with the rule.

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. On December 16, 2011, the EPA Administrator finalized MATS and the rule was published in the Federal Register on February 16, 2012. Following publication of the rule, EPA received 20 petitions for reconsideration of MATS. On November 19, 2014, the EPA finalized the action reconsidering the provisions applicable during startup and shutdown under MATS.

MATS became effective on April 16, 2012. Compliance with MATS is required by April 2015. 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.

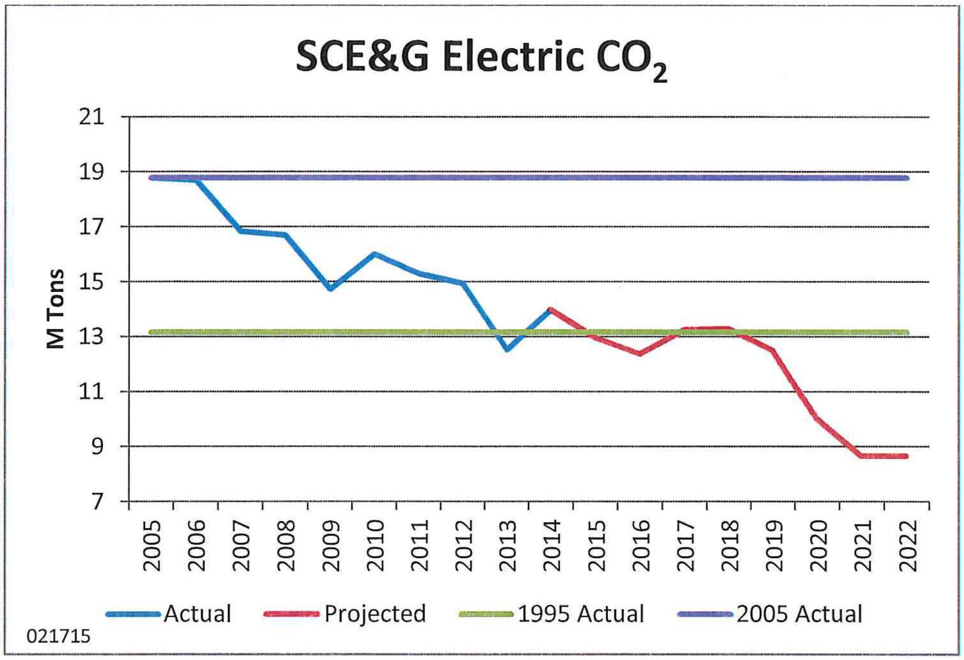
SCE&G applied for and received a 1-year extension from DHEC for both McMeekin and Canadys. With the retirement of Canadys in the 4th quarter of 2013, only McMeekin has a waiver that will allow the continued use of coal until April 2016. SCE&G has also requested a compliance extension for Williams Station, Cope Station, and Wateree in part due to the additional requirements of the reconsideration rule which dealt with startup and shutdown that was finalized on November 19, 2014. This extension will also allow time to install additional pollution control devices that will enhance the control of certain MATS-regulated pollutants. DHEC approval of these extension requests has recently been approved.

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 was published 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. The Company is evaluating the rule, but does not plan to construct new coal-fired units in the near future.

On June 2, 2014, the EPA announced proposed standards (Clean Power Plan) to limit carbon pollution from existing power plants and modified and reconstructed power plants. The rule to govern carbon pollution from existing power plants is state specific and differs from the rule for new power plants published on January 8, 2014. EPA plans to issue final rules for all three proposed plans by summer 2015. In addition, a federal plan for meeting the state goals established by the Clean Power Plan is scheduled to be released by summer 2015.

