South Carolina Electric and Gas Company

1995 Integrated Resource Plan

INTEGRATED RESOURCE PLAN

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EXECUTIVE SUMMARY

1. Introduction

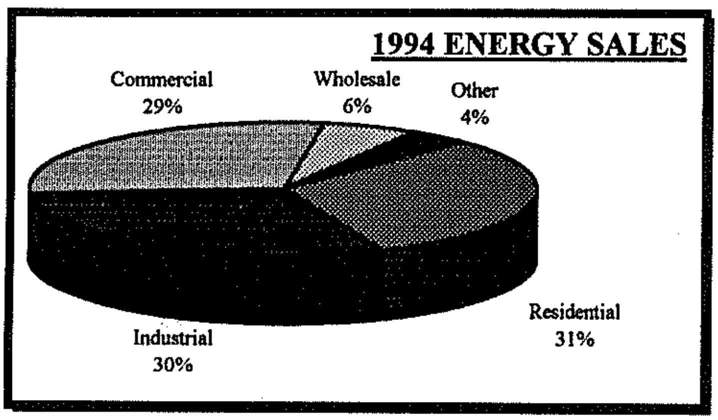
The purpose of this document is to present the South Carolina Electric and Gas Company's Integrated Resource Plan (IRP) for meeting the energy needs of its customers over the next twenty years, 1995 through 2014, and to explain the methodology employed in developing the plan. Integrated resource planning has three primary components: the forecast, the demand-side and the supply-side. These three components must be integrated, that is, the results derived in each component depend on the results derived in the other two.

This Executive Summary will discuss the Company's planning methodology and its objectives as well as present summary results from the forecast, the demand-side and the supply-side components of the IRP. A discussion of the Company's commitment to protecting the environment is also included.

2. Electric Business Profile

SCE&G, a subsidiary of the SCANA Corporation, has an electric service territory that extends into 24 counties covering more than 15,000 square miles in the central, southern and southwestern portions of South Carolina. It operates 3,876 megawatts of generating capacity which includes Williams Station, owned by South Carolina Generating Company, also a subsidiary of the SCANA Corporation. The Company's transmission system is part of the interconnected grid extending over a large part of the southern and eastern portion of the nation. The Company, Virginia Power Compnay, Duke Power Company, Carolina Power & Light Company, Yadkin Incorporated, and the South Carolina Public Service Authority are members of the Virginia-Carolinas Reliability Group (VACAR), one of several geographical divisions within the Southeastern Electric Reliability Council (SERC) which provices for coordinated planning for reliability among bulk power systems in the Southeast. The Company is also interconnected with Georgia Power Company, Savannah Electric & Power Company, Oglethorpe Power Company and the Southeastern Power Administration's Clark Hill Project.

The Company serves a mix of residential, commercial and industrial customers. In 1994, sales totalled 17,011 millions of KWH and was spread across the classifications shown in the adjacent chart. The highest demand on the system occurred on July 29, 1993 and reached 3,557 MW. The highest winter demand of 3,444 MW was recorded on January 19, 1994.



The Company is currently constructing the Cope Plant, a 385 MW pulverized coal plant located in Orangeburg County. The plant is expected on-line in early 1996.

3. The Planning Process

The goal of the integrated resource planning process is to meet the forecasted energy and demand requirements of our customers with an optimal mix of demand-side options and supply-side resources. The process used at SCE&G follows sequential steps but has the flexibility to iterate through the steps in order to converge on an optimal solution.

The process starts by updating the demand and energy forecasts. This includes a new economic forecast from Data Resources, Inc. (DRI), new econometric equations, and revised system impacts for existing DSM programs. Optimal supply plans are constructed to serve the energy needs represented by the basecase forecast and a "No DSM" forecast, that is, a forecast without the benefit of DSM programs. Avoided generation costs are derived by analysis of these supply plans. Transmission and distribution avoided costs are also calculated.

With estimates of avoided costs, the Company evaluates the benefits and costs of various DSM programs. Modifications to existing programs and the addition of new programs are evaluated through the use of four tests: the Participant Test, the Ratepayer Impact Measure (RIM) Test, the Utility Cost Test, and the Total Resource Cost (TRC) Test.

With a new portfolio of DSM programs developed, a new forecast of demand and energy is made and new supply plans are constructed. This then completes one iteration through the planning process. The Company can iterate through this sequential process as many times as necessary to arrive at an optimal solution. Iteration through this process was not necessary for the Company at this time because the avoided generation costs do not change significantly from one iteration to the next.

4. Goals and Objectives

Simply stated the overall objective of the Company is to maximize the customer value of our product. There are several components to this objective which guide the Company's course of action. These components are:

Develop and maintain an adequate and reliable source of power. It is the Company's goal to have sufficient generation on-line to satisfy the firm power requirements of our customers at all times. When a customer throws the switch, the Company intends that the lights come on each and every time.

Encourage energy conservation. The Company believes in the efficient use of all resources and will provide programs to help customers use energy wisely. For example, if a customer wants an air conditioner, the Company will encourage and assist him in choosing the most efficient unit that meets his needs.

Protect the environment. The Company will meet the requirements of all local, state and federal environmental laws and regulations and will work with government at all levels to isolate, analyze and solve problems related to the environment.

Include flexibility in all planning. Because of the tremendous uncertainties associated with planning for the future, the Company will seek to develop plans that do not commit the Company to a course of action until it is prudent to do so and that are flexible enough to respond to changes in operating conditions that may occur.

Minimize long-term costs to our customers. One of the primary objectives of the Company is to provide an adequate and reliable source of power at the least possible cost to our customers. Our actions in the short term and our plans for the longer term are guided by this fundamental objective.

Maintain a strong financial position and provide a fair and secure return to investors. In order to provide reliable and quality service to our customers, it is necessary to maintain the financial health of the organization and to provide a fair return to its owners.

5. The Forecast

The Company expects the energy needs of its service territory to grow at 1.8% over the next twenty years with a growth of annual peak demand averaging 1.5%.

	1995	*2014*	*Growth Rate*
Energy (GWH)	*18,439*	*25,975*	*1.8%*
Peak (MW)	*3,533*	*4,664*	*1.5%*

The energy sales forecast 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 over 90% of our sales. The other classes are street lighting, other public authorities, municipalities and cooperatives. Sales projections to each group are based on statistical and econometric models derived from historical relationships. Projections for the economy of the State of South Carolina and for the service territory of SCE&G are produced by Data Resources, Inc. (DRI). DRI uses a complex system of national, regional, state and county models to produce a consistent set of economic projections for the nation as a whole and for each economic sub-region that, in summation, comprises the whole. Some of the economic projections for the SCE&G service territory are presented below.

	1995	*2014*	*Growth Rate*
Population (000)	*1235.3*	*1501.3*	*1.0%*
Real Personal Income ($ Millions)	*18262.1*	*29112.7*	*2.5%*
Industrial Production Index	*1.204*	*1.665*	*1.7%*

The sales forecast for the Company takes into account the effects of demand-side management (DSM) efforts. The total energy load for the Company is the sum of Company use, unaccounted for energy, and total sales. The forecast of peak demands is based on the application of load factors to energy sales projections by class of customer. The use of this methodology has been verified through comparison to the Company's actual experience over the last thirty years. A forecast of peak demands for the winter season is made using econometric techniques. Note that the winter season is associated with the year containing the previous summer. The table below summarizes the sales forecast, the total load and the summer and winter peak demand projections.

TERRITORIAL FORECAST				
SALES (GWH)	*1995*	*2000*	*2005*	*2014*
Residential	*5,641*	*6,228*	*6,883*	*8,166*
Commercial	*5,040*	*5,681*	*6,179*	*7,180*
Industrial	*5,221*	*5,729*	*6,177*	*6,988*
Other				
Total Sales	*17,477*	*19,342*	*21,126*	*24,591*
Total Load (GWH)	*18,439*	*20,410*	*22,300*	*25,975*
Peak Demand (MW):				
Summer	*3,533*	*3,828*	*4,114*	*4,664*
Winter	*2,950*	*3,211*	*3,427*	*3,885*

6. Demand-Side Planning

The Company's DSM efforts are designed to help our customers use energy wisely and manage peak demand. Our DSM portfolio promotes energy efficiency to residential, commercial and industrial customers through incentives, financing, education and a comprehensive menu of rate options. The following table lists the Company's proposed DSM portfolio of programs.

RESIDENTIAL PROGRAMS	*COMMERCIAL AND INDUSTRIAL PROGRAMS*
Good Cents/Conservation Program	*Thermal Energy Storage*
Home Energy Check Program	*Stand-by Generator*
High Efficiency Heat Pump Program	*Interruptible Program*
Replacement Water Heater Program	*Real-Time Pricing*
Time of Use Rate (Rate 5)	*Time of Use Rates*
Low Use Rate (Rate 2)	*Commercial Heat Pump Water Heater and Pool Heater Program **
	*High Efficiency Chillers Program ***
	*Commercial HVAC Program ***
	* Research and Development Program
	**Education Programs

Following is a brief description of the individual programs that the Company plans to include in its DSM portfolio.

Good Cents/Conservation Program: This program provides a discounted rate to new and retro-fit homes that meet a prescriptive thermal envelope and an appliance efficiency requirement above state building code standards. Most notably, air conditioners must have at least a 12 SEER, and walls, R-15 insulation. This program will replace the existing Good Cents Home Program and the Residential Energy Conservation Rate Program (REC).

Home Energy Check Program: This program provides, at the customer's request, a detailed audit of the home's HVAC system, insulation, ventilation, and air loss around windows and doors. The Company offers rebates and financing of up to $1,000 at 9% interest to help the customer implement the recommended improvements. The Company plans to charge a $55 audit fee which would be credited back to the customer along with any other rebates upon completion of at least one of the recommended improvements within three months of the audit.

Replacement Water Heater Program: This program, also known as the Water Works Program, offers to finance the purchase and installation of an electric water heater without interest (0%) for up to five years. The Company provides a small incentive to the installer for participating in the program. The program is only available in the replacement market.

High Efficiency Heat Pump Program: This program provides 10% financing to customers who purchase heat pumps with at least a 12 SEER efficiency rating. Customer can also finance up to $1,500 at the same time for duct system improvements. Dealers receive an incentive ranging from $75 to $115 per unit depending on the number installed. The program also provides a cash incentive of up to $500 to customer who install approved experimental technologies.

Commercial HVAC Program: This program educates commercial customers on the benefits and cost-effectiveness of high efficiency heat pumps and air conditioners.

Thermal Storage Program: This program provides incentives to customers to install thermal energy storage systems. These systems will help customers lower their energy costs by shifting energy needs to off-peak periods.

High Efficiency Chiller Program: This program educates commercial and industrial customers on the benefits and cost-effectiveness of high efficient chillers.

Stand-by Generator Program: This program offers incentives to customers with emergency generators rated at 200 KW or larger to operate their generators when beneficial to the SCE&G system. The program pays $2.00 per contracted KW per month and $0.07 per KWH. The contract period is five years.

Interruptible Program: The Company provides a rate discount to customers who can commit at least 1,000 KW of interruptible power.

Commercial Heat Pump Pool Heaters and Water Heaters: This is a research and development program that will help foster the use of the heat pump water heating technology.

Menu of Time Differentiated Rates: The Company considers its menu of time differentiated rates as an intrinsic part of its DSM efforts. Whether seasonal, time of use, or the new real time pricing, these rates offer customers the opportunity to lower their electric bills and phase in system cost savings that result when they lower their peak period consumption.

As our DSM strategy has evolved, increased emphasis is being placed on safeguarding ratepayers from higher rates caused by DSM programs. As part of program evaluation, the Company has found some of its electric DSM programs begun with the 1992 IRP to be no longer cost effective or practical to continue. The Company has either already received or is seeking approval from the S.C. Public Service Commission to discontinue the following programs.

- Residential Thermal Storage
- Residential Heat Pump Pool Heaters
- High Efficiency Commercial Lighting
- High Efficiency Fluorescent Ballasts
- Variable Speed Drives
- High Efficiency Motors
- Off-Peak Water Heating
- Compact Fluorescent Lamps
- Gas Air Conditioning (The Company will continue to promote and incent the gas air conditioning technology through its gas marketing programs.)

The proposed DSM portfolio offers many system benefits including the following:

- More than a 25% reduction in the annual peak demand growth on the system.
- A cumulative reduction in peak demand of over 500 megawatts by 2014.
- About a 6% reduction in the annual energy growth on the system.
- A cost savings of $191 millions to our customers in terms of present-worth revenue requirements.

The table below shows how much greater the energy needs of our customers would be over the next twenty years if all the Company's DSM programs were halted.

ENERGY (GWH) IMPACT OF DSM EFFORTS				
	1995	2000	2005	2014
No DSM Level	18,434	20,503	22,506	26,425
Basecase Level	18,439	20,410	22,300	25,975
DSM Impact	(5)	93	206	450
% Change	0.0	0.5	0.9	1.7
PEAK DEMAND (MW) IMPACT OF DSM EFFORTS				
	1995	2000	2005	2014
No DSM Level	3,611	4,004	4,402	5,193
Basecase Level	3,533	3,828	4,114	4,664
DSM Impact	78	176	288	529
% Change	2.2	4.6	7.01	11.3

Similar information is provided on peak demands. The hypothetical "No DSM" scenario represents the system impacts if the Company stopped its DSM efforts. Of course, much of the DSM benefits achieved to date do not depend on the Company's on-going efforts and are still reflected in both the Basecase and "No DSM" scenarios.

The Company estimates that its DSM programs will save $191 million in accumulated present-worth revenue requirements over the next twenty years. The table following highlights some of the major components of this savings.

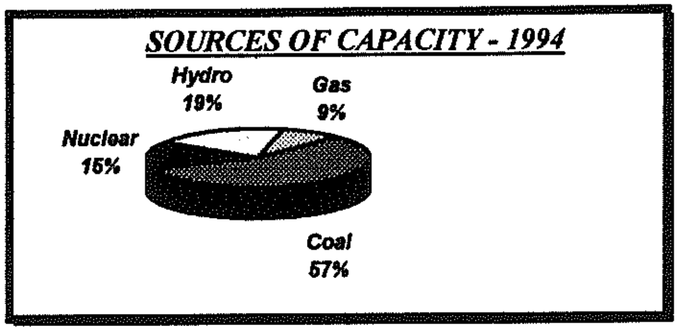
	Change in Present Worth Revenue Requirements ($/Millions)
DSM Expenses	*$ 58*
Non-Fuel Revenues	*(155)*
Fuel Revenues	*(94)*
Total Change	*$(191)*

SCE&G's Demand-Side Management portfolio is evolving to reflect current market conditions, our experience with demand-side management and changes in the economic parameters of each program. As indicated above, managing demand and promoting efficiency will continue to have a significant impact on the Company's energy and demand forecast. The Company remains committed to promoting efficiency in a manner that minimizes cost to ratepayers.

7. Supply-Side Planning

Although the Company's DSM programs have been extremely effective and have slowed the growth in peak demand by more than 25%, they have not eliminated all growth. With a peak demand of 3,557 MW experienced in 1993 and generating capacity of 3,876 MW, it is clear that new capacity must be added.

Table ES-1 contains a list of the 3,876 MW of net generating capacity that the Company has available. The following chart shows the distribution of this capacity by fuel type.



Over the next twenty years, the Company plans to increase this capability by more than 1,500 megawatts. This includes two coal fired plants totalling almost 800 megawatts and five internal combustion turbines of about 150 megawatts each.

The first of the two coal fired plants contained in the supply-side plan is currently under construction. The Cope Generating Station, a 385 MW pulverized coal plant, is scheduled to come on-line in early 1996. The plant is located two miles from the town of Cope in Orangeburg County and will be the sixth coal fired baseload plant in SCE&G's system.

The Company's supply plan is summarized in Table ES-2. It should be kept in mind that this supply-side plan is just a plan and is subject to frequent review and update. As new information becomes available and new issues develop, the plan will be modified accordingly. The current IRP is in fact the plan to beat, that is, it is a reference point for doing better.

TABLE ES.1

SOUTH CAROLINA ELECTRIC & GAS CO.
GENERATING STATION STATISTICS
(END OF YEAR 1994)

	First and Last Unit in Service	Net Capability Rating (mW) Summer	Winter
Coal-Fired Steam:			
Canadys - Canadys, SC	1962-1967	430	430
McMeekin - near Irmo, SC	1958-1959	252	254
Urquhart - Beech Island, SC	1953-1955	250	254
Wateree - Eastover, SC	1970-1971	700	720
Williams - Goose Creek SC **(1)**	1973	560	565
Total Coal-Fired Steam Capacity		2,192	2,223
Nuclear:			
V.C. Summer - Parr, SC	1984	590	604
I.C. Turbines:			
Burton, SC	1961-1963	28.5	30
Faber Place - Charleston, SC	1961	9.5	10
Hardeeville, SC	1968	14.0	14
Canadys, SC	1968	14.0	15
Urquhart - Beech Island, SC	1969	38.0	46
Coit - Columbia, SC	1969	30.0	36
Parr, SC	1970-1971	60.0	76
Williams - Goose Creek, SC	1972	49.0	58
Hagood - Charleston, SC	1991	95.0	112
Total I.C. Turbines Capacity		338	397
Hydro:			
Columbia Canal - Columbia, SC	1927-1929	10	10
Neal Shoals - Carlisle, SC	1905	5	5
Parr Shoals - Parr, SC	1914-1921	14	14
Saluda - near Irmo, SC	1930-1971	206	206
Stevens Creek - near Martinez, GA	1914-1926	9	9
Fairfield Pumped Storage - Parr, SC	1978	512	512
Total Hydro Capacity		756	756
Grand Total:		**3,876**	**3,980**

(1) SCE&G purchases the output of Williams Station, a plant owned by S. C. Generating Company.

TABLE ES-2

SUPPLY-SIDE OF THE 1995 BUDGET EXPANSION PLAN

CAPACITY CHANGES

YEAR	PEAK (MW)	ONE YEAR (MW)	LONG TERM (MW)	DESCRIPTION	CAPACITY (MW)	RESERVE MARGIN
1995	3,533	0 - 250		SPOT PURCHASES OF CAPACITY	3876-4126	9.7%-16.8%
1996	3,586		385	COPE PULVERIZED COAL UNIT	4,291	19.7%
			30	VCSN UPRATE		
1997	3,656				4,291	17.4%
1998	3,723				4,291	15.3%
1999	3,775		150	ICT	4,441	17.6%
2000	3,828				4,441	16.0%
2001	3,881		150	ICT	4,591	18.3%
2002	3,937				4,591	16.6%
2003	4,000		-13	SCRUBBER PARASITIC LOAD	4,578	14.4%
2004	4,058		150	ICT	4,728	16.5%
2005	4,114				4,728	14.9%
2006	4,171		150	ICT	4,878	17.0%
2007	4,225				4,878	15.5%
2008	4,281		150	ICT	5,028	17.4%
2009	4,336				5,028	16.0%
2010	4,397	100		CAPACITY PURCHASE	5,128	16.6%
2011	4,462	200		CAPACITY PURCHASE	5,228	17.2%
2012	4,529		400	PULVERIZED COAL UNIT	5,428	19.8%
2013	4,598				5,428	18.1%
2014	4;664				5,428	16.4%

8. The Environment

South Carolina Electric & Gas Company recognizes that the environment is a fragile resource. We further understand that responsible institutions have a duty to the people and places they serve to conduct business in a way that exhibits ecological concern. And while we are committed to providing dependable, affordable energy, it is our stated goal to do so in an environmentally sensitive manner. In keeping with those principles, SCE&G's environmental policy is:

- To respect the environment in all phases of our operations.
- To meet the requirements of all local, state, and federal environmental laws and regulations.
- To work with government at all levels to isolate, analyze and solve problems related to the environment.
- To address environmental policy issues with positive strategies that reflect the interests and concerns of our customers.
- To utilize sophisticated, cost-effective environmental technology and procedures, and to encourage and investigate new technologies whose ultimate benefit is a better environment.
- To employ prospective planning that enables us to respond quickly and effectively to any environmental incidents involving SCE&G, and to be guided in our response by our concern for the community health and well-being.

- To ensure that all SCE&G employees are aware of the Company's commitment to environmental protection.

- To provide employee training programs that demonstrate SCE&G's concern for the environment, and that encourage employee involvement in environmental protection efforts.

- To aggressively oversee all Company activities to ensure compliance with these tenets and with all legal and regulatory requirements.

- To provide our customers environmentally compatible sources of energy and to promote the use of efficient, state-of-the-art electric and gas technologies.

The Company is continuing to study various strategies to comply with the 1990 Clean Air Act Amendment. With regard to sulfur dioxide, the Company has no plants affected by the Phase I emission limits and has purchased sufficient SO2 allowances to meet the Phase II limits through 2002. This allows the Company to postpone making a larger term compliance decision such as installing flue-gas desulfurization equipment. With respect to nitrogen oxides, the Company continues to study various compliance strategies such as installing low NOx burners at some or all plants. A final decision will probably not be made until the EPA promulgates final rules.

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2. The Planning Process
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1.0 INTRODUCTION

1. About the Company

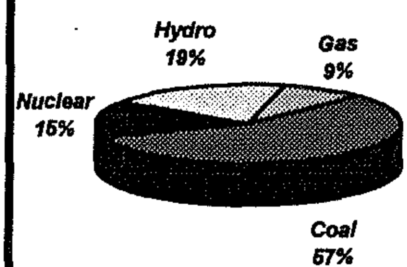
The Company, a subsidiary of the SCANA Corporation, is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, of natural gas in South Carolina. The Company also renders urban bus service in the metropolitan areas of Columbia and Charleston, South Carolina. The Company's business is seasonal in that, generally, sales of electricity are higher during the summer and winter months because of air conditioning and heating requirements.

The Company's electric service area extends into 24 counties covering more than 15,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 29 of the 46 counties in South Carolina and covers more than 20,000 square miles. Total estimated population of the counties representing the Company's combined service area is approximately 2.3 million.

The Company purchases all of the electric generation of Williams Station, owned by South Carolina Generating Company, under a Unit Power Sales Agreement which has been approved by the FERC.

The Company's transmission system is part of the interconnected grid extending over a large part of the southern and eastern portion of the nation. The Company, Virginia Power Company, Duke Power Company, Carolina Power & Light Company, Yadkin Incorporated, and South Carolina Public Service Authority are members of the Virginia-Carolinas Reliability Group, one of the several geographic divisions within the Southeastern Electric Reliability Council which provides for coordinated planning for reliability among bulk power systems in the Southeast. The Company is also interconnected with Georgia Power Company, Savannah Electric & Power Company, Oglethorpe Power Company, and the Southeastern Power Administration's Clark Hill Project.

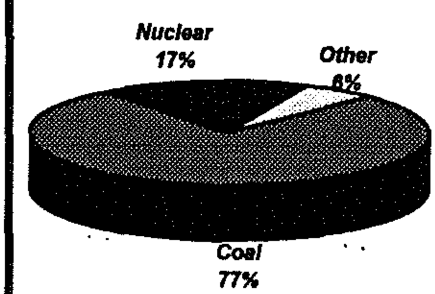
SOURCES OF CAPACITY - 1994



The Company operates 3,876,000 KW of net generating capability with 57% fueled by coal, 15% by nuclear, 19% hydro, and 9% oil and natural gas. The sources of energy (including Williams Station) in 1994 were 77% coal, 17% nuclear and 6% other.

The Company owns 445 substations having an aggregate transformer capacity of 18,885,437 KVA. The transmission system consists of 3,057 miles of lines and the distribution system consists of 15,421 pole miles of overhead lines and 3,122 trench miles of underground lines.

SOURCES OF ENERGY - 1994



2. The Planning Process

There are eight steps in the planning process which are followed in a sequential manner. The Company has the flexibility to iterate through these steps as many times as necessary to arrive at an optimal solution. Iteration through this process was not necessary for the Company at this time because the avoided costs do not change significantly from one iteration to the next.

The eight steps are:

✔ The first step in the planning process is to update the projected system impacts of the existing DSM programs. This update process would include gathering information on the latest field experience on customer penetration and an update of demand and energy impacts. Based on this experience with implementing the program, a revised forecast of penetration levels and demand and energy impacts is prepared.

✔ A new demand and energy forecast is then prepared. This would include the latest economic projections available from Data Resources, Inc. (DRI) as well as a review of existing econometric forecasting methodologies, a re-estimation of statistical relationships and development of new models where appropriate.

✔ A base supply plan is developed based on the new energy and demand requirements of our customers and based on current opportunities for purchasing power and/or building generators. The Company runs through the complete generation planning cycle. This cycle includes gathering current information on all supply resources and performing generation planning studies which use dynamic programming techniques to develop optimal expansion plan strategies.

✔ A No-DSM forecast is developed in this step. This forecast estimates what the demand and energy requirements would be if the Company discontinued its DSM efforts. The No-DSM forecast takes into account that much of the DSM benefits already achieved by the Company's programs would continue even if the program ceased.

✔ A No-DSM supply plan is developed at this stage. This requires performing generation planning studies to develop optimal expansion plan strategies.

✔ The Company's avoided costs related to DSM can now be calculated. Simply stated, DSM avoided costs are those costs that will be avoided because of DSM efforts. The DSM avoided costs related to generation can be calculated as the cost difference between the base supply plan and the No-DSM supply plan. In addition to these avoided costs of generation, the Company also estimates the avoided costs related to transmission and distribution investments. The sum of the generation, transmission and distribution avoided costs represents the value of DSM to the system.

✔ Using the avoided costs calculated in the previous step, the Company can determine the cost effectiveness of its existing DSM programs and evaluate the benefits of new DSM efforts. The Company relies on four benefit/cost tests: the Participant Test, the Utility Cost Test, the Ratepayer Impact Measure (RIM) Test, and the Total Resource Cost (TRC) Test. These tests provide an analysis of each program from several perspectives and enable the Company to make a balanced decision.

✔ Based on the analysis performed above, a new portfolio of DSM programs may be developed with revised demand and energy impacts on the forecast. If necessary, a new forecast is prepared and a new supply plan. Any number of iterations through these steps can be made when necessary.

3. Goals and Objectives

Simply stated the overall objective of the Company is to maximize the customer value of our product. There are several components to this objective which guide the Company's course of action. These components are:

- Develop and maintain an adequate and reliable source of power. It is the Company's goal to have sufficient generation on-line to satisfy the firm power requirements of our customers at all times. When a customer throws the switch, the Company intends that the lights come on each and every time.

- Encourage energy conservation. The Company believes in the efficient use of all resources and will provide programs to help customers use energy wisely. For example, if a customer wants an air conditioner, the Company will encourage and assist him in choosing the most efficient unit that meets his needs.

- Protect the environment. The Company will meet the requirements of all local, state and federal environmental laws and regulations and will work with government at all levels to isolate, analyze and solve problems related to the environment.

- Include flexibility in all planning. Because of the tremendous uncertainties associated with planning for the future, the Company will seek to develop plans that do not commit the Company to a course of action until it is prudent to do so and that are flexible enough to respond to changes in operating conditions that may occur.

- Minimize long-term costs to our customers. One of the primary objectives of the Company is to provide an adequate and reliable source of power at the least possible cost to our customers. Our actions in the short term and our plans for the longer term are guided by this fundamental objective.

Maintain a strong financial position and provide a fair and secure return to investors. In order to provide reliable and quality service to our customers, it is necessary to maintain the financial health of the organization and to provide a fair return to its owners.

INTEGRATED RESOURCE PLAN

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2.0 THE FORECAST

2.1 ELECTRIC SALES FORECAST

This chapter presents the development of the long-range electric sales forecast for the Company. The electric sales forecast is developed in two stages. The first stage of development incorporates economic analysis, econometric techniques, an evaluation of statistical measures and an analysis of the historical electric sales trends. This stage of the process produces a preliminary or "base" case electric sales forecast. In the second stage the base case electric forecast is adjusted for the selected demand side management programs and other external factors that would not be measured in the first stage. This year it included adjustments for large industrial customers and the loss of a wholesale customer. This produces the final electric sales forecast.

The long range electric sales forecast is developed for each of our seven classes of service: residential, commercial, industrial, street lighting, other public authorities, municipal and cooperatives. These classes were disaggregated into appropriate subgroups where data was available and there were notable differences in the data patterns. The residential, commercial, and industrial classes are considered the "major" classes of service and account for 91% of total territorial sales. A customer forecast was developed for each major class of service. For the residential class, forecasts are produced for those customers with electric space heating and for those without electric space heating and disaggregated into housing type (single family, multi-family and mobile homes). In addition, two residential marketing classifications--Good Cents customers [Rate 1] and Conservation Rate customers [Rate 7]--were evaluated separately. Residential sales attributed to the street lighting rates were 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 and the 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 and small industrial group, the forecast for sales was estimated based on total usage in that class of service. For the residential and small industrial group, customers and average usage per customer were estimated and total sales were calculated as a product of the two.

The forecast for each class of service is developed utilizing an econometric approach. The structure of the econometric model is based upon the relationships between the variable to be forecasted and the economic environment, weather, conservation, or price. The following analysis examines the methodology, economic assumptions, customer and sales assumptions, forecast equations, assumptions for the Charleston Naval Base closing, and the demand side management programs that were used to develop the forecast.

1. Econometric Methodology

Development of the models for long-term forecasting is econometric in approach and uses 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 which should explain the first (such as weather, personal income or population growth). This method is mathematically contrived so that the resulting combination of explanatory variables produces 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 multiplied by an estimated coefficient. Several statistics which indicate the success of the regression analysis fit are shown in Section 9 for each model. The indicators are R-SQUARE, mean squared Error of the Regression, Durbin-Watson Statistic and the T-Statistics of the Coefficient. The T-Statistics are shown in parenthesis under each variable in the equation. PROC STEPWISE, PROC REG, and PROC AUTOREG of the Statistical Analysis System (SAS) were used to estimate all regression models. PROC STEPWISE was used for preliminary model specification and elimination of insignificant variables. PROC REG was used 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, and 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 sales. These forecasted growth rates are 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 very important to evaluate the reasonableness of the model coefficients.

✔ One way to incorporate the effects electricity. Models selected for the major classes would include this variable, if of "conservation", was to incorporate the real price of 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.
4. Variables identified through residual analysis or knowledge of political changes, major economics events, etc. (e.g., foreign oil price increases in 1979 and recession versus non-recession years).

Standard statistical procedures (all possible regressions, stepwise regression) were used to obtain preliminary specifications for the models. Model parameters were then estimated using historical data through 1993 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 1994. 1994 historical sales data was the basis for this evaluation.

- An analysis of the reasonableness of the long-term trend generated by the models. The evaluative criteria was whether there were 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.

As a result of the evaluative procedure, final models were obtained for each class. The equations and selected statistical measures for each class of service in the electric sector are provided in Section 9.

The drivers for the long-range electric forecast included the following variables.

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

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties which account for 88% of total territorial electric sales. Service area data was used for all classes with the exception of the industrial class. The industrial or manufacturing sector is generally considered an "export" industry whose activity is more dependent on national and international factors rather than on regional specifics. Therefore, State data was used for the industrial class.

2. Economic Assumptions

In order to generate the electric sales forecast, forecasts must be available for the exogenous variables. The forecasts for the economic and demographic variables were obtained from Data Resources, Inc., (DRI) and the forecasts for the price and weather variables were based on historical data. Three forecasts of the economic and demographic variables for the United States were obtained, (1) a trend or most probable growth case, (2) a more optimistic case with higher growth and lower inflation and (3) a pessimistic case with lower growth and higher inflation. The three economic scenarios for the SCE&G Service Area and the State of South Carolina were then developed by taking a ratio between the trend projection of GDP and the optimistic or pessimistic scenario. This ratio was used to lower or increase State and Service Area variables to provide upper and lower bounds. DRI assumes a 50% probability that the economy will closely resemble the trend, a 25% chance that it will resemble the optimistic scenario, and a 25% chance that it will be closest to the pessimistic case.

The exogenous trend projection by DRI 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. Increases in real GDP average 2.0% between 1994 and 2014 with consumer prices averaging 3.7% annually over the same time frame. In the 1990's, growth in real output is constrained by slower population growth, averaging .9% from 1994 to 2004 and .8% thereafter, a slight deceleration from the 1.0% average since 1968. Slower population growth leads to a period of softening in housing and other consumer goods markets. Real interest rates should remain high by pre-1979 standards as the Federal Reserve guards against any significant increases in inflation and the civilian unemployment rate deviates only slightly from its 6.4% average levels. Although energy prices eventually rise faster than overall inflation, crisis of the magnitude of OPEC I and OPEC II are not projected in the trend scenario.

The optimistic and pessimistic scenarios begin from the central trend projection and explore the implications of higher and lower underlying growth paths of the economy. These bandwidth projections depart from the trend in both their supply-side assumptions and their inflation outlooks. In the optimistic scenario for instance, the labor force, capital stock and exogenous technological change grow at a faster pace than in the trend. The pessimistic scenario makes the opposite assumptions: higher inflation which rises steadily through the first half of the forecast, and slower economic growth. In the pessimistic case, growth is reduced by 0.5% annually relative to the trend and in the optimistic case, potential output grows almost .5% per year more rapidly. Because output is primarily supply determined in the long run, the difference in real GDP growth is very similar.

The growth in the nominal price of electricity is expected to average about 1.54% annually from 1994 to 2004. This expectation is based on the Company's most recent Financial Plan. With inflation projected at a rate close to 3.4%, as measured by the Implicit Price Deflator for Personal Consumption, over this time period, the real price of electricity should decline over the forecast horizon. This projection for real price is consistent with historical experience. Since 1975, the mean growth in the real price of electricity has been -.9% with a high of 12.6% and a low of -9.2%. For forecasting, growth in the real price of electricity is assumed to be zero. Average summer temperature (Average of June, July and August temperature) and average winter temperature (Average of December (previous year), January and February temperature) are assumed to be equal to the normal values used in the short range forecast. In other words, there is no change projected for the weather variables in the long term forecast. The tables in Section 4 show the historical data and the tables in Section 5 show the forecast for the exogenous variables.

3. Forecast Ranges

The sales forecast presented in this documentation is based on the trend economic scenario, zero growth in real price and the normal values for the weather variables used in the short range forecast. However, in reality the values of the exogenous variables may differ from these. It would be unrealistic to expect weather to be normal in every year or to expect economic growth to be exactly as projected. Therefore, ranges around the consensus sales forecast can be developed based on assumptions about changes in the exogenous variables.

The impact that a change in any of the exogenous variables can have on sales can be described in terms of elasticity. As noted earlier, elasticity explains the responsiveness of changes in one variable (e.g. sales) to changes in any other variable (e. g. price). The elasticity coefficient for economic activity (as measured by real personal income), the real price of electricity, average summer temperature and average winter temperature with respect to total territorial sales were estimated. The coefficients were estimated based on the three economic scenarios presented earlier, average summer temperature ranging from 82.6 degrees to 77.9 degrees, average winter temperature ranging from 52.0 degrees to 42.7 degrees and the growth in the real price of electricity ranging from +12.60% to -9.16%. These values were based on the high and the low value occurring since 1975. A uniform distribution was used to generate a value for summer temperature, winter temperature and the real price of electricity for each of the economic scenarios and each year of the forecast. Regression analysis was used to estimate the coefficients over the forecast period. Using a logarithmic transformation, the elasticities are given directly by the regression coefficients. The elasticity coefficients resulting are shown here in Table 2.1.1.

TABLE 2.1.1 *ELASTICITY COEFFICIENTS*	
VARIABLE	*COEFFICIENT*
Real Personal Income	***.6***
Real Price of Electricity	***-.2***
Average Summer Temperature	***.5***
Average Winter Temperature	***-.2***

The interpretation of the coefficients is fairly straight forward and can be described in terms of percent change. For example, price elasticity can be defined as the percent of change in the level of sales as a result of a given percent change in price. Since the coefficient of the real price of electricity is -.2, a 1% increase in the real price of electricity would result in a .2% decline in total territorial sales. Similarly, a 1% increase in real personal income would result in a .6% increase in total territorial sales. In terms of temperature, if the average summer temperature is 81.2 degrees instead of the mean value of 80.4 degrees, a 1.0% increase, sales would be expected to be .5% higher. If the average winter temperature is 46.9 degrees instead of the mean value of 47.9 degrees, a 2% decline, then total territorial sales would be expected to be .4% higher. Using the trend sales forecast and assumptions as the base level, ranges can be developed using a similar type of analysis. Table 2.1.2 shows a scenario based on the pessimistic and optimistic economic data presented in Section 2.

TABLE 2.1.2 *A FORECAST SCENARIO FOR 2014*			
	BASE CASE	***PESSIMISTIC***	***OPTIMISTIC***
SCE&G Real Personal Income	***29.113***	***26.056***	***32.140***
% Change to Base		***-10.5***	***+10.4***
Elasticity		***.60***	***.60***
% Change in Sales *		***-6.3***	***+6.24***
Total Territorial Sales	***24.591***	***23.042***	***26.125***
Annual % Change (1997 - 2014)	***1.8***	***1.4***	***2.1***

****Calculated based on the following formula:***

((Alternate scenario value / Base case value) - 1) x Elasticity coefficient) x 100

In the trend scenario, real personal income in the service area grows at a 2.5% annual rate from 1997 to 2014. In the pessimistic and optimistic scenarios, the growth is 2.0% and 3.0%, respectively. Although temperature and price can also affect electricity sales, as noted above, our assumption for the long term was that temperature would be close to normal although any particular year may vary and that the price of electricity would grow close to inflation in all three scenarios resulting in zero real growth. Based on the alternative economic scenarios, total territorial sales grow at an annual rate of 1.4% and 2.1% in the pessimistic and optimistic scenarios respectively, compared to the trend of 1.8%. As noted earlier, the trend scenario has a 50% probability of occurring compared to 25% for the pessimistic and 25% for the optimistic.

