1992 Integrated Resource Plan

Executive Summary

SCE&G
A SCANA Company

INTEGRATED RESOURCE PLAN

EXECUTIVE SUMMARY

Table of Contents

INTEGRATED RESOURCE PLAN

EXECUTIVE SUMMARY

List of Tables and Charts

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, 1992 through 2011, 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 makes the planning process very complex because a simultaneous solution in all three components is required as opposed to a sequentially derived solution.

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 and a discussion of risk and IRP flexibility are also included.

2. 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 19,000 square miles. Total estimated population of the counties representing the Company's combined service area is approximately 2.2 million.

The Company purchases all of the electric generation of Williams Station, owned by South Carolina Generation 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 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 and Savannah Electric & Power Company and the Southeastern Power Administration's Clark Hill Project.

The Company operates 3,912,000 KW of net generating capability with 56% fueled by coal, 15% by nuclear, 20% hydro and 9% oil and natural gas. The sources of energy in 1991 were 69% coal, 21% nuclear and 10% other.

The Company owns 427 substations having an aggregate transformer capacity of 18,422,620 KVA. The transmission system consists of 3,003 pole miles of lines and the distribution system consists of 14,698 pole miles of overhead lines and 2,719 trench miles of underground lines.

3. THE PLANNING PROCESS

There are three phases to the planning process with each phase containing several steps. The goal of the first phase is to establish the reference plan by which to evaluate new DSM efforts. If no new DSM efforts are found to be cost-effective, the reference plan would be the optimal plan under which the Company would operate. The goal of the second phase of the process is to try to improve on the reference plan by altering our customers' needs for energy through new and/or expanded demand-side programs. The end result of the second phase would be the optimal supply-side plan subject to financial verification. The third phase of the process is essentially a verification of the results of the second phase. There are two goals to this verification: one is to re-evaluate the DSM analysis to verify that the expected benefits are reflected in the optimal plan and the second goal is to make certain that the Company can finance the optimal plan. If the optimal plan fails verification in the third phase, the process returns to phase two to develop an alternate plan. Following is a general discussion of each step within each phase of the planning process.

PHASE 1 - ESTABLISH THE REFERENCE PLAN

Step 1. The first step in establishing the reference plan 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 programs, a revised forecast of penetration levels and demand and energy impacts is prepared. This DSM plan represents the demand-side of the reference plan.

Step 2. 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.

Step 3. The reference 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 would run through the complete generation planning cycle. This cycle includes: gathering current information on all supply resources; performing generation planning studies which use dynamic programming techniques to develop optimal expansion plan strategies; and performing financial studies to fine tune expansion plans through detailed calculations.

The final expansion plan which emerges from a multitude of generation planning and financial runs represents the supply-side of the reference plan.

Step 4. Demand and energy credits are calculated based on the supply-side reference plan for evaluating new DSM efforts. These credits are used in Phase 2 of the planning process.

PHASE 2 - ESTABLISH THE BASE PLAN

Step 1. The reference plan represents the Company's course of action and future expectations without further DSM efforts. Using the demand and energy credits calculated in Phase 1, the Marketing Department determines whether there are other cost-effective DSM opportunities available to the Company. If there are such opportunities, the Company would be able to change the reference plan in a cost-effective manner by developing and implementing programs that capture these opportunities. The Company uses four benefit/cost tests to evaluate DSM options. These are: the Participant Test, the Total Resource Cost Test (TRC), the Ratepayer Impact Measure Test (RIM), and the Utility Cost Test.

Step 2. Based on the expanded DSM efforts, a new forecast of demand and energy is prepared.

Step 3. A new supply-side plan is developed to meet the new forecast. This requires running through the generation planning cycle of making planning studies to develop potential plans and financial studies to confirm those results. The resulting expansion plan becomes the supply-side base plan subject to financial verification in Phase 3 of the planning process.

Step 4. The final step in Phase 2 is to compute new demand and energy credits based on the new supply-side plan. These will be used in the financial verification phase to judge the need for re-evaluation of the DSM benefit/cost tests.

PHASE 3 - FINANCIAL VERIFICATION

Step 1. The first step of financial verification is to decide if the demand and energy credits used to evaluate DSM programs changed significantly during the process of incorporating DSM system impacts. If so, then it would be necessary to re-evaluate the DSM programs in a sequential manner so that the costs of each program or group of programs are being valued with the correct credits.