The Company is currently constructing two new nuclear generation units (see Section 4d, "New Nuclear Capacity"). The proposed Clean Power Plan rules for existing units do not give full credit for reductions in emissions achieved when SCE&G's new nuclear units are completed and come on line. The EPA received about two million public comments on the proposed rules under the Clear Power Plan. However, it is not known what modifications will be made in the final rules and how they will affect the final State Implementation Plan. The following chart shows that SCE&G's CO_2 emissions will fall well below its 1995 level after new nuclear begins generating.



d. Cooling Water Intake Structures The Clean Water Act Section 316(b) Existing Facilities Rule became effective on October 14, 2014. This rule is intended to reduce damage to fish and shellfish due to impingement, when organisms are trapped against inlet screens, and entrainment, when small organisms are drawn through the screens into the facility's cooling water system. Facilities capable of withdrawing at least 2 million gallons per day are generally subject to the rule. Facilities that are subject to the rule must, at a minimum, submit a series of reports which describe the design and operation of the cooling water intake, as well as physical and biological characteristics of the cooling water source waterbody. For some facilities, operational or design changes will be necessary to meet the requirements of the rule. Potential design changes range from enhanced screening and reconfiguration of water intake systems to installation of closed-cycle cooling towers to reduce flow rates. Of the SCE&G generating facilities potentially subject to the rule (those that use cooling water), two, Wateree and Cope Stations, currently meet Best Technology Available (BTA) requirements for impingement mortality and entrainment. Two others, McMeekin and Jasper Stations, have been determined to be not-in-scope for the rule. The Company is currently in discussions with the South Carolina Department of Health & Environmental Control regarding compliance requirements for Summer Station Unit 1, Urquhart Station and Williams Station. Biological study plans, which would evaluate current impacts to fish and shellfish, are being developed for Summer Station and Urquhart Station.

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 elected to further regulate coal combustion residual (CCR or ash) management in landfills and surface impoundments (ponds). On December 19, 2014, EPA signed the final CCR management rules. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rules will become effective six (6) months from the date of its publication in the Federal Register, which is expected in the first quarter of 2015.

The rule acknowledges that CCR can be safely reused in encapsulated uses such as cement and wallboard manufacture. SCE&G has long provided CCR as a useful raw material to those industries and expects to continue to do so.

The rule is over 700 pages long and SCE&G is still reviewing the final rules to determine how it will apply to its facilities. However, it is believed that certain CCR management units at multiple coal-fired plants will be subject to all or parts of the rule, including units at Cope, Wateree, and Williams Stations. CCR units at McMeekin, Urquhart and Canadys Stations may be subject to the rule, and SCE&G is seeking clarification of certain provisions in the rule to properly classify those units.

Notwithstanding this new CCR rule, SCE&G has already closed its ash storage ponds or has begun the process of ash pond closure at all of its operating facilities. Those ash storage ponds that are still open are subjected to a rigorous inspection and maintenance program to ensure the safe management of those units. Once all ash storage ponds have been closed, SCE&G will dry-handle all fly-ash.

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 the 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 has proposed amendments to the effluent guidelines and standards for the Steam Electric Power Generating category.

To develop this proposed rule, the 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, SCE&G participated in an EPA Information Collection Request ("ICR") which requested information on plant operations, pollution control technologies, and current wastewater discharges. In 2013 and 2014, SCE&G conducted pilot testing of selected wastewater treatment systems at its Wateree Station and provided the results of those tests to the EPA in order to demonstrate the inability of existing technologies to consistently meet the proposed standards. It is hoped that the EPA will take this into consideration when issuing the final rule.

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. Proposed federal effluent limitation guidelines for steam electric generating units (the ELG Rule) were published in the Federal Register on June 7, 2013. A final rule is expected by September 30, 2015. 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. Compliance dates will vary by type of wastewater and some will be based on a plant's 5-year permit renewal cycle and thus may range from 2018 to 2023. 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.

On May 13, 2014, EPA proposed the Data Requirements Rule for implementing the 1-Hour SO_2 standard. This rule requires state agencies to characterize air quality in areas with large sources of SO_2 emissions using either modeling of actual source emissions or using appropriately sited ambient air quality monitors. 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).