4. Historical Economic Data

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
HISTORICAL DATA
FOR ELECTRIC SERVICE AREA
ECONOMIC VARIABLES

YEAR	POPULATION (THOUS)	REAL PER CAPITA INCOME ($) 1	REAL PERSONAL INCOME (MILL$) 1	AVERAGE WINTER TEMPERATURE	AVERAGE SUMMER TEMPERATURE	REAL PRICE OF RES SPHT ELEC ($/KWH) 1	REAL PRICE OF RES NONSPHT ELEC ($/KWH) 1	REAL PRICE OF COMM ELEC ($/KWH) 1	REAL PRICE OF COOP ELEC ($/KWH) 1
1976	949.7	10579	10046	49.3	77.9	0.06235	0.07238	0.05726	0.03934
1977	963.5	10706	10316	43.3	81.0	0.06722	0.07800	0.06235	0.04024
1978	984.1	11030	10855	42.7	79.7	0.06667	0.07690	0.06186	0.04225
1979	1001.9	11234	11255	46.8	78.5	0.06681	0.07614	0.06128	0.04287
1980	1019.1	11312	11528	45.7	80.2	0.06674	0.07339	0.06075	0.04215
1981	1038.6	11556	12003	45.1	80.8	0.07072	0.07886	0.06540	0.04663
1982	1053.0	11536	12147	46.1	79.3	0.07764	0.08294	0.06818	0.04822
1983	1068.1	11799	12602	48.2	80.7	0.07949	0.08454	0.06854	0.05276
1984	1081.9	12397	13412	46.8	79.5	0.08012	0.08589	0.06946	0.05692
1985	1090.6	12784	13942	48.4	79.5	0.08084	0.08476	0.06808	0.05541
1986	1112.6	13012	14476	47.5	82.6	0.07731	0.08046	0.06461	0.05200
1987	1128.3	13181	14872	47.5	82.1	0.07083	0.07376	0.05878	0.04195
1988	1138.7	13644	15536	46.6	80.3	0.06482	0.06766	0.05360	0.04051
1989	1156.0	13565	15682	51.1	80.9	0.06253	0.06526	0.05158	0.03982
1990	1175.6	14251	16753	51.2	82.1	0.06020	0.06262	0.04929	0.03716
1991	1205.2	13898	16750	52.0	81.1	0.05695	0.05964	0.04674	0.03679
1992	1222.2	14223	17383	51.0	80.1	0.05596	0.05879	0.04593	0.03391
1993	1234.3	14431	17812	49.0	82.5	0.05535	0.05842	0.04481	0.03434

1 1987 DOLLARS

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
HISTORICAL DATA
FOR SOUTH CAROLINA
INDUSTRIAL PRODUCTION INDICES 1

YEAR	TOTAL MFG PRODUCTION INDEX	SIC 22 PRODUCTION INDEX	SIC 24-25 PRODUCTION INDEX	SIC 26 PRODUCTION INDEX	SIC 28 PRODUCTION INDEX	SIC 30 PRODUCTION INDEX	SIC 32 PRODUCTION INDEX	SIC 33-37 PRODUCTION INDEX
1976	0.700	0.923	0.719	0.584	0.635	0.341	0.805	0.428
1977	0.751	0.962	0.766	0.607	0.682	0.441	0.883	0.498
1978	0.789	0.954	0.818	0.631	0.730	0.500	0.933	0.555
1979	0.818	0.996	0.819	0.651	0.769	0.556	0.930	0.602
1980	0.809	0.992	0.815	0.655	0.732	0.584	0.838	0.626
1981	0.818	0.974	0.820	0.665	0.729	0.716	0.859	0.665
1982	0.768	0.853	0.775	0.656	0.672	0.735	0.777	0.617
1983	0.846	0.960	0.876	0.780	0.798	0.777	0.849	0.683
1984	0.888	0.955	0.923	0.836	0.823	0.823	0.902	0.820
1985	0.872	0.907	0.918	0.849	0.815	0.844	0.902	0.831
1986	0.927	0.955	0.928	0.960	0.905	0.912	0.978	0.863
1987	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
1988	1.056	0.988	0.983	1.032	1.116	1.013	1.012	1.166
1989	1.078	0.982	0.960	1.046	1.206	1.057	1.004	1.207
1990	1.065	0.918	0.958	1.058	1.269	1.095	0.962	1.208
1991	1.049	0.917	0.914	1.108	1.301	1.045	0.918	1.173
1992	1.096	0.975	0.981	1.173	1.364	1.098	0.908	1.233
1993	1.141	0.976	1.045	1.238	1.424	1.151	0.919	1.360

1 1987=1.000

5. *Forecast Economic Data*

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
FORECAST DATA
FOR ELECTRIC SERVICE AREA
ECONOMIC VARIABLES

LOWER BOUND

YEAR	POPULATION (THOUS)	REAL PER CAPITA INCOME ($) 1	REAL PERSONAL INCOME (MILL $) 1
1995	1235.3	14547	17970
1996	1224.8	14754	18071
1997	1228.7	15155	18620
1998	1240.6	15381	19082
1999	1253.3	15552	19492
2000	1268.3	15696	19907
2001	1284.1	15839	20338
2002	1300.8	15955	20754
2003	1317.5	16089	21198
2004	1334.0	16207	21619
2005	1348.4	16339	22031
2006	1363.2	16486	22473
2007	1379.0	16596	22886
2008	1395.7	16667	23262
2009	1412.6	16727	23629
2010	1429.8	16838	24076
2011	1447.5	16961	24551
2012	1465.6	17092	25050
2013	1483.6	17218	25544
2014	1501.3	17355	26056

1 1987 DOLLARS

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
FORECAST DATA
FOR ELECTRIC SERVICE AREA
ECONOMIC VARIABLES

TREND

YEAR	POPULATION (THOUS)	REAL PER CAPITA INCOME ($) 1	REAL PERSONAL INCOME (MILL $) 1
1995	1235.3	14783	18262.1
1996	1224.8	15024	18402.0
1997	1228.7	15496	19039.4
1998	1240.6	15824	19631.7
1999	1253.3	16099	20178.0
2000	1268.3	16299	20672.4
2001	1284.1	16499	21185.9
2002	1300.8	16689	21709.1
2003	1317.5	16901	22266.8
2004	1334.0	17114	22828.8
2005	1348.4	17345	23387.9
2006	1363.2	17576	23958.3
2007	1379.0	17788	24529.6
2008	1395.7	17979	25093.8
2009	1412.6	18162	25655.6
2010	1429.8	18383	26283.7
2011	1447.5	18618	26949.9
2012	1465.6	18865	27648.7
2013	1483.6	19131	28382.1
2014	1501.3	19391	29112.7

1 1987 DOLLARS

2.12(b)

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
FORECAST DATA
FOR ELECTRIC SERVICE AREA
ECONOMIC VARIABLES

UPPER BOUND

YEAR	POPULATION (THOUS)	REAL PER CAPITA INCOME ($) 1	REAL PERSONAL INCOME (MILL $) 1
1995	1235.3	15005	18536
1996	1224.8	15340	18788
1997	1228.7	15883	19515
1998	1240.6	16267	20181
1999	1253.3	16598	20803
2000	1268.3	16854	21375
2001	1284.1	17126	21991
2002	1300.8	17390	22621
2003	1317.5	17695	23313
2004	1334.0	17986	23993
2005	1348.4	18316	24698
2006	1363.2	18648	25420
2007	1379.0	18962	26149
2008	1395.7	19274	26901
2009	1412.6	19561	27631
2010	1429.8	19890	28439
2011	1447.5	20256	29322
2012	1465.6	20620	30220
2013	1483.6	21025	31192
2014	1501.3	21408	32140

1 1987 DOLLARS

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
FORECAST DATA
FOR SOUTH CAROLINA
INDUSTRIAL PRODUCTION INDICES 1

LOWER BOUND

YEAR	TOTAL MFG PRODUCTION INDEX	SIC 22 PRODUCTION INDEX	SIC 24-25 PRODUCTION INDEX	SIC 26 PRODUCTION INDEX	SIC 28 PRODUCTION INDEX	SIC 30 PRODUCTION INDEX	SIC 32 PRODUCTION INDEX	SIC 33-37 PRODUCTION INDEX
1995	1.185	0.967	1.116	1.304	1.476	1.176	0.936	1.569
1996	1.202	0.983	1.139	1.327	1.505	1.180	0.951	1.621
1997	1.238	1.013	1.178	1.364	1.553	1.236	0.982	1.686
1998	1.260	1.023	1.190	1.397	1.582	1.272	1.000	1.742
1999	1.266	1.015	1.195	1.414	1.601	1.272	1.014	1.772
2000	1.281	1.017	1.201	1.435	1.630	1.290	1.028	1.810
2001	1.293	1.018	1.205	1.457	1.658	1.315	1.032	1.841
2002	1.313	1.022	1.218	1.481	1.690	1.345	1.044	1.887
2003	1.334	1.028	1.241	1.504	1.721	1.371	1.062	1.934
2004	1.350	1.032	1.266	1.522	1.747	1.388	1.081	1.970
2005	1.366	1.034	1.287	1.542	1.770	1.407	1.097	2.001
2006	1.381	1.037	1.300	1.564	1.793	1.429	1.111	2.029
2007	1.395	1.039	1.315	1.582	1.817	1.447	1.123	2.050
2008	1.407	1.040	1.331	1.600	1.840	1.472	1.134	2.072
2009	1.416	1.039	1.344	1.616	1.861	1.496	1.135	2.092
2010	1.433	1.042	1.367	1.639	1.889	1.526	1.142	2.120
2011	1.449	1.044	1.395	1.662	1.917	1.557	1.154	2.147
2012	1.464	1.045	1.418	1.682	1.948	1.584	1.167	2.171
2013	1.477	1.043	1.434	1.698	1.974	1.609	1.179	2.191
2014	1.490	1.043	1.449	1.717	2.002	1.638	1.192	2.212

1 1987=1.000

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
FORECAST DATA
FOR SOUTH CAROLINA
INDUSTRIAL PRODUCTION INDICES 1

TREND

YEAR	TOTAL MFG. PRODUCTION INDEX	SIC 22 PRODUCTION INDEX	SIC 24-25 PRODUCTION INDEX	SIC 26 PRODUCTION INDEX	SIC 28 PRODUCTION INDEX	SIC 30 PRODUCTION INDEX	SIC 32 PRODUCTION INDEX	SIC 33-37 PRODUCTION INDEX
1995	1.204	0.983	1.134	1.325	1.500	1.195	0.951	1.595
1996	1.224	1.001	1.160	1.351	1.533	1.202	0.968	1.651
1997	1.266	1.036	1.204	1.395	1.588	1.264	1.004	1.724
1998	1.296	1.052	1.224	1.437	1.628	1.309	1.029	1.792
1999	1.311	1.051	1.237	1.464	1.657	1.317	1.050	1.834
2000	1.330	1.056	1.247	1.490	1.693	1.340	1.068	1.879
2001	1.347	1.060	1.255	1.518	1.727	1.370	1.075	1.918
2002	1.373	1.069	1.275	1.549	1.768	1.407	1.092	1.973
2003	1.401	1.080	1.304	1.580	1.808	1.440	1.116	2.032
2004	1.426	1.090	1.337	1.607	1.845	1.466	1.141	2.080
2005	1.450	1.098	1.366	1.637	1.879	1.494	1.165	2.125
2006	1.472	1.106	1.386	1.667	1.912	1.523	1.184	2.163
2007	1.495	1.114	1.409	1.696	1.948	1.551	1.204	2.198
2008	1.518	1.122	1.435	1.726	1.985	1.588	1.223	2.235
2009	1.538	1.128	1.459	1.755	2.021	1.624	1.232	2.272
2010	1.564	1.138	1.493	1.789	2.062	1.666	1.247	2.314
2011	1.591	1.146	1.531	1.824	2.104	1.709	1.267	2.357
2012	1.616	1.153	1.565	1.856	2.150	1.748	1.288	2.396
2013	1.641	1.159	1.593	1.887	2.193	1.788	1.310	2.434
2014	1.665	1.165	1.620	1.918	2.237	1.830	1.332	2.472

1 1987=1.000

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
FORECAST DATA
FOR SOUTH CAROLINA
INDUSTRIAL PRODUCTION INDICES 1

UPPER BOUND

YEAR	TOTAL MFG. PRODUCTION INDEX	SIC 22 PRODUCTION INDEX	SIC 24-25 PRODUCTION INDEX	SIC 26 PRODUCTION INDEX	SIC 28 PRODUCTION INDEX	SIC 30 PRODUCTION INDEX	SIC 32 PRODUCTION INDEX	SIC 33-37 PRODUCTION INDEX
1995	1.222	0.998	1.151	1.345	1.523	1.213	0.965	1.619
1996	1.250	1.022	1.184	1.379	1.565	1.227	0.988	1.686
1997	1.298	1.062	1.234	1.430	1.628	1.296	1.029	1.767
1998	1.332	1.081	1.258	1.477	1.674	1.346	1.058	1.842
1999	1.352	1.084	1.275	1.509	1.708	1.358	1.083	1.891
2000	1.375	1.092	1.290	1.541	1.751	1.386	1.104	1.943
2001	1.398	1.100	1.303	1.576	1.793	1.422	1.116	1.991
2002	1.431	1.114	1.328	1.614	1.842	1.466	1.138	2.056
2003	1.467	1.131	1.365	1.654	1.893	1.508	1.168	2.127
2004	1.499	1.146	1.405	1.689	1.939	1.541	1.199	2.186
2005	1.531	1.159	1.442	1.729	1.984	1.578	1.230	2.243
2006	1.562	1.173	1.471	1.769	2.029	1.616	1.256	2.295
2007	1.594	1.188	1.502	1.808	2.077	1.653	1.283	2.343
2008	1.627	1.203	1.539	1.850	2.128	1.702	1.311	2.396
2009	1.656	1.215	1.571	1.890	2.177	1.749	1.327	2.447
2010	1.692	1.231	1.615	1.936	2.231	1.803	1.349	2.504
2011	1.731	1.247	1.666	1.985	2.289	1.859	1.378	2.564
2012	1.766	1.260	1.711	2.029	2.350	1.911	1.408	2.619
2013	1.803	1.274	1.751	2.074	2.410	1.965	1.440	2.675
2014	1.838	1.286	1.788	2.117	2.470	2.020	1.471	2.729

1 1987=1.000

6. Electric Sales Assumptions

The results of the long-range forecast process along with the short range numbers are shown in the tables in Section 11. Total territorial sales are expected to increase at an annual rate of 1.8% from 1997 to 2014. Slightly higher growth over the forecast period is expected to be concentrated in the commercial sector. This trend reflects the economic assumptions which show the economy moving away from a manufacturing emphasis to a more services-oriented economy. In addition, population growth slows over the forecast period, which results in a general slowdown in the economic demand for goods and services.

An analysis for the major classes of service follows with an explanation of the assumptions which were incorporated into the long-range electric customer and sales forecasts.

Residential

In the residential sector, sales will increase at 2.0% over the 17 year period. In the past several years, we have seen a reversal in the declining trend in customers in the non-space heating sector, therefore, our forecast incorporates some growth in non-space heating customers with most of the growth in the space heating segment. Sales in the space heating sector increase at an annual rate of 2.5% and in the non-space heating sector, sales increase at 1.4%.

Residential customers are expected to increase at a 1.6% annual rate, averaging 7,869 per year. The customer forecast for each subgroup was based on assumptions regarding what percent of the new customers would fall within each category. An evaluation of the historical data and current expectations provided the basis for the allocations. From 1970 to 1974 an average of 50% of our new customers were non-space heating; however, with the oil embargo of 1973 we saw a dramatic change in this trend. From 1975 to 1981 we actually saw a net decline in these customers. In other words over 100% of our new customer growth was attributable to electric heating customers. Since 1981, on average 12% of new customer growth has been non electric heating. However, from 1989 to 1993 this percent increased to 19 and this is attributed to the current gas marketing programs of the Company. Based on this information and current Company policy regarding extending residential gas mains we assumed 20% of new customers would be non-electric heating for the long term. The remainder of the new customers would be electric heating customers. The assumptions for dwelling type were based on a similar analysis. An evaluation of the sixteen years of historical data and taking into account that the current tax laws do not support rapid growth in the multi-family market, we assumed for the long term that, for the electric heating group 60% of new customers would be single family, 20% multi-family and 20% mobile homes. The respective percentages for non-electric heating are 80%, 10% and 10%.

In addition, Good Cents customers [Rate 1] and Conservation Rate customers [Rate 7] were forecasted separately. The number of customers forecasted for each rate was based on growth information provided by the Marketing department. The number of customers falling in each of the housing-type groups, (i.e., space heating single family) was based on the growth in each group using available historical data.

For Rate 1, we assumed 85% of the growth would be single family homes with 30% non-electric heating and 55% electric heating. The remainder would be multi-family homes with 5% non-electric heating and 10% electric heating. For Rate 7, we assumed 33% would non-space heating with 30% single family, 2% multi-family and 1% mobile homes. The remaining 67% would be electric heating with the housing type percentages 50%, 15%, and 2%, respectively. Average use for these customers was based on 1993 historical data. Rate 7 average use was calculated as a percent of Rate 8 for each of the six subgroups and Rate 1 was calculated as a percent of Rate 7. The percentages for Rate 7 for non-electric heating were 1.34%, .83%, and 1.35% for single family, multi-family, and mobile homes, respectively. The respective percentages for space heating were 1.03%, .88%, and 1.00%. Rate 1 average use was forecasted as 90% of Rate 7 for each subgroup.

Overall, average use per customer remains fairly constant over the forecast period in space heating, with a slight decrease, -.2%. As a result of the replacement water heater program, there is an increase in non-space heating average use of .8%. As expected, average use for the non-electric heating customers was a function of summer temperature, real electric price (a proxy for conservation in the market), and real per capita income, (a measure of the standard of living in a region) with winter temperature included for single-family homes. Average use for electric heating customers was a function of winter temperature and real electric price with summer temperature included for mobile homes. Summer temperature was not significant for the single family and multi-family subgroups. Real per capita income had a negative sign which is not consistent with economic expectations therefore was not included in these equations. In all cases, the price elasticities were negative as expected and consistent with reported industry data. Total sales for each subgroup was calculated from customers and average use and summed to arrive at total residential sales. Demand-side management adjustments were then made to sales, and average use for each subgroup was recalculated. Total residential sales were then calculated including these adjustments.

Commercial

The forecast for commercial sales is a compound annual rate of 1.7% over the 17 year period. Commercial customers are expected to increase about 2,005 per year.

Industrial

The long-range annual rate of growth forecast for industrial sales is 1.4%. This incorporates a base load of 295 GWH for 1997 to 2014 for the Savannah River Project forecast. This forecast was based on information supplied by Industrial Sales and Support and historical data from January 1994 to July 1994. The industrial forecast was produced by standard industrial classification (SIC) as noted earlier. In each subgroup, sales were estimated as a function of the respective industrial production index for that industry. The major assumption underlying the specification was that industrial electric sales should grow at about the same rate as or less than economic activity in that industry. Therefore, a coefficient close to or less than 1.0 would support this assumption. The exceptions were the chemical products (SIC 28) which tend to be textile related, and lumber and wood products both of which have, historically, grown slower than the industry average and other large industries or unclassified which have historically grown much faster than the overall manufacturing sector. In addition, SIC 91 (Governmental) which includes two accounts at the PomFlant Weapons Station at the Charleston Naval Base were set equal to their 1996 estimated level.

Street Lighting and Other Public Authorities

Street lighting sales are expected to grow at 1.8%. The consensus averages about a 1.0 GWH a year increase. The forecast for OPA sales is a 2.7% annual rate.

Municipal and Cooperatives

Municipal sales are expected to increase 1.8% and cooperative sales are expected to increase 1.6% from 1997 to 2014.

Company Use and Unaccounted For Energy

Company use is forecasted to grow at 3% annually throughout the forecast period. Unaccounted for energy is forecasted as 5% of total territorial sales.

7. Demand-Side Management Adjustments

The Company's long term electric sales forecast is also adjusted for the impact of each demand side program that proved to be economical in the Integrated Resource Planning (IRP) process. The demand side programs that impact the electric sales forecast were home energy check, replacement water heaters, replacement heat pumps, commercial thermal storage, commercial high efficiency chillers, and commercial HVAC. The adjustments for these demand side programs were provided by the Marketing Department. For the programs that have been in effect for a year or longer, the long-term impact of the program was reduced by the 1995 amount based on the assumption that this impact was already reflected in the short-range forecast data, since the short-range forecast is based on historical data through May 1994.

The adjustments to the forecast are shown in Tables 2.1.3, 2.1.4 and 2.1.5. Table 2.1.3 shows the residential programs, Table 2.1.4 shows the commercial programs with the total for all programs shown in Table 2.1.5. In 1997, these programs reduce the electric sales forecast by .7 GWH. By the year 2014, the adjustment was -89.0 GWH.

TABLE 2.1.3

DEMAND SIDE MANAGEMENT
ADJUSTMENTS TO ELECTRIC SALES FOR RESIDENTIAL DSM PROGRAMS

(GWH)

YEAR	RESIDENTIAL HOME ENERGY CHECK	RESIDENTIAL REPLACEMENT WATER HEATER	RESIDENTIAL REPLACEMENT HEAT PUMP	RESIDENTIAL PROGRAMS ADJUSTMENT
1995	0.0	12.4	-7.6	4.8
1996	-4.2	25.0	-15.4	5.4
1997	-8.7	37.9	-23.3	5.9
1998	-13.6	51.0	-31.4	6.0
1999	-19.0	64.4	-39.7	5.7
2000	-24.7	78.1	-48.1	5.3
2001	-30.8	92.1	-56.7	4.6
2002	-37.3	106.3	-65.5	3.5
2003	-44.1	120.8	-74.4	2.3
2004	-51.4	135.6	-83.5	0.7
2005	-59.1	150.7	-92.8	-1.2
2006	-67.1	166.1	-102.3	-3.3
2007	-75.6	181.8	-112.0	-5.8
2008	-84.4	197.8	-121.9	-8.5
2009	-93.7	214.2	-131.9	-11.4
2010	-103.3	230.8	-142.2	-14.7
2011	-113.3	247.8	-152.7	-18.2
2012	-123.7	265.2	-163.3	-21.8
2013	-134.5	282.9	-174.2	-25.8
2014	-145.7	300.9	-185.4	-30.2

TABLE 2.1.4

DEMAND SIDE MANAGEMENT
ADJUSTMENTS TO ELECTRIC SALES FOR COMMERCIAL DSM PROGRAMS

(GWH)

YEAR	COMMERCIAL THERMAL STORAGE	COMMERCIAL HIGH EFF. CHILLER	COMMERCIAL HVAC	COMMERCIAL PROGRAMS ADJUSTMENT
1995	0.0	0.0	0.0	0.0
1996	0.6	-0.6	-3.3	-3.3
1997	1.2	-1.3	-6.5	-6.6
1998	1.8	-2.0	-9.8	-10.0
1999	2.5	-2.6	-13.0	-13.1
2000	3.2	-3.3	-16.3	-16.4
2001	3.9	-4.0	-19.5	-19.6
2002	4.7	-4.8	-22.8	-22.9
2003	5.5	-5.5	-26.0	-26.0
2004	6.4	-6.3	-29.3	-29.2
2005	7.3	-7.0	-32.5	-32.2
2006	8.2	-7.8	-35.8	-35.4
2007	9.2	-8.6	-39.0	-38.4
2008	10.2	-9.4	-42.3	-41.5
2009	11.3	-10.2	-45.6	-44.5
2010	12.4	-11.1	-48.8	-47.5
2011	13.6	-11.9	-52.1	-50.4
2012	14.9	-12.8	-55.3	-53.2
2013	16.2	-13.7	-58.6	-56.1
2014	17.6	-14.6	-61.8	-58.8

TABLE 2.1.5

DEMAND SIDE MANAGEMENT
TOTAL ADJUSTMENTS TO ELECTRIC SALES

(GWH)

YEAR	TOTAL ALL PROGRAMS ADJUSTMENT
1995	4.8
1996	2.1
1997	-0.7
1998	-4.0
1999	-7.4
2000	-11.1
2001	-15.0
2002	-19.4
2003	-23.7
2004	-28.5
2005	-33.4
2006	-38.7
2007	-44.2
2008	-50.0
2009	-55.9
2010	-62.2
2011	-68.6
2012	-75.0
2013	-81.9
2014	-89.0

8. The Charleston Naval Base Closing

In July 1993, it was announced that the majority of the facilities at the Naval Base in Charleston would be closed. This year, we assumed the impact that the closing would have on the electric sales forecast was embedded in the historical data.

The Naval Base has been downsizing since 1989 as shown in Table 2.1.6. Employment was reduced by 8,914 in 1993 and an estimated 10,538 jobs have been lost in 1994. However, we still added almost 6,000 residential customers in both years. Since the forecast is based on this historical data, it was assumed that the closure would be reflected in the historical data and, thus, in our forecast. In 1995, an additional 12,700 jobs are projected to be lost. Our residential projection of 4,898 new customers seems reasonable given the historical data.

TABLE 2.1.6
CHARLESTON NAVAL BASE IMPACT

	EMPLOYMENT CHANGE AT THE NAVAL FACILITIES IN CHARLESTON	SCE&G RESIDENTIAL CUSTOMER GROWTH (AVERAGE ANNUAL)
1990	-1,919	7,551
1991	-1,627	7,749
1992	-6,177	6,402
1993	-8,914	5,956
1994 (E)	-10,538	5,600
1995 (F)	-12,700	4,898

(E) Estimated

(F) Forecast

9. Electric Forecast Equations

VARIABLE DEFINITIONS	
VARIABLE	*DEFINITION*
AVG	*Average usage per customer*
CUST	*Number of customers*
JQIND	*State industrial production index - all manufacturing*
JQIND22	*State industrial production index - SIC 22*
JQIND245	*State industrial production index - average of SIC 24 and SIC 25*
JQIND26	*State industrial production index - SIC 26*
JQIND28	*State industrial production index - SIC 28*
JQIND30	*State industrial production index - SIC 30*
JQIND32	*State industrial production index - SIC 32*
JQIND337	*State industrial production index - average of SIC 33-37*
POP	*Service area population*
PRICE	*Real price per KWH*
RPCI	*Service area real per capita income*
RYPI	*Service area real personal income*
SALES	*Electric sales in KWH*
STMP	*Average summer (June, July, August) temperature*
SUM2	*Sum of SCE&G's residential, commercial, and non-SRP industrial sales*
WTMP	*Average winter (December (previous year), January, February) temperature*
*	*Indicates multiplication*
ln	*Natural logarithm*
LAG1	*One year lag in data*

Long-Range Equations

RESIDENTIAL CLASS

A. TOTAL CUSTOMERS

ln(CUST) = 7.6214 + .3660 * ln(RYPI) + .5941 * ln(POP) + .0125 * YR89
t-statistic: (6.329) (3.319) (2.795) (2.503)

R^2 = .9951
Mean Square Error = .00002
Durbin-Watson = 1.900 with first order autocorrelation = -.167
Number of Observations = 8, 1986-1993

Where YR89 = 1, if year is equal to 1989
= 0, otherwise
Customers - space heating and non-space heating by housing type

CHCUST = CUST - LAG1(CUST)
CUSTSH = LAG1(CUSTSH) + CHCUST * X
CUSTO = CUST - CUSTSH
CHCUSTSH = CUSTSH - LAG1 (CUSTSH)
CUSTSFS = LAG1 (CUSTSFS) + CHCUSTSH * Y
CUSTAPS = LAG1 (CUSTAPS) + CHCUSTSH * Z
CUSTMHS = CUSTSH - CUSTSFS - CUSTAPS
CHCUSTO = CUSTO - LAG1 (CUSTO)
CUSTSFO = LAG1 (CUSTSFO) + CHCUSTO * P
CUSTAPO = LAG1 (CUSTAPO) + CHCUSTO * Q
CUSTMHO = CUSTO - CUSTSFO - CUSTAPO

Where:

CHCUST = Growth in Residential Customers
CUSTSH = Space Heating Residential Customers
CUSTO = Non-Space Heating Residential Customers
CHCUSTSH = Growth in Space Heating Residential Customers
CHCUSTO = Growth in Non-Space Heating Residential Customers
CUSTSFS = Single Family Space Heating Homes
CUSTAPS = Multi-Family Space Heating Units
CUSTMHS = Mobile Homes with Space Heating
CUSTSFO = Single Family Non-Space Heating Homes
CUSTAPO = Multi-Family Non-Space Heating Units
CUSTMHO = Mobile Homes with Non-Space Heating

and

If Year is Greater than 1996, X = .80, Y = .60, Z = .20, P = .80 and Q = .10

B. SPACE HEATING AVERAGE USE

1. Single Family Homes

ln(AVG) = 13.7392 - .2115 * ln(Price) - 1.1388 * ln(WTMP) -.0584 * YR88
t-statistic: (31.553) (-3.691) (-9.313) (-2.203)

Where YR88 = 1, if year is equal to 1988
= 0, otherwise

R^2 = .8710
Mean Square Error = .00065
Durbin-Watson = 1.655 with first order autocorrelation =.098
Number of Observations = 17, 1977-1993

2. Multi-Family Homes

ln(AVG) = 11.9095 - .2648 * ln(Price) - .8478 * ln(WTMP) -.0554 * YR88
t-statistic: (32.492) (-5.625) (-7.865) (-2.539)

Where YR88 = 1, if year is equal to 1988
= 0, otherwise

R^2 = .8354
Mean Square Error = .00043
Durbin-Watson = 1.690, with first order autocorrelation = .096
Number of Observations = 17, 1977-1993

3. Mobile Homes

ln(AVG) = 10.7165 - .4744 * ln(Price) - 1.0707 * ln (WTMP)
t-statistic: (8.450) (-12.794) (-12.972)

+.4034 * ln(STMP) - .0603 * YR88
(1.340) (-3.506)

Where YR88 = 1, if year is equal to 1988
= 0, otherwise

R^2 = .9529
Mean Square Error = .00027
Durbin-Watson = 2.343, with first order autocorrelation = -.207
Number of Observations = 17, 1977-1993

C. NON-SPACE HEATING AVERAGE USE

1. Single Family Homes

$$\ln(AVG) = -1.404757 + .1636 * \ln(RPCI) + 1.9983 * \ln(STMP) - .1530 * \ln(Price) - .1839 * \ln(WTMP)$$

t-statistic: (-1.140) (1.887) (6.371) (-3.761) (-1.443)

R^2 = .9328
Mean Square Error = .00023
Durbin-Watson = 2.405, with first order autocorrelation = -.210
Number of Observations = 17, 1977-1993

2. Multi-Family Homes

$$\ln(AVG) = -5.5426 + .3982 * \ln(RPCI) + 1.8695 * \ln(STMP) - .2263 * \ln(Price)$$

t-statistic: (-3.457) (5.060) (4.906) (-4.530)

R^2 = .9621
Mean Square Error = .00036
Durbin-Watson = 1.598 with first order autocorrelation = .130
Number of Observations = 17, 1977-1993

3. Mobile Homes

$$\ln(AVG) = -8.2601 + .5782 * \ln(RPCI) + 1.9066 * \ln(STMP) - .3577 * \ln(Price)$$

t-statistic: (-5.168) (7.460) (4.972) (-7.154)

R^2 = .9797
Mean Square Error = .00037
Durbin-Watson = 1.351 with first order autocorrelation = .200
Number of Observations = 17, 1977-1993

D. RESIDENTIAL STREET LIGHTING

$$\ln(SALES) = \underset{(72.179)}{14.8474} + \underset{(11.010)}{.8618} * \ln(RYPI) - \underset{(-2.360)}{.0660} * YRL80 + \underset{(14.378)}{.3873} * YR9193$$

Where YRL80 = 1, if year is less than 1980
= 0, otherwise

Where YR9193 = 1, if year is equal to 1991, 1992 or 1993
= 0, otherwise

R^2 = .9905
Mean Square Error = .00097
Durbin-Watson = 1.619 with first order autocorrelation = .099
Number of Observations = 17, 1977-1993

COMMERCIAL CLASS

A. TOTAL CUSTOMERS

ln(CUST) = 5.0148 + .6998 * ln(RYPI) + .5602 * ln(POP) + .0250 * YR89
t-statistic: (2.541) (3.873) (1.608) (3.069)

Where YR89 = 1, if year is equal to 1989
= 0, otherwise

R^2 = .9939
Mean Square Error = .00006
Durbin-Watson = 1.880, with first order autocorrelation = -.183
Number of Observations = 8, 1986-1993

B. TOTAL SALES

ln(SALES) = 10.9699 + .5443 * ln(RYPI) + .8102 * ln(STMP)
t-statistic: (9.466) (2.611) (3.056)

- .4861 * ln(Price)
(-4.210)

R^2 = .9960
Mean Square Error = .00010
Durbin-Watson = 2.567, with first order autocorrelation = -.448
Number of Observations = 9, 1985-1993

From autocorrelation:

ln(SALES) = 10.9422 + .6973 * ln(RYPI) + .6889 * ln(STMP)
-.4037 * ln(PRICE)

INDUSTRIAL CLASS (EXCLUDING SAVANNAH RIVER SITE)

A. TOTAL SALES

1. Textile Mill Products (SIC=22)

ln(SALES) = 20.4440 + 1.1079 * ln(JQIND22) + .0616 * YR90 - .0665 * YR83
t-statistic: (1757.847) (6.618) (2.325) (-2.563)

Where YR90 = 1, if year is equal to 1990
= 0, otherwise

Where YR83 = 1, if year is equal to 1983
= 0, otherwise

R^2 = .8609
Mean Square Error = .00061
Durbin-Watson = 1.822, with first order autocorrelation = .087
Number of Observations = 12, 1982-1993

2. Lumber, Wood Products, Furniture and Fixtures (SIC=24,25)

ln(SALES) = 18.8550 + .3994 * ln(JQIND245) -.8024 * YRL80 - .1559 * YR92
t-statistic: (738.438) (1.856) (-16.562) (-2.283)

Where YRL80 = 1, if year less than or equal to 1980
= 0, otherwise

Where YR92 = 1, if year is equal to 1992
= 0, otherwise

R^2 = .9788
Mean Square Error = .0041
Durbin-Watson = 1.324, with first order autocorrelation = .238
Number of Observations = 18, 1976-1993

INDUSTRIAL CLASS (EXCLUDING SAVANNAH RIVER SITE) (continued)

3. Paper and Allied Products (SIC=26)

ln(SALES) = 19.1881 + .8877 * ln(JQIND26) - .0944 * YR87 + .0909 * YR92
t-statistic: (1609.558) (23.859) (-2.490) (2.296)

Where YR87 = 1, if year is equal to 1987
= 0, otherwise

Where YR92 = 1, if year is equal to 1992
= 0, otherwise

R^2 = .9804
Mean Square Error = .00130
Durbin-Watson = 2.025, with first order autocorrelation = -.039
Number of Observations = 18, 1976-1993

4. Chemical and Allied Products (SIC=28)

ln(SALES) = 20.5067 + .2224 * ln(JQIND28) - .0771 * YR9091
t-statistic: (2388.546) (6.538) (-3.155)

Where YR9091 = 1, if year is equal to 1990 or 1991
= 0, otherwise

R^2 = .7957
Mean Square Error = .00082
Durbin-Watson = 1.507, with first order autocorrelation = .215
Number of Observations = 14, 1980-1993

5. Rubber and Miscellaneous plastic products (SIC=30)

ln(SALES) = 18.8325 + .5673 * ln(JQIND30) +.2118 * YR8184
t-statistic: (1089.413) (12.464) (6.806)

Where YR8184 = 1, if year is equal to 1981, 1982, 1983, or 1984
= 0, otherwise

R^2 = .9292
Mean Square Error = .00292
Durbin-Watson = 1.240, with first order autocorrelation = .256
Number of Observations = 17, 1977-1993

INDUSTRIAL CLASS (EXCLUDING SAVANNAH RIVER SITE) (continued)

6. Stone, clay, glass and concrete products (SIC=32)

ln(SALES) = 19.6366 + .9481 * ln(JQIND32) + .1166 * YR9293
t-statistic: (1292.367) (6.295) (4.514)

- .076 * YR82
(-1.743)

Where YR9293 = 1, if year is equal to 1992 or 1993
= 0, otherwise

Where YR82 = 1, if year is equal to 1982
= 0, otherwise

R^2 = .9177
Mean Square Error = .00112
Durbin-Watson = 1.476, with first order autocorrelation = .082
Number of Observations = 14, 1980-1993

7. Primary Metal, Fabricated Metal Products, Electric and Non-Electronic Machinery, Equipment and Supplies and Transportation Equipment (SIC=33, 34, 35, 36 and 37)

ln(SALES) = 20.0949 + .7374 * ln(JQIND337) - .0685 * YR90
t-statistic: (2558.414) (29.030) (-2.367)

Where YR90 = 1, if year is equal to 1990
= 0, otherwise

R^2 = .9865
Mean Square Error = .00072
Durbin-Watson = .884, with first order autocorrelation = .355
Number of Observations = 15, 1979-1993

8. Governmental (SIC=91)

The PomFlant Weapons Station accounts at the Naval Facilities in Charleston were set equal to their 1994 Short Range Forecast value of 129.5 millions of KWH for the Long Range Forecast prior to the DSM adjustments.

INDUSTRIAL CLASS (EXCLUDING SAVANNAH RIVER SITE) (continued)

9. Other large industrials or Unclassified

ln(SALES) = 19.7695 + 2.3390 * ln(JQIND)
t-statistic: (794.557) (12.154)

R^2 = .9307
Mean Square Error = .00734
Durbin-Watson = 1.583, with first order autocorrelation = .204
Number of Observations = 13, 1981-1993

10. Westvaco (Rate = 60, SIC = 26)

ln(SALES) = 19.2275 + 1.1006 * ln(JQIND26) + .1098 * ln(YR93)
t-statistic: (1020.961) (4.625) (1.947)

Where YR93 = 1, if year is equal to 1993
= 0, otherwise

R^2 = .9344
Mean Square Error = .00147
Durbin-Watson = 2.426, with first order autocorrelation = -.240
Number of Observations = 8, 1986-1993

B. AVERAGE USE

1. Small Industrial Customers

ln(AVG) = 13.2141 + .6704 * ln(JQIND)
t-statistic: (1301.417) (8.536)

R^2 = .8688
Mean Square Error = .00122
Durbin-Watson = 1.460, with first order autocorrelation = .227
Number of Observations = 13, 1981-1993

C. CUSTOMERS

Small industrial customers decrease by 5 per year.
Large industrial customers were set equal to their 1996 Forecast value for the Forecast interval; at 127 per year.

STREET LIGHTING CLASS - TOTAL SALES

ln(SALES) = 8.8042 + .7203 * ln(RYPI) + .1074 * ln(YR8486)
t-statistic: (191.698) (40.870) (12.587)

Where YR8486 = 1, if year is equal to 1984, 1985, or 1986
= 0, otherwise

R^2 = .9922
Mean Square Error = .00018
Durbin-Watson = 1.958, with first order autocorrelation = -.094
Number of Observations = 18, 1976-1993

OTHER PUBLIC AUTHORITY CLASS - TOTAL SALES

ln(SALES) = 9.9818 + 1.0593 * ln(RYPI) - .0464 * YR92
t-statistic: (194.996) (53.708) (-2.985)

Where YR92 = 1, if year is equal to 1992
= 0, otherwise

R^2 = .9953
Mean Square Error = .00020
Durbin-Watson = 1.900, with first order autocorrelation = -.053
Number of Observations = 18, 1976-1993

MUNICIPAL CLASS - TOTAL SALES

$$\ln(SALES) = -2.9283 + 1.0010 * \ln(SUM2) - .0250 * YR8788$$

t-statistic: (-9.676) (53.925) (-3.603)

Where YR8788 = 1, if year is equal to 1987 or 1988
= 0, otherwise

R^2 = .9966
Mean Square Error = .00008
Durbin-Watson = 1.870, with first order autocorrelation = .009
Number of Observations = 13, 1981-1993

COOPERATIVE CLASS - TOTAL SALES

$$\ln(SALES) = 4.7909 + .9049 * \ln(SUM2) - .5825 * \ln(Price)$$

t-statistic: (2.989) (9.582) (-5.310)

R^2 = .9269
Mean Square Error = .00423
Durbin-Watson = 1.306, with first order autocorrelation = .265
Number of Observations = 18, 1976-1993

10. Historical Electric Sales Data

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 1

ACTUAL RESIDENTIAL SPACE HEATING DETAIL BY HOUSING TYPE
1987 -- 1993

YEAR	SINGLE FAMILY SP.HT. CUSTOMERS	SINGLE FAMILY SP.HT. AVG USE (KWH)	SINGLE FAMILY SP.HT SALES (GWH)	MULIT FAMILY SP.HT. CUSTOMERS	MULTI FAMILY SP.HT. AVG USE (KWH)	MULTI FAMILY SP.HT SALES (GWH)
1987	108	15096.39	2	2	6993.50	0
1988	741	16225.93	12	42	8886.24	0
1989	1589	17134.56	27	191	11632.90	2
1990	2544	17430.60	44	479	9436.18	5
1991	3539	17186.63	61	581	9661.66	6
1992	4803	16900.03	81	838	8424.40	7
1993	6365	17824.96	113	1106	9000.69	10

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 7

ACTUAL RESIDENTIAL SPACE HEATING DETAIL BY HOUSING TYPE
1982 -- 1993

YEAR	SINGLE FAMILY SP.HT. CUSTOMERS	SINGLE FAMILY SP.HT. AVG USE (KWH)	SINGLE FAMILY SP.HT SALES (GWH)	MULIT FAMILY SP.HT. CUSTOMERS	MULTI FAMILY SP.HT. AVG USE (KWH)	MULTI FAMILY SP.HT SALES (GWH)	MOBILE HOMES SP.HT. CUSTOMERS	MOBILE HOMES SP.HT. AVG USE (KWH)	MOBILE HOMES SP.HT SALES (GWH)
1982	64	17524.20	1	1	18262.00	0	1	16894.00	0
1983	355	20404.21	7	13	12500.77	0	5	14582.20	0
1984	799	19948.41	16	126	10164.49	1	9	14153.33	0
1985	1509	18685.24	28	726	8249.45	6	12	16068.42	0
1986	2471	19353.86	48	1516	8665.10	13	24	15494.58	0
1987	3982	19464.79	78	2066	9310.06	19	54	15581.35	1
1988	5372	19206.99	103	2857	9358.84	27	81	15823.85	1
1989	6308	19232.84	121	3446	9764.24	34	110	15524.81	2
1990	7006	19516.91	137	3536	9823.15	35	142	15543.70	2
1991	7684	19324.04	148	3664	9701.52	36	167	15362.13	3
1992	8333	19092.97	159	3874	9592.54	37	190	15220.82	3
1993	8880	20474.68	182	4013	10211.16	41	217	16258.29	4

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 8 AND OTHER NON STREET LIGHTING RATES

ACTUAL RESIDENTIAL SPACE HEATING DETAIL BY HOUSING TYPE
1977 -- 1993

YEAR	SINGLE FAMILY SP.HT. CUSTOMERS	SINGLE FAMILY SP.HT. AVG USE (KWH)	SINGLE FAMILY SP.HT SALES (GWH)	MULIT FAMILY SP.HT. CUSTOMERS	MULTI FAMILY SP.HT. AVG USE (KWH)	MULTI FAMILY SP.HT SALES (GWH)	MOBILE HOMES SP.HT. CUSTOMERS	MOBILE HOMES SP.HT. AVG USE (KWH)	MOBILE HOMES SP.HT SALES (GWH)
1977	28416	23239.35	660	21473	12536.94	269	2975	17123.50	51
1978	33633	22980.67	773	23730	12332.85	293	3661	16877.27	62
1979	38520	21073.80	812	25998	11420.59	297	4329	15616.04	68
1980	43141	21675.42	935	28343	11907.65	337	4997	16212.05	81
1981	46957	20652.77	970	30458	11582.99	353	5733	15700.97	90
1982	47583	19325.03	920	33579	10981.09	369	6360	14201.21	90
1983	48030	19741.97	948	37355	11184.94	418	7253	14243.40	103
1984	51266	19763.68	1013	40753	11203.45	457	8414	14179.90	119
1985	54091	18974.57	1026	45553	10485.19	478	9721	13485.76	131
1986	57469	19884.57	1143	50799	10753.72	546	11166	14326.35	160
1987	60536	20154.37	1220	53322	11065.58	590	12555	14934.88	188
1988	62581	19663.82	1231	55198	11092.70	612	13769	14911.67	205
1989	64144	19278.42	1237	56375	11125.02	627	14877	14920.78	222
1990	65400	19297.00	1262	58033	11249.70	653	16179	14876.88	241
1991	66977	19038.46	1275	59120	11101.59	656	17480	15005.88	262
1992	68253	18718.04	1278	59144	11001.95	651	18650	15147.12	282
1993	69646	19884.68	1385	59107	11660.59	689	19936	16248.17	324

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 1

ACTUAL RESIDENTIAL NON-SPACE HEATING DETAIL BY HOUSING TYPE
1987 -- 1993

YEAR	SINGLE FAMILY NON-SP.HT. CUSTOMERS	SINGLE FAMILY NON-SP.HT. AVG USE (KWH)	SINGLE FAMILY NON-SP.HT SALES (GWH)	MULIT FAMILY NON-SP.HT. CUSTOMERS	MULTI FAMILY NON-SP.HT. AVG USE (KWH)	MULTI FAMILY NON-SP.HT SALES (GWH)
1987	18	11680.72	0	1	8136.00	0
1988	203	14303.69	3	5	9310.00	0
1989	666	14696.95	10	24	11453.79	0
1990	1300	15072.64	20	155	7473.05	1
1991	2055	14688.58	30	448	5818.01	3
1992	2889	14244.32	41	707	5344.81	4
1993	3708	15837.83	59	763	6418.37	5

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 7

ACTUAL RESIDENTIAL NON-SPACE HEATING DETAIL BY HOUSING TYPE
1982 -- 1993

YEAR	SINGLE FAMILY NON-SP.HT. CUSTOMERS	SINGLE FAMILY NON-SP.HT. AVG USE (KWH)	SINGLE FAMILY NON-SP.HT SALES (GWH)	MULIT FAMILY NON-SP.HT. CUSTOMERS	MULTI FAMILY NON-SP.HT. AVG USE (KWH)	MULTI FAMILY NON-SP.HT SALES (GWH)	MOBILE HOMES NON-SP.HT. CUSTOMERS	MOBILE HOMES NON-SP.HT. AVG USE (KWH)	MOBILE HOMES NON-SP.HT SALES (GWH)
1982	13	16414.00	0	0	.	0	0	.	0
1983	94	16984.35	2	7	7900.71	0	4	12103.75	0
1984	207	17204.19	4	64	5714.83	0	9	12781.00	0
1985	363	17087.06	6	279	4781.68	1	17	13473.76	0
1986	531	17839.55	9	324	5382.23	2	25	14676.76	0
1987	809	17518.35	14	334	5706.89	2	36	15416.72	1
1988	1118	16609.33	19	355	5989.65	2	46	14874.98	1
1989	1493	16675.21	25	545	6696.60	4	56	14815.39	1
1990	1870	16908.02	32	725	7287.87	5	69	15398.93	1
1991	2268	16632.64	38	991	6446.18	6	86	15411.74	1
1992	2576	16069.31	41	1009	6257.03	6	96	15308.16	1
1993	2948	17222.09	51	1006	6858.66	7	110	16363.42	2

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 8 AND OTHER NON STREET LIGHTING RATES