Step 2. The second step of verification is to analyze the financial stability and condition of the Company under the plan. The Company must be able to maintain adequate interest coverage ratios, internal generation of funds, earnings growth, etc. to remain financially sound. Financial strength is a prerequisite for a reliable source of electricity for our customers.

Step 3. The final step in the financial analysis phase of the planning process is to calculate the net benefits of the demand-side portion of the optimal plan. This is the amount of savings that the Company expects will accrue to our customers because of the Company's DSM efforts.

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:

1. <u>Develop and maintain an adequate and reliable source of power</u>: It is the Company's goal to have sufficient generation on-line to satisfy the 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.

2. <u>Encourage energy conservation</u>: 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.

3. <u>Protect the environment</u>: The Company will meet and, if possible, exceed 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.

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

5. <u>Minimize long-term costs to our customers</u>: 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.

6. <u>Maintain a strong financial position and provide a fair and secure return to investors</u>: 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 2.2% over the next twenty years with a growth of annual peak demand averaging 1.8%.

	1992	2011	Growth Rate
Energy (GWH)	16,047	24,250	2.2%
Peak (MW)	3,306	4,600	1.8%

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 DRI's projections for the nation and the SCE&G service territory are presented below.

4. 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 itself to a course of action until it is prudent to do so and plans that are flexible enough to respond to changes in operating conditions that may occur.

5. 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.

6. 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 2.2% over the next twenty years with a growth of annual peak demand averaging 1.8%.

	1992	2011	Growth Rate
Energy (GWH)	16,047	24,250	2.2%
Peak (MW)	3,306	4,600	1.8%

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 DRI's projections for the nation and the SCE&G service territory are presented below.

	1992	2011	Growth Rate
U.S. Real Personal Income	3337.585	4920.500	2.0%
S.C. Real Personal Income	38.568	56.603	2.0%
SCE&G Real Personal Income	14.294	22.878	2.5%
Inflation (Deflator for Personal Income)	1.499	3.283	4.2%

NOTE: Personal income stated in billions of 1982 dollars.

The sales forecast for the Company takes into account the effects of demand-side management (DSM) efforts. Table ES-1 contains the sales forecast for the primary customer classes.

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. The resulting forecast is shown in Table ES-2.

A forecast of peak demands for the winter season is made using econometric techniques. Table ES-3 contains projections for the winter and summer period. Note that the winter season is associated with the year containing the previous summer.

TABLE ES-1

TERRITORIAL ENERGY FORECAST (GWH)

CATEGORY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Residential	5,290	5,422	5,531	5,655	5,787	5,923	6,059	6,199	6,334	6,469
Commercial	4,604	4,689	4,807	4,955	5,114	5,275	5,436	5,605	5,767	5,930
Industrial	4,697	4,781	4,853	4,948	5,019	5,096	5,206	5,282	5,357	5,447
Municipals	763	786	805	1,026	1,052	1,079	1,108	1,136	1,163	1,191
Cooperatives	180	183	187	191	195	200	204	209	213	217
Other	513	529	545	560	577	593	610	628	644	661
Total Sales	16,047	16,390	16,729	17,335	17,744	18,167	18,623	19,058	19,478	19,914
Company Use	99	102	105	108	111	115	118	122	125	129
Unaccounted For	803	819	836	867	887	908	931	953	974	996
TOTAL LOAD	16,948	17,311	17,670	18,310	18,742	19,190	19,672	20,133	20,577	21,039

CATEGORY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential	6,596	6,729	6,872	7,015	7,147	7,281	7,419	7,557	7,695	7,837
Commercial	6,082	6,244	6,422	6,603	6,769	6,937	7,112	7,287	7,465	7,649
Industrial	5,531	5,617	5,702	5,780	5,855	5,933	6,006	6,076	6,144	6,207
Municipals	1,217	1,245	1,273	1,302	1,329	1,356	1,383	1,411	1,437	1,463
Cooperatives	221	226	230	234	239	243	247	251	256	260
Other	676	693	711	729	745	762	780	797	815	833
Total Sales	20,324	20,753	21,210	21,663	22,084	22,512	22,947	23,380	23,811	24,250
Company Use	133	137	141	145	150	154	159	163	168	173
Unaccounted For	1,016	1,038	1,061	1,083	1,104	1,126	1,147	1,169	1,191	1,212
TOTAL LOAD	21,473	21,928	22,412	22,891	23,338	23,792	24,253	24,712	25,170	25,635