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 4,762 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 and 5,468 MWs in winter. This is summarized in the table on the following page.

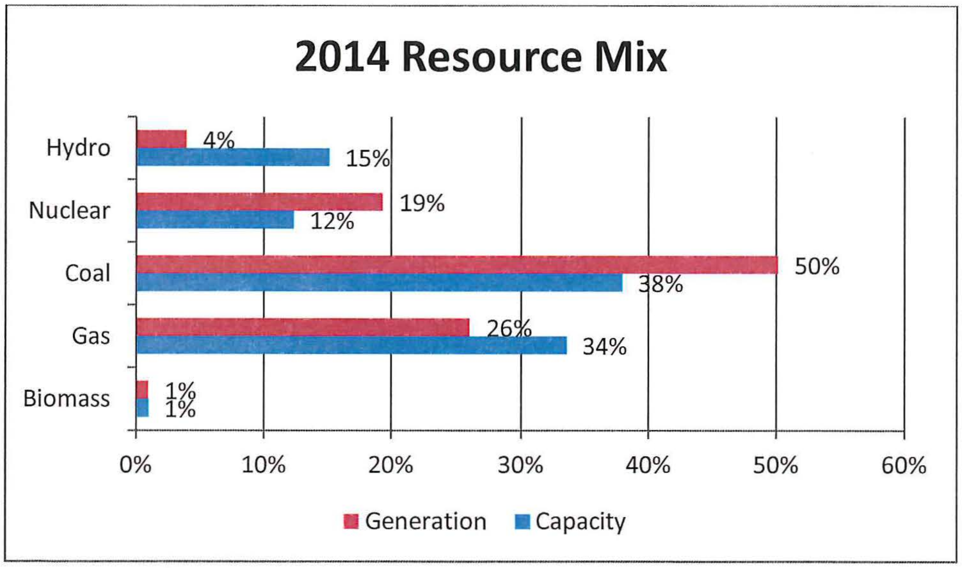
Existing Long Term Supply Resources

The following table shows the generating capacity that is available to SCE&G in 2015.

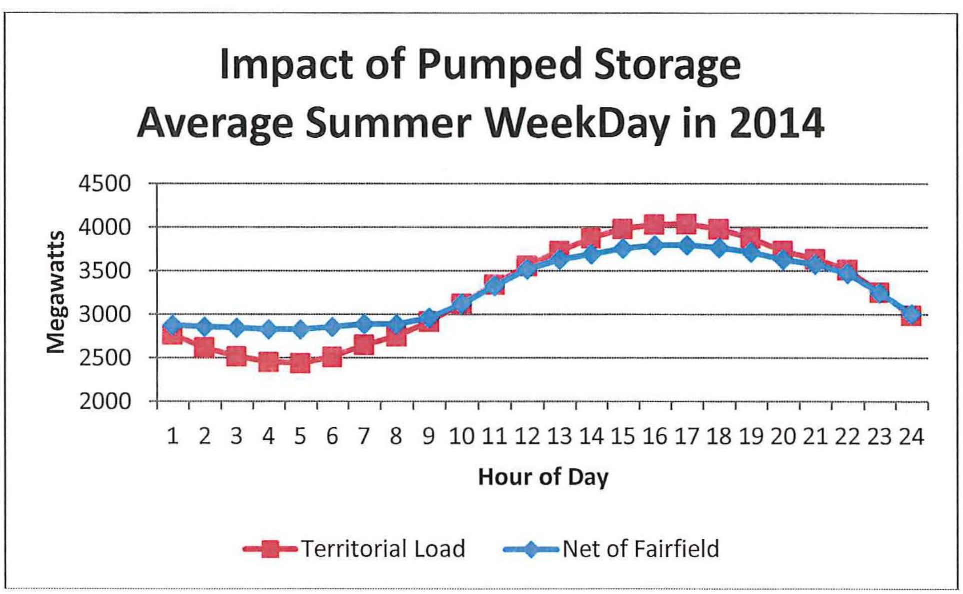
	In-Service Date	Summer (MW)	Winter (MW)
Coal-Fired Steam:			
McMeekin – Irmo, SC	1958	250	250
Wateree – Eastover, SC	1970	684	684
Williams – Goose Creek, SC*	1973	605	610
Cope - Cope, SC	1996	415	415
Kapstone – Charleston, SC	1999	85	85
Total Coal-Fired Steam Capacity		2,039	2,044
Gas-Fired Steam:			
Urquhart – Beech Island, SC	1955	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	36
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	1,820
Hydro:			
Neal Shoals – Carlisle, SC	1905	3	4
Parr Shoals – Parr, SC	1914	7	12
Stevens Creek - Near Martinez, GA	1914	8	10
Saluda - Irmo, SC	1930	200	200
Fairfield Pumped Storage - Parr, SC	1978	576	576
Total Hydro Capacity		794	802
Other: Long-Term Purchases		25	25
Southeastern Power Administration (SEPA)		20	20
Grand Total:		5,282	5,468