ACTUAL RESIDENTIAL NON-SPACE HEATING DETAIL BY HOUSING TYPE
1977 -- 1993

YEAR	SINGLE FAMILY NON-SP.HT. CUSTOMERS	SINGLE FAMILY NON-SP.HT. AVG USE (KWH)	SINGLE FAMILY NON-SP.HT SALES (GWH)	MULIT FAMILY NON-SP.HT. CUSTOMERS	MULTI FAMILY NON-SP.HT. AVG USE (KWH)	MULTI FAMILY NON-SP.HT SALES (GWH)	MOBILE HOMES NON-SP.HT. CUSTOMERS	MOBILE HOMES NON-SP.HT. AVG USE (KWH)	MOBILE HOMES NON-SP.HT SALES (GWH)
1977	171899	11452.80	1967	26463	6426.76	170	25172	8755.52	220
1978	171042	11381.18	1947	26097	6398.03	167	25571	8593.50	220
1979	170303	10665.18	1816	25632	6053.65	155	25903	8108.76	210
1980	169747	11603.79	1970	25238	6582.46	166	26116	8838.52	231
1981	169103	11104.23	1878	25482	6387.12	163	26391	8616.04	227
1982	168910	10816.07	1827	25358	6315.93	160	27177	8377.24	228
1983	168705	11101.69	1873	25516	6530.66	167	28003	8701.45	244
1984	168749	11016.00	1859	25884	6525.92	169	28633	8900.26	255
1985	168734	11211.85	1892	26062	6657.07	173	29186	9023.50	263
1986	168536	12113.93	2042	26072	7152.41	186	29448	9825.67	289
1987	168308	12013.80	2022	26309	7136.44	188	29467	10071.95	297
1988	168210	11666.76	1962	26028	7003.30	182	29593	10112.66	299
1989	168181	11771.96	1980	26089	7225.84	189	29676	10397.61	309
1990	167877	12399.04	2082	26263	7746.20	203	29741	11016.96	328
1991	168078	12183.05	2048	26144	7791.59	204	29789	11146.01	332
1992	168129	11800.38	1984	26343	7567.55	199	29638	11192.00	332
1993	167985	12836.47	2156	26238	8253.75	217	29399	12098.25	356

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL STREET LIGHTING SALES

1977 -- 1993

YEAR	STREET LIGHTING SALES (GWH)
1977	19
1978	20
1979	22
1980	23
1981	24
1982	24
1983	25
1984	25
1985	26
1986	27
1987	28
1988	29
1989	29
1990	33
1991	45
1992	48
1993	51

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

ACTUAL INDUSTRIAL DETAIL (NON-SRP) BY STANDARD INDUSTRIAL CLASSIFICATION
SALES ARE IN MILLIONS OF KWH (GWH)
1976 -- 1993

YEAR	SIC 22 CUSTOMERS	SIC 22 SALES	SIC 24 CUSTOMERS	SIC 24 SALES	SIC 26 CUSTOMERS	SIC 26 SALES	SIC 28 CUSTOMERS	SIC 28 SALES	SIC 30 CUSTOMERS	SIC 30 SALES	SIC 32 CUSTOMERS
1976	21	756	3	54	2	133	4	404	2	73	4
1977	22	781	3	61	2	137	5	592	3	88	4
1978	22	771	4	69	2	146	6	624	4	103	4
1979	23	775	4	68	2	144	7	722	4	109	6
1980	23	758	5	63	2	145	8	735	6	117	6
1981	24	730	7	132	2	145	8	754	7	148	6
1982	21	636	7	146	2	157	7	706	7	155	6
1983	21	676	7	159	2	173	7	767	7	164	6
1984	22	689	6	152	2	184	7	758	7	173	6
1985	21	689	6	157	3	192	7	802	6	153	6
1986	21	732	5	160	3	197	7	820	6	144	6
1987	21	779	5	143	3	196	6	832	6	153	7
1988	21	748	4	144	4	212	6	838	6	151	7
1989	21	754	3	144	5	226	5	825	6	160	7
1990	21	732	3	154	5	243	5	773	6	164	6
1991	18	686	3	148	5	243	5	804	6	155	6
1992	19	709	3	131	5	272	6	840	6	143	7
1993	19	734	3	156	5	252	6	863	6	153	8

YEAR	SIC 32 SALES	SIC 33 CUSTOMERS	SIC 33 SALES	SIC 91 CUSTOMERS	SIC 91 SALES	OTHER LARGE CUSTOMERS	OTHER LARGE SALES	WESTVACO SALES	OTHER SMALL CUSTOMERS	OTHER SMALL AVG USE (KWH)	OTHER SMALL SALES
1976	226	11	246	2	78	27	215	181	705	478768.1	338
1977	237	12	253	2	97	27	252	196	704	530069.8	373
1978	256	13	303	2	101	30	295	173	684	530396.6	363
1979	277	15	360	2	109	30	312	224	674	506253.6	341
1980	269	18	369	2	118	31	308	233	669	502603.4	336
1981	290	20	407	2	129	27	236	267	683	494483.8	338
1982	246	21	379	2	138	28	219	219	711	440587.4	313
1983	296	23	411	2	138	29	231	245	702	464642.3	326
1984	324	24	462	2	138	29	269	260	683	506360.4	346
1985	309	24	470	2	149	31	317	230	658	524768.4	345
1986	318	23	475	2	147	31	345	219	637	546736.1	348
1987	333	25	521	2	138	34	373	212	622	555549.3	346
1988	340	26	575	2	147	33	386	233	610	558761.8	341
1989	343	26	596	2	148	33	434	232	608	562248.1	342
1990	323	25	573	2	148	33	455	246	605	587678.7	356
1991	319	26	600	2	161	37	486	262	603	556805.6	336
1992	337	26	628	2	146	33	498	259	596	565103.5	337
1993	360	29	707	2	135	35	533	316	585	606308.1	355

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

ACTUAL SALES DATA BY CLASS
1976 -- 1993

YEAR	TOTAL RESIDENTIAL CUSTOMERS	TOTAL RESIDENTIAL SALES (GWH)	SP HEATING RESIDENTIAL CUSTOMERS	SP HEATING RESIDENTIAL AVG USE (KWH)	SP HEATING RESIDENTIAL SALES (GWH)	NON SP HEATING RESIDENTIAL CUSTOMERS	NON SP HEATING RESIDENTIAL AVG USE (KWH)	NON SP HEATING RESIDENTIAL SALES (GWH)
1976	270235	3059	46452	17731	824	223783	9989	2235
1977	276398	3357	52865	18548	980	223533	10632	2377
1978	283732	3481	61024	18474	1127	222708	10569	2354
1979	290684	3380	68847	17085	1177	221837	9933	2203
1980	297580	3744	76480	17699	1354	221100	10809	2390
1981	304124	3705	83148	16989	1413	220976	10374	2292
1982	309047	3620	87588	15753	1380	221459	10114	2240
1983	315341	3787	93012	15878	1477	222329	10390	2310
1984	324912	3919	101366	15848	1607	223546	10344	2312
1985	336252	4032	111612	14958	1669	224640	10518	2363
1986	348379	4467	123444	15475	1910	224935	11365	2557
1987	357906	4649	132625	15810	2097	225281	11327	2552
1988	366199	4689	140641	15584	2192	225558	11072	2497
1989	373769	4818	147039	15451	2272	226730	11230	2546
1990	381320	5083	153320	15511	2378	228000	11863	2705
1991	389069	5154	159212	15368	2447	229857	11776	2707
1992	395471	5156	164084	15225	2498	231387	11486	2658
1993	401427	5651	169270	16233	2748	232157	12504	2903

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

ACTUAL SALES DATA BY CLASS
1976 -- 1993

YEAR	TOTAL COMMERCIAL CUSTOMERS	TOTAL COMMERCIAL SALES (GWH)	NON SRP INDUSTRIAL SALES (GWH)	TOTAL INDUSTRIAL SALES (GWH)	STREET LIGHTING SALES (GWH)	OTHER PUBLIC AUTHORITY SALES (GWH)	TOTAL ULTIMATE CUSTOMER SALES (GWH)
1976	35827	2291	2705	3390	35	247	9022
1977	37116	2454	3068	3665	36	256	9768
1978	38242	2608	3204	3826	37	274	10226
1979	39322	2582	3441	4005	38	281	10286
1980	39980	2706	3451	4072	39	290	10851
1981	40807	2784	3575	4163	40	296	10988
1982	41408	2855	3314	3898	41	306	10720
1983	42869	2949	3586	4151	42	316	11245
1984	44680	3130	3754	4332	48	331	11760
1985	46953	3351	3814	4398	50	352	12183
1986	49237	3585	3905	4428	51	374	12905
1987	51372	3777	4025	4611	47	385	13469
1988	53242	3951	4114	4569	48	394	13651
1989	55094	4150	4204	4607	49	409	14033
1990	56709	4384	4167	4540	50	425	14482
1991	57956	4501	4200	4635	50	429	14769
1992	59413	4539	4300	4684	51	425	14855
1993	60723	4844	4564	4887	54	447	15883

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

ACTUAL SALES DATA BY CLASS
1976 -- 1993

YEAR	TOTAL ULTIMATE CUSTOMER SALES (GWH)	MUNICIPAL SALES (GWH)	COOPERATIVE SALES (GWH) 1	TOTAL TERRITORIAL SALES (GWH) 1	UNACCOUNTED FOR ENERGY (GWH)	COMPANY USE (GWH)	TOTAL TERRITORIAL LOAD (GWH) 1
1976	9022	431	164	9617	556	41	10214
1977	9768	457	196	10421	681	43	11145
1978	10226	468	209	10903	602	47	11552
1979	10286	471	208	10965	595	43	11603
1980	10851	520	225	11596	705	131	12432
1981	10988	542	233	11763	731	105	12599
1982	10720	535	236	11491	563	147	12201
1983	11245	565	253	12063	671	111	12845
1984	11760	592	238	12590	489	131	13210
1985	12183	606	255	13044	724	119	13887
1986	12905	640	163	13708	645	101	14454
1987	13469	662	124	14255	703	126	15084
1988	13651	674	147	14472	741	113	15326
1989	14033	707	155	14895	639	100	15634
1990	14482	747	165	15394	527	84	16005
1991	14769	756	177	15702	691	96	16489
1992	14855	767	179	15801	755	78	16634
1993	15883	817	189	16889	772	84	17745

1 DOES NOT INCLUDE SALES TO OTHER UTILITIES

NOTE: COOPERATIVE SALES WERE ADJUSTED TO REFLECT CURRENT ACTIVE CUSTOMERS AND ANY FUTURE KNOWN CONTRACT TERMINATIONS. FROM 1976 TO 1993 THE SALES WOULD BE AS FOLLOWS:
87 , 106 , 107 , 106 , 111 , 112 , 109 , 116 , 96 , 103, 110 , 120 , 143 , 150 , 160 , 172, 174 , 188

11. Final Electric Sales Forecast

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SPACE HEATING SALES FORECAST SUMMARY

TOTAL

	SINGLE FAMILY HOMES			MULTI FAMILY HOMES			MOBILE HOMES		
YEAR	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1995	90,815	19,114	1,736	64,846	11,447	742	22,759	16,114	367
1996	93,522	18,993	1,776	65,102	11,431	744	24,044	16,115	387
1997	96,426	18,877	1,820	66,070	11,417	754	25,012	16,115	403
1998	99,907	18,766	1,875	67,230	11,403	767	26,172	16,115	422
1999	103,260	18,655	1,926	68,348	11,389	778	27,290	16,115	440
2000	106,625	18,550	1,978	69,470	11,377	790	28,411	16,115	458
2001	110,132	18,447	2,032	70,639	11,365	803	29,581	16,115	477
2002	113,766	18,348	2,087	71,849	11,354	816	30,791	16,115	496
2003	117,528	18,253	2,145	73,103	11,344	829	32,046	16,115	516
2004	121,260	18,156	2,202	74,348	11,332	843	33,290	16,115	536
2005	124,765	18,059	2,253	75,517	11,320	855	34,458	16,115	555
2006	128,330	17,965	2,305	76,705	11,311	868	35,646	16,115	574
2007	131,997	17,873	2,359	77,926	11,301	881	36,868	16,115	594
2008	135,720	17,781	2,413	79,168	11,292	894	38,110	16,115	614
2009	139,449	17,691	2,467	80,411	11,283	907	39,353	16,115	634
2010	143,440	17,603	2,525	81,741	11,274	922	40,683	16,115	656
2011	147,596	17,518	2,586	83,127	11,266	936	42,069	16,115	678
2012	151,895	17,436	2,648	84,559	11,258	952	43,502	16,115	701
2013	156,291	17,363	2,714	86,025	11,250	968	44,967	16,115	725
2014	160,639	17,289	2,777	87,474	11,242	983	46,416	16,115	748

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SPACE HEATING SALES FORECAST SUMMARY

RATE 1

YEAR	SINGLE FAMILY HOMES			MULTI FAMILY HOMES		
	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1995	9,485	17,873	170	1,644	9,188	15
1996	11,324	17,873	202	1,961	9,188	18
1997	13,108	17,873	234	2,285	9,188	21
1998	14,899	17,873	266	2,611	9,188	24
1999	16,793	17,873	300	2,955	9,188	27
2000	18,563	17,873	332	3,277	9,188	30
2001	20,324	17,873	363	3,597	9,188	33
2002	21,985	17,873	393	3,899	9,188	36
2003	23,739	17,873	424	4,218	9,188	39
2004	25,627	17,873	458	4,562	9,188	42
2005	27,527	17,873	492	4,907	9,188	45
2006	29,251	17,873	523	5,221	9,188	48
2007	30,988	17,873	554	5,536	9,188	51
2008	32,823	17,873	587	5,870	9,188	54
2009	34,598	17,873	618	6,193	9,188	57
2010	36,394	17,873	650	6,519	9,188	60
2011	38,217	17,873	683	6,851	9,188	63
2012	40,077	17,873	716	7,189	9,188	66
2013	41,966	17,873	750	7,532	9,188	69
2014	43,854	17,873	784	7,876	9,188	72

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SPACE HEATING SALES FORECAST SUMMARY

RATE 7

YEAR	SINGLE FAMILY HOMES AVERAGE CUSTOMERS	SINGLE FAMILY HOMES AVERAGE USE IN KWH	SINGLE FAMILY HOMES TOTAL GWH	MULTI FAMILY HOMES AVERAGE CUSTOMERS	MULTI FAMILY HOMES AVERAGE USE IN KWH	MULTI FAMILY HOMES TOTAL GWH	MOBILE HOMES AVERAGE CUSTOMERS	MOBILE HOMES AVERAGE USE IN KWH	MOBILE HOMES TOTAL GWH
1995	10,147	19,858	202	4,342	10,209	44	267	16,114	4
1996	10,926	19,859	217	4,544	10,209	46	298	16,115	5
1997	11,723	19,859	233	4,783	10,209	49	330	16,115	5
1998	12,523	19,859	249	5,023	10,209	51	362	16,115	6
1999	13,369	19,859	265	5,277	10,209	54	396	16,115	6
2000	14,159	19,859	281	5,514	10,209	56	427	16,115	7
2001	14,945	19,859	297	5,750	10,209	59	459	16,115	7
2002	15,687	19,859	312	5,972	10,209	61	488	16,115	8
2003	16,470	19,859	327	6,207	10,209	63	520	16,115	8
2004	17,314	19,859	344	6,460	10,209	66	554	16,115	9
2005	18,162	19,859	361	6,715	10,209	69	587	16,115	9
2006	18,932	19,859	376	6,946	10,209	71	618	16,115	10
2007	19,708	19,859	391	7,178	10,209	73	649	16,115	10
2008	20,527	19,859	408	7,424	10,209	76	682	16,115	11
2009	21,320	19,859	423	7,662	10,209	78	714	16,115	12
2010	22,122	19,859	439	7,903	10,209	81	746	16,115	12
2011	22,936	19,859	455	8,147	10,209	83	778	16,115	13
2012	23,767	19,859	472	8,396	10,209	86	812	16,115	13
2013	24,610	19,859	489	8,649	10,209	88	845	16,115	14
2014	25,454	19,859	505	8,902	10,209	91	879	16,115	14

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SPACE HEATING SALES FORECAST SUMMARY

RATE 8 AND OTHER NON STREET LIGHTING RATES

	SINGLE FAMILY HOMES			MULTI FAMILY HOMES			MOBILE HOMES		
YEAR	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1995	71,183	19,173	1,365	58,860	11,601	683	22,492	16,114	362
1996	71,272	19,038	1,357	58,597	11,601	680	23,746	16,115	383
1997	71,595	18,900	1,353	59,002	11,601	684	24,682	16,115	398
1998	72,485	18,761	1,360	59,596	11,601	691	25,810	16,115	416
1999	73,098	18,615	1,361	60,116	11,601	697	26,894	16,115	433
2000	73,903	18,469	1,365	60,679	11,601	704	27,984	16,115	451
2001	74,863	18,321	1,372	61,292	11,601	711	29,122	16,115	469
2002	76,094	18,174	1,383	61,978	11,601	719	30,303	16,115	488
2003	77,319	18,027	1,394	62,678	11,601	727	31,526	16,115	508
2004	78,319	17,873	1,400	63,326	11,601	735	32,736	16,115	528
2005	79,076	17,711	1,400	63,895	11,601	741	33,871	16,115	546
2006	80,147	17,552	1,407	64,538	11,601	749	35,028	16,115	564
2007	81,301	17,391	1,414	65,212	11,601	757	36,219	16,115	584
2008	82,370	17,227	1,419	65,874	11,601	764	37,428	16,115	603
2009	83,531	17,062	1,425	66,556	11,601	772	38,639	16,115	623
2010	84,924	16,900	1,435	67,319	11,601	781	39,937	16,115	644
2011	86,443	16,741	1,447	68,129	11,601	790	41,291	16,115	665
2012	88,051	16,583	1,460	68,974	11,601	800	42,690	16,115	688
2013	89,715	16,439	1,475	69,844	11,601	810	44,122	16,115	711
2014	91,331	16,293	1,488	70,696	11,601	820	45,537	16,115	734

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC NON-SPACE HEATING SALES FORECAST SUMMARY

TOTAL

YEAR	SINGLE FAMILY HOMES AVERAGE CUSTOMERS	SINGLE FAMILY HOMES AVERAGE USE IN KWH	SINGLE FAMILY HOMES TOTAL GWH	MULTI FAMILY HOMES AVERAGE CUSTOMERS	MULTI FAMILY HOMES AVERAGE USE IN KWH	MULTI FAMILY HOMES TOTAL GWH	MOBILE HOMES AVERAGE CUSTOMERS	MOBILE HOMES AVERAGE USE IN KWH	MOBILE HOMES TOTAL GWH
1995	176,451	12,384	2,185	27,848	7,818	218	29,206	11,959	349
1996	177,278	12,466	2,210	27,886	7,814	218	29,117	11,961	348
1997	178,246	12,611	2,248	28,007	7,899	221	29,238	12,180	356
1998	179,406	12,735	2,285	28,152	7,953	224	29,383	12,332	362
1999	180,524	12,853	2,320	28,292	7,994	226	29,523	12,458	368
2000	181,646	12,960	2,354	28,432	8,021	228	29,663	12,550	372
2001	182,814	13,066	2,389	28,578	8,048	230	29,809	12,641	377
2002	184,026	13,169	2,423	28,729	8,074	232	29,960	12,727	381
2003	185,280	13,276	2,460	28,887	8,103	234	30,117	12,823	386
2004	186,525	13,385	2,497	29,042	8,130	236	30,273	12,919	391
2005	187,693	13,497	2,533	29,187	8,161	238	30,419	13,022	396
2006	188,882	13,606	2,570	29,336	8,192	240	30,567	13,124	401
2007	190,103	13,714	2,607	29,489	8,220	242	30,720	13,218	406
2008	191,345	13,820	2,644	29,644	8,243	244	30,875	13,303	411
2009	192,586	13,926	2,682	29,800	8,265	246	31,031	13,383	415
2010	193,916	14,035	2,722	29,966	8,293	248	31,197	13,479	421
2011	195,303	14,147	2,763	30,139	8,323	251	31,370	13,581	426
2012	196,735	14,262	2,806	30,319	8,355	253	31,549	13,688	432
2013	198,201	14,372	2,849	30,501	8,390	256	31,733	13,801	438
2014	199,651	14,481	2,891	30,682	8,424	258	31,914	13,912	444

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC NON-SPACE HEATING SALES FORECAST SUMMARY

RATE 1

	SINGLE FAMILY HOMES			MULTI FAMILY HOMES		
YEAR	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1995	5,322	14,651	78	871	5,924	5
1996	6,273	14,651	92	935	5,924	6
1997	7,246	14,727	107	1,097	5,998	7
1998	8,223	14,778	122	1,260	6,048	8
1999	9,256	14,820	137	1,432	6,090	9
2000	10,222	14,850	152	1,593	6,120	10
2001	11,182	14,880	166	1,753	6,150	11
2002	12,088	14,908	180	1,904	6,178	12
2003	13,045	14,938	195	2,064	6,210	13
2004	14,075	14,969	211	2,235	6,241	14
2005	15,111	15,002	227	2,408	6,274	15
2006	16,052	15,035	241	2,565	6,308	16
2007	16,999	15,065	256	2,723	6,338	17
2008	18,000	15,091	272	2,889	6,365	18
2009	18,968	15,116	287	3,051	6,391	19
2010	19,947	15,146	302	3,214	6,422	21
2011	20,942	15,178	318	3,380	6,455	22
2012	21,957	15,211	334	3,549	6,489	23
2013	22,987	15,246	350	3,721	6,525	24
2014	24,017	15,280	367	3,892	6,561	26

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC NON-SPACE HEATING SALES FORECAST SUMMARY

RATE 7

	SINGLE FAMILY HOMES			MULTI FAMILY HOMES			MOBILE HOMES		
YEAR	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1995	3,809	16,279	62	1,006	6,582	7	135	16,118	2
1996	4,338	16,279	71	1,006	6,582	7	151	16,118	2
1997	4,816	16,363	79	1,038	6,664	7	167	16,410	3
1998	5,296	16,420	87	1,070	6,720	7	183	16,612	3
1999	5,804	16,466	96	1,104	6,767	7	200	16,779	3
2000	6,278	16,500	104	1,135	6,800	8	216	16,899	4
2001	6,749	16,533	112	1,167	6,834	8	231	17,019	4
2002	7,195	16,564	119	1,196	6,865	8	246	17,132	4
2003	7,664	16,598	127	1,228	6,900	8	262	17,258	5
2004	8,171	16,633	136	1,262	6,934	9	279	17,384	5
2005	8,680	16,669	145	1,295	6,972	9	296	17,520	5
2006	9,142	16,706	153	1,326	7,008	9	311	17,654	5
2007	9,607	16,739	161	1,357	7,042	10	327	17,778	6
2008	10,099	16,768	169	1,390	7,073	10	343	17,889	6
2009	10,574	16,796	178	1,422	7,101	10	359	17,994	6
2010	11,055	16,829	186	1,454	7,135	10	375	18,120	7
2011	11,544	16,865	195	1,486	7,172	11	391	18,254	7
2012	12,042	16,901	204	1,520	7,210	11	408	18,395	8
2013	12,548	16,940	213	1,553	7,250	11	425	18,545	8
2014	13,055	16,978	222	1,587	7,290	12	442	18,691	8

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC NON-SPACE HEATING SALES FORECAST SUMMARY

RATE 8 AND OTHER NON STREET LIGHTING RATES

	SINGLE FAMILY HOMES			MULTI FAMILY HOMES			MOBILE HOMES		
YEAR	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1995	167,320	12,223	2,045	25,971	7,930	206	29,071	11,939	347
1996	166,667	12,285	2,047	25,945	7,930	206	28,966	11,939	346
1997	166,184	12,410	2,062	25,872	8,029	208	29,071	12,156	353
1998	165,887	12,517	2,076	25,822	8,097	209	29,200	12,305	359
1999	165,464	12,617	2,088	25,756	8,153	210	29,323	12,429	364
2000	165,146	12,708	2,099	25,704	8,193	211	29,447	12,518	369
2001	164,883	12,801	2,111	25,658	8,233	211	29,578	12,607	373
2002	164,743	12,893	2,124	25,629	8,271	212	29,714	12,691	377
2003	164,571	12,990	2,138	25,595	8,313	213	29,855	12,784	382
2004	164,279	13,088	2,150	25,545	8,355	213	29,994	12,877	386
2005	163,902	13,190	2,162	25,484	8,399	214	30,123	12,978	391
2006	163,688	13,293	2,176	25,445	8,444	215	30,256	13,077	396
2007	163,497	13,395	2,190	25,409	8,485	216	30,393	13,169	400
2008	163,246	13,498	2,203	25,365	8,521	216	30,532	13,251	405
2009	163,044	13,601	2,218	25,327	8,556	217	30,672	13,329	409
2010	162,914	13,710	2,233	25,298	8,597	217	30,822	13,422	414
2011	162,817	13,822	2,250	25,273	8,641	218	30,979	13,522	419
2012	162,736	13,938	2,268	25,250	8,687	219	31,141	13,626	424
2013	162,666	14,050	2,286	25,227	8,735	220	31,308	13,737	430
2014	162,579	14,162	2,302	25,203	8,783	221	31,472	13,845	436

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL STREET LIGHTING SALES FORECAST SUMMARY

YEAR	TOTAL GWH
1995	44
1996	43
1997	44
1998	45
1999	46
2000	47
2001	48
2002	49
2003	50
2004	51
2005	52
2006	54
2007	55
2008	56
2009	57
2010	58
2011	59
2012	61
2013	62
2014	63

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SALES FORECAST SUMMARY

BY HEATING TYPE

	NON SPACE HEATING 1			SPACE HEATING			TOTAL RESIDENTIAL		
YEAR	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1995	233,505	11,974	2,796	178,420	15,945	2,845	411,925	13,694	5,641
1996	234,281	12,031	2,819	182,668	15,919	2,908	416,949	13,735	5,727
1997	235,491	12,184	2,869	187,508	15,880	2,978	422,999	13,822	5,847
1998	236,941	12,307	2,916	193,309	15,847	3,063	430,250	13,897	5,979
1999	238,339	12,421	2,960	198,898	15,810	3,145	437,237	13,963	6,105
2000	239,741	12,520	3,002	204,506	15,775	3,226	444,247	14,018	6,228
2001	241,201	12,619	3,044	210,352	15,741	3,311	451,553	14,073	6,355
2002	242,715	12,714	3,086	216,406	15,709	3,399	459,121	14,125	6,485
2003	244,284	12,814	3,130	222,677	15,677	3,491	466,961	14,179	6,621
2004	245,840	12,915	3,175	228,898	15,643	3,581	474,738	14,231	6,756
2005	247,299	13,020	3,220	234,740	15,606	3,663	482,039	14,279	6,883
2006	248,785	13,124	3,265	240,681	15,571	3,748	489,466	14,327	7,012
2007	250,312	13,224	3,310	246,791	15,535	3,834	497,103	14,371	7,144
2008	251,864	13,321	3,355	252,998	15,499	3,921	504,862	14,413	7,276
2009	253,417	13,418	3,400	259,213	15,464	4,008	512,630	14,452	7,409
2010	255,079	13,520	3,449	265,864	15,430	4,102	520,943	14,495	7,551
2011	256,812	13,625	3,499	272,792	15,397	4,200	529,604	14,538	7,699
2012	258,603	13,733	3,551	279,956	15,365	4,301	538,559	14,581	7,853
2013	260,435	13,840	3,604	287,283	15,337	4,406	547,718	14,625	8,010
2014	262,247	13,944	3,657	294,529	15,308	4,509	556,776	14,666	8,166

1 INCLUDES STREET LIGHTING SALES

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

COMMERCIAL AND INDUSTRIAL CUSTOMERS FORECAST SUMMARY

YEAR	COMMERCIAL FORECAST	INDUSTRIAL FORECAST
1995	64,041	687
1996	65,823	679
1997	67,531	674
1998	69,368	669
1999	71,114	664
2000	72,807	659
2001	74,576	654
2002	76,409	649
2003	78,335	644
2004	80,265	639
2005	82,127	634
2006	84,030	629
2007	85,976	624
2008	87,943	619
2009	89,917	614
2010	92,073	609
2011	94,343	604
2012	96,714	599
2013	99,174	594
2014	101,624	589

SOUTH CAROLINA ELECTRIC & GAS CO: INDUSTRIAL DETAIL FORECAST

INDUSTRIAL SALES-(GWH)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
SALES										
SIC 22	760	764	794	807	807	811	814	822	831	840
SIC 24	160	165	167	168	169	170	170	171	173	174
SIC 26	272	276	284	291	296	301	306	312	317	322
SIC 28	924	930	938	943	947	951	956	961	966	970
SIC 30	168	174	179	183	184	185	188	191	193	195
SIC 32	381	392	406	416	424	430	433	440	449	458
SIC 33	788	814	841	865	880	896	910	929	949	966
GOVERNMENTAL	130	129	129	129	129	129	129	129	129	129
OTHER LARGE	620	649	701	740	760	786	810	846	887	924
WESTVACO	373	373	387	399	408	416	424	434	443	452
S R P	295	295	295	295	295	295	295	295	295	295
OTHER SMALL	349	351	356	358	358	358	358	359	360	361
TOTAL INDUSTRIAL SALES	5221	5314	5477	5597	5656	5729	5793	5888	5993	6086

SOUTH CAROLINA ELECTRIC & GAS CO: INDUSTRIAL DETAIL FORECAST

INDUSTRIAL SALES-(GWH)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
SALES										
SIC 22	847	853	860	867	872	881	888	894	899	904
SIC 24	176	177	178	179	181	182	184	186	187	188
SIC 26	327	333	338	343	348	354	360	366	371	377
SIC 28	974	978	982	986	990	994	999	1004	1008	1013
SIC 30	197	199	201	204	207	210	213	216	219	221
SIC 32	467	475	482	490	493	499	506	514	523	531
SIC 33	981	994	1006	1019	1031	1045	1059	1072	1085	1097
GOVERNMENTAL	129	129	129	129	129	129	129	129	129	129
OTHER LARGE	960	994	1030	1067	1100	1144	1190	1234	1279	1322
WESTVACO	461	470	479	489	498	508	519	529	539	549
S R P	295	295	295	295	295	295	295	295	295	295
OTHER SMALL	362	362	362	362	361	362	362	362	362	362
TOTAL INDUSTRIAL SALES	6177	6260	6344	6430	6506	6604	6706	6801	6896	6988

SOUTH CAROLINA ELECTRIC & GAS CO: TEN YEARS OF FORECAST
ADJUSTED FOR DEMAND SIDE MANAGEMENT

TERRITORIAL LOAD-(GWH)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
RESIDENTIAL	5641	5727	5847	5979	6105	6228	6355	6485	6621	6756
COMMERCIAL	5040	5248	5372	5485	5588	5681	5776	5873	5975	6077
INDUSTRIAL -EX SRP	4926	5019	5182	5301	5361	5434	5498	5593	5697	5791
SAVANNAH RIVER PLANT	295	295	295	295	295	295	295	295	295	295
INDUSTRIAL - TOTAL	5221	5314	5477	5597	5656	5729	5793	5888	5993	6086
STREET LIGHTING	56	58	59	60	62	63	64	65	66	67
OTHER PUBLIC AUTHORITY	467	477	494	510	525	539	553	568	583	599
MUNICIPALS	853	884	906	927	943	959	975	993	1012	1031
COOPERATIVES	200	133	136	139	141	144	146	148	151	153
TOTAL TERRITORIAL SALES	17477	17840	18292	18698	19021	19342	19661	20020	20401	20770
COMPANY USE	88	90	93	96	99	101	105	108	111	114
UNACCOUNTED FOR	874	892	915	935	951	967	983	1001	1020	1038
TOTAL TERRITORIAL LOAD	18439	18822	19300	19729	20071	20410	20749	21129	21532	21922

SOUTH CAROLINA ELECTRIC & GAS CO: TEN YEARS OF FORECAST
ADJUSTED FOR DEMAND SIDE MANAGEMENT

TERRITORIAL LOAD-(GWH)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
RESIDENTIAL	6883	7012	7144	7276	7409	7551	7699	7853	8010	8166
COMMERCIAL	6179	6281	6383	6483	6582	6692	6808	6929	7055	7180
INDUSTRIAL -EX SRP	5881	5964	6048	6135	6210	6309	6410	6506	6600	6693
SAVANNAH RIVER PLANT	295	295	295	295	295	295	295	295	295	295
INDUSTRIAL - TOTAL	6177	6260	6344	6430	6506	6604	6706	6801	6896	6988
STREET LIGHTING	69	70	71	72	73	75	76	77	79	80
OTHER PUBLIC AUTHORITY	614	630	646	662	677	695	714	733	754	774
MUNICIPALS	1049	1066	1084	1102	1119	1139	1160	1181	1202	1223
COOPERATIVES	156	158	161	163	165	168	171	173	176	179
TOTAL TERRITORIAL SALES	21126	21478	21832	22189	22532	22923	23333	23748	24172	24591
COMPANY USE	118	121	125	129	132	136	140	145	149	154
UNACCOUNTED FOR	1056	1074	1092	1109	1127	1146	1167	1187	1209	1230
TOTAL TERRITORIAL LOAD	22300	22673	23049	23427	23791	24205	24640	25080	25530	25975

2.2 PEAK DEMAND FORECAST

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

1. Summer Peak Demand

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

Briefly, the following steps were used to develop the summer peak demand projections. Load factors for selected classes and rates were first calculated and then utilized to convert projected energy consumption among these categories to peak demands. Next, planning peaks were determined for a number of large industrial customers. The demands of these customers were forecasted directly. Summing these class, rate, and individual demands provided a preliminary forecast of summer territorial peak demand. Next, the incremental reductions in demand resulting from the Company's demand-side programs were subtracted from the preliminary forecast. This calculation gave the final estimate of summer territorial peak demand, which was used for planning purposes.

2. Load Factor Development

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

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

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

Rearrangement of the above equation makes it possible to calculate peak demand, given energy and a corresponding load factor. This is the technique used to project peak demand herein. The question then becomes one of determining an appropriate load factor to apply to projected energy sales. The starting point for this determination was the Load Research Department, which developed KW demand by class and/or rate as required.

The demand levels used to create the load factors for the peak demand forecast were not one-hour coincident peaks. Instead, it was determined that use of an adjusted 4-hour average class peak for the period 1991-1993 was more appropriate for forecasting purposes. This was true for two primary reasons. First, analysis of territorial peaks showed that over the past 24 years (1970-1993) all of the peaks had occurred between the hours of 2 and 6 PM. However, the distribution of these peaks between those four hours was fairly evenly spread. It was thus concluded that while the annual peak would occur during the 4-hour band, it would not be possible to say with a high degree of confidence during which hour it would happen.

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

Given that 4-hour average demands were used to construct the 1-hour coincident peak meant that a small positive difference of 48 MW occurred between the actual and developed coincident peaks for the period 1991-1993. This difference was allocated to the residential and commercial classes, since those two categories drive the actual occurrence of the annual peak. It was these demands which were then applied to the average 1991-1993 energies to derive the class/rate load factors used for forecast development.

The effect of system line losses were embedded into the class load factors so they could be applied directly to customer level sales and produce generation level demands. This was a convenient way of incorporating line losses into the peak demand projections. Combining sales-level load factors and line loss multipliers, then, resulted in the generation-level load factors shown in Table 2.2.1.

TABLE 2.2.1

SYSTEM-LEVEL LOAD FACTORS BASED ON CUSTOMER LEVEL ENERGY

CLASS/RATE	*ANNUAL LOAD FACTOR*
Residential:	
Good Cents	0.460
Conservation Rate	0.458
Regular Non-Space Heating	0.369
Regular Space Heating	0.451
Commercial	0.556
Industrial[1]	0.772
Municipalities	0.563
Cooperatives	0.536
OPA	0.669
Miscellaneous	0.852

[1]***Excludes customers that were directly forecasted.***

Inspection of Table 2.2.1 shows that the regular residential class was divided into two categories, space and non-space heating. This was done to allow for the different usage characteristics of regular residential customers between those groups. Good Cents and Conservation Rate customers have similar load factors in all cases. It should also be noted that the industrial sector load factor excluded those major customers whose peaks were determined separately. As a result, load factors were not calculated for those customers, and their usage was removed from the industrial sector when its load factor was calculated.

3. Energy Projections

For those categories whose peak demand was to be projected from KWH sales, the next requirement was a forecast of applicable sales on an annual basis. However, it was not possible to directly use the final energy sales projections described earlier in the chapter, because those values contained DSM program impacts within the appropriate classes. The load factors developed earlier were exclusive of any incremental DSM impacts, and therefore should be applied to sales levels which also exclude incremental DSM programs. A separate sales forecast was thus developed which met this requirement by eliminating the incremental impact of DSM from the energy forecast. These revised projections were then utilized in the peak demand forecast construction. In addition, street light sales were excluded from forecast sales levels when required, since there is no contribution to peak demand from this type of sale.

4. Unadjusted Peak Demands

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The large industrial customers whose peak demands were developed separately were also added to this estimate. The complete unadjusted peak demand forecast is shown as part of Table 2.2.2.

5. Adjusted Peak Demands

Derivation of the planning peak required that the impact of DSM programs be subtracted from the unadjusted peak demand forecast. This is true because the capacity expansion plan is sized to meet expected demand, which includes the reductions attributable to DSM. However, the adjustments to peak demand for DSM were not just a straight reduction to the unadjusted peak demand first created. For example, the residential class forecast already incorporated the demand reductions from the Good Cents and Rate 7 programs, since these were projected separately as part of the energy forecast. Therefore, marketing estimates of demand reductions for these programs were not used to develop adjusted demands.

Calculation of the impact of DSM programs on peak demand was done in the following way. First, cumulative KW reduction estimates were obtained from the Marketing Department. Second, the Good Cents and Conservation Rate impacts were excluded from consideration as discussed above. Third, using 1995 as the base year, the difference was calculated between each year's reduction and the 1995 value. This was to account for the fact that currently existing programs were embedded in the actual KWH values used to project sales. Removing these decrements to sales once more would have overstated the impact of the DSM programs, so only the incremental DSM impacts from 1995 were used to determine the adjusted peak demands from existing programs.

Fourth, once the proper KW savings, full or incremental, were determined, they were increased to represent system-level savings. Marketing estimates are for sales-level units, and a one KW deferral at the customer level represents a greater than one KW deferral at generation level. System line losses were used to increase the KW impact of each marketing program, based on the customer group impacted. A further reduction to demand was made for SEPA passthrough to municipal and cooperative customers. This power is wheeled through the SCE&G system and is scheduled for delivery to the above customers during peak periods. It, therefore, does not represent a generation requirement for planning purposes and should be removed from the calculation. Finally, the sum of these adjustments was determined, and this accumulated value was used to reduce the unadjusted peak

TABLE 2.2.2
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
TERRITORIAL SUMMER PEAK DEMAND DEVELOPMENT BY CLASS
(MW)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
RESIDENTIAL										
GOOD CENTS	67	79	91	104	117	130	142	154	167	180
CONSERVATION RATE	80	87	93	100	107	114	121	127	134	141
REGULAR	1,411	1,413	1,424	1,438	1,449	1,460	1,473	1,488	1,504	1,517
RESIDENTIAL TOTAL	1,558	1,579	1,608	1,642	1,673	1,704	1,736	1,769	1,805	1,838
COMMERCIAL TOTAL	1,029	1,073	1,099	1,122	1,144	1,163	1,184	1,204	1,225	1,247
REGULAR INDUSTRIALS	562	574	592	605	611	619	626	636	648	658
INTERRUPTIBLE CUSTOMERS	170	171	172	173	175	176	177	178	180	181
TOTAL INDUSTRIAL	732	745	764	778	786	795	803	814	828	839
MUNICIPALITIES	173	179	184	188	191	194	198	201	205	209
COOPERATIVES	43	28	29	30	30	31	31	32	32	33
MISCELLANEOUS	92	93	96	100	103	106	108	111	115	117
UNADJUSTED DEMAND	3,627	3,697	3,780	3,860	3,927	3,993	4,060	4,131	4,210	4,283
LESS:										
INCREMENTAL DSM PROGRAMS	3	10	18	26	35	43	52	61	71	81
STAND-BY GENERATORS	23	27	31	35	39	43	47	52	56	60
INTERRUPTIBLE LOAD	52	53	54	55	57	58	59	60	62	63
SEPA PASSTHROUGH	16	21	21	21	21	21	21	21	21	21
TOTAL DEMAND REDUCTIONS	94	111	124	137	152	165	179	194	210	225
ADJUSTED DEMAND	3,533	3,586	3,656	3,723	3,775	3,828	3,881	3,937	4,000	4,058

TABLE 2.2.2
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
TERRITORIAL SUMMER PEAK DEMAND DEVELOPMENT BY CLASS
(MW)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
RESIDENTIAL										
GOOD CENTS	193	206	218	231	244	256	269	283	296	309
CONSERVATION RATE	148	155	162	169	175	182	190	197	205	212
REGULAR	1,529	1,543	1,557	1,571	1,586	1,602	1,621	1,640	1,659	1,679
RESIDENTIAL TOTAL	1,870	1,904	1,937	1,971	2,005	2,040	2,080	2,120	2,160	2,200
COMMERCIAL TOTAL	1,268	1,290	1,311	1,332	1,353	1,376	1,400	1,425	1,451	1,477
REGULAR INDUSTRIALS	668	678	687	697	705	717	728	739	750	761
INTERRUPTIBLE CUSTOMERS	183	184	185	187	188	189	192	193	195	196
TOTAL INDUSTRIAL	851	862	872	884	893	906	920	932	945	957
MUNICIPALITIES	213	216	220	223	227	231	235	239	244	248
COOPERATIVES	33	34	34	35	35	36	36	37	38	38
MISCELLANEOUS	121	124	127	130	134	137	141	144	149	153
UNADJUSTED DEMAND	4,356	4,430	4,501	4,575	4,647	4,726	4,812	4,897	4,987	5,073
LESS:										
INCREMENTAL DSM PROGRAMS	91	102	113	124	135	147	160	172	185	199
STAND-BY GENERATORS	65	70	75	80	85	90	95	100	106	111
INTERRUPTIBLE LOAD	65	66	67	69	70	71	74	75	77	78
SEPA PASSTHROUGH	21	21	21	21	21	21	21	21	21	21
TOTAL DEMAND REDUCTIONS	242	259	276	294	311	329	350	368	389	409
ADJUSTED DEMAND	4,114	4,171	4,225	4,281	4,336	4,397	4,462	4,529	4,598	4,664

demand to its final adjusted peak demand. These estimates are also shown in Table 2.2.2, and are the values used to represent the planning peak.

6. Development of the "No DSM" Scenario

In order to calculate the net benefits of the Company's DSM programs, it was necessary to project peak demand and energy under a "No DSM" scenario. The No DSM scenario assumed that all of the Company's DSM programs were discontinued in 1995. Of course, the existing impact of some programs, such as the Great Appliance Trade-Up, would continue at current levels into the future, but these levels would not increase. Table 2.2.3(a) shows the results of these calculations for the peak demand and Table 2.2.3(b) shows the results for energy. By 2014, the peak demand forecast would be 529 MW, or 11% higher than currently projected without the Company's DSM programs and the energy forecast, 450 GWH or 1.7% higher.