TABLE ES-2

PEAK DEMAND FORECAST (MW)

CATEGORY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Residential	1,496	1,517	1,533	1,555	1,578	1,603	1,627	1,652	1,676	1,700
Commercial	908	922	943	970	1,000	1,030	1,060	1,091	1,121	1,152
Industrial	616	619	618	624	621	625	633	637	641	646
Municipals	149	154	157	203	208	213	218	223	228	233
Cooperatives	42	43	43	44	45	46	47	48	49	50
Miscellaneous	96	99	102	105	108	112	115	118	121	125
TOTAL DEMAND	3,306	3,354	3,396	3,502	3,561	3,629	3,700	3,770	3,837	3,907

CATEGORY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential	1,722	1,746	1,772	1,798	1,821	1,845	1,869	1,894	1,918	1,943
Commercial	1,180	1,211	1,244	1,277	1,308	1,339	1,372	1,404	1,437	1,472
Industrial	651	655	660	664	667	671	674	677	679	681
Municipals	238	243	248	254	259	264	269	274	279	284
Cooperatives	51	52	53	54	55	56	57	58	59	60
Other	128	131	135	138	142	145	149	152	156	160
TOTAL DEMAND	3,971	4,039	4,112	4,185	4,252	4,320	4,390	4,459	4,529	4,600

TABLE ES-3

SEASONAL PEAK DEMANDS

Year	Summer	Winter
1992	3,306	2,969
1993	3,354	3,021
1994	3,396	3,069
1995	3,502	3,162
1996	3,561	3,223
1997	3,629	3,291
1998	3,700	3,362
1999	3,770	3,432
2000	3,837	3,500
2001	3,907	3,569
2002	3,971	3,634
2003	4,039	3,702
2004	4,112	3,774
2005	4,185	3,847
2006	4,252	3,914
2007	4,320	3,982
2008	4,390	4,053
2009	4,459	4,122
2010	4,529	4,192
2011	4,600	4,264

6. DEMAND-SIDE PLANNING

The goal of the Company's DSM efforts is to help our customers use energy more wisely and to acquire their assistance in postponing the need for new capacity resources. These efforts are having a significant impact on the marketplace. Table ES-4 shows how much greater the energy needs of our customers would be over the next twenty years if all of the Company's DSM programs were halted. Table ES-5 has similar information on peak demands. Tables ES-4 and ES-5 give the system impacts associated with a hypothetical "No DSM" scenario.

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

	Change in Present Worth Revenue Requirements (000)
DSM Expenses	$ +89,235
Non-Fuel Revenues	-201,258
Fuel Revenues	-78,498
Total Change	$-190,521

TABLE ES-4

ENERGY (GWH) IMPACT OF DSM EFFORTS

Year	No DSM Case	DSM Impact	Base Case	DSM Impact %
1992	17,010	-62	16,948	-0.4%
1993	17,458	-147	17,311	-0.8%
1994	17,919	-249	17,670	-1.4%
1995	18,590	-280	18,310	-1.5%
1996	19,059	-317	18,742	-1.7%
1997	19,541	-351	19,190	-1.8%
1998	20,057	-385	19,672	-1.9%
1999	20,552	-419	20,133	-2.0%
2000	21,032	-455	20,577	-2.2%
2001	21,526	-487	21,039	-2.3%
2002	21,526	-520	21,473	-2.4%
2003	22,483	-555	21,928	-2.5%
2004	23,002	-590	22,412	-2.6%
2005	23,516	-625	22,891	-2.7%
2006	24,000	-662	23,338	-2.8%
2007	24,490	-698	23,792	-2.9%
2008	24,989	-736	24,253	-2.9%
2009	25,484	-772	24,712	-3.0%
2010	25,979	-809	25,170	-3.1%
2011	26,483	-848	25,635	-3.2%

TABLE ES-5

PEAK DEMAND (MW) IMPACT OF DSM EFFORTS

Year	No DSM Case	DSM Impact	Base Case	DSM Impact %
1992	3,377	-71	3,306	-2.1%
1993	3,470	-116	3,354	-3.5%
1994	3,557	-161	3,396	-4.7%
1995	3,687	-185	3,502	-5.3%
1996	3,777	-216	3,561	-6.1%
1997	3,870	-241	3,629	-6.6%
1998	3,967	-267	3,700	-7.2%
1999	4,063	-293	3,770	-7.8%
2000	4,155	-318	3,837	-8.3%
2001	4,249	-342	3,907	-8.8%
2002	4,338	-367	3,971	-9.2%
2003	4,431	-392	4,039	-9.7%
2004	4,530	-418	4,112	-10.2%
2005	4,629	-444	4,185	-10.6%
2006	4,721	-469	4,252	-11.0%
2007	4,815	-495	4,320	-11.5%
2008	4,911	-521	4,390	-11.9%
2009	5,006	-547	4,459	-12.2%
2010	5,103	-574	4,529	-12.7%
2011	5,200	-600	4,600	-13.0%

Following is a brief description of the individual programs that are included in the Company's DSM efforts.