* 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. Purchases totaling 300 MWs of firm capacity for the years 2015-2016 are also not reflected in the table.

The bar chart below shows SCE&G's actual 2014 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 229 MWs from the daily peak times of 2:00 p.m. through 6:00 p.m. and to move about 2.1% 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. An additional 2% will go to SCE&G one year later and another 2% one year after that. The expected completion date for Unit 2 is currently mid-year 2019 with Unit 3 expected to be complete about a year later. By the end of 2021, SCE&G expects to own 60% of both units (about 670 MWs each) while Santee Cooper will own 40%.

The parties constructing the new nuclear units have advised SCE&G that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the constructors' contention that the new Substantial Completion Dates are made necessary by delays that are excusable under the underlying Contract. SCE&G is continuing discussions with the contractors in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

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
Total	730	

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.[1] As part of this retirement plan the Company has retired Canadys' Units 1, 2 and 3 and has converted Urquhart Unit 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 Units 1 and 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 DHEC these units cannot run on coal after

[1] 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. See 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.").

April 15, 2016. The Company expects to bridge the gap between the MATS compliance date and the availability of the new nuclear capacity by firing McMeekin Units 1 and 2 on natural gas and purchasing the balance of needed capacity.

f. High Energy Efficiency (EE) Penetration Scenario: Increased levels of EE will reduce energy and demand requirements and change the Company's generation plans. A High EE scenario was prepared to analyze these changes, and is described below.

The Company's base EE plan calls for an incremental reduction of 0.33% annually in retail sales after 2015. The High EE scenario increased that percentage to 0.50%. Since lighting impacts are projected separately in the Company's forecasting process, EE savings attributed to lights were subtracted from total EE savings, and the remainder was separated into residential and commercial components depending upon program type. In the base case residential and commercial incremental non-lighting annual percentage reductions were 0.28% and 0.10%, respectively. These became 0.66% and 0.23% in the High EE case. These High EE percentages were then applied to the base case residential and commercial energies and accumulated to derive new High EE values. Once the additional energy reductions due to increased EE were calculated, the impact in demand was estimated by assuming a constant load factor of 0.46. These energy and demand impacts were then applied to the base case energies and demand to derive the final, lower values used in the generation planning process. The table on the right shows the incremental changes to the base case forecast that result.

Incremental EE Impacts		
	Peak MWs	Energy GWhs
2015	0	0
2016	0	0
2017	-10	-41
2018	-20	-81
2019	-30	-122
2020	-41	-163
2021	-52	-208
2022	-63	-252
2023	-73	-295
2024	-85	-342
2025	-96	-388
2026	-108	-436
2027	-120	-482
2028	-132	-532
2029	-145	-584

A new resource plan was developed to serve the new forecast of peak demands and energy. The change in present value of revenue requirements for the base case resource plan and the high EE resource plan was calculated and summarized in the nearby table in terms of $ per MWh. Three scenarios of gas prices and three scenarios of CO_2 emission costs were considered.