TABLE 2.2.3(a)
COMPARISON OF SUMMER PEAK DEMAND WITH AND WITHOUT DSM IMPACTS (MW)

YEAR	PEAK BEFORE DSM	DSM IMPACTS	PEAK AFTER DSM
1995	3,611	78	3,533
1996	3,682	96	3,586
1997	3,680	115	3,565
1998	3,858	135	3,723
1999	3,931	156	3,775
2000	4,004	176	3,828
2001	4,078	197	3,881
2002	4,156	219	3,937
2003	4,242	242	4,000
2004	4,322	264	4,058
2005	4,402	288	4,114
5006	4,484	313	4,171
2007	4,563	338	4,225
2008	4,644	363	4,281
2009	4,724	388	4,336
2010	4,811	414	4,397
2011	4,906	444	4,462
2012	4,989	460	4,529
2013	5,098	500	4,598
2014	5,193	529	4,664

TABLE 2.2.3(b)
COMPARISON OF ANNUAL ENERGY WITH AND WITHOUT DSM IMPACTS (GWH)

YEAR	ENERGY BEFORE DSM	DSM IMPACTS	ENERGY AFTER DSM
1995	18,434	-5	18,439
1996	18,836	14	18,822
1997	19,333	33	19,300
1998	19,781	52	19,729
1999	20,143	72	20,071
2000	20,503	93	20,410
2001	20,864	115	20,749
2002	21,265	136	21,129
2003	21,691	159	21,532
2004	22,105	183	21,922
2005	22,506	206	22,300
5006	22,903	230	22,673
2007	23,306	257	23,049
2008	23,709	282	23,427
2009	24,098	307	23,791
2010	24,541	336	24,205
2011	25,003	363	24,640
2012	25,472	392	25,080
2013	25,951	421	25,530
2014	26,425	450	25,975

7. Winter Peak Demand

Although SCE&G historically has been a summer-peaking utility, estimation of its future winter peak demands is also required for various planning functions. To project winter peaks a regression model was developed based on the 28-year period 1965-1992. Actual winter peak demands were related to three primary explanatory variables. These were real gross domestic product, weather during the day of the winter peak's occurrence, and residential space-heating customers.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in real gross domestic product reflects economic growth and activity in SCE&G's service area, and as such may be used as a proxy variable for those economic factors which cause winter peak demand to change. It should be noted that the winter peak for any given year occurs by definition after the summer peak for that year. The winter period for each year is December of that year, along with January and February of the following year. For example, the winter peak in 1968 of 962 MW occurred on December 11, 1968, while the winter peak for 1969 of 1,126 MW took place on January 8, 1970. In addition to economic factors, weather also causes winter peak demand to fluctuate, so the impact of this variable was measured by the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston. The presence of a weather variable reduces the bias which would exist in the other explanatory variables' coefficients if weather were excluded from the regression model, given that the weather variable should be included. When the actual forecast of winter peak demand was calculated, the median value of heating degree days over the sample period was used, so no growth in the winter peak is attributable to future changes in weather. Finally, although the ratio of winter to summer peak demands fluctuated over the sample period, it did show an increase over time. A primary cause for this increasing ratio was growth in the number of electric space heating customers. Due to the introduction and rapid acceptance of heat pumps over the past three decades, space-heating residential customers increased from less than 5,000 in 1965 to over 169,000 in 1993, a 13.4% annual growth rate. Inclusion of this variable thus provided further explanatory power in the regression analysis.

A number of exploratory regression models were tested before the final version containing the above variables was selected. A dummy variable was added for the years 1984 and 1985, which experienced severe winter weather. Dummy variables were also added to the intercept and real gross domestic product for the year 1984 and after. The results of the regression analysis are shown following in Equation 2.2.1.

EQUATION 2.2.1

$$WPEAK = -1289.686 + 0.700 * RGDP + 228.370 * D8485 + 9.346 * HDD$$
$$(-3.40) \quad (5.01) \quad (2.37) \quad (4.45)$$
$$+ 0.006 * CUSTSH + 1870.147 * INTDUM - 0.496 * RGDPDUM$$
$$(3.05) \quad (2.93) \quad (-3.62)$$

Estimation Period: 1965-1992	*Where:*	*WPEAK= Winter Peak*
F-statistic: 507.950		*RGDP=Real Gross Domestic Product*
R^2: 0.992		*D8485=1 for years 1984 and 1985, 0 otherwise*
Root MSE: 63.73		*HDD=Average of Heating Degree Days for winter peak day, Columbia and Charleston*
Dependent Mean: 1973.78		*CUSTSH=Residential Space-Heating Customers*
DW: 1.98		*INTDUM=1 for 1983 and after, 0 otherwise*
		*RGDPDUM=RGDP * INTDUM*

The adjusted R^2 and F-statistic indicated that winter peak was strongly related to the combination of explanatory variables chosen, and the t-statistics for the individual variables also confirmed their inclusion in the regression equation.

Forecasting the winter peak demand utilizing the above equation required projections of real gross domestic product, heating degree days, and residential space-heating customers. Real gross domestic product was obtained from the DRI forecasting service, while heating degree days were based on the median for the estimation period 1965-1991, which was 31 HDD. Finally, projections of residential space-heating customers developed as part of the energy sales forecast were used as the that variable's forecast input.

Just as DSM programs reduce summer peak demand, a similar process occurs for winter peaks, and downward adjustments were made to the values derived from the forecast equation results. However, DSM savings applicable only to summer peak demand were not included in these reductions, such as commercial ice storage. The final result of this process is shown in Table 2.2.4. Winter peak demand is expected to grow from 2,916 MW in 1994-1995 to 3,846 MW in 2012-2013, a compound annual growth rate of 1.6%.

TABLE 2.2.4

WINTER TERRITORIAL PEAK DEMANDS (MW)

YEAR	WINTER PEAK
1994-1995	2,916
1995-1996	2,950
1996-1997	3,001
1997-1998	3,058
1998-1999	3,109
1999-2000	3,159
2000-2001	3,211
2001-2002	3,266
2002-2003	3,318
2003-2004	3,371
2004-2005	3,427
2005-2006	3,480
2006-2007	3,531
2007-2008	3,586
2008-2009	3,640
2009-2010	3,689
2010-2011	3,738
2011-2012	3,791
2012-2013	3,846

8. Monthly Peak Demand

The creation of monthly peak demands was based on the relationship of historic monthly peaks for the period 1986-1993. This provided eight observations for each month, yet was current enough to avoid using irrelevant historic data. First, the data was broken down into two seasons: winter and summer, with summer defined as the months of May through October, and winter defined as all other months. A ratio was then calculated for each month within these groupings, with the monthly peaks in each year divided by its resepctive seasonal peak. Thus, one month in each witner and summer category for each year had a ratio of 1.00, corresponding to the month in which the seasonal peak occurred.

The ratios were next assembled into ranked categories by season, with a total of six groupings (one for each month) within each season. The highest ranked category had eight observations with a value of 1, while the second ranked category also had eight observations, but with different ratio values. To eliminate any distortion from extreme values, the high and low observations within each category were deleted. The impact of this process was to eliminate any "outliers" which might have occurred in the historic sample period, and resulted in six observations for each ranked category. A mean category ratio was then calculated using these six observations for each category. At this stage of the analysis, then, there were two sets of ratios: one for summer and one for winter, with these ratios ranked by size into categories.

For the second stage of the process, the original monthly ratios were grouped by month and season. For example, there were 8 monthly ratios for August and each of the other summer months. The high and the low observations for each month were then dropped for the reasons described earlier, and monthly average ratios were then calculated. The months were then categorized by the magnitude of their average ratio, so July, for example, was assigned a category value of 1, since its average ratio was higher than the other summer months. It should be noted, however, that the monthly July ratio was not 1.0, since the seasonal peak did not always occur in that month.

The categories of ratios determined in the first stage of the process, i.e., grouped ratios irrespective of months, were then merged with the monthly ratio categories for each season. Again, consider July; since it had the highest monthly ratio, it was matched with the highest ratio category, which had a value of 1.0. At this point, it was possible to compare the monthly ratios with those ratios created by the ranking process only. In general, there was an extremely close match between ratios calculated in each fashion. For example, the ratio for the third highest ranked summer category estimated independent of month was 0.94, while the ratio for the third highest ranking month ratio (June) was also 0.94. This close match stems from the stable relationship between monthly and annual peaks, and provides a measure of reassurance that such a relationship will continue into the future.

In the final step, the ranked categories, irrespective of month, were assigned to their corresponding months to develop projected monthly peaks and are shown in Table 2.2.5.

TABLE 2.2.5

RATIOS APPLIED TO SEASONAL PEAKS TO CREATE MONTHLY PEAKS

SUMMER		***WINTER***	
July	*1.00*	*January*	*1.00*
August	*0.98*	*December*	*0.97*
June	*0.94*	*February*	*0.91*
September	*0.91*	*March*	*0.83*
May	*0.83*	*November*	*0.82*
October	*0.70*	*April*	*0.74*

These ratios were then multiplied by their respective seasonal peaks, unadjusted for DSM, to create interim monthly peaks. Next, DSM program savings multiplied by the monthly ratios were subtracted from the unadjusted monthly peaks. Finally, reductions for interruptible load and stand-by generation were made using the full value of these DSM measures. This was done because contracts for these programs allow for their full use in any month. The final monthly planning peaks are shown in Table 2.2.6.

9. Scenario Analysis

The Company develops forecast scenarios through the use of elasticities. As discussed earlier in the chapter, an elasticity relates the percent change in an independent variable to that of the dependent variable. The income elasticity associated with territorial sales was 0.6, i.e., each one percent drop in real personal income results in a 0.6 percent change in territorial sales for the Company.

Assuming a stable territorial load factor between scenarios, the income elasticity for energy can be used to derive an approximte income effect on summer peak demand. Table 2.2.7 below shows the result for 2014 under pessimistic and optimistic scenario outcomes for real income. Recall that DRI associates a 50% probability of occurrence with its baseline projections, and 25% probabilities for the pessimistic and optimistic scenarios.

TABLE 2.2.7

PEAK DEMAND FORECAST SCENARIO FOR 2014

(MW)

	BASE CASE	PESSIMISTIC	OPTIMISTIC
SCE&G Real Personal Income	29.113	26.056	32.140
% Change to Base		-10.5	10.4
Elasticity		0.60	0.60
% Change in Sales		-6.30	6..24
Territorial Summer Peak Demand	4,664	4,374	4,955
Annual % Change (1997-2014)	1.4	1.1	1.8

TABLE 2.2.6

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

PROJECTED MONTHLY TERRITORIAL MONTHLY PEAK DEMANDS

(MW)

YEAR	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
1995	2,916	2,639	2,537	2,133	2,915	3,311	3,533	3,446	3,198	2,425	2,407	2,876
1996	2,950	2,669	2,565	2,156	2,958	3,360	3,586	3,498	3,245	2,459	2,443	2,920
1997	3,001	2,715	2,609	2,192	3,015	3,425	3,656	3,566	3,308	2,506	2,489	2,976
1998	3,058	2,766	2,658	2,233	3,070	3,488	3,723	3,631	3,369	2,551	2,530	3,026
1999	3,109	2,812	2,702	2,269	3,112	3,536	3,775	3,682	3,415	2,585	2,570	3,074
2000	3,159	2,857	2,745	2,305	3,155	3,586	3,828	3,733	3,463	2,620	2,611	3,124
2001	3,211	2,904	2,790	2,342	3,198	3,635	3,881	3,785	3,511	2,656	2,656	3,178
2002	3,266	2,953	2,837	2,381	3,243	3,687	3,937	3,839	3,561	2,693	2,698	3,229
2003	3,318	3,000	2,882	2,418	3,295	3,746	4,000	3,901	3,617	2,735	2,739	3,280
2004	3,371	3,047	2,927	2,456	3,342	3,800	4,058	3,957	3,670	2,773	2,785	3,335
2005	3,427	3,098	2,976	2,496	3,387	3,852	4,114	4,012	3,720	2,810	2,827	3,385
2006	3,480	3,145	3,021	2,533	3,433	3,905	4,171	4,067	3,771	2,848	2,867	3,435
2007	3,531	3,191	3,065	2,569	3,477	3,956	4,225	4,120	3,819	2,884	2,912	3,489
2008	3,586	3,240	3,112	2,608	3,523	4,008	4,281	4,174	3,870	2,920	2,954	3,541
2009	3,640	3,289	3,159	2,647	3,567	4,059	4,336	4,228	3,919	2,957	2,993	3,588
2010	3,689	3,333	3,201	2,681	3,617	4,116	4,397	4,287	3,974	2,997	3,034	3,638
2011	3,738	3,377	3,242	2,715	3,669	4,177	4,462	4,350	4,032	3,040	3,075	3,687
2012	3,791	3,424	3,288	2,753	3,724	4,239	4,529	4,416	4,092	3,085	3,119	3,742
2013	3,846	3,473	3,335	2,792	3,780	4,303	4,598	4,483	4,154	3,130	3,164	3,796

SCE&G is not promoting any direct load control programs, although a few residential customers still have timers on their water heaters under the discontinued Off-Peak Water Heating Program.

Evaluation Process

Evaluation Changes Since 1992

In the last three years, SCE&G has made significant refinements in the steps it takes to evaluate programs. In addition, there have been changes within the industry itself which have a significant effect on the analyses. Most notable is the drop in the cost of generating capacity.

Falling Cost Of Capacity

Avoided capacity costs have fallen almost 60% in the last three years. Advances in technology and increased competition have caused price cutting by the suppliers of generating equipment. Meanwhile, the availability of power off-system means that SCE&G can reduce its own on-system reserve margins, further lowering the value of avoided capacity. Finally, the only deferrable generation in the near-term for SCE&G comes from gas turbines and combined cycle units, both of which are relatively low-cost capacity.

Improved Methodology

SCE&G has dramatically revamped its ability to analyze marketing programs. First, the Company decided to factor in the effects of free riders and free drivers whenever it could reasonably estimate them. Free riders are participants in a program who would have adopted the technology or service even without the program. Free drivers are people who adopt the technology or service but do not participate in the program.

The Company has also installed new software tools to develop required end-use data and analyze the programs. This has allowed analysts to take better advantage of more detailed data and information gained from experience with the programs.

Free Riders

Free riders affect the net energy and load impacts at generation level. They do not affect program costs.[3] Free riders can sometimes be more important than any other factor. With new technologies in particular, free ridership may be inconsequential early in the product life, but may be very significant later on. For instance, suppose a utility established a program four years ago offering rebates to promote electric widgets. Further, suppose that the utility is still providing rebates a few years later, despite the fact that nearly every household in the country is purchasing a widget regardless of whether or not rebates are offered in their area. In that extreme case, nearly every participant is a free rider, and the ratepayer's money is being wasted.

There are several methods of estimating free ridership. First, the utility may choose to survey customers to determine predisposition, using the resulting likelihood of adoption as a proxy for free ridership percentage. Second, the utility may seek expert opinions. Third, the utility may survey participants in existing programs. Fourth, the utility may use two demographic

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[3] End-Use Technical Assessment Guide (End-Use TAG) by Barakat & Chamberlin, Inc., Electric Power Research Institute, EPRI CU-7222s Vol. 4, pp. 1-4 to 1-9.

and appliance saturation surveys taken at different times to estimate changes in penetration of a technology or service.


Customer gets free energy usage analysis at SCE&G's Innovation Station

In the absence of much historical data about free ridership, SCE&G has made estimates using appliance surveys and the opinions of customer representatives and other experts. Free ridership levels may be one of the first indications that a program has outlived its usefulness and requires modification or elimination.

New Software Tools

The Company has invested resources and personnel for the task of implementing new software tools to study and track demand-side management programs. In the past year, SCE&G has joined a long list of utilities using an EPRI software tool called DSManager to perform the TAG tests evaluating demand-side management alternatives. Residential load simulations are performed using a model called ESPRE. Commercial and industrial simulations are produced with COMTECH, which uses load shapes from Micro-AXCESS. In addition, the Company uses in-house analyses to judge the accuracy of the off-the-shelf models and to provide supplemental detail.

More Detailed Data

The new software tools are allowing the Company to use more detailed data. For instance, system load shapes and marginal costs are now evaluated in the DSM models on an hour-by-hour basis for the entire forecast period. In the past, the data would have first been summarized by season and on-peak or off-peak periods.

The Company is participating in a collaborative effort sponsored by EPRI's Center For Electric End-Use Data (CEED) to develop loadshapes specific to the Southeastern United States. SCE&G has also purchased state-of-the-art demographic data bases to help it better understand customer needs. Customer requirement and customer satisfaction surveys are providing additional insights and understanding.

Knowledge Gained From Experience

For several years, SCE&G has kept careful records of participation in programs. This historical data is providing insight into the effectiveness and costs of demand-side management options. Management uses this information when allocating resources. In addition, evaluation of on-going programs is based on actual cost data.

Focus On Competition — RIM Test Becomes A Necessary Criterion

Perhaps the most significant impact on the evaluation process has been the emergence of competition in the utility industry. In that environment, it is imperative that we make sure that demand-side management programs do not result in cross-subsidies or higher rates. "[E]ven if cost recovery and lost revenue issues are addressed, DSM-related rate increases may create other problems in competitive markets, possibly driving away incremental customers or sales, with consequent loss of contributions to fixed costs and profits."[4]

On the other hand, any DSM program that applies downward pressure on rates becomes increasingly valuable. The Ratepayer Impact Measure (RIM) Test is the best method currently available to judge this effect on rates. All of the TAG tests the Company performs are useful, but passing the RIM test has now become a necessary criterion for the DSM portfolio if not for every single program.

Portfolio Of Programs

As stated earlier, SCE&G has continued some programs that fail the RIM test, although not without making changes to minimize the effect on ratepayers. Ideally, the overall portfolio applies downward pressure on rates while promoting conservation, peak-clipping, and other demand-side management objectives. The effectiveness of the portfolio can be analyzed by summing the end-use margins produced by each program. As shown in the tables near the end of this chapter, the portfolio we are proposing does not apply downward pressure on rates. However, it does make significant improvements over our existing portfolio. Moving the portfolio to the point where it has a positive impact on all ratepayers would mean dramatic cuts in (or elimination of) conservation programs such as Home Energy Check, the Good Cents/Conservation Rate, and our educational programs for high efficiency chillers and

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[4] Demand-Side Management Incentive Regulation by Michael Reid at Barakat & Chamberlin, Inc., Edison Electric Institute, 1991.

commercial HVAC. We do not feel it is prudent to take such dramatic measures now because of the potential impact on our customer base. Over time, however, we plan to evolve the portfolio to a positive end-use margin, thus applying downward pressure on rates.

Four Tests

There are many tests used to evaluate the effectiveness of demand-side management programs. The four employed at SCE&G are known as TAG tests, referring to their endorsement in EPRI's end-use Technical Assessment Guide. Figure 3.1 shows the general cost and benefit components. Each of the four tests is summarized with a benefit/cost ratio. A ratio greater than 1.0 is positive — benefits exceed costs. If the ratio is less than one, then costs exceed benefits. Each of the four tests are described below.

Figure 3.1

Test	Benefits	Costs
Ratepayer Impact Measure (RIM) Test	Avoided Supply Costs Revenue Increases Participation Charges	Increase Supply Costs Revenue Decreases Incentive Payments Utility Costs (e.g. Program Costs)
Participant Test	Bill Reductions Avoided Participant Costs Incentive Payments Tax Credits	Bill Increases Participant Costs Participation Charges
Total Resource Cost (TRC) Test	Avoided Supply Costs Avoided Participant Costs (Net Of Free Riders) Tax Credits	Increased Supply Costs Participant Costs (Net Of Free Riders) Utility Costs
Utility Cost Test	Avoided Supply Costs Participation Charges	Increased Supply Costs Incentives Utility Costs

The TAG test benefit and cost components presented for each program in this chapter are stated in terms of the net present value over a minimum of 15 years.

Participant Test

The Participant Test looks at the decision to adopt the technology or service from the participating customer's *quantifiable* perspective. It is designed to provide an indication of whether or not a program is economically attractive to a customer. It is not useful to decide whether or not a program is "good" for a customer, since "good" is a value judgment based on attributes that may or may not be quantifiable.

For instance, suppose the utility company is providing a rebate to encourage a customer to buy fuel-efficient widget B, which saves enormous amounts of energy over the old style widget A. Assuming his initial cost (minus the rebates) is not very high, the customer will probably enjoy a quantifiable benefit (lower electric bills) from the use of widget B.

Now, in contrast, assume the utility company gives a residential customer a rebate for purchasing an electric Gizmo which is only useful in recreational activities on the weekend. The utility's ratepayers benefit because the off-peak sales lower the overall average rate (Valley-filling). The customer benefits because this Gizmo has revitalized his personal life and is worth much more than what he pays for the electricity it consumes. Despite this win-win situation, the Gizmo would fail the Participant Test because there is no way to quantify the benefits the participant receives from plugging the gadget into the outlet.

SCE&G relies on the Participant Test to give an indication of monetary attraction, but recognizes that it can not capture the full value to the customer of all alternatives.

Utility Cost Test

The Utility Cost Test looks at the change in a utility's total costs arising from implementation of a DSM program. These costs include incurred or avoided supply costs, incentives, administrative and advertising costs, and other utility costs. Since it measures the change in revenue requirements, the test is sometimes referred to as the Utility Revenue Requirements test. Since the major component of the test is usually the change in supply costs, it is frequently used to evaluate supply-side options.

SCE&G routinely performs the test and considers it to be useful for gaining insight into the change in costs, but also recognizes that it does not include any revenue effects and therefore provides an incomplete picture.

Ratepayer Impact Measure (RIM) Test

The Ratepayer Impact Measure test compares the change in total benefits (including revenues paid to a utility) and the change in total costs to a utility resulting from a DSM program. If the benefit change is larger than the cost change, then rates may go down. If the benefit change is smaller than the cost change, then rates may go up. A RIM test benefit/cost ratio that is greater than one is said to apply downward pressure on rates. A ratio less than one applies upward pressure.

Benefits include any additional revenues and avoided supply costs. Costs include any lost revenues, increased supply costs, capital and expensed program costs, and incentives.

In this era of increasing competition in the electric utility market, prudent business management requires companies to keep rates as low as possible. Passing the RIM test is an important criterion for demand-side management.

Total Resource Cost (TRC) Test

The Total Resource Cost test measures a DSM program's net expenditures incurred by the utility and its ratepayers. The factors include supply costs, utility costs, and participant costs. Transfers of payments between the utility and its ratepayers (e.g. incentives and revenue) are ignored. Ignoring free riders and any differences in discount rate, the TRC test is otherwise a sum of the Ratepayer Impact Measure test and Participant test factors. Components that appear in both tests (e.g. utility revenue and participant electric bill) cancel out.

While the TRC test provides an important perspective, there are two caveats that must be considered when interpreting the results. First, since utility revenue changes are ignored, it provides an incomplete picture of the program's effects in a competitive environment. Second, since it basically sums the RIM and Participant tests, the TRC test suffers from the


Customer gains "hands-on" knowledge of energy efficient water heaters at SCE&G's Innovation Station

Participant Test's inability to quantify some of the participant's benefits. (Please refer to the "Participant Test" section.)

Software

SCE&G has made increasing use of sophisticated software packages to evaluate programs and develop needed input data. In particular, the Company calculated the load impacts of the programs with engineering simulations. Both engineering calculations and end-use metering estimate electricity usage by calculating or monitoring the physical electrical loads. Properly constructed engineering models are cheaper to run and allow more immediate experimentation with the effect of changes.

> Electricity consumption and demand derives from the loads of the electric equipment. Engineering calculations go to the source—the equipment—to measure changes in usage patterns. They ensure, for example, that the per-unit change in load ascribed to a residential air conditioner direct load control program is less than the connected load of the air conditioners on the program. Engineering calculations also ensure, for example, that load reduction is not ascribed to a direct load control program that cycles air conditioners off for 15 minutes each hour when the natural duty cycle of the equipment is 50% (that is, air conditioners are off 30 minutes of each hour even in the absence of control). Engineering calculations might also be used to ensure that the savings attributed to each component of a comprehensive building shell retrofit program (e.g. roof insulation, wall insulation, basement insulation, window treatments, and air sealing) add up to something less than total heating load. These examples may appear to be extreme, but statistical methods used without consideration of the underlying physical and engineering relations have been known to lead to such implausible results.[5]

[5] DSM Evaluation—Six Steps For Assessing Programs by M. McRae, P. Herman, J. Peters, and A. Goett at Barakatt & Chamberlin, Inc., Electric Power Research Institute, 1992.

SCE&G believes that engineering models calibrated with real world experience provide a good, economical method of estimating end-use load changes. Packages employed to evaluate programs in this Integrated Resource Plan are ESPRE and COMTECH, which uses information produced by Micro-AXCESS.

ESPRE

The EPRI Simplified Program for Residential Energy (ESPRE) software performs engineering simulations of residential energy use on an hour-by-hour basis for up to one year. Originally released in 1989, the program has been extended significantly in version 2.1. Inputs include a description of the building's thermal envelope, building location and orientation, weather, operating profiles, occupancy, and HVAC equipment information. Outputs include btuh and kWh load profiles for the HVAC and water heating systems.

SCE&G compared simulations produced by ESPRE to load research data for several specific homes. For each calibration scenario, the model performed well. Since then, the Company has used it to calculate the kW and kWh impacts of several programs. Obtaining information from engineering models such as ESPRE is far more economical than many load research alternatives for calculating the load impacts.

Micro-AXCESS

The Edison Electric Institute developed the AXCESS computer program in 1971 to simulate hourly energy use in commercial buildings. Originally a mainframe program, it was eventually ported to personal computers and renamed Micro-AXCESS. The Electric Power Research Institute (EPRI) became involved in its continuing development in 1988.

The package performs a detailed hour-by-hour simulation of building energy use for up to one year. Inputs include building construction materials, building location and orientation, weather, operating profiles, occupancy, and HVAC equipment performance characteristics. Outputs include energy consumptions and demands for all major categories of building energy use (e.g. lighting and space conditioning).

COMTECH

EPRI COMTECH is a flexible software tool that allows analysts to scale building loads produced by Micro-AXCESS and apply a number of technology schemes to satisfy the thermal and lighting requirements. Output from this program can be imported into DSManager directly.

DSManager

EPRI DSManager is a software tool to forecast demand-side management impacts. The package is currently in use at over 100 utilities, research laboratories, and commissions across the United States and Canada. Use of a package such as DSManager has a number of advantages. Most importantly, it promotes consistency. Additionally, it provides the opportunity to study the data in more detail.

DSManager expects numerous inputs including forecasted hourly system demand and marginal costs, capacity costs, loss factors, rates, and end-use load curves. The output it produces includes a forecast of each revenue and cost stream along with a summation of its present value. DSManager performs all of the TAG tests, and also allows for additional sensitivity analysis.

In-house Validation

SCE&G has been careful to validate the models it uses as much as possible. The Company validated ESPRE's reasonableness using load research data. The results also agree with less detailed engineering simulations run previously. For evaluating the reasonableness of its commercial models, SCE&G relied upon in-house expertise and also talked with engineering consultants who have real world experience choosing and installing the equipment. The Company has performed analyses to augment DSManager's calculations and verify DSManager's results.

In summary, the models currently in use at SCE&G are reliable and useful.

Process Methodology

South Carolina Electric & Gas Company has established a formal methodology for developing or revising programs. The guidelines identify three phases in establishing a program: planning, development, and commercialization. Depending upon their natures, some projects may not follow every step of every phase, but overall structure remains clearly defined. The method is intended to be flexible while still providing a framework that assures overall consistency in approach.

The first planning task is exploration, collecting ideas from vendors, customers, employees, and other sources who know the market. Typically, this survey will stimulate additional inquiries and thought processes. After exploration comes screening. Each of the ideas must be analyzed for merit. If a concept makes strategic sense, it may be subjected to a full business analysis. Depending on the results, the idea may be modified and resubmitted to the screening step.

Once an idea emerges from the planning phase, management must decide whether or not to enter the development phase. This involves pilot tests, marketing and communications development, and market testing.

If the idea completes the development stage as a viable program, it enters the commercialization phase. This final phase includes two primary missions: full scale implementation and continuing evaluation of results.

Programs

Comparison To The 1992 IRP

SCE&G has made several changes to its demand-side management portfolio, and proposes even more in this Integrated Resource Plan. By streamlining and concentrating on the most effective programs, the Company will be able to achieve the DSM objectives more quickly with less impact on rates. For instance, money spent on commercial thermal storage makes a much larger difference than if it were spent on fluorescent ballasts. The following section provides a breakdown of the changes.

Closed, Grandfathered, or Discontinued

SCE&G has discontinued the following programs:

Residential Compact Fluorescent Lights (Still Promoted At Innovation Station)
Residential Off-Peak Water Heating
Commercial/Industrial Fluorescent Ballast
Commercial/Industrial High Efficiency Lighting

The Company proposes to close:

Residential Rate 1, Good Cents Rate (Existing Customers Will Be Grandfathered)
Residential Rate 7, REC (Existing Customers Will Be Grandfathered)
Residential Great Appliance Trade-Up (Renamed High Efficiency Heat Pump)
Residential Thermal Storage
Residential Heat Pump Pool Heaters
Commercial/Industrial Gas Air Conditioning
Commercial/Industrial High Efficiency Motors
Commercial/Industrial Adjustable Speed Drives

Changed

The Company proposes to modify:

Residential Home Energy Check
Commercial Heat Pump Water Heater (& Pool Heater)
Commercial HVAC
Commercial High Efficiency Chillers
Commercial Thermal Storage

Unchanged

SCE&G will continue the following programs without substantial change:

Residential Rate 2, Low Use
Residential Rate 5, Time-Of-Use (TOU)
Commercial/Industrial Standby Generator
Commercial/Industrial Rates 11, 16, 21, 24, Time-Of-Use (TOU)
Commercial/Industrial Rider To Rates 23 & 24, Interruptible

Created

The Company proposes to create the following programs, and will soon file with the PSC for approval.

Good Cents/Conservation Program
Residential Replacement Water Heater Program
Residential High Efficiency Heat Pump Program

Residential

Plan To Close: Rate 1 (Good Cents)

When the previous Good Cents (Rate 1) program was first introduced, it represented a significant improvement over state building code standards. Therefore, the program resulted in significant kW and kWh reductions. These reductions were valuable, not only because of their magnitude but also because avoided marginal capacity and energy costs were relatively high at the time.

TABLE 3.1

Rate 1 (Previous Good Cents) Results Per Participant	Net Present Value
Avoided Generation Capacity Costs	$402.22
Avoided Transmission Capacity Costs	29.42
Avoided Distribution Capacity Costs	42.10
Avoided Production Costs (Fuel + Var. O&M)	427.60
Total Benefits	$901.34
Administrative & Program Costs	$-339.37
Change In Revenues From Reduced kWh	$-1,764.40
Change In Revenues From Rate 8, Rate 1 Diff.	$-1,586.11
Total Costs	$-3,689.88
Net Loss	$-2,788.54
RIM Benefit/Cost Ratio	0.24
Participant Benefit/Cost Ratio	2.66
Utility Test Benefit Cost Ratio	2.66
Total Resource Cost Test	0.51

Now conditions have changed. Thanks largely to the success of Good Cents and other measures that raised social awareness of conservation, a home built to state code often qualifies for Good Cents with little or no alterations. We are proud of what Good Cents has accomplished. The direct and indirect benefits will continue to accrue for decades to come.

However, due to the small difference between home construction guidelines, the kW and kWh reductions are much smaller than they used to be. Rate 1 homes built today do not defer as much capacity or energy. The calculated decreases are 0.72 kW and 2,231 annual kWh per home at the system level. Compounding the effect, the value of deferred capacity has declined.


Customer explores insulation options at SCE&G's Innovation Station

All of these changes imply that the program, which was extremely valuable when it was introduced, is no longer in the best interest of ratepayers. As Table 3.1 shows, the administrative and program costs are $339.37 per participant. The net present value of the loss of revenues over 20 years due to the reduction in kWh sales is $1,764.40, and the additional loss of revenues due to the lower price on Rate 1 is $1,586.11. Unfortunately, the benefits no longer justify the costs and cross-subsidies. Ratepayers would be worse off if we continued this program.

Not only does the program fail the RIM test, but it also fails the TRC test. SCE&G recommends closing this program. Existing customers on Rate 1 will be grandfathered.

Plan To Close: Rate 7 (REC)

As with Rate 1, conditions have changed significantly since Rate 7 (REC) was first introduced. At that time, it represented a dramatic improvement over state building code. This fact, combined with a higher value for avoided marginal capacity and energy, made the program worthwhile. The existence of Rates 1 and 7 in the marketplace have dramatically altered people's perception of what constitutes an energy efficient home. Builders sought to comply with the requirements, and over time state standards improved to the point that there are few differences between it and Rate 7.

We conclude that Rate 7 was successful in meeting its original objectives. However, we are also forced to recognize that the kW and kWh savings (0.34 and 1,001 respectively at the system level) over standard construction are no longer as large as they used to be.

Table 3.2

Rate 7 (REC) Results Per Participant	Net Present Value
Avoided Generation Capacity Costs	$162.03
Avoided Transmission Capacity Costs	11.85
Avoided Distribution Capacity Costs	16.96
Avoided Production Costs (Fuel + Var O&M)	163.32
Total Benefits	$354.16
Administrative & Program Costs	$-385.00
Change In Revenues	
Change In Revenues (kWh & price reductions)	$-1,336.96
Total Costs	$-1,721.96
Net Loss	$-1,367.80
RIM Benefit/Cost Ratio	0.21
Participant Benefit/Cost Ratio	4.77
Utility Test Benefit Cost Ratio	0.92
Total Resource Cost Test	0.45

The program fails the TRC test as well as the RIM test (see Table 3.2). Based on these results, SCE&G recommends closing Rate 7 (REC) and grandfather existing customers.

Created: Good Cents/Conservation Program

The Company plans to replace Rate 1 and Rate 7 with a new "Good Cents/Conservation" rate that has prescriptive thermal envelope and appliance efficiency requirements above state building code standards. Most notably, the air conditioner will have a minimum rating of 12 SEER. Walls will have a minimum of R-15 insulation. (The wall insulation requirement will be waived for existing homes.) Attics will have at least R-30 insulation; existing homes must have

R-38 attic insulation. Floors will have R-19 insulation. Ducts will be joined with permanent duct sealant (e.g. mastic). A vapor barrier will cover any bare earth in the crawl space. Recessed ceiling lights will be sealed if the ceiling is on the top floor of the home. Windows will be double glass or have storm windows. Doors will be solid construction and weather-stripped.

The rate will be available to new and retro-fit construction. In addition, the program will offer a $200 cash incentive to builders of all-electric homes, replacing the $200 co-op advertising incentive currently provided for all-electric construction. This measure will generate off-peak season sales that will help offset the cost of the program to ratepayers.

Table 3.3

Rate GC (Proposed Good Cents) Results Per Participant	Net Present Value
Avoided Generation Capacity Costs	$278.49
Avoided Transmission Capacity Costs	20.37
Avoided Distribution Capacity Costs	29.15
Avoided Production Costs (Fuel + Var. O&M)	280.54
Total Benefits	$608.55
Revenue Decrease, kWh Effect	$-1,162.77
Revenue Decrease, Price Effect	$-730.57
Utility Rebates Paid (On Average)	$-150.00
Utility Administrative Cost Increase	$-35.00
Total Costs	$-2,078.34
Net Loss	$-1,469.79
RIM Benefit/Cost Ratio	0.29
Participant Benefit/Cost Ratio	3.19
Utility Cost Test Benefit/Cost Ratio	3.29
Total Resource Cost Test	0.80

On average, the rate will reduce system peak demand by 0.59 kW per participant. The annual energy reduction per participant will average approximately 1,725 kWh at the system level. The TAG test results are shown in Table 3.3.

The results of the Utility Cost Test suggest that total revenue requirements will go down. However, the RIM test shows a net loss, indicating that the loss of kWh sales (revenue) will exceed the benefits from cost savings (change in assumed revenue requirements). In other words, there will be upward pressure on rates. The expected price difference between this rate and Rate 8 accounts for over half of the net loss.

Despite the fact that it will apply upward pressure on rates, SCE&G decided that offering this new program was preferable to abruptly discontinuing promotion of conservation through residential rate incentives. The Company considers it a reasonable balance between the ratepayers' needs and the societal objective of promoting conservation. The prescriptive requirements were carefully selected to encourage measures that offer energy savings over current building codes without imposing undue financial hardship on the builder/homeowner. Having one residential rate instead of two will allow the Company to focus its resources and more effectively market the program. In addition, by making the standards prescriptive, overall program expenses will be reduced dramatically.

Unchanged: Rate 2 (Low Use)

The Low Use Residential Service Rate 2 provides a lower electricity price to any residential customer who meets the following conditions of service:

(1) The customer has occupied the same dwelling unit for the twelve months preceding initial service under Rate 2. During that time, no monthly consumption has exceeded 400 kWh.

(2) The second billing month within a twelve month period that consumption under Rate 2 exceeds 400 kWh will terminate eligibility under this schedule.

(3) Once removed from Rate 2, the customer will be billed under his previous rate schedule for the next twelve months before becoming eligible for Rate 2 again.

The metered consumption in a month is multiplied by a fraction whose numerator is 30 and whose denominator is the actual number of days in the billing period.

In 1994, the average monthly consumption on Rate 2 was 160 kWh. Rate 2's price per kWh is $0.01703 cheaper than Rate 8. Therefore, the average annual revenue difference per customer is approximately $32.70. There are no changes in cost of service and no direct program costs. Therefore, the TAG tests would be inappropriate.

SCE&G recommends continuation of Rate 2.

Unchanged: Rate 5 (Time-Of-Use)

Rate 5 is a voluntary time-of-use rate for residential service. In June through September, the on-peak hours are 2:00 p.m. to 7:00 p.m. on Monday through Friday. From October through May, the on-peak hours are 7:00 a.m. to 12:00 noon on Monday through Friday. Any hours not defined as on-peak hours are off-peak. So are holidays. The on-peak price is higher than Rate 8, but the off-peak price is lower.

Since this rate is voluntary, SCE&G recognizes that most of the customers who sign up for it do so because they can save money with few if any changes. It is impossible to exactly quantify the costs or benefits of this program, so the TAG tests are inappropriate.

SCE&G will continue offering Rate 5 since the knowledge gained on the small number of customers who have chosen it is useful for research and development purposes.

Plan to Discontinue: Residential Thermal Storage

SCE&G discontinued marketing the Residential Thermal Storage Program discussed in the 1992 IRP primarily due to the prohibitive cost of the technology. SCE&G remains interested in this option, but has concluded that it is still too immature for wide scale implementation. Therefore, we recommend closing this program.

Discontinued: Compact Fluorescent Lighting

In 1992, SCE&G established a compact fluorescent light bulb program to promote efficient lighting. It provided a $5.00 discount on the purchase of a bulb and charged the remainder of the price on the customer's electric bill. The bulbs were sold at the Energy Information Centers.

In its 1994 Short Term Action Plan, the Company discontinued the program.[6] In 1995, SCE&G opened its new Innovation Station at Columbiana Center in Columbia, SC. In that

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[6] 1994 Short Term Action Plan by South Carolina Electric & Gas Company, 1994, pp. 21-22.

facility, SCE&G promotes the use of compact fluorescent light bulbs and sells them to the public.

Changed: Home Energy Check Program (HEC)

The Home Energy Check Program provides a service to homeowners in SCE&G's territory. At the customer's request, a Company representative will perform a detailed audit of the home's HVAC system, insulation, ventilation and air loss around windows and doors. Afterwards, the representative will give the customer formal, written recommendations on efficiency improvements. If the customer submits the HEC form along with an invoice proving he/she followed one or more of the recommendations, the Company offers rebates and financing of up to $1,000 at 9% interest.

On January 17, 1995, the Company filed a request to modify the Home Energy Check Program with the South Carolina PSC. In 1992, 52% of the customers who had a home energy check made one or more of the recommended improvements. By 1994, the percentage had fallen to 23%. In 1993, the Company's cost to perform a check was $57. Since participation (defined as adoption of one or more measures) fell by more than 50%, the cost per participant effectively doubled. The Company became concerned as the cost to ratepayers grew.

Customer representatives performing the inspections reported that a significant number of customers who requested the audit never appeared serious about making improvements. In an attempt to improve the percentage participation among customers who request audits, SCE&G requested to institute a $55 audit fee which would be credited back to the customers along with

Table 3.4

Activity	Previous	Proposed
Attic R11 to R30	$6.50/100 sq. ft.	$2.50/100 sq. ft.
Attic R0 to R30	$10.00/100 sq. ft.	$5.00/100 sq. ft.
Storm Windows	$50.00	$30.00
Duct Insulation	$75.00	$50.00
Wall Insulation	$125.00	$80.00

any other rebates upon completion of at least one of the recommended improvements within 3 months of the audit.

Recognizing that the value of avoided capacity has fallen, the Company has also requested to lower its rebates as shown in Table 3.4.

The TAG test results are shown in Table 3.5.

Table 3.5

Home Energy Check Program (Proposed) Results Per Program Based On 1993 Participation	Net Present Value
Avoided Supply Cost	$1,045,496
Total Benefits	$1,045,496
Revenue Loss (from kWh sales reduction)	$-1,478,457
Incentives	$-58,425
Utility Cost	$-61,923
Total Costs	$-1,598,805
Net Loss	$-553,310
RIM Benefit/Cost Ratio	0.65
Participant Benefit/Cost Ratio	2.87
Utility Test Benefit Cost Ratio	8.69
Total Resource Cost Test	1.75

Even with the proposed changes, the Home Energy Check program fails to pass the Ratepayer Impact Measure (RIM) test, which means that it will exert some upward pressure on rates. Considering all viewpoints, however, SCE&G felt that HEC provides an important service to the community and should continue. Therefore, the Company chose instead to modify the program to reduce the negative impact to ratepayers as much as possible while still assuring that it is good for the participant and society in general.

Plan to Discontinue: Residential Heat Pump Pool Heaters

SCE&G began the Residential Heat Pump Pool Heater Program with the hope that a utility's encouragement of the technology would allow it to establish a foothold in the market. Unfortunately, suppliers in South Carolina were not interested in carrying the device. The Company recommends discontinuing the program.

Discontinued: Off-Peak Water Heating

The Off-Peak Water Heating Program used an electronic timer located on the residential participant's water heater to limit the appliance's contribution to summer and non-summer peaks. Although the timer caused a demand reduction of 0.27 kW per water heater, program costs were higher than expected due to equipment replacement and the timing of capital expenses. Table 3.6 shows the test results.