1. Great Appliance Trade-Up (GATU): Focuses on high efficiency HVAC equipment for Residential and Commercial markets. Minimum efficiency of 11 SEER and maximum capacity of 5 tons to qualify.

2. Good Cents Homes: Focuses on energy efficiency measures such as insulation, ventilation, HVAC systems, window and door requirements for new construction. These factors are optimized to lower the customers' energy costs.

3. Home Energy Check (HEC): Audit customer's home. Make recommendations on efficiency improvements. If homeowner makes improvements, SCE&G provides rebates and financing.

4. Residential Energy Conservation (Rate 07): Energy efficiency measures such as insulation, ventilation, water heater systems, window and door requirements for retrofit. Includes an in-home inspection with recommendations to meet program standards.

5. Residential Thermal Storage: Uses Heat Pump driven water bank system to produce off-peak cooling, heating and water heating.

6. High Efficiency Chillers: Utilizes a rebate to customers based on the installation of high efficiency chillers on a KW deferred basis.

7. Thermal Storage: Minimizes energy costs by generating cooling capacity during off-peak hours and storing it for use during peak periods.

8. Interruptible Rate (Rate 27): An interruptible rate available to customers who can commit at least 1000 KW of interruptible power from June to September. Customers must commit to a five-year contract.

9. Stand-by Generator: Allows businesses with large capacity stand-by generators to meet their own electrical requirements during peak hours. SCE&G pays a stand-by fee for available capacity and a fuel supplement fee based on operation.

10. High Efficiency Commercial Lighting: Influences decision-makers within commercial and industrial facilities to purchase high efficiency lighting equipment for installation during normal maintenance activities.

11. Variable Speed Motor Drives: Provides a method for commercial and industrial customers to better match their large drive energy requirement with the process being performed.

12. <u>High Efficiency Fluorescent Ballasts (New and Retrofit)</u>: Provides commercial and industrial customers with an incentive for replacing inefficient ballasts with high efficiency units.

13. <u>High Efficiency Motors</u>: Provides an incentive to replace or upgrade small- to medium-size motors with high efficiency models.

14. <u>Off-Peak Water Heating</u>: Allows customers to heat water off-peak. Consists of a high capacity hot water storage tank, an electronic timer and insulation jacket.

15. <u>Rooftop HVAC Units</u>: Provides commercial and industrial customers with an incentive to retrofit current HVAC equipment with high efficiency models.

16. <u>High Efficiency Dual Fuel Heat Pumps</u>: An HVAC system that meets the Great Appliance Trade-Up guidelines and uses a gas heating system for supplemental heat. (Existing gas water heater only.)

17. <u>Great Appliance Trade-Up Financing</u>: Incentive addition to current Great Appliance Trade-Up program. Restricted to customers who retrofit HVAC equipment with a minimum SEER of 13.

18. Residential/Commercial Heat Pump Pool Heaters: Gives customers an incentive for installing high efficiency HP pool equipment.

19. Commercial Heat Pump Water Heaters: Gives commercial customers incentives for installing high efficiency water heaters.

20. Commercial Electric Cooking: Offers customers incentives for purchasing electric cooking equipment.

21. Compact Fluorescent Lamps: Provides an opportunity for residential customers to purchase high efficiency compact fluorescent lamps.

22. Gas Air Conditioning: Provides large commercial and industrial customers an incentive to install gas-fired chillers.

7. SUPPLY-SIDE PLANNING

Although the Company's DSM programs have been extremely effective in slowing the growth of peak demands on the system, they cannot eliminate all growth. Our DSM efforts have been able to limit the growth to about 70 MW per year. With a current reserve margin of 18.5% and a goal of 20%, it is clear that new capacity must be added.