Value of Displaced Energy $/MWh			
CO_2 Cost Per Ton	Natural Gas Prices Percent Above Base Case		
	0%	50%	100%
$0	-63	-71	-78
$15	-76	-84	-91
$30	-88	-98	-105

g. 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. The following table shows the amount of distributed solar PV on SCE&G's system by the end of 2014. The Company also has a 2,600 DC kW plant at the Boeing facility near Charleston and will have two other solar plants available later this year: 3,800 AC kW[2] at the Otarre site in Cayce and 500 AC kW at the Leeds Avenue site in Charleston. The total solar PV capacity on SCE&G's system, operational or soon to be operational, is about 8,924 kW DC.

Year of Installation	DC kW Rating	Accumulated DC kW Approximate
2007	4	4
2008	12	15
2009	58	73
2010	202	275
2011	211	486
2012	405	891
2013	631	1522
2014	502	2024

In compliance with South Carolina Act 236, SCE&G filed on February 9, 2015, a Distributed Energy Resource (DER) plan whose goal is to have an amount of solar capacity on the system by January 1, 2021, that equals 2% of the retail peak load averaged over five years. As a result SCE&G plans to add about 100 MWs of solar capacity to its system

Scenarios of Future Solar Capacity Growth

Two future scenarios of solar capacity growth are considered: a base case representing the status quo scenario and a high solar penetration case based on significantly lower installation costs for solar panels. The base case solar scenario is the Company's forecast and is reflected in its resource plan shown later in this report. Assumptions for the base case include: SCE&G meeting its DER goals; the elimination of the federal 30% ITC subsidy leaving only a 10% ITC; a new NEM rate that incorporates a grid parity charge and finally the assumption that the installation cost of solar panels will continue to decline but at a modest rate. Under these assumptions in the base case, solar capacity will grow significantly under the DER program until 2021 at which time only minimal growth will occur on the system. The growth is expected to be

[2] The Company's request for proposals (RFP) specified 3,800 kW AC at the Otarre site and 500 kW AC at the Leeds Avenue site. The DC ratings will not be known until the RFP process is finalized.

about 500 kW per year which is about what the Company has experienced over the last few years.

In the high solar penetration scenario, it is assumed that installing solar panels becomes economic for most customers on SCE&G's system. Solar prices are expected to fall in line with the goals of the U.S. Department of Energy's SunShot Program[3]. The SunShot program has the goal of reducing the price of solar installations by 75% from 2010 to 2020. The table below shows these price expectations.

Goals of the US DOE's Sunshot Program	
Category	Cost in 2010$
Residential Rooftop	$1.50 per Watt
Commercial Rooftop	$1.25 per Watt
Utility Scale	$1.00 per Watt

SCE&G expects that as the penetration of solar capacity increases on the system, the incremental value of solar energy will decline until a tipping point is reached which changes the economics of additional solar capacity. The fact of declining value with increasing penetration results from the output profile of all solar generators essentially following the arc of the sun in the sky. Thus more and more energy is produced in the same hours of the day until the value of even more energy at that hour becomes minimal. While it is difficult to identify this tipping point, SCE&G assumes it will be about 500 MWs of solar capacity. This should represent enough solar energy to cause SCE&G to either become a winter peaking utility or at least nearly one. Using 500 MWs of solar capacity as a start and allowing for 2% growth per year, the tipping point in 2029 should be about 660 MWs. When 100 MWs of base case solar capacity is subtracted, the high solar penetration scenario will include an additional 560 MWs of solar approximately. The table on the right shows the

Year	Incremental Solar MWs	Accumulated Solar MWs
2019	56	56
2020	34	90
2021	50	140
2022	64	204
2023	76	280
2024	74	354
2025	64	418
2026	50	468
2027	34	502
2028	22	524
2029	14	538