Table 3.6 Off-Peak Water Heating Program Program Results	Net Present Value
Revenue Gain	$424,672
Avoided Supply Cost	$717,540
Total Benefits	$1,142,212
Increased Supply Cost	$-123,501
Revenue Loss	$-795,746
Incentives	$-563,730
Utility Cost	$-335,879
Total Costs	$-1,818,856
Net Loss	$-676,644
RIM Benefit/Cost Ratio	0.63
Participant Benefit/Cost Ratio	1.99
Utility Test Benefit Cost Ratio	0.70
Total Resource Cost Test	1.00

Based on these results and the significant number of equipment problems, SCE&G discontinued the Off-Peak Water Heating Program at the end of 1993. The necessary documentation was submitted to and approved by the PSC in 1994.

Created: Replacement Water Heater Program

Table 3.7

Replacement Water Heating Program Results Per Participant	Net Present Value
Electric Revenue Increase	$1,060.41
Customer Loan Payments @ 0% Interest	$337.31
Total Benefits	$1,397.72
Program Costs	$-65.00
Production Cost Increase	$-248.37
Generation Capacity Cost	$-41.76
Transmission Capacity Cost	$-3.05
Distribution Capacity Cost	$-4.37
Utility's Cost Of Money @ 9%	$-420.12
2% Write-offs	$-6.75
Total Costs	$-789.42
Net Benefit	$608.30
RIM Benefit/Cost Ratio	1.77
Participant Benefit/Cost Ratio	0.68
Utility Test Benefit Cost Ratio	0.47
Total Resource Cost Test	Undefined

SCE&G has established a program called WaterWorks to promote electric water heaters in the replacement market. The Company offers to finance the purchase and installation of an electric water heater without interest (0%) for up to five years. In addition, the Company provides a $30 incentive per unit to the installer for participating in the program.

SCE&G is a summer peaking utility. An electric water heater's energy consumption in the winter is more than twice what it is in the summer, plus the daily load shapes have good base load characteristics. These two factors make it ideal for strategic load growth and, more importantly, valley filling. For a three person household, the water heater has a coincident load of 0.27 and uses 3,674 kWh annually. Adjusting for free riders, the water heater adds only 0.09 kW to the system peak while generating 1,548 kWh in annual energy sales. Table 3.7 emphasizes how good the load is for ratepayers.

As shown by the RIM test result, the program applies significant downward pressure on rates, benefiting the ratepayer and placing the Company in a more competitive position.

Planned For Modification & Renaming: Great Appliance Trade Up Program

The GATU Program is in the process of modification. SCE&G proposes to discontinue using the name, but plans to continue incenting high-efficiency HVAC equipment with the High Efficiency Heat Pump Program.

In its previous form, the GATU program had three sub-programs: Great Appliance Trade-up, Great Appliance Trade-Up Financing, and Great Appliance Trade-Up Piggyback.

Great Appliance Trade-Up gave rebates to residential and commercial electric customers (Rates 07, 08, 09, 20, and 23) in the new construction and replacement market for high efficiency cooling using unitary systems less than 5 tons in size.

Table 3.8

Great Appliance Trade-Up Program Results Per Participant		Net Present Value Over 20 Years
Utility Production Cost Decrease		$149.60
Utility Generation Capacity Credit		$215.48
Utility Transmission Capacity Credit		$15.76
Utility Distribution Capacity Credit		$22.55
Total Benefits		$403.39
Utility Revenue Decrease		$-628.96
Utility Rebates		$-330.78
Utility Administrative Cost Increase		$-72.67
Total Costs		$-1,032.41
Net Loss		$-629.02
	GATU	Piggyback
RIM Benefit/Cost Ratio	0.39	0.08
Participant Benefit/Cost Ratio	2.06	0.72
Utility Test Benefit Cost Ratio	1.00	0.13
Total Resource Cost Test	0.77	0.07

Great Appliance Trade-Up Financing offered loans to qualified customers for 48 months at interest rates of 12% for 12 SEER and 9% for 13+ SEER for heat pumps only. The maximum allowable financing was $10,000. Choosing to finance did not disqualify the customer for the other GATU rebates.

Great Appliance Trade-Up Piggyback gave a one-time, $200 rebate to residential and commercial electric customers (Rates 07, 08, 09, 20, and 23) with cooling using unitary systems less than 5 tons in the new construction and replacement markets. In order to qualify, the customer had to install a heating system that used supplemental heat delivered by a hot water coil charged by an existing gas water heater. The Piggyback incentive did not disqualify the customer for other GATU rebates.

The Great Appliance Trade-Up program reduced summer system peak demand by 0.39 kW per participant. Annual energy reductions per participant averaged 847 kWh for homes with electric space heating and 585 kWh for those with non-electric space heating. The weighted average was 758 kWh per participant, or 1,942 kWh for each kW reduction. The GATU Piggyback program reduced consumption an additional 200 kWh per participant annually.

Table 3.8 summarizes the TAG test results and the impact on ratepayers. The program fails the TRC test as well as the RIM test. The Company decided that a major change in the program was warranted. The High Efficiency Heat Pump Program was designed to supplant GATU.

Planned Creation: High Efficiency Heat Pump Program

Table 3.9

# of Units	Amount/Unit
1-49	$75
50-99	$85
100-199	$95
200-299	$105
300+	$115

The proposed High Efficiency Heat Pump Program, designed to supplant the Great Appliance Trade-Up Program, provides 10% financing to customers who purchase heat pumps with at least a 12 SEER efficiency rating. Customers can also finance another $1,500 at the same time for duct system improvements. Dealers who sell a 12+ SEER heat pump will receive an incentive calculated using Table 3.9. Focus groups held with HVAC dealers and customer representatives indicated that dealers have a great influence on the choice of appliance efficiency.

From the Company's perspective, paying the dealer incentive reduces paperwork and increases the effectiveness of our marketing expenses.

The program also provides customers who purchase approved experimental technologies (e.g. PowerMiser) with a cash incentive of up to $500.

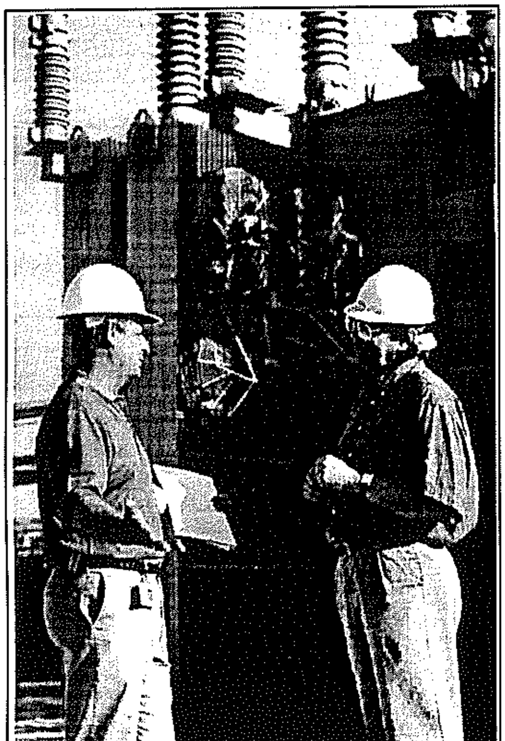
Table 3.10

High Efficiency Heat Pump Program Results Per Participant	Net Present Value
Utility Production Cost Decrease	$18.27
Utility Generation Capacity Credit	$182.28
Utility Transmission Capacity Credit	$13.33
Utility Distribution Capacity Credit	$19.08
Utility Loan Repayment From Customer	$5,375.15
Total Benefits	$5,608.11
Utility Revenue Decrease	$-95.19
Utility Administrative Costs	$-45.00
Utility Rebates	$-100.00
0.5% Write-Offs	$-26.88
Utility Cost Of Money @ 9%	$-5,251.52
Total Costs	$-6,011.65
Net Loss	$-89.53
RIM Benefit/Cost Ratio	1.02
Participant Benefit/Cost Ratio	0.85
Utility Test Benefit Cost Ratio	1.03
Total Resource Cost Test	0.55

Table 3.10 assumes that the average amount financed is $5,000 and the incremental price of choosing a 12 SEER instead of a 10 SEER unit is $500. The average participant's reduction in contribution to system peak is 0.39 kW. The program generates some off-peak energy sales from the promotion of heat pumps. Even so, the average energy savings is 58 kWh annually at the system level.

The High Efficiency Heat Pump Program passes the RIM test and is therefore a significant improvement over GATU. The Utility Cost Test suggests that Revenue Requirements will go down. SCE&G believes this program is a reasonable and worthwhile means of continuing to assist the customer with a major purchase.

Commercial and Industrial


SCE&G listens to customers. Understanding their needs is the first step to assisting customers with energy decisions.

Plan To Discontinue: Gas Air Conditioning

Through its gas sales program, SCE&G offers incentives for the adoption of gas air conditioning. The Company concluded that additional incentives would not provide incremental value.

Discontinued: Fluorescent Ballast

SCE&G implemented a high efficiency ballast program in 1990 to promote efficient lighting to commercial and industrial customers. When the program was developed, the typical lighting installation used magnetic ballasts. The program was designed to convince customers to install high efficiency electronic ballasts.

SCE&G's Electronic Ballast program has made a significant impact on the awareness levels of customers, lighting suppliers, lighting designers, architects and engineers on the benefits of electronic ballasts. As a result of the National Energy Policy Act, market forces, and SCE&G's program, the advancement and acceptance of electronic ballasts has led to reduced costs and wide acceptance of the technology. In fact, shipments of electronic ballasts have been backlogged for up to six months over the past two years. Based on customer feedback and the short economic payback of installing electronic ballasts, it is estimated that at least 25% of those taking part in SCE&G's ballast program were "free riders".

The Company factored this information and the 1993 program results and costs into an updated analysis of the program. The results are shown in Table 3.11.

Table 3.11
Electronic Ballast Program

Results Per Program Based On 1993 Participation	Amount
Avoided Supply Cost	$1,445,170
Total Benefits	$1,445,170
Revenue Loss (from kWh sales reduction)	$-1,393,963
Incentives	$-173,910
Utility Cost	$-80,777
Total Costs	$-1,648,650
Net Loss	$-203,481
RIM Benefit/Cost Ratio	0.88
Participant Benefit/Cost Ratio	2.08
Utility Test Benefit Cost Ratio	5.67
Total Resource Cost Test	1.73

For every kW deferred, there is an accompanying energy reduction of 3,500 kWh. Since the program does not pass the Ratepayer Impact Measure test and it has already accomplished the objectives for which it was originally intended, SCE&G eliminated the program effective December 31, 1994. The required documentation was submitted to the PSC in 1994. It was approved in 1995.

Changed: Commercial Heat Pump Pool Heaters & Water Heaters

For several years, SCE&G has maintained a research program to seek methods of introducing heat pump water heating (and pool heating) to the commercial sector. However, dealers in South Carolina have remained reluctant to commit to the new technology. Therefore, installation and service are practically non-existent in the Company's service territory. SCE&G

finally decided to discontinue offering incentives and concentrate of the education task of encouraging suppliers.

Plan to Discontinue: High Efficiency Motors

The High Efficiency Motors Program offers a rebate of $100 per kW eliminated by replacing inefficient motors with high efficiency models. Assuming the motor needs replacement anyway, the customer typically pays about $550 extra for high efficiency in a 50-hp motor. For that investment, the customer saves about 1.7 kW in monthly demand and 10,380 kWh per year. The demand and energy savings result in a short payback period even without the incentives.

Table 3.12

High Efficiency Motors Program Results Per kW Of Deferment Paid	Net Present Value
Utility Production Cost Decrease	$507.05
Utility Generation Capacity Credit	$242.70
Utility Transmission Capacity Credit	$17.75
Utility Distribution Capacity Credit	$25.40
Total Benefits	$792.91
Utility Revenue Decrease	$-2,165.86
Utility Rebates	$-102.89
Utility Administrative Cost Increase	$-20.58
Total Costs	$-2,289.33
Net Loss	$-1,496.43
RIM Benefit/Cost Ratio	0.35
Participant Benefit/Cost Ratio	14.76
Utility Test Benefit Cost Ratio	6.42
Total Resource Cost Test	4.25

Given the short payback, SCE&G assumed 50% free ridership for this analysis. This meant that each kW of deferment paid for by the program reduced the system peak (adjusted for losses) by only 0.51 kW. The corresponding annual energy reduction at system level was 3,141 kWh. The TAG test results are shown in Table 3.12.

Given the customer's strong economic incentive for investing in high efficiency motors even without a rebate, and considering the negative impact on rates if the program were to continue its rebates, SCE&G recommends discontinuing the program.

Plan To Discontinue: Adjustable Speed Drives

In times past, the volume of output of an electric pump or fan was controlled mechanically with valves, dampers, or inlet vanes. Today, it is much more efficient to control the drive electrically by varying the applied frequency of the power. Whenever a pump or fan normally operates at loads below its maximum rating, adjustable speed control will reduce energy consumption.

Table 3.13

Adjustable Speed Drives Program Results Per kW Of Demand Reduction	Net Present Value Over 15 Years
Utility Production Cost Decrease	$543.13
Utility Generation Capacity Credit	$242.36
Utility Transmission Capacity Credit	$17.72
Utility Distribution Capacity Credit	$25.37
Total Benefits	828.58
Utility Revenue Decrease	$-2,323.42
Utility Rebates	$-102.75
Utility Administrative Cost Increase	$-5.64
Total Costs	$-2,431.81
Net Loss	$-1,603.22
RIM Benefit/Cost Ratio	0.34
Participant Benefit/Cost Ratio	13.05
Utility Test Benefit Cost Ratio	7.64
Total Resource Cost Test	4.01

Adjustable speed drives are so economical that customers can frequently expect paybacks of less than two years even without a rebate. SCE&G confirmed this in a hypothetical analysis recently in which the Company assumed a high incremental cost for adjustable speed and no rebates. The benefit/cost ratio on the participant test was still 4.26. The RIM benefit/cost ratio was only 0.36. SCE&G's customer contact representatives estimated that the Adjustable Speed Drives Program, which gave a $100 rebate per kW demand reduction, had free ridership of nearly 100%.

SCE&G ran the TAG tests for the current program assuming a conservative 50% free ridership. The results, shown in Table 3.13, reinforce the view that continuation of the program is not in the best interest of ratepayers.

The Company concluded that the technology was now mature enough to reach its market potential without further incentives. Therefore, SCE&G proposes to discontinue the Adjustable Speed Drives Program.

Plan To Change: Commercial HVAC

The Commercial HVAC program offers customers the incentives shown in Table 3.14 for choosing high efficiency heat pumps and air conditioners up to 65,000 BTUH. For equipment larger than that, the rebates are shown in Table 3.15.

Table 3.14

	Retrofit		New Construction
SEER Level	Heat Pump Incentive	A/C Incentive	Heat Pump Incentive
12-12.99	$175	$50	$125
13-13.99	$200	$75	$125
14-14.99	$225	$100	$125
15-15.99	$175	$50	$125
16+	$175	$50	$125

Table 3.15

EER Rating	Customer Rebate	Dealer Rebate
9.5-9.99	$50/ton	$5/ton
10+ EER	$75/ton	$5/ton

After accounting for line losses and free ridership, a kW deferred by the customer at the time of the system peak only results in a 0.86 kW reduction at the system level. The corresponding annual kWh sales reduction is 2,798. Since the Company is recommending a change to the Commercial HVAC program, Table 3.16 shows the TAG test results before and after the change. The first column shows the numbers for the program as it exists now. From the ratepayer's perspective, there is a significant loss of revenue. When combined with high program incentive costs, this loss exceeds the total benefits by a large margin.

Table 3.16

Commercial HVAC Program Results Per kW Of Demand Reduction	Net Present Value With Incentives	Net Present Value Without Incentives
Utility Production Cost Decrease	$464.41	$464.41
Utility Generation Capacity Credit	$405.07	$405.07
Utility Transmission Capacity Credit	$29.62	$29.62
Utility Distribution Capacity Credit	$42.40	$42.40
Total Benefits	$941.50	$941.50
Utility Revenue Decrease	$-1,915.93	$-1,915.93
Utility Rebates	$-1,785.71	$0.00
Utility Administrative Cost Increase	$-71.43	$-71.43
Total Costs	$-3,773.07	$-1,987.36
Net Loss	$-2,831.57	$-1,045.86
RIM Benefit/Cost Ratio	0.25	0.47
Participant Benefit/Cost Ratio	1.88	1.33
Utility Test Benefit Cost Ratio	0.51	13.18
Total Resource Cost Test	0.35	0.35

As the participant test results show, investment in a high efficiency option is beneficial. This is true even without the rebates. If all of the incentives are eliminated, the participant's benefit/cost ratio is still 1.33.

So, by eliminating the incentives, SCE&G can change the present value of the net loss over 15 years from $2,831.57 to $1,045.86. Even without the rebates, customers will want to participate because high efficiency ultimately saves them money. Considering these two facts, SCE&G proposes to change the commercial HVAC program by eliminating incentive payments while continuing to promote the technology and inform customers of their options.

Discontinued: High Efficiency Lighting

SCE&G implemented a high efficiency lighting program in 1990 to promote efficient lighting to commercial and industrial customers. When the program was developed, the typical fluorescent lighting installation used 40W lamps. SCE&G's program was designed to convince customers to install 34W or 32W lamps.

Table 3.17

High Efficiency Lighting Program Results Using 1993 Data	Net Present Value
Avoided Supply Costs	$1,283,761
Total Benefits	$1,283,761
Incentives	$-82,782
Change In Revenues	$-1,238,273
Utility Cost	$-81,919
Total Costs	$-1,402,973
Net Loss	$-119,213
RIM Benefit/Cost Ratio	0.92
Participant Benefit/Cost Ratio	15.55
Utility Test Benefit Cost Ratio	7.79
Total Resource Cost Test	7.69

SCE&G's High Efficiency Lighting program has made a significant impact on the awareness levels of customers, lighting suppliers, lighting designers, architects and engineers on the benefits of efficient lighting. As a result of the National Energy Policy Act, market forces and SCE&G's program, the advancement and acceptance of efficient lighting technology has led to reduced costs and wide acceptance of 34W and 32W lamps. In fact, 40W lamps are no longer manufactured. Based on customer feedback and the short economic payback of installing high efficiency lighting, it is estimated that at least 60% of those taking part in SCE&G's program are "free riders".

The Company recently reevaluated the program using this information and the 1993 participation levels and costs. For every kW deferred, there was an associated 3,500 kWh savings. Table 3.17 summarizes the TAG test results.

Since the High Efficiency Lighting program had accomplished its objectives and continuing it would have caused upward pressure on rates, SCE&G eliminated the program effective 12/21/94. The required documentation was submitted to the PSC in 1994. It was approved in 1995.

Plan To Change: Thermal Storage

Citing excess generating capacity and the disappearance of cash incentives by utilities, speakers at a recent ASHRAE Winter Meeting said that thermal energy storage must market for itself[7]. Despite that trend, SCE&G still finds thermal storage to be a valuable component of its DSM strategy and will continue incenting the technology. However, as the cost of future capacity additions has fallen, so must the incentive payment offered by the Company. Currently, SCE&G offers $300 per deferred kW. The proposed incentive would be slightly lower, as shown in the Table 3.18. Thus, a customer installing a system capable of deferring 300 kW would receive 200 x $225 + 100 x $150. A unit deferring 1,600 kW would receive 200 x $250 + 1,300 x $150.

Table 3.18

Total Projected kW Deferral	Proposed Incentive Per kW Deferred
1-200	$225
200-1,500	$150

[7] "Utilities say thermal energy storage must speak, market for itself", Air Conditioning, Heating, and Refrigeration News, February 20, 1995, p. 39.

The TAG test results are shown in Table 3.19. With the proposed change in rebate level, the program passes the RIM test. SCE&G has approximately 2 MW of thermal storage capacity on its system and expects an additional 3.5 MW to be added this year.

Table 3.19

Thermal Storage Program Results Per kW Of Demand Reduction	Old Program (15 yr. PV)	Changed Program (15 yr. PV)
Utility Generation Capacity Credit	$485.59	$485.59
Utility Transmission Capacity Credit	$35.51	$35.51
Utility Distribution Capacity Credit	$50.82	$50.82
Total Benefits	$571.93	$571.93
Utility Revenue Decrease	$-266.85	$-266.85
Utility Production Cost Increase	$-41.15	$-41.15
Utility Rebates	$-300.00	$-200.00
Utility Administrative Cost Increase	$-15.44	$-15.44
Total Costs	$-623.44	$-523.44
Net Benefit / (Loss)	$-51.51	$48.49
RIM Benefit/Cost Ratio	0.90	1.09
Participant Benefit/Cost Ratio	1.21	1.06
Utility Test Benefit Cost Ratio	1.57	2.15
Total Resource Cost Test	0.80	0.80

Unchanged: Standby Generator

The Standby Generator Program pays customers who have an emergency generator with at least 200 kW connected load an incentive to self-generate when SCE&G needs extra capacity. The Company is restricted on how often it can make this request. The contract period is five years. The program pays $2.00 per contracted kW per month and $0.07 per kWh.

Table 3.20

Standby Generator Program Results Per kW Of Demand Reduction	Net Present Value Over 15 Years
Utility Production Cost Decrease	$4.05
Utility Generation Capacity Credit	$210.13
Utility Transmission Capacity Credit	$15.37
Utility Distribution Capacity Credit	$21.99
Total Benefits	$251.54
Utility Revenue Decrease	$-13.20
Utility Rebates	$-113.31
Utility Administrative Cost Increase	$-35.00
Total Costs	$-161.50
Net Benefit	$90.03
RIM Benefit/Cost Ratio	1.56
Participant Benefit/Cost Ratio	46.62
Utility Test Benefit Cost Ratio	1.70
Total Resource Cost Test	7.19

The TAG test results shown in Table 3.20 indicate that this is a valuable program to both the participant and other ratepayers. The model assumes that the only cost to the participant is the price of fuel. For every kW removed from the system, there is a reduction of 40 kWh. Peak clipping is accomplished with almost no loss of utility sales.

The program is a successful demand-side management tool currently capable of providing 18,498 kW of generation. SCE&G plans to continue aggressive promotion of this program.

Plan To Change: High Efficiency Chillers

SCE&G's High Efficiency Chiller Program offers $200 per deferred kW for electric chillers which meet or exceed the efficiency values shown in Table 3.21.

Table 3.21

Chiller Technology	kW/Ton	Refrigerant
Centrifugal	0.67	R-11
Screw	0.71	R-22
Reciprocating, Water Cooled	0.85	R-22
Reciprocating, Air Cooled	1.15	R-22

The TAG test analysis shown in Table 3.22 assumed a conservative 20% free ridership, although a test run with no free riders did not significantly affect the findings. For every kW reduction at customer level, 0.82 kW is saved at the system level. The corresponding annual system level energy falls 1,312.86 kWh. The RIM test shows a present value loss over 15 years, approximately 40% of which is due to the rebates. The study shows that without the rebates, the customer still has substantial benefits. Our customer representatives confirmed this result, saying that the rebates no longer play an important part in the customer's decision-making. The

Table 3.22 High Efficiency Chillers Program Results Per kW Of Demand Reduction	Old Program (15 yr. PV)	Changed Program (15 yr. PV)
Utility Production Cost Savings	$223.19	$223.19
Utility Generation Capacity Credit	$388.48	$388.48
Utility Transmission Capacity Credit	$28.41	$28.41
Utility Distribution Capacity Credit	$40.66	$40.66
Total Benefits	$680.74	$680.74
Utility Revenue Decrease	$-962.73	$-962.73
Utility Rebates	$-205.87	$0.00
Utility Administrative Cost Increase	$-8.33	$-8.33
Total Costs	$-1,176.93	$-971.06
Net Benefit / (Loss)	$-496.20	$-290.32
RIM Benefit/Cost Ratio	0.58	0.70
Participant Benefit/Cost Ratio	3.09	2.82
Utility Test Benefit Cost Ratio	3.18	8.33
Total Resource Cost Test	1.08	1.08

incremental cost of choosing the high efficiency option is fairly small compared to the bill savings. This is normally what convinces the customer to proceed with high efficiency.

Based on this information, the Company proposes to eliminate the rebates while continuing to promote high efficiency chillers through an education program. The effect on participation should be minimal.

Unchanged: Time Differentiated Rates

Price signals influence consumption behavior more strongly than any other single factor within the utility's purview. By allowing price to track costs by time period, a rate can provide an incentive to modify a load shape in a manner which benefits the system. Prices can change by month, season, or hour. As Table 3.23 shows, most of SCE&G's rates differentiate price by season of the year. The rate not only varies by time of year, but in many cases, by usage blocks as well. This tiered, season-differentiated format has proven to be easily understood and implemented.

Table 3.23

Rate Schedule	Class	# Of Seasons	Description of Seasons
Rate 1 (RGC) -Plan to close	Residential	2	Jun-Sep, Oct-May
Rate 2 (Low Use)	Residential	0	None
Rate 5	Residential	2	Jun-Sep, Oct-May
Rate 7 (REC) -Plan to close	Residential	2	Jun-Sep, Oct-May
Rate 8	Residential	2	Jun-Sep, Oct-May
Rate 3 (M)	Municipal	2	Jun-Sep, Oct-May
Rate 10	Small Construction	0	None
Rate 11	Irrigation	2	Jun-Sep, Oct-May
Rate 12 (C)	Church	0	None
Rate 13 (ML)	Municipal Lighting	0	None
Rate 14	Farm	2	Jun-Sep, Oct-May
Rate 16	General Service	2	Jun-Sep, Oct-May
Rate 21	General Service	2	Jun-Sep, Oct-May
Rate 22	School	0	None
Rate 9	General Service	2	Jun-Sep, Oct-May
Rate 20	Medium General Service	2	Jun-Sep, Oct-May
Rate 23	Industrial	2	Jun-Sep, Oct-May
Rider to 20 & 23	Thermal Storage	2	Jun-Sep, Oct-May
Rate 24	Large Gen. Service	3	Jun-Sep, Nov-Apr, May&Oct
Rider to 23 & 24	Interruptible	2	Nov-Apr, Oct-May
Rate 17	Muni. Street Lighting	0	None
Rate 25	Overhead Floodlight	0	None
Rate 26	Overhead Priv. Street Light	0	None
Subdiv. Street Light	Residential	0	None

In addition, several SCE&G rates vary price by time of day. Most are voluntary, but Large General Service Rate 24 is mandatory. Table 3.24 lists the rates that are formally dubbed "time-of-use".

Table 3.24

Rate Schedule	Class	Requirement
Rate 5	Residential	Voluntary
Rate 11	Irrigation	Voluntary
Rate 16	General Service	Voluntary
Rate 21	General Service	Voluntary
Rider to Rates 20 & 23	Thermal Storage	Voluntary
Rate 24	Large General Service	Mandatory
Rider to Rates 23 & 24	Interruptible	Voluntary

Voluntary time-of-use rates are useful for research, but they potentially result in lower revenues with little corresponding reduction in costs. This is due to the fact that the customers most likely to choose the rate are the ones who can benefit with minimal changes. Mandatory time-of-use prices are much more likely to motivate changes in load shapes and their associated costs.

Unchanged: Interruptible Rates

SCE&G has more than 90 MW of customer load that can be interrupted. Over half of that total is represented by customers on the Rider to Rates 23 and 24. The remainder is on special contract. This flexible load shape tool allows system operators to reduce their spinning reserve requirement by a percentage of the full 90 MW, in essence reducing capacity costs over time. For this reason, SCE&G will continue aggressive promotion of this program. In 1993 and 1994, the Company signed up an average of 21 MW per year.

Created: Real Time Pricing Rate (Experimental)

Real Time Pricing (RTP) is a step beyond the Company's "traditional" time-of-use rates that assign fixed, published prices to the on-peak and off-peak periods of each seasonal day type. In RTP, each hour has its own price, and that price is set daily.

"Rates are becoming increasingly important as a market implementation method. Rates are credited with producing the largest changes to industrial load shape for most utilities."[8] Recognizing that fact, SCE&G plans to be innovative, offering its industrial customers attractive rate options that stimulate growth while encouraging efficient use of system resources.

By getting involved early in a project, SCE&G representatives can assist the customer with a variety of technologies, from lighting to thermal storage.

To meet that objective, the Company is currently implementing an experimental Real Time Pricing rate which includes two pricing structures. The first is a standard tariff that applies to the customer baseline load (CBL) established by the customer's historical load profile. The second is a real time price that changes as marginal costs fluctuate and applies to energy consumption above and below the CBL.

The customer is always billed on the standard tariff for the CBL. If a customer's load pattern continues to approximate the CBL, the real time pricing rate is revenue neutral. On the other hand, if consumption exceeds the CBL, the customer also pays SCE&G the real time price

[8] Demand-Side Management Volume 5, Industrial Markets And Programs by Battelle-Columbus Division, Synergic Resources Corporation, Resource Dynamics Corporation, and Enviro-Management and Research, Inc. for Edison Electric Institute, 1988.

for the energy above the CBL. If consumption instead falls below the CBL, the Company buys back the kWh difference between the CBL and actual consumption at the real time price.

As stated in earlier sections, "traditional" time-of-use rates run the risk of revenue erosion if they are voluntary. Customers who can save money without making any changes to their usage patterns will be the most likely to join. In contrast, voluntary real time pricing averts that risk by use of the CBL. The customer only saves money if he makes a change that is beneficial to the system.

That change may be a decrease in usage when costs are high, or an increase in usage when costs are low. Either way, the participant benefits by gaining additional control of their energy expenses. Ratepayers benefit from more efficient utilization of production resources, which will apply downward pressure on rates. SCE&G benefits by achieving more efficient pricing and a more competitive position. The citizens of South Carolina benefit because real time pricing attracts business expansion while encouraging wise energy usage.

Education & Customer Input

Innovation Station & Energy Info Center

Education is the most cost-effective tool available to promote conservation and demand-side management. There are many available technologies that provide a good economic payback, and telling the customer about them is often the only measure necessary to insure their adoption.

The Company pursues methods of encouraging wise conservation. For many years, customer contact representatives have assisted customers informally with advice. Beginning in

1984 and 1985, the Company took this commitment even further by opening the Energy Info Centers. To the best of our knowledge, they were the first facilities to offer customers an opportunity to get information interactively from the utility company, home builders associations, appliance manufacturers, and vendors. Customers could not only find out about a new technology, they could often put their hands on it and examine it close up.

The Energy Info Center in Charleston is located at Citadel Mall and hosts over 20 educational exhibits. The Center in Columbia was located in Dutch Square until it closed at the end of 1994. It has been replaced by SCE&G's new Innovation Station, which opened at Columbiana Center in early 1995.

SCE&G's Innovation Station at Columbiana Center in Columbia, SC

Both facilities educate consumers on power safety, conservation measures, and energy efficient appliances. Complex subjects are addressed in simple terms, and are always approached from the customer's perspective. Customers can talk with an expert about their energy bills, learn how to apply weather-stripping and caulk, or look at appliances and home models with "cut-away-construction" that lets them see energy efficiency measures first-hand. They can even pay their energy bills. Computer simulation models are available which estimate the annual energy savings resulting from conservation or efficiency options. These savings are based on the individual customer's lifestyle.

The new Innovation Station updates this interactive concept for the 1990s. A large "video wall" in the back continuously displays helpful information in a location that is visible from inside and outside the store. A "kids corner" gives small children a safe place to play and watch videos while their parents learn what's new in home improvement. Although simply walking through (or even walking by) the facility can be educational, helpful staff are always available to provide more details.

The Innovation Station has been designed to minimize its cost to ratepayers while enhancing the service provided to customers. The facility has taken a number of steps to cut on-going operating expenses by:

- <u>Reducing the square footage of the facility</u>. The Innovation Station uses approximately half the square footage of the Dutch Square Energy Info Center it replaced. This results in an annual savings of over $30,000 in lease payments. By using advanced computer and video technology, education is provided in much less space.

- Renting space on the Video Wall. Advertising space on the video wall is being rented to manufacturers of appliances, insulation, and other home-related products to allow an effective vehicle for displaying information and to generate revenues to offset the cost of the Innovation Station. Video Wall rentals are expected to total $120,000 per year. This compares to $45,000 per year raised from renting display space in the Dutch Square Energy Info Center. The Video Wall is also easier to update as new technologies are introduced.

- Renting space on the Contractor Contacter. The Innovation Station has developed a touch screen video display to identify local HVAC, insulation and plumbing contractors that take part in SCE&G's programs. The contractors represented on the Contractor Contacter pay monthly fees that will generate over $50,000 per year in income.

- Renting the use of the conference facility. The Innovation Station has a 100-seat conference room to present new technologies and give demonstrations on energy-saving strategies. SCE&G now makes this facility available to outside groups for an hourly fee. The response has been overwhelming. Over $20,000 per year will be generated from the rental of this facility.

- Selling energy efficient merchandise. A number of energy-related products are now on sale at the Innovation Station, ranging from compact fluorescent light bulbs to caulking and solar power battery chargers. Profit generated from the sale of these items will be used to offset the operating cost of the Station and is expected to total over $10,000 per year.

The Charleston Energy Info Center has also implemented the Contractor Contacter and is renting its meeting facilities. Plans are currently being developed to make additional updates (described above) to the Charleston facility. SCE&G is constantly searching for ways to promote efficiency while minimizing promotion and program costs to ratepayers.

Since they are strategically situated in shopping malls, both facilities stay open during the full range of normal retail hours for six days per week. Over two million people have visited these facilities since June of 1984, and SCE&G looks forward to more stopping by in years to come.

Customer Input And Feedback

"DSM was the first marketing strategy that specifically promoted a customer focus."[9] In the past 18 months, SCE&G has significantly increased its emphasis on understanding customers' requirements and satisfaction levels. In 1994, focus groups were held with residential customers from across the service territory to identify and define drivers of satisfaction with SCE&G's service. This was followed by a telephone survey of residential customers to measure current performance and overall impact of each driver. In those areas identified as weaknesses, additional interviews were conducted to determine specific customer requirements which must be met to consider SCE&G a "world class" service provider. This information is now being used to set service level standards and to focus the improvement efforts of the company. In

[9] Utility Marketing Strategies: Competition and the Economy, by Clark W. Gellings, The Fairmont Press, 1994, p. 265.

1995, SCE&G initiated a new residential customer satisfaction survey which is being sent on a monthly basis to customers who have had recent contact with the Company. The survey measures performance on a number of attributes and provides an overall satisfaction score which is used as a corporate incentive goal for all SCE&G employees.

Consistent with the residential research described above, SCE&G is committing significant resources to better understand the requirements and satisfaction levels of its commercial and industrial customers. On an annual basis (beginning in 1994), SCE&G takes part in a national key account benchmark survey which polls 3,600 large industrial and commercial businesses from across the U.S. to gauge satisfaction levels with their local utility. The 1994 survey results showed SCE&G to be in the top 10 of the over 90 utilities represented.

In 1994, SCE&G initiated an innovative process to clearly determine service level requirements from its commercial and industrial customers to be considered "world class". The process involved two-person teams of SCE&G employees conducting structured interviews with customers. In the interviews, customers were asked their requirements for DSM programs and technology seminars (among a variety of other questions). That input has helped shape our proposed changes to the Commercial and Industrial DSM programs and is dictating the number of technology seminars being held on an annual basis. In addition, the results of these interviews are providing focus for improvement efforts and are being used to set service level standards for such things as: number of service interruptions per year, the responsiveness of technical support personnel and the number of times per year an account representative initiates contact with a customer.

In addition to the surveys and interviews described above, SCE&G directly and indirectly seeks input from customers and trade allies as part of the planning process for DSM programs. For the residential, commercial and industrial markets, SCE&G representatives meet with customers on a daily basis to market our programs. When evaluating potential program changes, input is gathered from our representatives to better understand the barriers to customer acceptance and the impact programs have on customer decision making. When the economics dictate a program be eliminated or scaled back, customer representatives are consulted to determine ways of minimizing any negative effects on customers as changes are made. When considering changes to the Energy Info Center, customers were surveyed to determine ways to increase the value of the Centers to our customers. When considering changes to our residential programs, focus groups were held with over 40 HVAC dealers and home builders to provide input to planning and evaluation.

In summary, SCE&G is committed to improving the service provided to customers and is using their input to shape the direction of the company. A number of mechanisms are now in place to measure satisfaction levels, determine customer requirements and to provide direct and indirect input to the DSM planning and evaluation process

Summary Of Program Changes (& TAG Test Results)

Table Summarizing TAG Test Results

Table 3.25 shows the TAG test results for the programs discussed in this chapter.

Table 3.25

1995 TAG Test Results	RIM Test Benefit/Cost Ratio	Participant Test Benefit/Cost Ratio	Utility Cost Test Benefit/Cost Ratio	TRC Test Benefit/Cost Ratio
Deleted Programs (Including Proposed Deletions)				
Rate 1 (Previous Good Cents)	0.24	2.66	2.66	0.51
Rate 7 (REC)	0.21	4.77	0.92	0.45
Off-Peak Water Heating	0.63	1.99	0.70	1.00
Great Appliance Trade Up	0.08	0.72	0.13	0.07
High Efficiency Motors	0.35	14.76	6.42	5.33
Adjustable Frequency Drives	0.34	13.05	7.64	4.01
High Efficiency Lighting	0.92	15.55	7.79	7.69
Fluorescent Ballast	0.88	2.08	5.67	1.73
Programs Kept, Added, Or Changed (Including Proposed Additions and Changes)				
Good Cents/Conservation	0.29	3.19	3.29	0.80
Home Energy Check (HEC)	0.65	2.87	8.69	1.75
Replacement Water Heaters	1.77	0.68	0.47	Inf
High Efficiency Heat Pumps	1.02	0.85	1.03	0.55
Commercial HVAC	0.47	1.33	13.18	0.35
High Efficiency Chillers	0.70	2.82	8.33	1.08
Thermal Storage	1.09	1.06	2.15	0.80
Standby Generators	1.56	46.62	1.70	7.19

Table Summarizing Program Impacts

Table 3.26 summarizes the system level kW and kWh impacts of marketing's demand-side management programs.

Table 3.26								
	Rate 7 (REC)		Rate 1 (Old Good Cents)		Rate GC (New Good Cents)		Home Energy Check	
Year	kW	kWh	kW	kWh	kW	kWh	kW	kWh
1990	7,335	22,005,600	6,571	18,719,700	0	0	452	48,180
1991	8,125	24,374,700	8,858	26,575,350	0	0	1,476	2,434,608
1992	8,884	26,651,580	12,171	33,437,400	0	0	2,592	4,674,384
1993	9,360	28,070,107	15,648	41,681,920	0	0	4,458	8,419,386
1994	9,721	28,613,045	17,808	46,501,031	0	0	5,846	11,539,565
1995	10,464	30,842,647	21,936	55,050,114	0	0	7,350	15,300,365
1996	10,464	30,842,647	21,936	55,050,114	5,728	15,629,737	9,011	19,451,765
1997	10,464	30,842,647	21,936	55,050,114	11,571	31,572,069	10,828	23,993,765
1998	10,464	30,842,647	21,936	55,050,114	17,531	47,833,247	12,801	28,926,365
1999	10,464	30,842,647	21,936	55,050,114	23,610	64,419,649	14,930	34,249,565
2000	10,464	30,842,647	21,936	55,050,114	29,810	81,337,779	17,216	39,963,365
2001	10,464	30,842,647	21,936	55,050,114	36,134	98,594,271	19,657	46,067,765
2002	10,464	30,842,647	21,936	55,050,114	42,585	116,195,894	22,255	52,562,765
2003	10,464	30,842,647	21,936	55,050,114	49,165	134,149,548	25,010	59,448,365
2004	10,464	30,842,647	21,936	55,050,114	55,877	152,462,276	27,920	66,724,565
2005	10,464	30,842,647	21,936	55,050,114	62,723	171,141,259	30,987	74,391,365
2006	10,464	30,842,647	21,936	55,050,114	69,705	190,193,821	34,210	82,448,765
2007	10,464	30,842,647	21,936	55,050,114	76,828	209,627,434	37,589	90,896,765
2008	10,464	30,842,647	21,936	55,050,114	84,092	229,449,720	41,124	99,735,365
2009	10,464	30,842,647	21,936	55,050,114	91,502	249,668,451	44,816	108,964,565
2010	10,464	30,842,647	21,936	55,050,114	99,061	270,291,557	48,664	118,584,365
2011	10,464	30,842,647	21,936	55,050,114	106,770	291,327,125	52,668	128,594,765
2012	10,464	30,842,647	21,936	55,050,114	114,634	312,783,405	56,828	138,995,765
2013	10,464	30,842,647	21,936	55,050,114	122,655	334,668,810	61,145	149,787,365
2014	10,464	30,842,647	21,936	55,050,114	130,836	356,991,923	65,618	160,969,565

The table is continued on the next two pages.