Table ES-6 contains a listing of the 3,912 MW of net generating capability that the Company has available. This capability is 56% coal, 15% nuclear, 20% hydro and 9% natural gas and oil. Over the next twenty years, the Company plans to increase this capability by a net of 1,628 MW. Table ES-7 contains the Company's supply-side plans. It includes three coal-fired plants totalling 985 MWs and 7 internal combustion turbines of 99 MWs each.

The Company has committed to building the first of the three coal plants contained in the supply-side plan. Construction on the Cope Generating Station, a 385 MW pulverized coal plant, will begin in late-1992 with the plant going "on-line" in spring of 1996. The plant will be located two miles from the town of Cope in Orangeburg County and will be the sixth coal-fired baseload plant on SCE&G's system. On November 1, 1991, the Company filed with the South Carolina Public Service Commission, its application for a Certificate of Environmental Compatibility and Public Convenience and Necessity. The Commission has approved the Company's application and an order is pending.

TABLE ES–6

Generating Station Capability

	First and Last Unit In Service	Rating in Kilowatts Net Capability Summer	Winter
Steam:			
Canadys – Canadys, SC	1962 – 1967	430,000	430,000
Hagood – Charleston, SC	1947 – 1951	20,000	20,000
McMeekin – near Irmo, SC	1958 – 1959	252,000	254,000
Urquhart – Beech Island, SC	1953 – 1955	250,000	254,000
Wateree – Eastover, SC	1970 – 1971	700,000	720,000
Williams – Goose Creek, SC	1973	560,000	565,000
Total Steam Capacity		2,212,000	2,243,000
Nuclear:			
V. C. Summer – Parr, SC	1984	590,000	596,000
I. C. Turbines: (1)			
Burton, SC	1961	9,500	10,000
Charleston, SC	1961	9,500	10,000
Burton, SC	1963	9,500	10,000
Burton, SC	1963	9,500	10,000
Hardeeville, SC	1968	14,000	14,000
Canadys, SC	1968	14,000	15,000
Urquhart (14 MWs, 12MWs) – Beech Is., SC	1969	26,000	32,000
Coit (2 X 15 MWs) – Columbia, SC	1969	30,000	36,000
Parr Turbines (2 X 13 MWs)	1970	26,000	34,000
Parr Turbines (2 X 17 MWs)	1971	34,000	42,000
Parr Heat Recovery – Parr, SC	1925 – 1929	28,000	28,000
Williams (2 X 24.5 MWs) – Goose Creek, SC	1972	49,000	58,000
Hagood – Charleston, SC	1991	95,000	112,000
Total I. C. Turbines Capacity		354,000	411,000
Hydro:			
Columbia – Columbia, SC	1927 – 1929	10,000	10,000
Neal Shoals – Carlisle, SC	1905	5,000	5,000
Parr Shoals – Parr, SC	1914 – 1921	14,000	14,000
Saluda – Near Irmo, SC	1930 – 1971	206,000	206,000
Stevens Creek – Near Martinez, GA	1914 – 1926	9,000	9,000
Fairfield Pumped Storage – Parr, SC	1978	512,000	512,000
Total Hydro Capacity		756,000	756,000
Grand Total:		3,912,000	4,006,000

Notes:

(1) I. C. Turbines net capability for summer is based on a 100o F day.

TABLE ES-7

Supply-Side of the Integrated Resource Plan

YEAR	PEAK (MW)	CAPACITY CHANGES ONE YEAR (MW)	CAPACITY CHANGES LONG TERM (MW)	DESCRIPTION	CAPACITY (MW)	RESERVE MARGIN
1992	3,306	50		SPOT CAPACITY PURCHASES	3,962	19.84%
1993	3,354	100		4 MONTH LIMITED TERM PURCHASE	4,014	19.68%
		50		4 MONTH LIMITED TERM PURCHASE		
			−28	RETIRE PARR STEAM		
			−20	RETIRE HAGOOD STEAM		
1994	3,396	100		4 MONTH LIMITED TERM PURCHASE	4,062	19.61%
		100		4 MONTH LIMITED TERM PURCHASE		
			−2	WILLIAMS COOLING TOWER		
1995	3,501	350		4 MONTH LIMITED TERM PURCHASE	4,222	20.59%
			10	VCSN STEAM GENERATOR UPGRADE		
1996	3,561		385	COPE UNIT	4,257	19.55%
1997	3,628		99	ICT	4,356	20.07%
1998	3,700		99	ICT	4,455	20.41%
1999	3,770		99	ICT	4,554	20.80%
2000	3,837		99	ICT	4,643	21.01%
			−10	SCRUBBER AT WILLIAMS		
2001	3,907		99	ICT	4,742	21.37%
2002	3,972				4,742	19.39%
2003	4,038		99	ICT	4,841	19.89%
2004	4,112	100		4 MONTH LIMITED TERM PURCHASE	4,941	20.16%
2005	4,185		300	PULVERIZED COAL UNIT	5,141	22.84%
2006	4,252				5,141	20.91%
2007	4,320		99	ICT	5,240	21.30%
2008	4,390				5,240	19.36%
2009	4,460	100		4 MONTH LIMITED TERM PURCHASE	5,340	19.73%
2010	4,528		300	PULVERIZED COAL UNIT	5,540	22.35%
2011	4,600				5,540	20.43%