Value of Displaced Energy $/MWH			
CO_2 Cost Per Ton	Natural Gas Prices Percent Above Base Case 0%	50%	100%
$0	-66	-72	-79
$15	-73	-86	-91
$30	-82	-96	-105

3 "U.S. Department of Energy Sunshot Vision Study" http://energy.gov/eere/sunshot/downloads/sunshot-vision-study-february-2012-book-sunshot-energy-efficiency-renewable Last accessed on January 31, 2015.

incremental and accumulated solar capacity that was added to the base case to form the high solar penetration scenario.

To estimate the value of this additional solar capacity to SCE&G's system, a new resource plan was created and the incremental revenue requirements of the base case and this high solar penetration scenario were calculated under three different forecasts of natural gas prices and under three different costs associated with emitting CO_2. The nearby table summarizes the levelized average value between the two plans.

Scenario of Future Off Shore Wind Capacity

To estimate the value of offshore wind capacity to SCE&G's system, a new resource plan was created using the schedule shown in the table to the right. A wind generation profile was created using Winyah Bay 6 Mile Buoy wind speed data extrapolated to a height of 100m and the power profile of a GE 4 MW wind turbine. The wind generation profile indicated that 20% of the generator's output would be available across the four hour peak period in July.

Year	Incremental Wind MWs	Accumulated Wind MWs	Annual Wind MWhs	MWs at Summer Peak
2019	100	100	341,640	20
2020	0	100	341,640	20
2021	0	100	341,640	20
2022	100	200	638,280	40
2023	0	200	638,280	40
2024	0	200	638,280	40
2025	0	200	638,280	40
2026	0	200	638,280	40
2027	0	200	638,280	40
2028	0	200	638,280	40
2029	0	200	638,280	40

The incremental revenue requirements between the base case and this wind scenario were calculated under three different forecasts of natural gas prices and under three different costs associated with emitting CO_2. The nearby table summarizes the levelized average value between the wind plan and the base plan.

Value of Displaced Energy $/MWH			
CO_2 Cost Per Ton	Natural Gas Prices Percent Above Base Case		
	0%	50%	100%
$0	-38	-51	-62
$15	-42	-55	-68
$30	-48	-58	-70

h. 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 – 2015 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 300 MWs 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 reliably 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 - 2015 IRP

(MW)

	YEAR	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast																
1	Baseline Trend	5006	5089	5212	5341	5467	5595	5719	5833	5950	6059	6162	6268	6366	6460	6559
2	EE Impact	-3	-8	-22	-36	-50	-62	-74	-86	-98	-111	-123	-136	-149	-163	-176
3	Gross Territorial Peak	5003	5081	5190	5305	5417	5533	5645	5747	5852	5948	6039	6132	6217	6297	6383
4	Demand Response	-256	-259	-265	-272	-275	-277	-280	-283	-286	-289	-292	-295	-298	-301	-304
5	Net Territorial Peak	4747	4822	4925	5033	5142	5256	5365	5464	5566	5659	5747	5837	5919	5996	6079
System Capacity																
6	Existing	5282	5289	5308	5314	5320	5951	6281	6327	6327	6420	6513	6606	6699	6792	6885
	Additions:															
7	Solar Plant (2% DER)	7	19	6	6	6	6									
8	Peaking/Intermediate									93	93	93	93	93	93	93
9	Baseload					625	669	46								
10	Retirements						-345									
11	Total System Capacity	5289	5308	5314	5320	5951	6281	6327	6327	6420	6513	6606	6699	6792	6885	6978
12	Firm Annual Purchase	300	300	300	425											
13	Total Production Capability	5589	5608	5614	5745	5951	6281	6327	6327	6420	6513	6606	6699	6792	6885	6978
Reserves																
14	Margin (L13-L5)	842	786	689	712	809	1025	962	863	854	854	859	862	873	889	899
15	% Reserve Margin (L14/L5)	17.7%	16.3%	14.0%	14.1%	15.7%	19.5%	17.9%	15.8%	15.3%	15.1%	14.9%	14.8%	14.7%	14.8%	14.8%