Table 3.26 Continued

	Replacement Water Heaters		GATU		High Efficiency Heat Pumps		Flourescent Ballasts	
Year	kW	kWh	kW	kWh	kW	kWh	kW	kWh
1990	0	0	12,167	12,046,272	0	0	0	0
1991	0	0	18,158	18,157,650	0	0	0	0
1992	0	0	25,757	25,909,602	0	0	166	581,000
1993	0	0	32,900	33,196,376	0	0	1,171	4,098,500
1994	0	0	48,108	46,087,321	0	0	5,793	20,275,500
1995	-720	-12,384,000	51,503	49,550,242	3,510	7,628,400	5,793	20,275,500
1996	-1,454	-25,015,680	51,503	49,550,242	7,090	15,409,368	5,793	20,275,500
1997	-2,203	-37,899,994	51,503	49,550,242	10,742	23,345,955	5,793	20,275,500
1998	-2,968	-51,041,993	51,503	49,550,242	14,467	31,441,274	5,793	20,275,500
1999	-3,747	-64,446,833	51,503	49,550,242	18,266	39,698,500	5,793	20,275,500
2000	-4,542	-78,119,770	51,503	49,550,242	22,142	48,120,870	5,793	20,275,500
2001	-5,353	-92,066,165	51,503	49,550,242	26,094	56,711,687	5,793	20,275,500
2002	-6,180	-106,291,489	51,503	49,550,242	30,126	65,474,321	5,793	20,275,500
2003	-7,023	-120,801,318	51,503	49,550,242	34,239	74,412,208	5,793	20,275,500
2004	-7,884	-135,601,345	51,503	49,550,242	38,434	83,528,852	5,793	20,275,500
2005	-8,761	-150,697,372	51,503	49,550,242	42,712	92,827,829	5,793	20,275,500
2006	-9,657	-166,095,319	51,503	49,550,242	47,076	102,312,785	5,793	20,275,500
2007	-10,570	-181,801,226	51,503	49,550,242	51,528	111,987,441	5,793	20,275,500
2008	-11,501	-197,821,250	51,503	49,550,242	56,069	121,855,590	5,793	20,275,500
2009	-12,451	-214,161,675	51,503	49,550,242	60,700	131,921,102	5,793	20,275,500
2010	-13,420	-230,828,909	51,503	49,550,242	65,424	142,187,924	5,793	20,275,500
2011	-14,409	-247,829,487	51,503	49,550,242	70,242	152,660,082	5,793	20,275,500
2012	-15,417	-265,170,076	51,503	49,550,242	75,157	163,341,684	5,793	20,275,500
2013	-16,445	-282,857,478	51,503	49,550,242	80,170	174,236,917	5,793	20,275,500
2014	-17,494	-300,898,628	51,503	49,550,242	85,284	185,350,056	5,793	20,275,500

Table 3.26 Continued

	High Efficiency Motors		Variable Speed Drives		Commercial HVAC		Thermal Storage	
Year	kW	kWh	kW	kWh	kW	kWh	kW	kWh
1990	0	0	0	0	0	0	503	-758,524
1991	0	0	0	0	0	0	676	-1,019,408
1992	1	7,170	49	175,665	1,023	1,331,946	1,499	-2,260,492
1993	91	652,470	274	982,290	3,314	4,314,828	1,937	-2,920,996
1994	96	688,320	332	1,190,220	4,847	6,310,794	2,132	-2,988,271
1995	196	1,440,320	582	2,086,470	5,847	9,564,514	5,632	-7,451,471
1996	196	1,440,320	582	2,086,470	6,847	12,818,234	6,632	-8,028,271
1997	196	1,440,320	582	2,086,470	7,847	16,071,954	7,682	-8,633,911
1998	196	1,440,320	582	2,086,470	8,847	19,325,674	8,785	-9,269,833
1999	196	1,440,320	582	2,086,470	9,847	22,579,394	9,942	-9,937,551
2000	196	1,440,320	582	2,086,470	10,847	25,833,114	11,158	-10,638,655
2001	196	1,440,320	582	2,086,470	11,847	29,086,834	12,434	-11,374,814
2002	196	1,440,320	582	2,086,470	12,847	32,340,554	13,774	-12,147,781
2003	196	1,440,320	582	2,086,470	13,847	35,594,274	15,181	-12,959,397
2004	196	1,440,320	582	2,086,470	14,847	38,847,994	16,659	-13,811,593
2005	196	1,440,320	582	2,086,470	15,847	42,101,714	18,210	-14,706,399
2006	196	1,440,320	582	2,086,470	16,847	45,355,434	19,839	-15,645,946
2007	196	1,440,320	582	2,086,470	17,847	48,609,154	21,549	-16,632,470
2008	196	1,440,320	582	2,086,470	18,847	51,862,874	23,345	-17,668,320
2009	196	1,440,320	582	2,086,470	19,847	55,116,594	25,231	-18,755,962
2010	196	1,440,320	582	2,086,470	20,847	58,370,314	27,211	-19,897,986
2011	196	1,440,320	582	2,086,470	21,847	61,624,034	29,289	-21,097,112
2012	196	1,440,320	582	2,086,470	22,847	64,877,754	31,472	-22,356,194
2013	196	1,440,320	582	2,086,470	23,847	68,131,474	33,764	-23,678,230
2014	196	1,440,320	582	2,086,470	24,847	71,385,194	36,171	-25,066,368

Table 3.26 Continued

	Standby Generators		Interruptible		High Efficiency Chillers		SYSTEM TOTAL IMPACT	
Year	kW	kWh	kW	kWh	kW	kWh	kW	kWh
1990	3,692	147,680		0	157	204,414	30,877	52,413,322
1991	9,542	381,680	18,000	0	556	723,912	65,391	71,628,492
1992	11,362	454,480	33,000	0	1,053	1,371,006	97,557	92,333,741
1993	13,035	521,400	52,500	0	1,466	1,908,732	136,154	120,925,013
1994	18,315	732,600	49,000	0	1,939	2,524,578	163,937	161,474,703
1995	21,978	879,120	91,100	7,244,000	2,421	3,152,741	227,593	183,178,962
1996	25,714	1,028,570	92,222	7,288,880	2,914	3,793,467	245,178	201,621,363
1997	29,525	1,181,010	93,366	7,334,658	3,416	4,447,008	263,247	220,657,807
1998	33,412	1,336,498	94,534	7,381,351	3,928	5,113,619	281,810	240,291,495
1999	37,377	1,495,096	95,724	7,428,978	4,450	5,793,563	300,874	260,525,653
2000	41,422	1,656,866	96,939	7,477,557	4,982	6,487,106	320,447	281,363,524
2001	45,547	1,821,871	98,178	7,527,108	5,526	7,194,519	340,538	302,808,370
2002	49,754	1,990,177	99,441	7,577,651	6,080	7,916,081	361,158	324,863,465
2003	54,046	2,161,848	100,730	7,629,204	6,645	8,652,074	382,314	347,532,098
2004	58,424	2,336,953	102,045	7,681,788	7,222	9,402,787	404,016	370,817,569
2005	62,889	2,515,560	103,386	7,735,423	7,810	10,168,514	426,275	394,723,186
2006	67,443	2,697,739	104,753	7,790,132	8,410	10,949,555	449,101	419,252,260
2007	72,089	2,883,562	106,148	7,845,935	9,022	11,746,218	472,504	444,408,107
2008	76,828	3,073,101	107,571	7,902,853	9,646	12,558,814	496,495	470,194,040
2009	81,661	3,266,431	109,023	7,960,910	10,282	13,387,661	521,085	496,613,371
2010	86,591	3,463,628	110,503	8,020,129	10,932	14,233,086	546,285	523,669,400
2011	91,619	3,664,769	112,013	8,080,531	11,594	15,095,419	572,109	551,365,419
2012	96,748	3,869,932	113,554	8,142,142	12,270	15,974,999	598,567	579,704,702
2013	101,980	4,079,199	115,125	8,204,985	12,959	16,872,170	625,674	608,690,504
2014	107,316	4,292,651	116,727	8,269,084	13,662	17,787,285	653,441	638,326,054

The Future

Analysis

SCE&G continues to improve and refine its ability to analyze marketing programs. We see three major opportunities to advance our capabilities: more end-use data, further calibration of our screening models, and better forecasts of market penetration.

To get more end-use data, the Company is participating in an EPRI collaborative effort to build the first large data base of end-use profiles specific to the Southeastern region of the US. We expect to have that information in-house by approximately mid-year 1995.

With this new data, we will be able to further calibrate the engineering simulations we used to calculate load curves for our screening models. The Company has already expended a significant amount of effort to verify the engineering assessments, but more information will allow for finer adjustments.

Finally, the Company is continually gaining experience with its programs. This knowledge will allow further improvements in our ability to project future penetration. Recognizing that fact, the Company has begun research on diffusion models such as Lawrence-Lawton[10] and Bass[11]. More work will be required before we know how useful they will be.

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[10] "Applications of Diffusion Models: Some Empirical Results" by K.D. Lawrence and W.H. Lawton, New Product Forecasting, D.C. Heath and Company, 1981
[11] "A New Product Growth Model for Consumer Durables" by Frank M. Bass, Management Science, 1969, 15(5), pp. 215-227

Benchmarking

When a new program is introduced, SCE&G now establishes internal yard-sticks that can be used to judge its success. One measure is always the number of participants. Another may be free ridership. Regardless of the specific choices, each program is analyzed once every three months to assess its performance. If it fails to meet its internal criteria, then it will be revised or terminated.

New Programs

Real Time Pricing

As presented earlier, SCE&G has an experimental Real Time Pricing rate. Implementing the administrative support requirements, recruiting participants, and fine-tuning the program as we gain experience will be a challenging, but rewarding activity. We have been performing pricing simulations for months, measuring expected versus actual rates. We are now ready to begin signing up customers.

Electrotechnology Programs

There are a number of industrial electrotechnologies which have the ability to increase energy efficiency, improve product quality and mitigate environmental problems. SCE&G plans to develop three programs to promote electrotechnologies to industrial customers. The technologies being evaluated at this time include:

- Infrared drying
- Ultraviolet curing
- Ozone water treatment
- Membrane process
- Induction heating

Once analysis is complete, programs will be developed. Current plans call for completion by late summer, 1995.

Conclusion

Times are changing, and SCE&G is adapting its demand-side management portfolio to respond. Many programs have fulfilled their original objective and are being discontinued. Others such as Standby Generators and Thermal Storage are gaining more momentum every day. We have also introduced several new programs. Table 3.27 shows the present value of the cumulative effect on ratepayers for participation in the programs in the old portfolio and the proposed portfolio over the 20-year forecast period. In the old portfolio, programs that were at one time positive have become extremely negative and warrant change. Clearly, the Company is making major strides in the right direction. The proposed portfolio reduces the impact on rates by over $430,000,000.

Table 3.27 The Present Value Of The Cumulative Effect On Ratepayers Of Participation Over 20 Years			
Program	Old Portfolio	Proposed Portfolio	Difference
Rate 1 (Old Good Cents)	$-324,913,150	$0	$-324,913,150
Rate 7 (REC)	$-53,170,958	$0	$-53,170,958
Good Cents/Conservation	$0	$-139,761,743	$139,761,743
Great Appliance Trade Up	$-53,519,687	$0	$-53,519,687
High Efficiency Heat Pump	$0	$14,968,582	$-14,968,582
Home Energy Check	$-23,063,863	$-17,190,770	$-5,873,093
Off-Peak Water Heating	$-18,271,018	$0	$-18,271,018
Replacement Water Heaters	$0	$70,304,744	$-70,304,744
Commercial HVAC	$-34,575,484	$-12,770,695	$-21,804,789
Fluorescent Ballasts	$-3,296,404	$0	$-3,296,404
High Efficiency Lighting	$-487,135	$0	$-487,135
High Efficiency Chillers	$-3,351,306	$-1,932,245	$-1,419,061
High Efficiency Motors	$-552,268	$0	$-552,268
Variable Speed Drives	$-1,892,595	$0	$-1,892,595
Standby Generators	$4,712,029	$4,712,029	$0
Thermal Storage	$-1,034,149	$973,127	$-2,007,276
Total	$-513,415,988	$-80,696,971	$-432,719,017

In summary, based on these results, we propose the portfolio shown in Table 3.28.

Table 3.28	
Residential Programs	***Commercial & Industrial Programs***
Good Cents / Conservation Program	*Thermal Energy Storage*
Home Energy Check Program	*Standby Generator*
High Efficiency Heat Pump Program	*Interruptible Program*
Replacement Water Heater Program	*Real-Time Pricing*
Time Of Use Rate (Rate 5)	*Time Of Use Rates*
Low Use Rate (Rate 2)	*Commercial Heat Pump Water Heater and Pool Heater Program**
	*High Efficiency Chiller Program ***
	*Commercial HVAC Program***

* Research and Development Program
** Education Programs

We have an obligation to society to promote responsible energy use, to participants to make sure that any DSM program is a positive experience for them, to stockholders to insure long-term viability, and to ratepayers to apply downward pressure on rates. The demand-side management portfolio we are offering balances those obligations effectively.

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CONCLUSION

Introduction

Demand-Side Management Implications For Today's World

The electric utility environment is changing for managers, regulators, ratepayers, and stockholders. Competition is forcing a paradigm shift. Economic efficiency is becoming a necessary precondition for any demand-side management (DSM) program. This is a dramatic move away from, or at least beyond, the previous view shared by all parties that sometimes considered it prudent for a utility to take DSM actions for societal reasons alone. The result was higher rates. A recent study by Oak Ridge National Laboratory concluded that DSM programs often increase electricity prices. "Although such programs may reduce overall electric bills, they typically increase prices slightly over the lifetimes of the measures installed."[1]

In a competitive marketplace, anything which raises costs, applies upward pressure on rates, or creates a cross-subsidization carries risk. If one class of customers receives a subsidy from another class, the benefit probably won't be enough to offset the loss if the latter class disappears from the system.

Throughout consideration of these issues, SCE&G has sought a balanced approach. We have carefully weighed downward pressure on rates vis-à-vis strategic and societal implications. We have changed, eliminated, or replaced many conservation programs that were reported in the last IRP three years ago because of their impact on ratepayers. However, we have also kept some that fail the Ratepayer Impact Measure (RIM) test, an indication of upward pressure on rates. We

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[1] "Price Impacts Of Electric-Utility DSM Programs", by Eric Hirst and Stan Hadley, Oak Ridge National Laboratory, ORNL/CON-402, Nov. 1994.

decided to do so because the cost to society of withdrawing them is too high. Even in these cases, we have taken precautions to minimize the negative effect on ratepayers.

As we discuss in the next section, there are also other DSM objectives besides conservation, and programs that pursue these objectives can have a dramatic, positive impact on ratepayers. We have placed renewed emphasis on such programs.

Looking at the overall plan, we have established a balanced portfolio that will reduce the impact on rates dramatically without abandoning the societal benefits we have pursued for years. We believe we have found the right combination for now, and we have the tools in place to adapt to the future.

Load Shape Objectives

By definition, any demand-side management program has one or more of the following six objectives: peak clipping, valley filling, strategic conservation, load shifting, strategic load growth, or a flexible load shape[2]. For the last decade, much of demand-side management has concentrated on conservation, expecting a secondary benefit of peak clipping. As the rest of this chapter reflects, we are now giving greater attention to valley filling, load shifting, and strategic load growth, all of which optimize the use of production resources and apply downward pressure to rates. This does not mean that we have abandoned conservation and peak clipping. We have

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[2] Demand-side Management: Concepts & Methods, 2nd Edition, by Clark Gellings and John H. Chamberlin, The Fairmont Press, Inc, 1992, pp. 238-240.

several programs targeted to those objectives, and we are considering others for the future. It does mean that we recognize and pursue the other goals too.

Peak Clipping

Demand-side management initially won endorsement by utilities and regulators because of the opportunity to reduce system peaks. By clipping peaks, utilities can defer or eliminate the need to build generation. During the era when DSM rose to the forefront of planning objectives, capacity carried a high price tag and appeared to be in short supply. Over the past few years, the cost of adding new capacity has fallen thanks to technology advances and increased competition in the market for internal combustion turbines (ICTs). The decrease in avoided capacity costs has significantly lowered the value of peak clipping DSM options.

Valley Filling

Valley filling refers to any attempt to increase electricity sales in off-peak periods, whether times of the day or seasons of the year. This is not simply a reallocation of sales; it is an increase in total sales resulting in more efficient system utilization. Downward pressure on rates results from adding incremental sales at times when costs are lower than average.

Strategic Conservation

Early in its development, demand-side management's charter mission to shave peaks was broadened to include strategic conservation of energy as well. Now, conservation initiatives are the cornerstones of many DSM programs. In theory, conservation programs reduce system coincident peaks (see "Peak Clipping" above) as well as total energy use. If the energy use also coincides with the highest fuel costs on the system, then the conservation measures also lower the average fuel cost on the system.

The rewards to the participant are usually significant on paper. After all, the utility company encourages him or her to use less energy, and that reduces electric bills. The problem is that this stream of savings and incentives to the customer is also a stream of losses and costs to the utility. Unless the avoided capacity costs and marginal energy savings are significant in comparison to the revenue loss, it will generally apply upward pressure on rates. In the current period of low avoided capacity costs and relatively cheap fuel, this is a difficult standard to meet.

Load Shifting

Utilities may choose to reduce system peak loads by encouraging consumers to shift their demand to off-peak periods. For instance, a customer may use a chiller to make ice at night, which will cool a building in the daytime, rather than running the chiller across the system peak. Capacity costs are avoided without a corresponding loss in total energy sales. Since plants that use higher priced fuels usually run at the time of the system peak, there is usually a reduction in marginal energy cost as well. The only revenue loss occurs if the utility has a rate differential between the on- and off-peak periods. As long as this revenue loss and the program costs are less than the avoided capacity costs and reduced marginal energy costs, the program applies downward pressure on rates.

Strategic Load Growth

Utilities are businesses. In at least two scenarios, growing those businesses may be highly beneficial financially to their own customers (ratepayers). First, if there are significant economies of scale at the margin to be realized from additional sales, making those sales will lower average costs. This will, in turn, lower rates. Second, during times when capacity is available, the extra sales will increase utilization of that capacity and spread the capital costs over greater sales, again reducing average rates.

Flexible Load Shape

Once a system load shape is derived by taking demand-side management effects into account, the planner must decide on an optimal configuration of supply-side options to meet that load. The decision is influenced by the flexibility of the load (or the required reliability of the supply). Curtailable or interruptible loads, direct load control devices, or pooled energy management systems may give the system operator some control over the load itself. That control has value.

DSM Options

Education

Education can be the most powerful DSM tool available. If the emphasis is strategic conservation, then the customer will save money simply by reducing consumption. If the utility can show the customer ways to accomplish that reduction with an acceptable payback term, then education is frequently the only step required to motivate adoption of a technology or a change in behavior. It is a win-win situation. The cost to the utility is usually modest compared to other methods required to accomplish the goal, and the customer only takes the actions that save money.

The biggest problem with education is that it is difficult to quantify success, so skeptics are often quick to dismiss its effects. A tally of people the message reached and random surveys are two methods of estimating effectiveness.

Pricing Signals

Pricing signals have a major impact on the demand for electricity. They generally fall into four groups: conservation, time-of-use, interruptible, and monthly incentive credits. SCE&G has DSM rates for each of the first three groups.

Conservation

Conservation rates provide discounts for people who use less energy. The methods of deciding who uses less energy vary. For instance, the utility may use a block rate that increases the price for kWh's above a certain level of consumption. SCE&G uses this approach on its residential rates in the summertime. Or, the utility may place all users who consistently use less than a certain number of kWh's on a special rate. This is essentially what SCE&G's Low Use Rate 2 does. Or, the utility may define guidelines such as higher insulation levels to assure that a home or business conserves energy. SCE&G is proposing a new Good Cents/Conservation Rate that defines prescriptive measures to assure energy conservation and give customers who meet those standards a lower price.

Time-Of-Use

Time-of-use rates vary the price by time periods coinciding with system costs. The prices may be published in advance, or they may be set in "real time" as conditions change. Depending on market elasticities, pricing need not track costs exactly. The important objective is to motivate change, which often comes as a mix of peak shaving and valley filling — essentially load shifting. So long as the price motivates behavior that has the desired effect on the system, the ratio of on-peak to off-peak price may be much higher or much lower than the ratio of on-peak to off-peak costs.

The time periods can be any intervals that make sense, from seasons to hours of the day. SCE&G makes extensive use of both methods. Most of its rates have different pricing in the summer and non-summer months. Some vary the price by time of day.

If time-of-use rates are mandatory for all customers in a class, then they can be designed to collect more or less than traditional rates. Most are designed to be revenue neutral. If the time-of-use rates are instead voluntary, then the majority of customers who sign up will be those who need to make few if any changes to save money. A revenue loss to the utility will result (unless the rate is so extreme that no one can save money on it without making changes). So time-of-use rates may or may not affect average prices if the rates are mandatory, but apply upward pressure on prices if the rates are voluntary.

SCE&G has some time-of-use rates that are mandatory (e.g. Rate 24 for commercial customers) and others that are voluntary (e.g. Rate 5).

Interruptible

Interruptible rates provide a discount to customers who are willing to allow the utility to interrupt their service whenever there is a critical need for the capacity used to serve them. The goal is strictly peak shaving. Usually, few if any energy sales are lost. So, depending upon the price, the effect on the average rate paid by ratepayers may be positive or negative (up or down).

SCE&G currently offers an interruptible rider to its large commercial and industrial customers (Rider to Rates 20 & 23).

Incentive Payments and Rebates

Incentives paid by the utility to customers who take a desired action may consist of one-time payments (rebates), monthly incentive credits (typically, on their bill), or annual incentive credits. Currently, SCE&G only uses one-time payments.

Financing

If initial investment costs are considered a market barrier preventing customers from adopting a desired technology, the utility may elect to provide a rebate or choose to finance the investment. The financing has no effect on ratepayers if the interest rate covers the utility's cost of money plus administrative and promotional costs plus bad debt write-offs. To the extent the rate is above or below that level, there is downward or upward pressure on rates respectively.

SCE&G considers financing to be a key service to customers, often providing them with the means to adopt a technology option from which they would otherwise be excluded.

Direct Control

By placing direct load control equipment on a customer's major electrical equipment, a utility company can be virtually assured that the equipment is off at the time of system peak. Since the controlled equipment is typically an energy storage or removal device (e.g. water heater, air conditioner), the energy deferred during the interruption is usually consumed later when control stops. Sometimes, in fact, this "payback energy" is greater than the original energy deferred. This means that there is no revenue loss from energy sales, and there may sometimes be a gain.

The actual kW deferred is often difficult to quantify because some equipment cycling occurs naturally. The diversified system peak demand may be lower than the full-load maximum demand, so the amount deferred may be less than intended.

For utilities, the control equipment can be expensive to install and difficult to maintain. Faulty equipment can leave the utility dissatisfied and the customer displeased. In addition, some customers blame problems with their own appliances on the controller despite the fact they are really unrelated. Perhaps the biggest argument against such programs is that customers may ultimately resent their loss of control.

INTEGRATED RESOURCE PLAN

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4.0 SUPPLY-SIDE PLANNING

1. Introduction

Despite such events as military base closings, the economies of our service territory, the state, and the whole southeast region are growing at rates such that development of new supply-side resources of energy and capacity will have to occur. The Company recognized this fact some years ago, and in 1991 we committed to construct the Cope plant, a 385 MW pulverized coal-fired steam plant to be in commercial service by 1996. Construction of this plant and its related facilities is on or ahead of schedule.

While Cope has been under construction, the Company has generally avoided adding to its generating capability, by means of demand-side management (DSM) programs and by making temporary capacity purchases from interconnected utilities. That strategy will enable us to absorb Cope into our system in 1996 without a capacity "bulge," which is a desirable outcome, but it also means that we will that much sooner need to determine what to do next to serve this continuing growth.

The long-range supply side plan presented in this chapter, like all such long-range plans in the past, is meant to establish a reference, a point of new departure into the future, rather than being an announcement of what we are certainly and definitely committed to carrying out. Decisions are made about resources, not about plans. But resource commitments are made in the context of reference plans, and if such decisions include elements that were not a part of the plan, that is because the new element is believed to improve on the plan. This is the plan to beat--and we will try to beat it, as we find new ideas and opportunities.

If the nature of such long-range plans has been speculative in the past, it is much more so today. Legislative and regulatory changes, both announced and impending, imply great changes in the structure of our industry and of its various players. Reference plans that assume "business-as-usual" circumstances, such as this one, are unlikely to be carried out, because they do not attempt to guess at all the changes the future might hold. Such plans are still necessary, however, if we are to have a way of knowing which changes (of those we can influence or choose) are changes in the direction of improvement.

2. How Different Types of Resources Provide Capacity and Energy

Although much attention gets focused on each year's expected single-hour peak, we expect loads to grow in all hours of the year, so any plan that considers a long horizon has to provide for expansion of energy supply as well as capacity to cover peaks. Because different types of resources have differing capabilities to provide energy and capacity reliably, the need to provide both economically implies a mix of capacity types.

Generating resources are usually classifed as baseload, intermediate, or peaking. Baseload resources are characterized by low variable costs and reliable operability for days, weeks, or even months at a time. Such resources may have high start-up costs, but the costs of few start-ups per year are spread over many hours of operation for a unit operated in a baseload mode. Baseload resources typically have high fixed costs, but they are an economical way to serve a proportion of the Company's energy that is much higher than their share of the Company's capacity, because the high fixed costs per kilowatt of capacity are spread over so many kilowatt-hours of operation. Baseload resources in the Company's current supply mix include our run-of-river hydro units at

Neal Shoals, Parr Shoals, Columbia Canal, and Stevens Creek; our two-thirds share of V.C. Summer nuclear plant; and the ten coal-fired steam units at our Canadys, McMeekin, Wateree, and Urquhart stations, plus the Williams coal-fired steam unit owned by sister SCANA subsidiary South Carolina Generating Company (the Williams unit is dispatched by SCE&G, which is the sole recipient of its output under a wholesale contract regulated by the Federal Energy Regulatory Commission). The Cope plant, which is within months of commercial operation, will also be a baseload resource.

In contrast to baseload resources, peaking resources typically provide a much smaller proportion of energy than their proportion of capacity. For some types of peaking resources, this low capacity factor results from high variable costs--this is generally typical of internal combustion turbines (ICTs), since they burn more expensive fuels and are generally less efficient at converting heat energy in the fuel into electrical energy than are baseload plants. For some other types of peaking resources, the low capacity factor results from limitation on some necessary input, such as natural water inflows into Lake Murray, the reservoir for our five hydro units at Saluda.

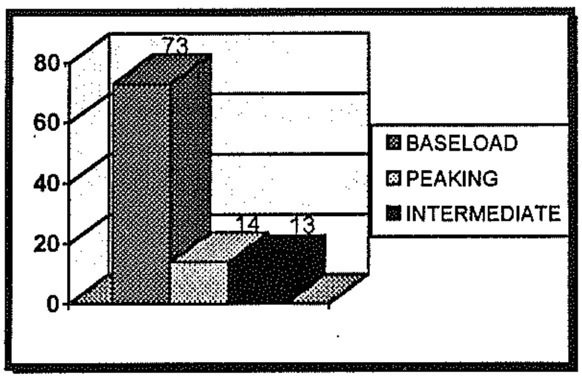
Although peaking resources provide relatively little energy, they ensure system reliability because they can be started either instantly (in the case of Saluda Hydro) or within minutes of being called up (our ICTs) to replace the output of another unit that is unexpectedly forced out of service. Baseload resources that are not on line typically require hours to achieve full output, so one cannot replace another quickly. Peaking resources provide energy during the intervals.

Peaking resources typically have low start-up costs and are engineered to withstand cycling operation. When an operating peaker is no longer needed, the system dispatcher can take it offline without being concerned that he will have made an uneconomic decision if it should suddenly be needed again. And thermal peaking resources--ICTs--have lower construction costs per kilowatt of capacity than baseload resources. A quality frame-built ICT, engineered to high utility standards, will still cost less than half or even a third of the construction cost of a baseload plant, on a per-kilowatt basis.

All utilities but the smallest have some mix of baseload and peaking resources, but not all utilities have intermediate resources. Intermediate resources are most appropriately described in terms of their energy-supply characteristics, rather than in terms of capacity. Intermediate resources supply energy more flexibly than baseload resources and less expensively than peaking resources. For most utilities, "intermediate" means a combined-cycle arrangement in which ICTs driving generators vent their exhaust into heat-recovery boilers feeding steam turbines that drive other generators. Because of the economical use of the otherwise wasted heat, the combined-cycle fuel conversion efficiency is better than that of a simple-cycle ICT, so the energy is cheaper than ICT energy. But because the heat-recovery boiler takes hours rather than minutes to achieve full output, the combined-cycle plant is less flexible in start-up than the same capacity in an ICT would be. The system dispatcher has to be more cautious about taking an operating combined-cycle offline, since it is less flexible in start-up, and since the achieved per-kilowatt-hour variable costs are less the greater the proportion of boiler-output hours to total operating hours per start-up.

Nevertheless, because the ICT component of a combined-cycle can be started quickly, such a plant is more flexible in its energy supply than a baseload plant is.

At SCE&G, the intermediate energy-supply niche is filled by the eight 64 MW pumped-storage hydro units at Fairfield. Fairfield is more flexible than a baseload plant, because the units can be started instantly, and their output can be varied over a wide range without efficiency penalty. But its energy is more costly than baseload energy, since the pumping is done with baseload, during off-peak hours, and there are efficiency losses in the double conversion of the energy. Pumped-storage energy is still cheaper than ICT energy, but pumped-storage dispatch is less flexible than ICT dispatch in one respect: pond capacity is limited so that the plant can produce at most about eight kilowatt-hours per kilowatt of capacity in a 24-hour cycle, while an ICT could produce 24 KWH per KW over the same period.



SCE&G's current mix of capacity types is a balance of about 73% baseload (including nuclear, coal, and run-of-river hydro), about 13% intermediate (pumped-storage hydro), and about 14% peaking (Saluda Hydro and ICTs). The exact balance among these capacity types will change as new units are added. Conceptions about the optimal balance are subject to change over time, since the optimal balance is a complex function of expected fixed costs for various capacity types that might be installed in the future; expected variable costs for all present and potential future capacity types; expected daily, weekly, seasonal, and annual load shapes and load factors; and various financial, environmental, regulatory, and tax considerations. But regardless of variations over time in the balance of capacity types and variations in conception of the ideal balance, SCE&G planners believe that a balanced mix has served the Company's customers well in the past, and that it is appropriate to include a mix of resource types in a menu from which the supply-side aspect of the IRP will make choices.

3. Existing Resources

SCE&G's peak electric generating capability as of the end of 1994 was 3,876 MW. This capability is composed of coal-fired, nuclear, hydroelectric, and oil- and natural gas-fired generating resources. Coal-fired generation contributes 57% of the system capability, nuclear 15%, hydroelectric 19%, and oil and natural gas 9%. A detailed listing of generating units is provided at the end of this chapter. Net capability for each generating unit is expressed in both summer and winter capacity ratings. The winter rating of thermal generating units is typically higher than the summer rating. In the winter the lower ambient air temperatures (ICT) and condenser circulating water temperatures (coal-fired, nuclear) improve the operating efficiency of the generating equipment, resulting in an increase in power output.

Included in SCE&G's generating capability is its two-thirds (590 MW) ownership interest in the 885 MW V. C. Summer Nuclear Station. The remaining one-third is owned by The South Carolina Public Service Authority. Also included in SCE&G's generating capability is the 560 MW A. M. Williams Station, which is owned and operated by South Carolina Generating Company. All of the output from the Williams coal-fired unit is sold to SCE&G under a long-term contract.

4. Maintenance and Refurbishment Plan

The maintenance of generating units on SCE&G's system requires careful planning and scheduling so as to minimize the risk of a capacity shortfall at any time during the year. A certain amount of flexibility is necessary when developing a comprehensive maintenance schedule for an electric utility system with a large number of generating units. Over the years SCE&G has developed and refined procedures to plan for and schedule maintenance outages for its coal, nuclear, hydroelectric, and oil and gas-fired power supply resources. This scheduling process could become quite unmanageable without a structured procedure for handling the timing of unit maintenance and refurbishment outages.

The operating nature of generating units on SCE&G's system dictates, for the most part, when they can be taken off line for normal and major maintenance outages. SCE&G's generating capacity is composed of baseload (73%) and peaking/intermediate (27%) type units.

Those units which fall into the baseload category (coal- fired, nuclear, and run-of-river hydro) typically have their maintenance periods scheduled in the off-peak seasons of the spring and fall. Because of their relatively small contribution to baseload capacity the run-of river (ROR) hydro units can be on maintenance at other times of the year as the amount of rainfall and resulting riverflow dictate. The timing of maintenance of peaking/intermediate units on SCE&G's system (ICTs and storage hydro) is not as critical as that for baseload units since their utilization is significantly less and when operated it is for shorter durations. As a matter of practice, however, these peaking units are normally scheduled for maintenance during off-peak seasons.

The scheduling of maintenance for generating units at SCE&G is looked at on both a short-range and long-range basis. The near-term maintenance outage projection covers an eighteen-month period and is updated as unit maintenance progresses into the maintenance window. A current short-range maintenance schedule is provided in Table 4.4.1 at the end of this chapter section. For long-range planning purposes the major maintenance outages for existing coal-fired and ICT units are extended into the future using a five-year cycle for ICT units and a six-year cycle for coal-fired units. For each of the first four years of the five-year cycle for ICTs, routine inspection and maintenance is performed on the generating units. This is also true for the first five years of the six-year major maintenance cycle for coal-fired units. In the last year of the cycles more thorough inspections are made, and extensive work is required which includes a turbine/generator overhaul. A table of long-range maintenance projections indicating the normal annual spring/fall outage days and major outage days by individual generating unit can be found in Table 4.4.2. Currently the long-range modeling projection for normal maintenance days is constant, but as the generating units on SCE&G's system continue to age, consideration for increasing the length of a normal maintenance outage will become more of a key issue in establishing future maintenance procedures.

The two largest generating units on SCE&G's system are the A. M. Williams coal-fired facility in Charleston and the V. C. Summer Nuclear Station in Jenkinsville. For reliability purposes these two generating facilities do not have their scheduled maintenances at the same time. This significant operating procedure is taken into account when the long-range projection of scheduled maintenance for the Williams unit is being developed.

The refueling outages for the Summer nuclear station are scheduled on an eighteen-month cycle. These refueling outages are currently projected to last approximately forty days. A major maintenance project was undertaken during the Fall 1994 refueling outage. This project consisted of the replacement of the steam generators with the outage lasting approximately ninety-eight days.

To comply with the Phase II January 1, 2000, requirements of the 1990 Clean Air Act Amendments, SCE&G will need to implement some measure of system-wide reduction in SO2 emissions. This may involve a retro-fit of flue gas desulfurization (FGD) equipment at one or more of SCE&G's existing coal units. With the purchase of SO2 allowances in 1994, earlier plans to install scrubbers at existing coal units by the year 2000 have been delayed several years. Current maintenance plans for the Williams and Wateree units include the installation of scrubbers some time after 2000. To comply with the Phase II requirements, SCE&G will also need to reduce NOx emissions from its coal-fired units. This can be accomplished with the installation of low NOx burners in some or all of the existing coal-fired units. Current maintenance plans for each existing coal unit allow the inclusion of low NOx burners in the late 1990's, if regulations (not yet released) should require that degree of compliance.

5. Purchased Power

Capacity in 1995:

In 1995, the last year before Cope is added to SCE&G's system capacity, our owned reserves after the forecast summer planning peak demand is subtracted from our system capacity amount to only 343 MW, a level so low that the loss of any one of four of our generating plants (Summer, Williams, Wateree 1, or Wateree 2) would result in an unscheduled dependence on our transmission ties with our neighbors. We could also find ourselves in a capacity deficit if combinations of smaller plants were to be forced offline.

For the past two summers SCE&G has contracted quantities of limited-term capacity from Carolina Power and Light, with whom it shares interconnection. We have also watched the markets for spot capacity during these years. Because the spot market opportunities have been favorable, SCE&G has not felt compelled to tie up capacity so far in advance for 1995.

SCE&G is holding discussions with other potential suppliers of capacity about our straitened situation in 1995, and it is still possible that we will make some sort of limited-term arrangement before the arrival of the summer season. However, no decision has been reached at the time of this filing. Even if we do not make capacity purchase arrangements ahead of time, we will watch spot capacity markets, and we will make spot capacity purchases as need arises, in order to fulfill our obligations to our firm customers and to the other utility parties to the VACAR Contingency Reserve Agreement.

Opportunity Energy Transactions:

SCE&G has as a matter of course maintained a real-time awareness of the marginal energy cost situations of the utilities with which it is interconnected, in order to identify opportunities for mutual benefit in economy energy transactions. Now SCE&G is participating in the establishment of the AIMS project, which is described elsewhere in this chapter. AIMS will provide an hour-ahead posting of economy transaction opportunities among a much wider group of participants, including utility and non-utility sources, all of whom will have been qualified by appropriate interchange agreements to do business with each other. AIMS should extend our capability to find economy transactions.

Long-Term Transactions:

The supply plan presented here does not include any long-term transactions beyond the assumption that SCE&G's contract to purchase power from South Carolina Generating Company's Williams plant and its contracts to sell power to its current full-requirements wholesale customers will continue through the plan horizon.

The absence of long-term power purchases in the base case supply plan is not intended to imply any determination against such purchases. Because of changes in law and regulation, both accomplished and impending, such long term supply arrangements will be much more frequently encountered in the future than in the past. However, because such deals are packaged and repackaged in such a variety of ways, it is not very meaningful to try to model a "generic" contract. And because Cope will supply our capacity and energy needs for some period of time, it would be inappropriate for SCE&G to invite parties to make us proposals merely to have some proposals to model.

6. Utility Joint Planning

Utilities sometimes combine forces to plan, own, or operate generation resources. SCE&G, for instance, operates the V. C. Summer Nuclear plant, but it shares ownership of the plant with the South Carolina Public Service Authority. SCE&G has in the past considered several sorts of joint participation with other utilities, considering among other things some particular opportunities arising from some baseload capacity in a neighboring state that was utility-owned but excluded from rate base. At this time, however, the Company is not actively discussing joint ownership or operation of any project.

Besides special situations such as the one mentioned above, utilities that enter into joint generation planning generally do so for one of two reasons. One or some of the utilities may be too small to absorb the output of a large project, but may wish to capture economies of scale in construction and operation, especially for a baseload resource. Or utilities may wish to take advantage of the fact that they have differing load patterns. Utilities that typically peak in the winter may combine with summer-peaking utilities to plan peaking-capacity projects that will serve either in turn.

Neither of those circumstances applies to SCE&G, however, or to any of the utilities with which it is interconnected. SCE&G is not a small utility, and all the utilities in South Carolina and in neighboring states tend to peak at the same time, summer and winter. The conditions that normally may lead to economies in joint long-range power supply planning do not obtain in South Carolina at the present time, and uncertainties about the forms and directions of national energy policy, currently being shaped, will probably make utilities reluctant to explore long-run possibilities with each other.

The fact that SCE&G is not currently involved in a long-range joint generation project does not mean that the Company is operating without information about or consideration for the plans and operations of neighboring utilities, however. SCE&G is an active member of the Virginia-Carolinas (VACAR) subregion of the Southeastern Electric Reliability Council (SERC), which is one of the regional members of the North American Electric Reliability Council (NERC). SCE&G is an active participant in the VACAR, Southern, and TVA (VST) group. These are all levels of associations of utilities, both private and public, intended to secure the adequacy and reliability of bulk power supply systems, considering both generation and interconnected transmission. SCE&G has representatives on all VACAR and VST committees, task forces, and working groups. Members share information on their current and projected future situations, up to the point of protection of proprietary information, and they share the tasks of modeling interutility effects and power-flow results of various contingencies. There are several VACAR meetings of one kind or another each year.

SCE&G also has schedules of terms for various sorts of temporary interchanges with all the utilities with which it is interconnected. SCE&G's System Control Department discusses operations under these agreements with VACAR and Southern companies several times a year, evaluating current operations and considering potentials for improvements and extensions of uses of the system interconnections. SCE&G's Chief Dispatcher talks with his counterparts at neighboring utilities daily, as they plan day-ahead to week-ahead operations to capture transaction economies, and SCE&G duty dispatchers confer with neighboring dispatchers many times each day, to coordinate immediate economy or emergency transactions.

In preparation for open access transmission system, SCE&G will be working to increase its short term wholesale purchase and sales markets. To this end, SCE&G is currently participating with 31 other utilities to develop and implement an electronic non-firm hourly energy trading system. As envisioned, the Automated Interchange Matching System (AIMS), as it is called, will electronically match prospective buying and selling utilities for next hour transactions. AIMS will not be a contracting mechanism, but rather a system which will facilitate energy trades using existing bilateral agreements among the participants. SCE&G is presently negotiating purchase and sales agreements with AIMS participants with whom we do not presently have interchange agreements. To date, we have secured a FERC approved agreement with Florida Power & Light Company and anticipate more filings in the near future.

SCE&G anticipates filing a FERC devised pro-forma open access transmission tariff in response to the FERC NOPR dated March 29, 1995. The majority of SCE&G's neighbors will be doing the same thing. As the number of transmission wheeling transactions increase in this region, SCE&G will have to work even closer with its neighbors to ensure the security and reliability of the interconnection. This coordination will take place on an hour-by-hour basis to avoid overloading of lines and preventable transmission related outages.

7. Owned Resource Options

The types of generating supply technologies considered by SCE&G in the IRP process can be assigned to two primary categories, conventional and non-conventional. A variety of both conventional and non-conventional technologies have been screened by SCE&G during the IRP development. The technology screening process considered, for example, such areas as operating experience, capital cost, equipment efficiency, available unit sizes, topographical conditions of service area, and land requirements.

SCE&G has taken upon itself the responsibility to review available non-conventional generating technologies for consideration as potential supply side candidates in the IRP process. The conclusions drawn from a recent review of these technologies are given in Section 6.3. Currently these technologies are not considered to be appropriate for inclusion in the Company's future generating resources. Because of the lack of maturity of the technology or inappropriate topographical or climatological conditions of SCE&G's service territory, some of the non-conventional power supply sources were not considered feasible. Other candidates did not pass the screening process when their capital and operating costs were compared to those of conventional power supply technologies. As a result of this review, SCE&G has concluded that there does not currently exist a non-conventional supply technology which exhibits both the maturity and the competitive costs required to be selected as a viable supply side alternative.

Several non-conventional technologies, such as those with distributed generation applications, may soon become competitive with conventional approaches. Two of these include fuel cells and solar photovoltaic cells. Recent advancements in these technologies have been lowering their capital and operating costs to some extent. The future potential of fuel cells and solar photovoltaic cells looks promising for the electric utility industry. While their inclusion in SCE&G's generation expansion planning process is not currently feasible, these two supply technologies will be re-evaluated in the future. As more new non-conventional technologies emerge and existing ones progress, SCE&G will continue to evaluate these as supply alternatives and monitor their development.

Those technologies that fall into the conventional category are ones of traditional engineering design which have a proven record of reliable operation. A history of actual operating costs and plant performance data are two major strengths of a conventional electric utility supply technology. Continuing refinements and modifications to the original engineering design of a conventional source improve both the efficiency and safe operation of this type of technology.

The menu of conventional supply technologies which SCE&G included in its IRP process consisted of seven unit types:

400 MW Scrubbed Coal Unit (SCE&G built)
300 MW Scrubbed Coal Unit (SCE&G built)
200 MW Scrubbed Coal Unit (SCE&G built)
400 MW Combined Cycke Unit
150 MW Simple Cycle Internal Combustion Turbine
136 MW Simple Cycle Internal Combustion Turbine
136 MW Simple Cycle Internal Combustion Turbine with Selective Catalytic Reduction Device

Descriptions of these technologies along with their associated costs and operating characteristics can be found in Section 4.12.

The pulverized coal units included for consideration in the IRP ranged in size from 200 MW to 400 MW. This range allowed for flexibility to match load growth and a varied selection for the expansion optimization process. These pulverized coal units included environmental equipment for the removal of SO2 (dry scrubber) and NOx (selective catalytic reduction, SCR). A discussion of the processes for removal of SO2 and NOx can be found in the technical write-up for pulverized coal units in Section 4.12.

The combined cycle unit considered as a viable conventional supply technology consisted of two 136 MW internal combustion turbines (ICT) heat recovery boilers that produce steam for one steam turbine. The resulting output of the combined cycle is 1.5 times the combustion turbine output (408 MW). Each of the ICTs contained a selective catalytic reduction device for NOx control. The associated capital and operating costs of the SCR equipment were taken into account.

Two capacity ratings were considered for the simple cycle ICTs, 136 MW and 150 MW. The generating output of both ICTs was based upon a 105°F ambient temperature. Each ICT was developed with the same basic design but power augmentation through water injection gave the 150 MW unit its additional capacity output.

The 136 MW simple cycle internal combustion turbine was included as a conventional supply technology in two different configurations, with and without selective catalytic reduction. Selective catalytic reduction technology is not applicable for a generating unit without a heat recovery boiler. The SCR process is a post-combustion process for the removal of NOx from the flue-gas. The exhaust temperature from an ICT is too high for the catalyst used in the SCR process. Thus, to apply an SCR device to a simple cycle turbine, a heat reduction boiler must be added as well as a cooling tower to dissipate the heat recovered. These additions increase both the capital costs and maintenance costs and are reflected in the technical data. Although this particular ICT configuration was included in the menu of conventional technologies for consideration, the requirement of SCR devices on simple cycle internal combustion turbines are not necessary with generating units typically operating as peaking capacity for less than 1500 hours annually.

8. Supply-Side Plan Preparation

The IRP process at SCE&G is a sequential process which begins with development of a supply-side plan to meet energies and demands in a new forecast cycle, using forecasts that assume some continuing effects from demand-side programs approved during the prior planning cycle. The results of that plan are used to develop reference values for avoidable generation resources that can be used in the next round of planning for demand-side programs. After the next round of demand-side planning has been completed, the territorial energy and demand forecasts are revised to reflect new programs or changes in existing programs, and a new supply-side plan is fitted to the revised forecasts. That plan, once tested and validated, is compared to the first plan. If there are significant differences, then a subsequent cycle may be required, in which demand-side plans are re-fitted in consideration of new avoided costs, and then energy and demand forecasts are revised again, and yet another supply-side plan is prepared. The entire IRP process is considered to have converged on a demand-side supply-side solution when a supply-side plan fitted to forecasts altered by the most recent round of demand-side work is not significantly different from the supply-side plan that preceded the demand-side work.

The primary function of supply-side planners in the process is to use their information, methods and computer models to identify a plan that provides energy and reserves to serve the growth that the Company expects to see in its service territory requirements after DSM effects have been taken into account, and that also minimizes the sums of the revenue streams required to finance and construct new resources; to operate, maintain, and fuel all new and existing resources; and to meet all legal, contractual, and regulatory obligations.

It is important to stress that the supply side of IRP planning is a generalized process that uses generic information. It is not aimed at a specific supply resource decision objective. Such decisions are made on a case-by-case basis, and they are not made without considerable additional study, which may take into consideration any or many of a number of factors and conditions not considered in the IRP supply plan.

Supply-side IRP planning determines the timing of resource additions, considering only the growth in energy requirements of the Company's territorial and wholesale customers and the growth in capacity requirements of our full-requirements customers. Supply-side IRP planning determines the arrangement of types of resources considering one consistent set of assumptions about future costs of all kinds. And supply-side IRP planning considers a scope of obligations and opportunities neither smaller nor larger than SCE&G's assigned service territory. The result is a narrowly defined base-case plan that becomes "the plan to beat." It is important to realize that because real-life decision circumstances are seldom so narrowly defined, it is not only possible but likely that "the plan to beat" will be beaten.

For example, a decision process that can take into account timing in growth of loads, and at the same time moves to take advantage of temporary financial circumstances, or slack conditions and soft prices in the market for some input, or the timing of needs or planned resources by some neighbor utility, is very likely to produce better decisions than a process that looks only at the timing of territorial load growth. A sequence of decisions made over time, with changing expectations about various future prices, will likely yield better results than would be possible if all the decisions were made and committed to at one time. And a decision process that can consider either very local circumstances and opportunities, such as local transmission needs or cogeneration opportunities, or very broad circumstances, such as the plans and activities of other power market participants over a broad region, will probably produce a better result than a plan that has strictly a service-territory scope.

The facts of life in the preceding paragraph should not be regarded as disparaging of the IRP supply-side process base-case plan, however it may seem. The base-case plan does not take advantage of all the information that is typically used in a particular resource decision process, but it does have the advantage of consistently "taking the long view" in a way that may otherwise not be adequately considered as individual decision steps are taken. Since every generation resource that may be added is baseload or intermediate or peaker, a series of decisions that ignored long-term considerations might result in a capacity mix that becomes seriously out of balance as one after another after another of the same type of resource is added. But a process that schedules several resources over a long horizon will identify a mix that achieves or maintains a good balance of resource types for the long run. The value of a long-run base-case plan is to raise the possibility that a potential decision that is out of line with the plan, but that is being considered because of some immediate circumstances or objective, may be a bad decision because the immediate objective is contrary to a long-range objective.

Supply-side planners at SCE&G concentrate on providing the long-run perspective in developing the IRP supply-side base-case plan. Plans are developed over twenty-year horizons, and planners model dispatch of the resulting systems for at least ten years beyond installation the of the last resource, in order to understand the economics of different supply resources as they are used, and not merely as they are acquired. Planners at SCE&G make use of various commercial and custom software products. Primary among the commercial products for this type of work is EGEAS, which is actually a system of software modules. Originally developed as an EPRI product, EGEAS has for many years been distributed and maintained by Stone and Webster, an engineering consulting firm. The EGEAS application that is most useful for the IRP is a tree-and-branch search for the optimal combination of different resource types and timing, given a pattern of loads and a menu of eligible resources along with their fixed and variable costs and an appropriate discount rate. This search is repeated each year over the specified planning horizon. Since this goes directly at the objective of the supply-side part of the IRP process--a minimized sum of discounted flows of revenue requirements--this is a very useful model. But the analyst must be very careful using and depending on EGEAS, for several reasons. There are several refinements of unit operation or description which EGEAS may not model very reliably. EGEAS seeks an optimal solution subject to constraints, but the model's ability to receive information about some kinds of constraining conditions is limited. And there are some circumstances, especially when more than a small number of resource types are included in the menu, when EGEAS may produce a solution which is not actually optimal, by EGEAS' own terms. Use of EGEAS requires much testing, experience with the model, and experience in supply planning work.

EGEAS outputs can be sent to files that can be imported into spreadsheets or other customer applications in general-purpose software; these may be the work of generation planners or financial planners or others, as appropriate. Such applications may develop information beyond EGEAS' capabilities or test EGEAS results in various ways.

9. Assumptions and Inputs

Supply-side planners begin with given and assumed information and work toward what is not yet known. Full input datasets include thousands of pieces of information, but some particular givens and assumptions in the 1995 IRP process should be identified.

The completion, commercial operation, and inclusion in regulatory ratebase of the coal-fired plant currently under construction at Cope, South Carolina, is assumed. Construction of the generating plant and of the associated transmission is on or ahead of schedule, and SCE&G confidently expects that the plant will be in full service early in 1996. SCE&G also assumes that some uprate projects that will be undertaken at V.C. Summer Nuclear plant during the next refueling outage, in the spring of 1996, will yield some additional generation. The entire scope of the uprate projects has not been settled at time of this filing, but an estimate of a 30MW net increase in SCE&G's two-thirds portion of the plant's output has been used for these studies. (The various VCSN uprate projects are different from the steam generator replacement project, which was completed during the fall, 1994, outage. The result of the steam generator replacement was a greater efficiency that has yielded a net increase in SCE&G's part of the plant's capability of 8MW, except in the summer season. Because of SCDHEC constraints on the release of heat into Lake Monticello, we expect that summertime plant operations may have to be limited to a level that produces the same MW output as before the steam generator replacements, although the efficiency gain means that less fuel will be consumed to produce that output.)

A more general assumption is that new resources will be needed only for growth of customer loads after demand-side program effects have been netted out, rather than for replacement of retired resources. That may be an optimistic assumption; nevertheless, SCE&G does not have an operational retirement date scheduled for any of its plants.

Considering constraints on Company operations imposed by the 1990 Clean Air Act Amendment, supply-side planners have eased environmental constraints on our plants through 2002. SCE&G has no plants affected by Phase I of the CAAA, and the Company determined a few years ago that its best course of action for Phase II SO2 compliance would be to purchase EPA-sanctioned SO2 emissions allowances to allow postponement of a decision to retrofit flue-gas desulfurization equipment (FGD, or "scrubbers") for at least a few years. The Company has purchased or committed to purchase emission allowances that it judges will be sufficient to allow it to comply during the first three years of Phase II without forcing it to go to such measures as gas co-firing at coal plants. After 2002, supply-side planners have altered the model inputs relating to operational and emissions characteristics of the Williams and Wateree plants to emulate the installation of "dry" scrubber technology, similar to that which is being installed at the Cope Plant.

This assumption for modeling purposes should not be taken as a statement of policy. It is necessary to reflect the effects of our obligations under the CAAA in some way, and this method identifies a boundary to our compliance costs. The Company had concluded earlier that of the SO2 compliance options available to it, excluding the purchase of emissions allowances, the least costly would be retrofitting dry scrubbers at some of its existing plants. The Company also determined that the relatively low cost of emissions allowances made postponement of a commitment to scrubber installation not only possible but also positively beneficial, and so it undertook to buy allowances to accomplish a three-year postponement. Within the next year, the Company will review its situation and determine whether to purchase more allowances and extend its postponement of scrubber capital projects. Whatever the decision, the cost should not be greater than the cost to retrofit scrubbers at the designated plants, so modeling those retrofits simply establishes the outside bound of the consequences of the SO2 provisions of the CAAA for SCE&G.

The assumption of scrubber retrofits at three plants in 2003 involves decreases in net output at those plants, primarily because of parasitic electric load, and increases in O&M costs, primarily because of the cost to acquire, deliver, store, handle, and dispose of the reagent. It is important to include these changes in operating characteristics of the plants, because total annual system dispatch is thereafter not simply an economic dispatch, but must also keep within annual

SO_2 limits without depending on emissions allowances. In reality, the Company will have greater flexibility than EGEAS can model, but EGEAS can establish an outside bound on the combined costs of generation and compliance.

One final item in the category of general assumptions arises from the supply-side planning functions that were part of the general Company budgeting process completed in fall/winter of 1994, to establish plan and budgets for 1995 and beyond. The supply-side plan submitted to management was accepted as far as the selection and sequencing was concerned, but management asked to see plans that were more attenuated. Perhaps we may find other demand-side or even other supply-side solutions to the problems presented us by growth. But this directive was also in part a response to concerns about the wisdom of construction that might be in any way undertaken ahead of need in a more competitive business environment.

Company planners prepared a budget generation expansion plan that preserved the character of its first recommended plan, but that "stretched" installation of its elements somewhat. The resulting plan, that began with Cope and nuclear uprate capacity in 1996, followed by several large-scale simple-cycle ICTs and finally by a mid-sized coal-fired steam plant late in the plan horizon, was the basis not only for budget-cycle planning, but also for the avoidable cost calculations that were used by demand-side planners in developing their program evaluations.

10. The IRP Supply Plan

When the work of demand-side program specification had been completed and the territorial energy and demand forecasts had been adjusted for DSM program effects, the supply-side effort was renewed. Besides the new energy and demand forecasts, some other inputs had been updated since the time of the first-round budget cycle supply-side plan had been prepared, but no inputs had changed by very much, including the load forecasts. Consequently, when EGEAS was used to respecify a supply plan, it produced the same plan that had been used in the budget business plan. The Cope plant and the uprate at V.C. Summer nuclear plant add 415 MW of baseload capacity in 1996. Then large peakers (150 MW or so) are added in 1999, 2001, 2004, 2006, and 2008. Finally, a mid-sized coal-fired steam plant appears near the end of the planning horizon, in 2012, preceded by a few years of temporary capacity purchases. (For a detailed schedule, see Table 4.10.1.)

Like the 1992 IRP plan, the 1995 plan mixes baseload and peaking resources, but the mix is a little different. The 1992 twenty-year supply-side plan included 693 MW of peaking resources and 995 MW of baseload resources, for a total of 1688 MW. In 1995, the total MW in the plan amounts to 1565 MW, 750 MW in peakers and 815 MW in baseload. The proportion of peaking capacity in the mix has changed, rising from 41% in 1992 to 48% in 1995. Compared to 1992, peakers are more successfully competing for a place in the mix, and the reason for that success is reduced costs to acquire and construct such plants. There is an aggressive market among firms that engineer and construct baseload plants and firms that manufacture their components, but that was as true in 1992 as it is in 1995. There is a more aggressive market to engineer and construct peaking units in North America in 1995, in part because some manufacturers that had previously attempted to sell into North American markets out of offshore engineering and manufacturing operations have now opened plants and divisions located within the U.S. Quoted prices for utility-grade ICTs have dropped from around $400 per KW in 1992 to less than $300 in 1995, so such units are more successful in capturing a greater share of the future mix than they had been in previous plans. (It is important to remember, however, that an initial price quotation and a price formally agreed to in a binding contract are not necessarily the same thing, and SCE&G has not entered into any such contract.)

The 1995 plan, like the 1992 plan, does not include any intermediate capacity. SCE&G did include in EGEAS' resource menu combined-cycle installations based on essentially the same ICTs that successfully appear as simple-cycle peakers, but EGEAS did not select this option, even when it was offered as something that could be installed in stages. The peaker portion of a combined-cycle plant was cheaper in 1995 than in 1992 but the heat-recovery boiler and related equipment were not, so the relative decrease in the installed cost of a combined-cycle plant was less than the decrease for a simple-cycle peaker. And the efficiencies of simple-cycle units have improved and are likely to be improved further, which means that they cut into the advantage of combined-cycle. Finally, the niche for intermediate-resource energy is already well served by our pumped storage, and as long as we can provide off-peak baseload energy for pumping, other intermediate resources will have a difficult task to out-perform Fairfield.

As in 1992, SCE&G supply-side planners ran sensitivity studies to see what adjustments in expected fuel prices would be necessary to allow a combined-cycle plant to find its way into an EGEAS-selected plan. We found that we could cause combined-cycle to "bump" the coal plant that appears near the end of the planning horizon either by reducing the initial price of gas lower than forecast (keeping its price escalation the same as that for coal, which is lower than forecast for gas), or by reducing the forecast escalation of the delivered price of gas to a rate not just below forecast but well below expected inflation. These studies were made to see whether combined-cycle's exclusion was the result of a near miss, or whether its economics were clearly inferior, and we did not find a near-miss situation. Furthermore, in cases where combined-cycle fuel costs were reduced enough to bring it into an expansion plan, it displaced baseload capacity rather than peakers, even though the peakers were not allowed to take advantage of the postulated cheaper combined-cycle fuel.

If combined-cycle is to compete with coal-fired generation, it must clear the hurdle of the current and potential future cost of its fuel. Even with its higher environmental compliance costs, coal is a low-cost fuel, and its future price escalation is credited with a high degree of predictability. Since the niche available for combined-cycle at SCE&G is displacement of baseload, its fuel must be regarded in light of a baseload-appropriate horizon, thirty or forty years or more. Supply-side planners at SCE&G are dubious that gas prices can stay predictable (not to mention low) over that long a horizon.

That position is debatable, but it is not particularly important to debate it at this time, because the next type of resource that SCE&G will need is a simple-cycle peaking resource, rather than a combined-cycle, under any scenario we have studied. As time passes and peakers are installed (assuming that the plans were actually to be carried out), information may develop that passes an advantage to combined-cycle or some similar or successor technology that it does not enjoy today.

Finally, the future baseload in the base-case supply plan this year consists of one 400 MW coal-fired steam plant. In 1992, the plan included two 300 MW plants, but the greater participation of peaking capacity in a plan with fewer megawatts added overall can be accomplished only by a reduction in baseload capacity. There is not much significance in the size of the plant--SCE&G supply-side planners have seen successive plans trade 300 MW and 400

MW plants off against each other repeatedly over the last several years. We conclude that generally a mid-sized coal plant suits the Company's scale well, and that a more precise determination of the size of the plant must await the better information that we expect to have when (if) the time arrives to make a decision on another baseload plant.

Economies of scale favor even larger plants, but plant outputs must be absorbed if the plants are to be justified. SCE&G might participate in such economies if such a plant were part of a joint project or if part of its output were sold away from its territorial customers, but such a scenario is outside the scope of what the IRP basecase considers. Similarly, smaller baseload plants have inferior economies of scale, but if SCE&G had found smaller increments of baseload over the years in economical projects with a local focus (such as cogeneration projects, for instance), then smaller baseload plants might turn out to fit our eventual circumstances best. That possibility is also outside the scope of what the IRP basecase can consider, since its focus is neither larger nor smaller than our service territory.

11. Flexibility and Risks

The 1995 base-case IRP plan providesthe Company with supply-side flexibility to manage either higher or lower growth in customer requirements than is posited.

Growth lower than expected can be managed by postponing commitment to successive elements of the plan, since nothing in the plan except for Cope has actually been placed under contract.

Growth higher than forecast may also have to be accommodated. The degree to which construction of new resources can be postponed by conservation efforts will be ultimately determined by our customers. Customers make both long-run and hour-to-hour decisions about their uses of energy, and customers presumably weigh the value of what they receive for their energy dollars against whatever else they might receive for those same dollars. Only wasted energy has zero or negative value for customers and many energy purchases provide high values for customers, much higher than the energy cost. SCE&G promotes high-value use of energy as a means of improving the productivity of the economy of its service territory and improving the quality of life for the people who live there. As the service territory economy grows, as the population grows and becomes more affluent, and as the value of energy services increases relative to other values, customer demands will grow, and the Company's planning will need to provide the flexibility to manage success in creating high-valued energy just as much as it needs to provide flexibility to manage success in promoting conservation.

SCE&G could accommodate growth higher than forecast by accelerating the components of its IRP supply plan, by enlarging components of its plan, or by going beyond the structure of the plan in some way. Acquiring a part of some resource too large to fit our needs alone would go beyond the IRP basecase boundaries, but we would certainly be willing to study such a proposal. Participating in cogeneration or other energy projects with particular industrial customers would likewise be something not envisioned within the scope of the IRP basecase, but such projects might help the Company move toward accomplishing some overall cost-minimizing objectives as well as advancing some local or customer-specific objectives.

Some risks arise that are particular to the character of the plan for several years after the Cope plant becomes commercial. All of the next several resources will be fired by natural gas, with #2 oil as a winter-season fuel. Although our expectations may change, we currently do not expect to need much energy from these resources for many years, but we do expect that we will need to be able to use their full capabilities at some points during every year. Because these machines require both high volumes and high inlet pressure in the gas delivered to them, finding sites for them will mean taking into account the ability of the gas service to the sites to deliver gas to all other firm loads served from the particular gas pipeline and at the same time to deliver gas in sufficient volume and pressure to serve all the peakers connected to that same pipeline. Reliability of the electricity supply for the region and the system will depend directly on reliability of the gas supply to the site.

Sites for peaking units are often chosen so that generation from the units can reduce stress on the local electric transmission system under some high-load or emergency circumstances, saving money by postponing transmission or substation upgrades. But if siting peakers to save electric transmission upgrates requires gas transmission in the form of enlarged or additional pipelines or additional compressor stations, then the overall project economics may not support that site. Because the IRP process considers only the timing and not the location of resources, the siting studies that will eventually have to be made for these peakers will have to go beyond the issues considered in the IRP.

Finally, the Company's planning processes may also have to be able to accommodate industry conditions, an industry structure, and corporate structure and division of responsibilities that are different from those that obtain at present. It is widely expected that open access to the transmission network, at least for wholesale transactions, will be a fact of life for utilities and other market participants before the first Short Term Action Plan follow-up to this IRP is published. As the Company's situation, obligations, and opportunities are changed, the Company itself and its planning process will have to change.

12. Technology Review -- Conventional

Pulverized Coal (Scrubbed)

The process of producing electricity in a power generating facility which uses coal as its primary fuel is one whereby the coal is burned to produce heat, which in turn is used to generate steam required to operate a steam-turbine generator.

The start-up of a coal-fired generating unit requires the burning of either gas or oil or a combination of both to initiate the combustion process and to reach the ignition temperature of coal. After sufficient heat is attained inside a large waterwall-lined furnace (boiler), the coal fuel can be added. The raw crushed coal is first pulverized and then blown with air into the boiler where the coal dust immediately ignites due to the extreme temperatures inside the boiler. Once the combustion process with coal is established, the start-up fuel(s) are discontinued and the process is self-sustaining with the continuous inflow of pulverized coal.

The heat produced by the combustion of coal inside the boiler is transferred to water which boils to generate steam. The steam is then forced across the blades of the steam turbine which rotates and spins, by means of a common shaft, the turbine-generator to produce electricity.

The major components of a pulverized coal-fired unit include coal handling equipment, steam generator equipment, turbine-generator equipment, flue-gas desulfurization system (FGD), fabric filter (baghouse) or electrostatic precipitator (ES), bottom ash handling system, and the stack.

The steam generator equipment consists of the coal pulverizers, burners, waterwall-lined furnace (boiler), superheater, reheater, economizer heat transfer surface, soot blowers, air heater and forced- and induced-draft fans. The turbine-generator components include the main, reheat, and extraction steam piping, feedwater heaters, condenser, mechanical draft cooling towers, boiler feed pumps, and auxiliary steam generator.

Emissions from coal burning power plants can be reduced by the installation of pollutant-specific removal devices or systems. These include among others flue-gas desulfurization systems (FGD), low NOx burners, selective catalytic reduction systems (SCR), and electrostatic precipitators or fabric filters (baghouse).

To remove fly ash from the flue-gas before being exhausted through the stack, either fabric filters (baghouse) or electrostatic precipitators are used. This filtering prevents dust from the combustion process from entering the atmosphere. The removal of SO2 from the stack gases is termed flue-gas desulfurization (FGD). The devices used in this process are commonly referred to as scrubbers. The purpose of the scrubbers is to bring the flue gases containing SO2 into contact with a chemical absorbent such a limestone, lime, or magnesium oxide. Currently, there are two FGD processes, nonregenerable (wet) and regenerable (dry). They are characterized as wet or dry depending on the state of the reagent as it leaves the absorber.

In the wet scrubber process, the absorbent and the SO2 react to form a product disposed of as a sludge or a solid. The dry scrubber process, however, recovers the absorbent for re-use in the scrubber and produces a marketable product (elemental sulfur or sulfuric acid). Typically for high-sulfur coal-fired units with FGD, the FGD system is wet-limestone. However, for low-sulfur coal-fired units with FGD, the system is typically spray dryer but can be wet-limestone depending on the sulfur content of the coal. Sulfur removal rates of current FGD systems are from the low to high 90% range.

To reduce NOx emissions from power plants, a modification of the design or operating conditions of the combustion equipment is necessary. The reduction of NOx emissions in coal-fired power plants can be achieved by installing low NOx burners in the boiler. The presence of a low NOx burner in a coal-fired boiler restricts the air flow in the combustion chamber which reduces the combustion temperature and NOx formation. Low NOx burners have the potential of reducing NOx emissions by up to 80%.

The reduction of nitrogen oxides can also be accomplished by means of a selective catalytic reduction process (SCR). This is a flue-gas treatment process which reduces NOx to nitrogen and water by means of a chemical reaction in the presence of a catalyst under high temperatures. Presently, the SCR process is the only commercial control technology that can remove nitrogen oxides up to 90%.

Combustion Turbine-Combined Cycle (CT-CC)

A combined cycle generating unit is a combustion turbine which has a steam turbine added to it to provide additional power output with no additional fuel input. In a combined cycle unit, the hot exhaust gases from the combustion turbine are routed to and passed through a heat recovery steam generator (HRSG). In this steam generator, the steam produced by the exhaust heat drives an additional turbine generator. Typically, two-thirds of the power produced comes from the combustion turbine generators, and one-third from the steam turbine generator. Construction of a combined cycle unit can be phased with the combustion turbine built and operated first, and the HRSG portion added at a later point in time. This staged installation allows for greater planning flexibility. With the addition of the HRSG, the overall operating efficiency of the unit is improved when compared with the combustion turbine by itself.

In combined cycle systems, NOx emissions are controlled by injecting water or steam into the ICT combustor as is done in the stand-alone combustion turbines. This approach can be adequate for a less stringent level of NOx emission standards; however, more stringent standards may require the use of a selective catalytic reduction process (SCR).

Combustion Turbine

An internal combustion turbine (ICT) consists of a combustor, an air compressor, an expansion turbine, and an electrical generator. A gaseous or liquid fuel is burned in the combustor and produces hot gases which pass through the expansion turbine, which in turn drives the air compressor and an electrical generator.

The operation of an ICT is very sensitive to the ambient temperature. Power output drops approximately .5% for each °F increase in ambient temperature. Nitrogen oxides (NOx) are the only significant emissions from combustion turbines. These NOx emissions are typically controlled by the injection of water or steam into the combustor. This process of controlling NOx in ICTs may reduce the energy efficiency because it tends to lower the combustion temperature. Another technology that can also contribute significantly to the reduction of NOx emissions in combustion turbines is the selective catalytic reduction process (SCR). As opposed to a pre-combustion approach to reducing NOx emissions as in water/steam injection, SCR is a post-combustion process whereby the flue-gas is treated and the NOx is broken down into nitrogen and water in the presence of a catalyst.

13. Calculation of Avoided Costs

Avoided costs related to DSM are those costs that the Company will avoid through the implementation of its DSM programs. There are three major categories of avoided costs: generation, transmission and distribution. Generation costs are further divided into capacity related and energy related with the latter being estimated over four time periods.

To estimate the capacity related avoided costs of generation, two supply side plans are developed: the basecase plan and the No-DSM plan. These plans are developed through use of the EGEAS computer model. EGEAS is an acronym for Electric Generation Expansion Analysis System. It contains a dynamic programming algorithm that tests thousands of supply plans meeting specified reliability and other criteria and finds the least cost plan. The No-DSM supply plan is the least cost expansion plan designed to serve the no-DSM demand and energy forecast. This forecast is the projection of system energy requirements that would result if the Company discontinued its current DSM efforts. The basecase supply plan is the least cost plan needed to serve the basecase forecast. The avoided cost of capacity-related generation is the difference in fixed costs between these two supply plans. Fixed costs include the owning costs of capacity and the fixed portion of operation and maintenance expenses. Additionally, the calculated avoided costs are increased to reflect associated investments in general plant.

The energy related avoided costs of generation are estimated through use of the ENPRO production costing model. ENPRO simulates the hourly dispatch of the Company's generating units taking into account maintenance, economy energy purchases and forced outage probabilities. ENPRO must be run five separate times in order to calculate the avoided costs correctly for the four time periods used at the Company. There is a basecase run and then a change case run with the system load decremented 100 MW in each hour of each of the four time periods. The time periods are shown in the table following.

DEFINITION OF TIME PERIODS
<u>Peak Season Peak Hours (PSPH)</u>
Months: June through September
Hours: 10AM - 10PM on week-days (excluding holidays)
<u>Peak Season Off-Peak Hours (PSOH)</u>
Months: June through September
Hours: All non-peak hours
<u>Off-Peak Season Peak Hours (OSPH)</u>
Months: May and October
Hours: 10AM - 10PM on week-days (excluding holidays)
and
Months: November through April
Hours: 6AM - 1 PM and 5PM - 10PM on week-days (excluding holidays)
<u>Off-Peak Season Off-Peak Hours (OSOH)</u>
Months: October through May
Hours: All non-peak hours

It is necessary to calculate avoided energy costs in this manner because a change in load one hour can result in a different generating unit dispatch and thereby change the production costs in other hours. This intertemporal effect is particularly strong on the SCE&G system because of the Fairfield Pumped Storage unit. The production costs related to Fairfield operations occur at other generating units during the off-peak pumping cycle while the generating cycle operates during peak periods typically resulting in less generation and lower cost at other units. Therefore, the cost of serving a change in load during the peak period may not be reflected on the SCE&G system until the off-peak period. In a final step, the avoided energy costs are adjusted for their impact on working capital and generation taxes.

The transmission and distribution (T&D) avoided costs are calcualted from the Company's ten-year capital budget. Incremental T&D investments that are related to peak demand growth are identified in the budget and separated from those related to other matters, such as, safety, performance, or reliability.

Since we are estimating avoided costs, the next step is to exclude from the analysis those transmission, substation and feeder/coordination investments that are already committed and hence not avoidable. The final steps in the estimation process start by converting the ten-year stream of avoidable investment costs related to demand growth into constant dollars by using the appropriate discount rate and summing. This constant dollar sum is expressed in dollars per KW of investment by dividing by the corresponding increase in demand. Finally, these investment dollars are expressed in terms of an annual economic carrying charge.

TABLES

TABLE 4.3.1

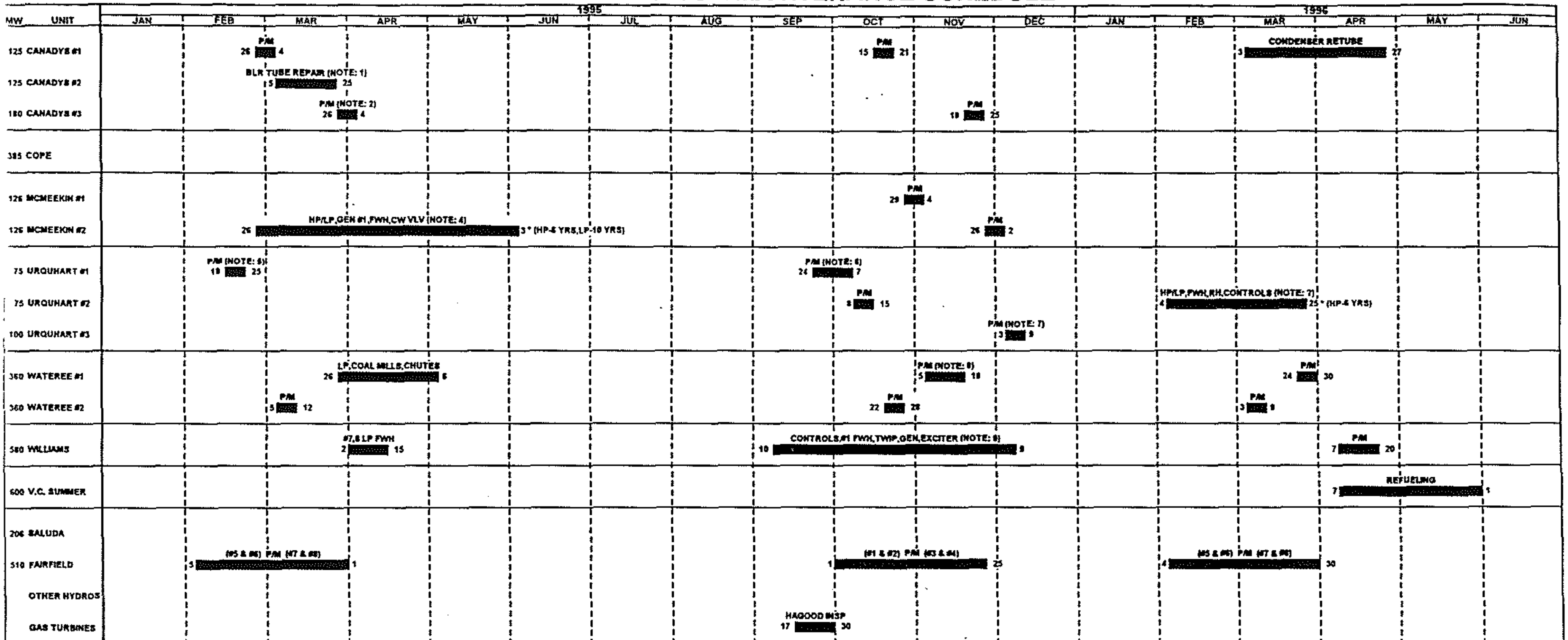
SOUTH CAROLINA ELECTRIC & GAS COMPANY GENERATING STATION STATISTICS (END OF YEAR 1994)

	First and Last Unit in Service	Net Capability Rating (mW) Summer	Winter
Coal-Fired Steam:			
Canadys - Canadys, SC	1962-1967	430	430
McMeekin - near Irmo, SC	1958-1959	252	254
Urquhart - Beech Island, SC	1953-1955	250	254
Wateree - Eastover, SC	1970-1971	700	720
Williams - Goose Creek SC (1)	1973	560	565
Total Coal-Fired Steam Capacity		2,192	2,223
Nuclear:			
V.C. Summer - Parr, SC	1984	590	604
I.C. Turbines: *(2)*			
Burton, SC	1961-1963	28.5	30
Faber Place - Charleston, SC	1961	9.5	10
Hardeeville, SC	1968	14.0	14
Canadys, SC	1968	14.0	15
Urquhart - Beech Island, SC	1969	38.0	46
Coit - Columbia, SC	1969	30.0	36
Parr, SC	1970-1971	60.0	76
Williams - Goose Creek, SC	1972	49.0	58
Hagood - Charleston, SC	1991	95.0	112
Total I.C. Turbines Capacity		338	397
Hydro:			
Columbia Canal - Columbia, SC	1927-1929	10	10
Neal Shoals - Carlisle, SC	1905	5	5
Parr Shoals - Parr, SC	1914-1921	14	14
Saluda - near Irmo, SC	1930-1971	206	206
Stevens Creek - near Martinez, GA	1914-1926	9	9
Fairfield Pumped Storage - Parr, SC	1978	512	512
Total Hydro Capacity		756	756
Grand Total:		**3,876**	**3,980**

(1) SCE&G purchases the output of Williams Station, a plant owned by S.C. Generating Company.

AB 4.4.

PLANNED MAJOR MAINTENANCE SCHEDULE



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
BOOK RESERVE	1037	1061	821	768	809	539	315	403	468	469	490	406	1378	1455	1074	887	855	873
RELIABLE RESERVE	837	961	421	568	609	339	115	203	268	269	290	206	1178	1255	874	687	455	673
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
	1995												1996					

APPROVALS

F.S. NAUFUL ----------
N.O. LORICK ----------
C.A. WHITE ----------
W.E. MOORE ----------
J.L. SKOLDS ----------

INSPECTION NOTES:

* (DATE OF LAST TURBINE INSPECTION)

SPRING 1995

1. CAN #2 A. RECEIVER INSPECTION
   B. PIPING INSPECTION
2. CAN #3 A. DA INSPECTION
3. MCM #1 A. DA INSPECTION
4. MCM #2 A. DA INSPECTION
   B. RECEIVER INSPECTION
   C. PIPING INSPECTION
5. URQ #1 A. DA INSPECTION
   B. RECEIVER INSPECTION
   C. BOILER CLEANING

FALL 1995

6. URQ #1 A. TURBINE REPAIR
7. URQ #2 A. DA INSPECTION
8. WAT #1 A. BOILER CLEANING
9. WIL A. DA INSPECTION
   B. PIPING INSPECTION

SPRING 1996

REVISION 0, 2 FEB 95

TABLE 4.4.2

EXISTING UNIT SCHEDULED MAINTENANCE				
UNIT	**NORMAL SPRING/FALL (DAYS/YEAR)**	**MAJOR (DAYS/YEAR)**	**MAJOR CYCLE INTERVAL (YEARS)**	**NEXT MAJO OUTAGE**
Williams	28	60	6	1995
Wateree 1 Wateree 2	28 28	60 60	6 6	1998 1997
Canadys 1 Canadys 2 Canadys 3	14 14 24	60 60 60	6 6 6	1998 1999 1996
McMeekin 1 McMeekin 2	14 14	60 60	6 6	2000 1995
Urquhart 1 Urquhart 2 Urquhart 3	14 14 14	60 60 60	6 6 6	1998 1996 1997
V.C. Summer	45 (Spring 1996) 43 (Fall 1997) 40 (After 1997)			
I.C. Turbines (excluding Hagood)	10	90	5	
Hagood ICT	14	21	5	1996

TABLE 4.10.1

SUPPLY-SIDE OF THE 1995 BUDGET EXPANSION PLAN

CAPACITY CHANGES

YEAR	PEAK (MW)	ONE YEAR (MW)	LONG TERM (MW)	DESCRIPTION	CAPACITY (MW)	RESERVE MARGIN
1995	3,533	0 - 250		SPOT PURCHASES OF CAPACITY	3876-4126	9.7%-16.8%
1996	3,586		385	COPE PULVERIZED COAL UNIT	4,291	19.7%
			30	VCSN UPRATE		
1997	3,656				4,291	17.4%
1998	3,723				4,291	15.3%
1999	3,775		150	ICT	4,441	17.6%
2000	3,828				4,441	16.0%
2001	3,881		150	ICT	4,591	18.3%
2002	3,937				4,591	16.6%
2003	4,000		-13	SCRUBBER PARASITIC LOAD	4,578	14.4%
2004	4,058		150	ICT	4,728	16.5%
2005	4,114				4,728	14.9%
2006	4,171		150	ICT	4,878	17.0%
2007	4,225				4,878	15.5%
2008	4,281		150	ICT	5,028	17.4%
2009	4,336				5,028	16.0%
2010	4,397	100		CAPACITY PURCHASE	5,128	16.6%
2011	4,462	200		CAPACITY PURCHASE	5,228	17.2%
2012	4,529		400	PULVERIZED COAL UNIT	5,428	19.8%
2013	4,598				5,428	18.1%
2014	4,664				5,428	16.4%

TABLE 4.12.1

Type of Plant:	***Pulverized Coal***	
Capacity (MW):	Maximum	400
	Minimum	100
Capital Cost ($/KW, 1994$):		1000
Construction Lead Time (Years):		7

Annual % Breakout for Construction Expenditures

Year #1	0.3	%
Year #2	3.5	%
Year #3	6.7	%
Year #4	24.4	%
Year #5	44.5	%
Year #6	17.5	%
Year #7	3.1	%
Year #8		%

Expected Life (Years):		41
Heat Rate (BTU/KWH):	@Maximum	9550
	@Minimum	11000
Forced Outage Rate:	Immature	10
	Mature	7
Fixed O&M ($/KW/Year, 1994$)		22.48
Variable O&M ($/MWH, 1994$)		1.79
Maintenance (Days/Spring-Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

TABLE 4.12.2

Type of Plant:	***Pulverized Coal***	
Capacity (MW):	Maximum	300
	Minimum	75
Capital Cost ($/KW, 1994$):		1041
Construction Lead Time (Years):		7

Annual % Breakout for Construction Expenditures

Year #1	0.3	%
Year #2	3.5	%
Year #3	6.7	%
Year #4	24.4	%
Year #5	44.5	%
Year #6	17.5	%
Year #7	3.1	%
Year #8		%

Expected Life (Years):		41
Heat Rate (BTU/KWH):	@Maximum	9599
	@Minimum	11292
Forced Outage Rate:	Immature	10
	Mature	7
Fixed O&M ($/KW/Year, 1994$)		28.85
Variable O&M ($/MWH, 1994$)		1.79
Maintenance (Days/Spring-Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

TABLE 4.12.3

Type of Plant:	***Pulverized Coal***	
Capacity (MW):	Maximum	200
	Minimum	50
Capital Cost ($/KW, 1994$):		1193
Construction Lead Time (Years):		7

Annual % Breakout for Construction Expenditures

Year #1	0.3	%
Year #2	3.5	%
Year #3	6.7	%
Year #4	24.4	%
Year #5	44.5	%
Year #6	17.5	%
Year #7	3.1	%
Year #8		%

Expected Life (Years):		41
Heat Rate (BTU/KWH):	@Maximum	9694
	@Minimum	11388
Forced Outage Rate:	Immature	10
	Mature	7
Fixed O&M ($/KW/Year, 1994$)		37.18
Variable O&M ($/MWH, 1994$)		2.62
Maintenance (Days/Spring-Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

TABLE 4.12.4

Type of Plant:	***Combined Cycle (Full Unit)***	
Capacity (MW):	Maximum	408
	Minimum	68
Capital Cost ($/KW, 1994$):		507
Construction Lead Time (Years):		4

Annual % Breakout for Construction Expenditures

Year #1	1	%
Year #2	30	%
Year #3	60	%
Year #4	9	%
Year #5		%
Year #6		%
Year #7		%
Year #8		%

Expected Life (Years):		33
Heat Rate (BTU/KWH):	@Maximum	6800
	@Minimum	13660
Forced Outage Rate:	Immature	15
	Mature	10
Fixed O&M ($/KW/Year, 1994$)		8.81
Variable O&M ($/MWH, 1994$)		2.51
Maintenance (Days/Spring-Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

TABLE 4.12.5

Type of Plant:	*ICT*	
Capacity (MW):	Maximum	150
	Minimum	75
Capital Cost ($/KW, 1994$):		250
Construction Lead Time (Years):		3

Annual % Breakout for Construction Expenditures

Year #1	1	%
Year #2	85	%
Year #3	14	%
Year #4		%
Year #5		%
Year #6		%
Year #7		%
Year #8		%

Expected Life (Years):		33
Heat Rate (BTU/KWH):	@Maximum	11103
	@Minimum	13660
Forced Outage Rate:	Immature	10
	Mature	8
Fixed O&M ($/KW/Year, 1994$)		4.50
Variable O&M ($/MWH, 1994$)		1.44
Maintenance (Days/Spring-Fall Outage)	Normal	10
	Major	21
Interval for Major Maintenance (Years):		5

TABLE 4.12.6

Type of Plant:	*ICT*	
Capacity (MW):	Maximum	136
	Minimum	68
Capital Cost ($/KW, 1994$):		275
Construction Lead Time (Years):		3

Annual % Breakout for Construction Expenditures

Year #1	1	%
Year #2	85	%
Year #3	14	%
Year #4		%
Year #5		%
Year #6		%
Year #7		%
Year #8		%

Expected Life (Years):		33
Heat Rate (BTU/KWH):	@Maximum	11103
	@Minimum	13660
Forced Outage Rate:	Immature	10
	Mature	8
Fixed O&M ($/KW/Year, 1994$)		4.50
Variable O&M ($/MWH, 1994$)		1.44
Maintenance (Days/Spring-Fall Outage)	Normal	10
	Major	21
Interval for Major Maintenance (Years):		5

TABLE 4.12.7

Type of Plant:	***ICT with SCR***	
Capacity (MW):	Maximum	136
	Minimum	68
Capital Cost ($/KW, 1994$):		350
Construction Lead Time (Years):		3

Annual % Breakout for Construction Expenditures

Year #1	1	%
Year #2	85	%
Year #3	14	%
Year #4		%
Year #5		%
Year #6		%
Year #7		%
Year #8		%

Expected Life (Years):		33
Heat Rate (BTU/KWH):	@Maximum	11103
	@Minimum	13660
Forced Outage Rate:	Immature	10
	Mature	9
Fixed O&M ($/KW/Year, 1994$)		14.94
Variable O&M ($/MWH, 1994$)		2.17
Maintenance (Days/Spring-Fall Outage)	Normal	15
	Major	21
Interval for Major Maintenance (Years):		5

INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

5.0 THE INTEGRATED RESOURCE PLAN

1. Demand-Side Planning
2. The Forecast
3. Supply-Side Resources

5.0 INTEGRATED RESOURCE PLAN

The goal of the integrated resource planning process is to meet the forecasted energy and demand requirements of our customers iwth an optimal mix of demand-side options and supply-side resources. The process used at SCE&G follows sequential steps but has the flexibility to iterate through the steps in order to converge on an optimal solution. This chapter contains a summary of the demand-side portfolio, the energy and demand forecast and the supply-side resources needed to meet our customer's energy needs.