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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 Long Range Planning Criteria 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 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 2014 Summer Study
2. SERC NTSG Reliability 2014/2015 Winter Study
3. SERC LTSG 2016 Summer Peak Study
4. SERC NTSG OASIS 2014 January Studies (14Q1)
5. SERC NTSG OASIS 2014 April Studies (14Q2)
6. SERC NTSG OASIS 2014 July Studies (14Q3)
7. SERC NTSG OASIS 2014 October Studies (14Q4)
8. ERAG 2014 Summer, 2014/2015 Winter Transmission System Assessment
9. CTCA 2018 Summer, 2021 Summer Expansion Plans Studies
10. CTCA 2016 Summer Voltage Stability Study
11. SCRTP 2015 Summer Peak and 2019 Summer Peak Transfer Studies
12. EIPC 2023 Roll-Up Heat and Drought Scenario Studies

13. SERC RAWG 2016 Summer, 2016/2017 Winter, 2018 Summer, 2018/2019 Winter Loss of Load Expectation Studies
14. FERC Simultaneous Import Limit (SIL) Studies – Triennial Filing
15. SIRPP 2015 Summer, 2016 Summer, 2018 Summer Economic Sensitivity Studies

where the acronyms used above have the following reference:

SERC – SERC Reliability Corporation
NTSG – Near Term Study Group
LTSG – Long Term Study Group
OASIS – Open Access Same-time Information System
ERAG – Eastern Interconnection Reliability Assessment Group
CTCA – Carolinas Transmission Coordination Arrangement
SCRTP – South Carolina Regional Transmission Planning
EIPC – Eastern Interconnection Planning Collaborative
RAWG – Resource Adequacy Working Group
FERC – Federal Energy Regulatory Commission
SIRPP – Southeast Inter-Regional Participation Process

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 Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improves coordination between neighboring transmission planning regions for new interregional transmission facilities. Also, this Final Rule requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule. Each cost allocation method must satisfy six cost allocation principles.

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 regional 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 regional filing addressing these points. On May 14, 2014, FERC conditionally accepted SCE&G's regional filing subject to SCE&G providing additional clarity to SCE&G's

compliance plans. On July 14, 2014, SCE&G submitted an additional regional filing addressing these points. On January 22, 2015, FERC conditionally accepted SCE&G's regional filing subject to SCE&G providing additional clarity to SCE&G's compliance plans. On February 23, 2015, SCE&G submitted an additional regional filing addressing these points. FERC is currently reviewing SCE&G's regional 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. On January 22, 2015, FERC conditionally accepted SCE&G's interregional filing subject to SCE&G providing more clarity and adding greater detail to SCE&G's compliance plans. By March 24, 2015, SCE&G will submit a second interregional filing addressing these points.

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 categorized individually or 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° and for CDD was 75°. 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 monthly calendar weather. 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, $q\ (B) = 1 - q_1 B - \ldots - q_q B^q$
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, thirty-five 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. Residential street lighting was also 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 and water-heater 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

A demand forecast is made for the summer peak, the winter peak and then for each of the remaining ten months of the year. The summer peak demand forecast and the winter peak demand forecast is made for each of the seven major classes of customers. Customer load research data is summarized for each of these major customer classes to derive load characteristics that are combined with the energy forecast to produce the projection of future peak demands on the system. Interruptible loads and standby generator capacity is captured and used in the peak forecast to develop a firm level of demand. By utility convention the winter season follows the summer season. The territorial peak demands in the other ten months are projected based on historical ratios by season. The months of May through October are grouped as the summer season and projected based on the average historical ratio to the summer peak demand. The other months of the year are similarly projected with reference to the winter peak demand.