1. Demand-Side Planning

The Company's DSM efforts are designed to help our customers use energy wisely and manage peak demand. Our DSM portfolio promotes energy efficiency to residential, commercial and industrial customers through incentives, financing, education and a comprehensive menu of rate options. The following table lists the Company's proposed DSM portfolio of programs.

RESIDENTIAL PROGRAMS	*COMMERCIAL AND INDUSTRIAL PROGRAMS*
Good Cents/Conservation Program	*Thermal Energy Storage*
Home Energy Check Program	*Stand-by Generator*
High Efficiency Heat Pump Program	*Interruptible Program*
Replacement Water Heater Program	*Real-Time Pricing*
Time of Use Rate (Rate 5)	*Time of Use Rates*
Low Use Rate (Rate 2)	*Commercial Heat Pump Water Heater and Pool Heater Program* *
	High Efficiency Chillers Program **
	Commercial HVAC Program **
	* **Research and Development Program**
	****Education Programs**

Our DSM programs have significant system benefits, such as:

- More than a 25% reduction in the annual peak demand growth on the system.
- A cumulative reduction in peak demand growth of over 500 megawatts by 2014.
- About a 6% reduction in the annual energy growth on the system.
- A cost savings of $191 million to our customers in terms of present-worth revenue requirements.

The table below shows how much greater the energy needs of our customers would be over the next twenty years if all the Company's DSM programs were halted.

ENERGY (GWH) IMPACT OF DSM EFFORTS				
	1995	2000	2005	2014
No DSM Level	18,434	20,503	22,506	26,425
Basecase Level	18,439	20,410	22,300	25,975
DSM Impact	(5)	93	206	450
% Change	0.0	0.5	0.9	1.7
PEAK DEMAND (MW) IMPACT OF DSM EFFORTS				
	1995	2000	2005	2014
No DSM Level	3,611	4,004	4,402	5,193
Basecase Level	3,533	3,828	4,114	4,664
DSM Impact	78	176	288	529
% Change	2.2	4.6	7.01	11.3

Similar information is provided on peak demands. The hypothetical "No DSM" scenario represents the system impacts if the Company stopped its DSM efforts. Of course, much of the DSM benefits achieved to date do not depend on the Company's on-going efforts and are still reflected in both the Basecase and "No DSM" scenarios.

The Company estimates that its DSM programs will save $191 million in accumulated present-worth revenue requirements over the next twenty years. The table following highlights some of the major components of this savings.

	Change in Present Worth Revenue Requirements ($/Millions)
DSM Expenses	$ 58
Non-Fuel Revenues	(155)
Fuel Revenues	(94)
Total Change	$(191)

SCE&G's Demand-Side Management portfolio is evolving to reflect current market conditions, our experience with demand-side management and changes in the economic parameters of each programs. As indicated above, managing demand and promoting efficiency will continue to have a significant impact on the Company's energy and demand forecast. The Company remains committed to promoting efficiency in a manner that minimizes cost to ratepayers.

2. The Forecast

The Company expects the energy needs of its service territory to grow at 1.8% over the next twenty years with a growth of annual peak demand averaging 1.5%.

	1995	2014	Growth Rate
Energy (GWH)	18,439	25,975	1.8%
Peak (MW)	3,533	4,664	1.5%

The sales forecast for the Company takes into account the effects of demand-side management (DSM) efforts. The total energy load for the Company is the sum of Company use, unaccounted for energy, and total sales. The forecast of peak demands is based on the application of load factors to energy sales projections by class of customer. The use of this methodology has been verified through comparison to the Company's actual experience over the last thirty years. A forecast of peak demands for the winter season is made using econometric techniques. Note that the winter season is associated with the year containing the previous summer. The table below summarizes the sales forecast, the total load and the summer and winter peak demand projections.

TERRITORIAL FORECAST				
SALES (GWH)	***1995***	***2000***	***2005***	***2014***
Residential	5,641	6,228	6,883	8,166
Commercial	5,040	5,681	6,179	7,180
Industrial	5,221	5,729	6,177	6,988
Other				
Total Sales	17,477	19,342	21,126	24,591
Total Load (GWH)	18,439	20,410	22,300	25,975
Peak Demand (MW):				
Summer	3,533	3,828	4,114	4,664
Winter	2,950	3,211	3,427	3,885

Without the benefit of our DSM efforts, annual energy would be increasing by 414 GWH per year about 6% faster than the projected rate of 390 GWH per year. Similarly, annual peak demand would be increasing by 83 megawatts per year without the DSM programs. This is 38% faster than the projected rate of 60 megawatts per year. There are significant impacts on the growing energy needs of the SCE&G service territory and they have equally significant effects on the needs for supply-side resources.

3. Supply-Side Resources

The Company's current generating capability is 3,873 megawatts. With the addition of the 385 MW Cope Plant and the 30 MW uprate at Summer Station, the Company is expecting to meet future capacity needs primarily through the addition of internal combustion turbines (ICTs). From a planning perspective, this provides the Company with great flexibility because ICTs can be constructed in a short period of time and the Company will be able to postpone decisions until the peak demand growth and resulting capacity need is almost certain. At present, the Company's supply plan includes the addition of five ICTs rated at 150 megawatts each by 2008 and another baseload coal plant in 2012 rated at 400 megawatts. The table below summarizes these capacity additions.

CAPACITY ADDITIONS			
YEAR	ADDED CAPACITY (MW)	DESCRIPTION	RESERVE MARGIN (%)
1996	385	Cope Plant	18.8
1996	30	VCS Uprate	19.7
1999	150	ICT	17.6
2001	150	ICT	18.3
2004	150	ICT	16.5
2006	150	ICT	17.0
2008	150	ICT	17.4
2012	400	Coal	19.8

Without the Company's DSM efforts, the peak demand in 2014 would be about 500 megawatts higher. Thus, four additional ICTs are being avoided by the Company's DSM efforts.

6.0 OTHER CONSIDERATIONS

6.1 ENVIRONMENTAL PLANNING

1. Introduction

Forecasting environmental expenses into the future implies knowledge of laws and regulations that will be implemented during these years. Changes in regulatory definitions or limits can affect actual costs. Because future trends in the environmental arena cannot be forecasted with certainty, the assumptions in this section are based on present laws and regulations and the fairly certain costs that they will require and those anticipated with some surety.

2. Policy

South Carolina Electric & Gas Company recognizes that the environment is a fragile resource. We further understand that responsible institutions have a duty to the people and places they serve to conduct business in a way that exhibits ecological stewardship. And while we are committed to providing dependable, affordable energy, it is our stated goal to do so in an environmentally sensitive manner. In keeping with those principles, SCE&G's environmental policy is:

- ☑ To respect the environment in all phases of our operations.
- ☑ To meet the requirements of all local, state, and federal environmental laws and regulations.

- To work with government at all levels to isolate, analyze and solve problems related to the environment.

- To address environmental policy issues with positive strategies that reflect the interests and concerns of our customers.

- To utilize sophisticated, cost-effective environmental technology and procedures, and to encourage and investigate new technologies whose ultimate benefit is a better environment.

- To employ prospective planning that enables us to respond quickly and effectively to any environmental incidents involving SCE&G, and to be guided in our response by our concern for the community health and well-being.

- To ensure that all SCE&G employees are aware of the Company's commitment to environmental protection.

- To provide employee training programs that demonstrate SCE&G's concern for the environment, and that encourage employee involvement in environmental protection efforts.

- To aggressively oversee all Company activities to ensure compliance with these tenets and with all legal and regulatory requirements.

- To provide our customers environmentally compatible sources of energy and to promote the use of efficient, state-of-the-art electric and gas technologies.

3. Air

The Clean Air Act Amendments of 1990 require SCE&G and GENCO to reduce sulfur dioxide and nitrogen oxides to certain levels by the year 2000. SCE&G and GENCO are forecasted to spend well over $200,000,000 in the next ten years to reduce the emissions of these two pollutants.

The regulation and control of air toxic emissions from fossil fuel-fired power plants will most likely occur by the end of the decade. Control costs could be as high as $150,000 per pound of pollutant removed. Control of particulate matter will become more aggressive as the regulations are promulgated. A large portion of the air toxic pollutants emitted can be controlled with more efficient particulate removal. SCE&G and GENCO are forecasted to spend $63,000,000 in the next ten years on particulate control projects.

In an attempt to preserve the protective stratospheric ozone layer above the earth, EPA has banned certain chlorofluorocarbons (CFCs) from manufacture by January 1996. Replacement chemicals for the specified refrigerants (freons) and fire extinguisher chemicals (halons) are being identified. As supplies of the banned chemicals dwindle and become more expensive, replacement systems for such items as air conditioners, chillers, and fire suppression systems may be required. Assessments are currently underway to determine those systems in need of replacement prior to their normal operating life span.

CFCs, also known as greenhouse gases along with carbon dioxide, methane and other volatile organic compounds, are thought to contribute to the greenhouse effect or potential warming of the earth's climate (a.k.a. global warming). These greenhouse gases are currently being controlled through voluntary efforts and reductions brought about by the Utility Climate

Challenge of Clinton's Climate Change Action Plan. Recent announcements from the Administration indicate that voluntary efforts alone cannot accomplish the current goal of reducing greenhouse gas emissions to 1990 levels by the year 2000. SCE&G is currently assessing forestry management initiatives and energy efficiency measures in response to the Utility Climate Challenge to offset or reduce carbon dioxide emissions.

4. V.C. Summer Uprate

Major non-radiological environmental expenses for the V.C. Summer Nuclear Station are driven by the current plans to uprate the facility. As a result of the planned uprate and the need to deal with increased heat rejection from the plant, a cooling tower may be constructed in the next year or so. A heat dissipation effects study may be required by Section 316(a) of the Clean Water Act. With any increases to the circulating water flow or intake velocity, an impingement/ entrainment study may be required by Section 316(b). Expenditures for ecological studies would probably occur one year before to two years after the uprate. Present estimates for these studies are in the $1/2 million to $2 million range. These costs assume that ecological studies would show no deleterious effects of the planned uprate.

5. Transformer Oil Spill and Response

As a result of storms, equipment malfunctions, and various non-operating incidents, transformer oil is occasionally released into the environment. The costs of spill response, soil sampling and analysis, excavation and restoration, transportation and disposal approach $250,000 annually. Virtually all spills are non-PCB. It is estimated that less than one percent of all transformers are PCB or PCB-contaminated.

6. Wastewater Treatment

Increasingly stringent wastewater treatment permits have required SCE&G to upgrade and integrate new systems into existing treatment facilities. Some of the upgrades include wastewater recycling, discharge modifications, oil water separators, and cooling towers to improve treatment capabilities and meet new and expected requirements. Planned expenditures exceed $6,000,000.

7. Solid Waste

SCE&G has an investment recovery program to manage resources including waste products generated as a result of normal operations. Investment recovery includes recycling programs for paper, cardboard, scrap metals, used oils, and fossil fuel ash. Ash is by far the major combustion by-product resource and requires larger scale management facilities such as ash storage ponds and ash storage landfills. Upgrades and expansions to existing, and installation of new ash management facilities will require investments of nearly $21,000,000 over the next decade.

8. Hazardous Waste

During routine operation and maintenance of SCE&G facilities, there is the potential to generate hazardous wastes. When managing hazardous wastes, costs can be significant not only from the administrative processes but also from the treatment and disposal fees as well. Even when hazardous waste disposal has been handled appropriately, a generator is responsible potentially for environmental impact which may occur after disposal. SCE&G performs audits of disposal vendors in order to minimize such liabilities. SCE&G is also committed to compliance with state and federal regulations and is continually seeking ways to minimize the wastes generated in order to reduce costs and to be good stewards of the environment. Even so, disposal costs related to hazardous wastes, including mercury vapor light bulbs, is in the realm of $100,000 per year.

9. Environmental Remediation

While current environmentally protective practices have reduced the number of incidents which can cause contamination and require remediation, past operations have precipitated the need to assess and design remediation for several locations within the system. Expected costs approach $1,000,000 for planned remedial activities over the next several years.

10. Environmental Support Services

SCE&G's Environmental Services Department (ESD) is charged with the responsibility of interfacing with federal, state, and local regulatory agencies to obtain and maintain required environmental permits, certificates, registrations and approvals. The ESD performs assessments and evaluations to verify regulatory compliance , to verify that best management practices are in place, functioning, and adequate, and to identify actual and potential environmental problems for purposes of correction and/or prevention. The ESD interfaces with other SCE&G departments to disseminate relevant environmental developments in regulatory requirements, policies and procedures, and to communicate effective solutions to environmental problems. Company-wide annual O&M environmental costs are on the order of $6 million.

11. Low and High Level Nuclear Waste

Low-level nuclear waste is controlled by the 1985 Amendments to the Low-Level Nuclear Waste Policy Act which established regional sites. The cost of burial for low level radioactive waste in a licensed facility has and will continue to increase due to many factors beyond our direct control. Should the current disposal facility close and no other alternative is available, we have the capability to store on site up to five years of low level waste.

High-level nuclear waste is regulated by the Nuclear Waste Policy Act of 1987. Since the federal government has not indicated when burial sites will be available for spent cores or what costs will be involved, major environmental costs are incorporated into the funding provided to the Department of Energy of which SCE&G has spent in excess of $47 million since 1984. In the meantime, SCE&G must maintain a pool which "temporarily" stores the spent fuel.

12. Hydro Power

Hydro power, a renewable resource, has added environmental costs of $1-2 million as the ecosystem of the lake and downstream area must be studied as each permit comes up for renewal under the Electric Consumers Protection Act of 1986.

13. Land and Lake Management

SCE&G has approximately 30,000 acres of land. Erosion control and fire prevention are the major operating costs involved. Silviculture is employed where practical to provide a source of income to offset land management costs. Included in lake management are approximately 64,500 acres of lakes which are included in the hydro system. SCE&G has 1,995 acres dedicated to public recreation.

14. Transmission Lines

SCE&G is seeing additional environmental costs associated with construction and operation of transmission lines. In certain situations, prior to construction, environmental assessments must be performed in order to satisfy siting and permitting requirements. Increased capital and maintenance costs are attributed to the specialized practices implemented in the sensitive habitat areas.

6.2 POWER DELIVERY AND DISTRIBUTION PLANNING

1. Mission Statement

The mission of the Power Delivery Planning Department is to develop and coordinate a program that provides for timely modifications to the SCE&G transmission system to insure an economical and reliable delivery of power.

2. Power Delivery Planning

The need for spending most capital money and some limited maintenance money on the SCE&G transmission system (all facilities operating at 230kV, 115kV, 46kV, and 33kV) is initiated and evaluated in the Power Delivery Planning Department.

Power Delivery Planning evaluates the existing and future transmission system to determine all service and reliability concerns such as line overloads, transformer overloads, low voltages, high voltages, power quality, loss of load, exposure related problems, etc. This evaluation includes decisions as to what contingencies the system must be able to withstand and still provide adequate service. These contingency situations are studied using several analytical tools such as the power flow, stability, and short circuit programs to predict the response of the system to events on the system and predict the performance of the existing system and the planned system over the next ten years. Using the results of these studies, economic evaluation, and engineering judgment, decisions are made concerning solutions in areas where service standards are not met. Recommendations may include any or all of the following: building new lines and/or substations, increasing the capability of existing lines and/or substations, retiring lines and/or substations, installing capacitors, installing power circuit breakers, installing sectionalizing switches (manual or radio-controlled), changing transformer tap settings, reconfiguring the system, etc. All alternatives are discussed with personnel throughout Power Delivery for their input. Upon approval of the final recommendation, the project is included in the Power Delivery budget.

Other transmission planning activities include: power quality studies, special operating studies, power circuit breaker evaluation, short circuit analysis, loss factor studies, power loss studies, stability studies, and generation siting studies.

Table 6.2.1 contains a list of proposed transmission facilities, rated 125 kV or above, that Power Delivery Planning has determined will be needed during the next ten years. Additions to and deletions from this list will be made as necessary during the planning process as described above.

Power Delivery Planning is involved in the development of Flexible Alternating Current Transmission System (FACTS) technology by remaining up to date on the advances in this new technology and evaluating potential applications of this technology on the SCE&G transmission system.

Power Delivery Planning is involved with Regional Transmission Group (RTGs) activities through involvement, though not a member, with the Interregional Transmission Coordination Forum (ITCF). ITCF is a organization of transmission owners and users with membership mostly from the Northeast. Power Delivery Planning is involved also with preliminary activities in the Southeast which is determining the most appropriate structure and organization for a RTG in the Southeast.

TABLE 6.2.1 SCE&G TRANSMISSION FACILITY ADDITIONS 125kV AND ABOVE 1995-2004			
	VOLTAGE	CAPACITY	SCHEDULED COMPLETION
TRANSMISSION LINES:			
COPE-CANADYS	230	720	11/95
RIDGELAND-OKEETEE	230	480	5/98
TRANSMISSION TRANSFORMERS:			
PINELAND #2	230/115	336	5/98
BURTON	230/115	224	5/98
OKEETEE	230/115	280	5/98
SALUDA HYDRO	230/115	336	5/99
MT. PLEASANT	230/115	224	5/99
ORANGEBURG #2	230/115	336	5/2000
BARNWELL	230/115	224	5/2000

3. Customer Substation Planning

Customer substation planning is coordinated with the Industrial Development Department, the Marketing Department, and for distribution substations the Distribution Planning Department. Power Delivery Planning evaluates service requirements for new industrial customers to determine the most reliable and economical method of serving a potential new customer while insuring that existing customers are not adversely affected. Power Delivery Planning works with existing industrial customers to address changes in service requirements and improvements in service. Power Delivery Planning coordinates with the Distribution Planning Department to identify the need for additional distribution transformer capacity on the SCE&G system. The best alternative for serving increasing distribution load is then chosen. Considerations would include cost, transmission transformer loading (230/115kV, 230/46kV, 115/46kV, 115/33kV), proximity to a given transmission line, system protection concerns, power quality concerns, system losses, voltage profiles, and service reliability. Personnel throughout Power Delivery and Retail Electric are consulted for their input.

4. Interconnection Planning

The Power Delivery Planning Department conducts joint operating and reliability studies with other utilities throughout the Southeast. Studies are conducted on the existing and future planned systems to determine transmission performance during normal and emergency conditions. Other studies conducted reveal transmission "bottlenecks" which limit power transfer and therefore limit reliability and economic opportunities. These studies may indicate the need for system modifications or an increase in system capability through upgrades and/or new facilities.

5. Distribution Planning

The need for spending system improvement capital money, and some limited maintenance money on the SCE&G distribution system (all facilities operating at a voltage of 25KV or below) is evaluated in the Distribution Engineering and Planning Department. Distribution Engineering and Planning evaluates the existing and future distribution system for service and reliability problems, line overloads, transformer overloads, low voltages, high voltages, loss of load, exposure related problems, and power quality problems. This evaluation includes decisions as to what contingencies the system must be able to withstand and still provide satisfactory service to all distribution customers. These contingency situations are studied using various computer programs to predict the performance of the existing system as well as the future planned system. The programs used include load flow programs, Outage Analysis System, SCADA, etc. Using the results of these studies, economic evaluation, and engineering judgment decisions are made concerning solutions to problem areas. Recommendations may include any or all of the following: reconductoring existing lines, building new lines, installing capacitors and regulators, installing distribution circuit coordination devices and SCADA equipment, reconfiguring the distribution system and converting to higher voltages. All alternatives are discussed with Distribution Operations. When appropriate, alternatives are discussed with System Relaying, Power Delivery Planning, and Power Delivery Engineering and Operations. Upon approval of the final recommendation, the project is entered into the Budget.

Other distribution planning activities conducted by Distribution Engineering and Planning are: Short Circuit Analysis, Loss Factor Studies, Voltage Drop and Ampacity Studies, and Harmonics and Power Quality studies, and circuit coordination studies. The department provides technical support to Electric Operations on a daily basis helping them to solve problems.

Distribution Engineering and Planning uses Scott and Scott Distribution Primary Analysis Programs, Cooper V-Pro coordination program, Cyme loadflow program, CDEGS, Motor Start, and other engineering related programs. In addition SCE&G is developing a GIS which will further enhance the accuracy of our studies.

6.3 TECHNOLOGY REVIEW

1. Introduction

The Company keeps up with the development of non-conventional generating technologies that may serve as potential supply side sources in the future. These technologies are not considered appropriate for inclusion in the Company's future generating resources at this time because of either a lack of maturity of the technology, inappropriate topographical or climatological conditions, or uncompetitive capital and operating costs. Below is a discussion of some of the technologies that were reviewed.

2. Distributed Generation

A large majority of the newest and most promising electric generation technologies fall under the category of what is known as distributed generation. Distributed generation consists of those relatively small-scale generation technologies, usually 5 KW to 100 MW, that provide flexibility to transmission and distribution (T&D) systems and avoid some of the problems associated with siting and constructing larger, more conventional generating plants. There are several advantages to distributed generation, among them:

- Reduced energy losses from T&D systems
- Deferred investment in T&D systems
- Reduced emissions with most distributed generation technologies

Improved system reliability

The technologies that fall under the distributed generation category are of 3 general types: fossil-fueled generation, energy storage and generation technology, and renewable generation. Fossil-fueled generation is certainly not new, but two particular technologies of this type that are new are small-scale combustion turbines and fuel cells. Energy storage and generation technology consist primarily of lead battery and advanced battery technology, compressed air energy storage, and Superconducting Magnetic Energy Storage. Renewable generation includes solar technologies such as photovoltaics and solar thermal, wind turbines, and ocean energy.

2.1 Fossil-Fueled Generation

Gas Turbines: The larger combustion turbines are discussed more thoroughly in the existing technology section. The new technology that is being developed in this area is called advanced gas turbine technology. Turbines of this type are currently only available as demonstration units, are primarily targeted for peaking duty, will be available in sizes up to 24 MW, and are scheduled to be commercially available in 1999. The projected capital cost of this technology is less than $400 per KW with efficiencies greater than 30%.

Fuel Cells: Fuel cell technology is similar to car battery technology. A chemical reaction takes place in an electrolyte in a container. The process is maintained by a steady infeed of hydrogen and oxygen from an external source (e.g., natural gas and air). The output of the fuel is D-C electricity and hot water which contain usable BTUs. The life expectancy of a fuel cell is also similar to that of a car battery. An electronic invertor can transform the D-C into three-phase A-C for use on a utility system. Fuel cells are modular in nature and are constructed in the form of stacks to make plants of various sizes. The qualities that make fuel cells most appealing are high energy conversion efficiency and minimal environmental impact.

There are three types of fuel cells being considered for use by utilities: phosphoric acid fuel cells (PAFC); molten carbonate fuel cells (MCFC); and solid oxide fuel cells (SOFC).

✔ The PAFC technology is the most mature fuel cell technology and is closest to commercialization. Prototypes currently in operation mostly range from 50 to 200 KW. An 11 MW pilot plant manufactured by International Fuel Cells Company is also in operation. The projected capital cost of a typical unit is $1,345/KW. The average annual net heat rate is projected to be 8549 BTU/KWH. The key issues associated with this technology are system reliability, performance, and operating and maintenance costs. Commercial availability is scheduled for 1997.

✔ The MCFC technology is a second-generation technology. These units operate at 1200°F. The major advantage this technology has over PAFC technology is a relatively simple design due to the fact that it requires fewer control systems to operate. The projected capital cost of a typical unit is $1,360/KW. The average annual net heat rate is projected to be 6640 BTU/KWH. The key issues associated with this technology are system reliability, manufacturing cost, and the scale-up of the technology to practical power plant size. Commercial availability is scheduled for 1999.

The SOFC technology is being actively pursued by Westinghouse. A 25 KW unit has been developed, and other units of various sizes are planned for commercialization. These fuel cells are made from ceramic materials and are of a smaller scale than the other technologies. Other technical and economic information is unavailable at this time. Commercial availability of this technology is not likely prior to the year 2000.

Fuel cells hold great promise because of their characteristic low emission of pollutants and high thermal efficiency. However, the technology is not yet fully mature. A utility making an investment in fuel cells must be willing to accept the risks, and be prepared for set-backs due to unexpected technical problems. When the technology matures and becomes more economically competitive, SCE&G plans to evaluate potential applications of fuel cells. SCE&G supports this technology with its membership investment in EPRI.

2.2 Energy Storage and Distributed Generation

Batteries: Battery energy storage is the counterpart to peaking duty conventional units. These units are most cost-effective when used for limited hours of operation and for spinning reserve. They can typically be located in a number of areas, and can therefore offset transmission problems. Batteries can be used for several important applications including: reduction of emissions, frequency control, and load-leveling. There are two major types of batteries. Lead acid batteries have been commercially available since 1988. These batteries are typically designed as 20 MW units requiring one hour storage time. The capital cost is approximately $400 per KW while operating costs are around $0.014/KWH. While these devices are environmentally benign and have extremely fast ramp rates, the useful life of this type of battery is only five to ten years. The cost of these batteries and their limited life are issues that keep this technology from being more viable.

Advanced batteries are currently under development. These batteries are based on sodium-sulfur or zinc-bromine design. They are expected to have a longer useful life (30 years) and lower cost ($300/KW). However, they may require careful maintenance and operate at high temperatures. These batteries will not be commercially available until 2015.

Compressed Air Energy Storage (CAES): A CAES plant is a central storage station where off-peak power is used to pressurize an underground storage cavern with air. The compressed air is later released to drive a gas turbine. The first U.S. CAES project began commercial operation in 1991.

The $65 million, 110 MW, compressed-air plant is owned by Alabama Electric Cooperative (AEC) of Andalusia, Alabama. During off-peak times, generally at night, electricity generated by coal-fired plants is used to heat and compress air into a 220-foot by 1000-foot salt-dome reservoir about 1500 feet below the ground at a pressure of 1100 lbs. per square inch.

When power is needed on AECs grid, the compressed air is withdrawn, heated using natural gas or fuel oil and used to generate power with a turbine.

In a conventional plant, the turbine must power its own compressor, which leaves only about one-third of the turbine's power available to produce electricity. The compressed air from a CAES is used in a turbine which, freed from its compressor, can drive an electric generator up to three times as large.

Three types of caverns may be used to store air: salt reservoirs, hard rock reservoirs, or aquifers. Salt reservoirs are found in Louisiana, eastern Texas, and Alabama, and is the type used by AEC.

Rock caverns are located throughout the United States. Aquifer reservoirs are naturally occurring geological formations, occurring in much of the Midwest, the Four-Corners region, eastern Pennsylvania, and New York.

Completion of AEC's facility has increased the interest in CAES in the United States. Like a pump storage facility, CAES will help improve the load factor of base load facilities and support system peak generation needs. Also like pump storage, it is energy limited, meaning that when the air in the cavern is exhausted, the unit stops. CAES units have a projected capital cost of $495 to $659 per KW. SCE&G continues to keep abreast of this technology but excludes it at the present time for two reasons:

1) SCE&G does not have access to a cavern; and
2) SCE&G could not effectively charge a CAES facility in addition to its existing pump storage facility.

☑ Superconducting Magnetic Energy Storage (SMES): SMES units use the same principle that pumped-storage hydroelectric and compressed air energy storage plants use. Energy is stored in an SMES plant in off-peak hours so that it can provide peak-shaving capacity during peak load hours. However, SMES units store the energy as direct current in a superconducting coil made from niobium titanium alloy. Since the energy is stored as electricity rather than some other form of energy, the efficiency of the unit is around 95%. Additional benefits include the frequency regulation and spinning reserve capacity this technology provides. SMES technology is relatively new as the commercialization date was 1989. Two prohibitive factors related to SMES prevent SCE&G from pursuing it. First, the cost of the technology is too high to make it economically feasible. Second, as noted earlier, SCE&G could not efficiently charge the SMES plant as well as the existing pumped storage hydro facility.

2.3 Renewable Resources and Distributed Generation

Photovoltaics: Of all the solar energy technologies, photovoltaics (PV) show the greatest promise for worldwide acceptance and application. Their universal appeal lies in the fact that they generate electricity from the sun. Working photovoltaics have no moving parts, are relatively simple in design, need very little maintenance (except for cleaning as needed) and are environmentally benign. They simply and silently produce electricity whenever they are exposed to light.

In the most common cell production process, very pure silicon is reduced to its molten form. Through a painstaking and time-consuming process, the silicon is re-formed into a solid, single-crystal cylinder called an ingot. Extremely thin slices cut from the ingot are chemically treated to form photovoltaic cells--sometimes referred to as solar cells. Wires attached to the negative and positive surfaces of the cell complete the electrical circuit. Direct current electricity flows through the circuit when the cell is exposed to light.

Photovoltaics, or the use of solar cells to generate electricity, is a field which is experiencing tremendous change and growth. Further advances in microelectronics and semiconductors can make photovoltaics competitive with conventional power sources by 2010, maybe earlier. Economical PV applications in service today are typically those requiring little energy and are remote from a utility system. For example, SCE&G has considered using a PV-powered high-voltage sectionalizing switch.

As a result of the expected enhancement in the development of solar cells and associated equipment, SCE&G has planned, designed, and installed a photovoltaic test facility. This facility consists of four 1 KW solar panels, a device that combines DC to AC conversion with power conditioning, and recording meters for analysis purposes.

SCE&G's objective is to gain experience in operating, testing, and evaluating a photovoltaic system. Metered data will be used to compare PV generation levels and system load levels under a variety of weather circumstances. The PV panels are also used to power some of the lighting and other facilities at SCE&G's Test Lab.

Currently, the capital cost for PV panels is about $3,000/KW. The targeted busbar cost if approximately 15 cents/KWH. However, the energy conversion efficiency is only about 15%. As the cost continues to fall and efficiency continues to rise, PV technology is expected to provide more effective demand-side and supply-side options to electric utilities.

Solar Thermal Generation: Solar thermal technology is used to convert solar energy to heat and then electricity. Although there are several different plant designs under development, the solar thermal trough design is the only one which has been commercialized on a significant scale. Troughs are used to collect sunlight. The solar energy collected in the troughs transfer the heat to a heat transfer fluid, which in turn passes the heat through heat exchangers to create steam. The capital cost of this technology is currently prohibitive, and development has been temporarily put on hold. A second type of solar thermal plant is based on molten salt central receivers. Several utilities, the Department of Energy, and EPRI have begun work on a demonstration plant in California, but the technology is not supposed to be ready for commercial use until 2005.

✔ Wind Turbines: Wind power is the solar energy technology closest to being economically competitive in the bulk power market. By 1992, 16,000 wind power plants were on line totaling over 1500 MW in capacity. These turbines can produce electricity at an average cost of 8 cents/KWH.

Wind is an intermittent resource which varies from region to region. Power output increases with the cube of wind speed. Wind-derived energy costs have dropped significantly over the last decade.

The Department of Energy and industry analysts believe that wind-derived power costs will drop to 3.5 cents/KWH over the next twenty years, while the installed cost for a wind turbine is expected to fall from $860 to $620 per KW over the next ten years. Variable speed rotor turbines have been developed that lower the busbar cost to 5 cents/KWH. Commercialized in 1992, these turbines are more capable of capturing the energy of wind gusts. This innovation and others will make wind power a highly competitive option. However, Midwestern states are most likely to benefit from any wind turbine technology advancement.

A site-specific wind resource assessment study is advisable to determine the feasibility of an installation of wind turbines in the particular area. For instance, a utility would be interested in the correspondence of the wind with the utility's seasonal and daily peak-load profiles. According to the Utility Wind Interest Group, however, South Carolina could only supply less than 0.1% of the nation's power requirement by harnessing winds available in the state.

Available utility grade wind turbines require a 10 mph wind to start the rotation of the blades, and a 17-26 mph wind to achieve rated capacity. From 1981 through 1987 during the summer months, Charleston experienced a 10 mph wind 12.3% of the time and never had a consistent wind greater than 15 mph except during durations of less than one hour. Columbia experienced a 10 mph wind 2.0% of the time and also never experienced consistent winds greater than 15 mph. Due to the less than favorable wind conditions existing in South Carolina, wind turbine generation is not currently considered to be a feasible generation source.

Ocean Energy: Technologies deriving electric power from the ocean are broken down into six technologies: ocean thermal energy conversion, tidal energy wave power, ocean current turbines, salinity gradient devices, and ocean wind turbines.

Ocean Thermal Energy Conversion (OTEC) works by utilizing different temperature gradients in the ocean to generate electricity. This technology has been demonstrated to be feasible in Hawaii and the Japanese Islands. Currently the only other United States sites, besides Hawaii, considered possible for Ocean Thermal Energy Conversion is in the Gulf of Mexico and along the Gulf Stream off the Florida Coast. No OTEC plants have been tested; however, OTEC-derived electricity may be competitive in five to ten years for small islands.

Tidal energy operates by storing ocean water in a reservoir during periods of high tides and generating electricity during low tides with a basic hydro-turbine. Tidal energy is in operation in France (240 MW facility) and Nova Scotia (19 MW). The most promising sites in the United States are around Alaska and Maine. The South Carolina coast does not have a great enough tidal variation to warrant this technology. Also, this technology's generation does not always coincide with the daily peak loads because high and low tides can occur during all hours.

There are several wave power technologies, two of which have been designed by Norwegian companies. One of these two designs is composed of a vertical tube which compresses air through a turbine from the fluxuating water level from the wave motion. The other design uses a narrowing channel which increases the wave height and causes water to spill over into a reservoir, to be used as a hydro-electric unit. So far, no orders for commercial construction have been placed for either of these technologies.

There is another technology under development by Ocean Power Technology (OPT) of New Jersey. According to the Financial Times, OPT has signed a contract with AMP to build a 1-KW generator which will take advantage of what is known as the piezoelectric effect, which harnesses wave power by the straining of plastic sheets that are attached to the ocean floor. This experimental unit is scheduled to be put in place in December, 1995, in the Gulf of Mexico for testing.

Ocean Current Turbines take advantage of swiftly flowing currents to generate electric energy. The only current considered strong enough in the United States is off the coast of Florida.

Salinity Gradient Devices use the energy difference that exists between fresh and salt water. So far, no test facilities have been built.

So far, no Ocean Wind Turbines have been built.

Ocean energy is not a feasible technology for SCE&G for all six technologies because the energy potential does not exist in our service territory nor is the technology commercially available at present.

There are several other new technologies that are available or under development that fall outside the distributed generation area. A number of these technologies are briefly discussed below.

3. Advanced Light-Water Nuclear Reactors (ALWR)

An agreement was reached between the Department of Energy (DOE) and the commercial nuclear power industry to develop standardized, advanced light-water nuclear reactors (ALWR). ALWR, while configured similarly to conventional light-water reactors, differs in that it has passive emergency core cooling, decay heat removal, and containment cooling systems. ALWR technology is designed to provide a ten-fold reduction in the probability of having a severe accident and to allow operators a longer response time during emergencies. The technology is not scheduled for commercial availability until the year 2002.

Advanced Light-Water Nuclear Reactor technology is not considered a feasible generating source at present. Nuclear power's future as an acceptable generation technology is still uncertain at this time.

4. Fluidized-Bed Combustion (FBC)

The Fluidized-Bed Combustion (FBC) process is generally classified as either atmospheric or pressurized, with further specification as bubbling-bed or circulating-bed according to the boiler type utilized. In lieu of having a flue gas scrubber for SO2 removal after the fluidized-bed combustion process, the sulfur in the fuel (coal) is captured at the point of combustion by reaction with injected limestone to control emissions. Nitrogen oxides are also limited in their formation by staged combustion at low temperatures.

With the exception of the boiler and the absence of the SO2 scrubber, the Atmospheric Fluidized-Bed Combustion (AFBC) generating unit is very similar to a conventional pulverized coal unit. An AFBC unit includes coal receiving and handling, air heater, steam turbine generator and auxiliaries, particulate removal, plant cooling, ash handling, and other balance of plant equipment.

The Pressurized Fluidized-Bed Combustion (PFBC) generating unit generates power in a gas turbine generator driven by the hot pressurized gas from the PFBC boiler in addition to generating power in a steam turbine generator. With the exception of the gas turbine stage and a pressurized boiler, the PFBC process is essentially the same as the AFBC process with similar power plant equipment. The PFBC technology is now entering the demonstration stage and currently lags AFBC technology by several years. Circulating PFBC units are scheduled for commercial availability in the year 2000. The latest available data concerning capital costs for these technologies is shown below:

Type: Atmospheric Fluidized-Bed Combustion Coal (Circulating-Bed)

Current capital cost (1993 $): $1522-$1826/KW

Type: Pressurized Fluidized-Bed Combustion Coal

Current capital cost (1993 $): $1382-$2013/KW

More than 1000 MWs of existing coal-fired capacity has been, or is scheduled, to be converted to the AFBC technology in the United States.

Fluidized-Bed Combustion is gradually becoming a competitive technology with pulverized coal even though this process is relatively new and in an early stage of commercial utilization. Its ability to remove SO2 during the combustion process in lieu of post combustion removal (scrubbers) makes this an attractive technology. The AFBC units are expected to have capital costs equivalent to conventional coal-fired plants with scrubbers. Plants built to date are limited to the 100-200 MW range. Larger utility-scale AFBC units are not expected to be ready for use before the mid-1990's. Due to the lack of commercial experience with this technology, fluidized-bed combustion is presently not considered to be a feasible generating alternative by SCE&G; however, SCE&G plans to consider this technology in modernizing some existing units.

5. Coal Gasification (ICGCC)

Coal gasification is a process whereby a relatively clean, burnable gas is produced from almost any type of coal. This gas can then be burned in a power plant steam boiler or directly piped into a gas turbine to generate electricity. The process of coal gasification integrates a number of different technologies which are necessary to make gasification both thermally efficient as well as environmentally safe. Ash is separated and disposed of while the clean gas is burned in a combustion turbine. The major advantages of an Integrated Coal Gasification Combined Cycle (ICGCC) system are its low rate of emissions and its fuel efficiency.

In the 1970's, a great deal of interest centered around coal gasification due to concerns about adequacy of natural gas supplies. However, since then many coal gasification projects have been canceled as the energy picture has changed.

Typical ICGCC specifications

Capital cost (1993$): $1703-$1951/KW

Size: 500 MW

Operating and maintenance costs: 0.6 to 1.5 mills/KWH

Average Annual Net Heat Rate (BTU/KWH): 8420 to 8950

Coal gasification is an excellent technology for using coal to make electricity. The efficiency potential is in the 40% range, and environmentally, it is approximately ten times better than a pulverized coal or fluidized-bed combustion unit.

Currently, the best utility application for power generation is in units such as gas turbines that cannot burn solid fuels such as coal. In order to compete with direct coal burning units, the heat rates must be very low along with the capital cost. Potentially the best application for coal gasification is to make it a part of a combined cycle facility, which would offer a lower heat rate than conventional coal units. However, natural gas prices would have to exceed $4 to $5 per million BTU to make such a plant feasible. At present, this is not the case.

The status of the technology has been a deterrent to SCE&G and other utilities moving forward with definite implementation plans. You can be sure, however, that this technology will be considered in SCE&G's future plans when fuel prices and capital costs make it economically feasible.

6. Refuse Derived Fuel (RDF)

About two-thirds of the solid waste generated by residential, commercial and industrial operations is burnable and can be converted to energy. Refuse Derived Fuel (RDF) is a low-sulfur fuel that is processed from garbage and can be burned in mass or co-fired in a boiler with coal.

Burning RDF requires a business relationship between the utility and the municipalities who supply the RDF. It is recommended that the RDF be prepared by the municipality and transported to the utility's plant. Preparing the RDF means removing the non-combustible waste.

It is estimated that current use of solid waste for electricity totals 0.11 quads. That amount is expected to rise to 0.45 quads by 2010.

Responsibilities of the Municipality:

- Prepare RDF
- Responsible for RDF quality
- Responsible for disposing of non-RDF wastes which could be toxic
- Responsible for recycling glass and metal wastes

Advantages to Municipality:

- Ease of Waste Disposal (if landfill capacity is limited)

- Reduces exposure to increasing regulatory requirements on waste disposal
- Reduces or postpones need for new landfills
- Capital costs of processing are 35-50% of landfill capital costs

Advantages to the Utility:

- Reduces SOx and NOx emissions
- Conserves coal and possibly allows for increased flexibility in the sulfur content of coal

Disadvantages to the Utility:

- New boiler may be required (if not co-firing)
- Fuel preparation needed
- Increased maintenance costs
- High capital costs
- Increased difficulty to control boiler operations
- Potential for carbon corrosion

Costs:

- Average cost: 6 to 15 cents/KWH
- Capital cost: $3,222 to $4,919/KW

Conclusion

SCE&G has experimented with burning diaper scrap materials along with coal in our existing coal plants, but found that the diaper material did not burn properly to warrant further use. Currently, the investment required to install waste-fired plants is prohibitive.

7. Wood-Fired Power Plants

Wood-fired power plants have emerged over the last 15 years as a means of using waste wood products as fuel to produce electricity. Wood waste is generated from a number of processes, including: furniture manufacturing, pulp and paper production, logging, and disposal of railroad ties, packing crates, and power poles. Currently, these plants are limited by the availability of the fuel within a fifty mile radius of the plant. The plant size is also limited to 40 MW at present. DOE is researching the development of fast-growing tree species to establish a longer-term supply of this low-cost fuel.

The first technology of this type used a stoker boiler and has been commercially available for forty years. This technology requires additional equipment to reduce NOx emissions. The second generation RFD technology developed in the 1970s uses a fluidized-bed boiler that greatly reduces the NOx emissions without any additional equipment. Nonetheless, both technologies have similar cost specifications. Installed capital costs range from $1,883 to $2,199 per KW. Variable O&M costs are relatively high at about 8.9 mills/KWH. The average heat rate is approximately 14,300 BTU/KWH. From the data just shown, it is clear that the primary advantage this technology has depends on an abundant supply of low-cost wood residue fuel. Additionally, wood contains very little sulfur, so SO2 emissions are not a concern.

8. Geothermal

In geothermal generation, heat is captured from the hot magma that lies beneath the earth's surface. The heat is transferred into steam and used to drive a turbine.

According to the U. S. Geological Survey, about 23,000 MW of geothermal capacity could be tapped over the next thirty years. In 1989, the U. S. Geothermal industry produced 2.8 billion KWH. However, the costs of identifying and developing geothermal resources are high. Reductions in these operating costs are needed to make geothermal a more viable alternative. Where geothermal resources are available, the applicability of geothermal electricity generation is good, with targeted busbar costs equaling 5 cents per KWH. However, most geothermal resources are located in the western third of the country.

Suitable geothermal resources in the United States are limited to the western states and not available in and around the SCE&G service territory. Therefore, geothermal is not a feasible generation source for SCE&G.

[Reference: ~~TAG Technical Assessment Guide~~. EPRI TR-102275-V1R7, Electric Power Research Institute, Palo Alto, California, 1993.]

INTEGRATED RESOURCE PLAN

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