The Company plans to meet its increasing need for capacity in the period leading up to the Cope Plant with short term purchases. This reliance on short term purchases results in the 1996 baseload unit's being phased in and eliminates the usual bulge in reserve capacity. Our reserve margin for 1996 will be 19.6% which is essentially right on the 20% target. The short term reliance on purchased power also provides a great deal of flexibility which is a critical attribute of any plan that deals with an uncertain future.

It should be kept in mind that this supply-side plan is just a plan which is subject to frequent review and change. As new information becomes available and current issues get more or less resolved and new issues crop up, the plan will be modified to take advantage of new opportunities. In a sense, the current IRP becomes the plan to beat, that is, it is a reference point for doing better. Of particular interest to the Company at this time are two alternative supply plans involving purchased power and/or combined cycle generation.

With regard to purchased power, the Company is currently developing a bidding package to acquire a long-term supply of power sometime before 2000. How the Company proceeds in this regard will depend to a great extent on the need for additional capacity which, in turn, depends on anticipated load growth. The Company is uncertain about the effectiveness of its DSM efforts and how receptive our customers will be to our programs. The Company plans to reduce this uncertainty by directly monitoring its own DSM programs and gathering information from other utilities. Over the next two or three years, the Company will have gathered a significant amount of information and will know better how to proceed with the purchased power option.

Another alternative supply plan includes the replacement of the baseload coal units planned beyond 2000 with combined cycle generation. A combined cycle plant will have lower capital costs than a coal unit but higher operating costs. Natural gas would be the primary fuel for the combined cycle plant so the price and deliverability of natural gas becomes a principal issue. Fortunately, the Company does not have to make a decision on this for several years and by then the natural gas market may be more predictable.

8. THE ENVIRONMENT

South Carolina Electric and Gas Company recognizes that the environment is a fragile resource and is committed to providing dependable, affordable energy in an environmentally sensitive manner. At a minimum, the Company will meet the requirements of all local, state and federal environmental laws and regulations and, furthermore, will work with government at all levels to isolate, analyze and solve problems related to the environment.

The 1990 Clean Air Act Amendments have set stringent environmental regulations that go into effect over the next ten years. The Company's preliminary plan for compliance with these regulations falls in two stages. Stage 1 of the plan, which deals with activities commencing prior to the year 2000, requires the installation of low NOx burner systems and continuous emission monitors at all units. Further, in anticipation of future particulate emission regulations, and potential use of low sulfur coal to reduce SO2 emissions, fabric filters are projected to be installed on all units at Canadys, Urquhart and Wateree Stations. Stage 2 of the emission compliance plan addresses the control of sulfur dioxide emissions. The plan incorporates the use of low sulfur compliance coals beginning in 2000 at Canadys, McMeekin, Urquhart and Wateree Stations as well as the installation of a scrubbing system at Williams Station in 1999. It should be kept in mind that this is a plan and that the Company has not made final decisions in these matters, but instead will continue to study the available options.

peaking-type generation in the form of a succession of ICTs until the year 2005. If our projections of load growth need to change, then these ICTs can be brought on line sooner, or postponed, with relative ease and minimal financial impact.

Thus, over the next several years, the Company's expansion plan is very flexible and can easily be adjusted with the changing times.

10. FINANCIAL ANALYSIS

Before the Company can adopt an IRP, it must verify the financial viability of the plan from the perspectives of both customers and investors. Chart ES-8 compares the projected cost per KWH with the anticipated rate of consumer inflation. Projected increases in cost are in line with the Company's goal of holding rate increases down to a level at or less than the rate of inflation.

Chart ES-9 illustrates the difference in annual average customer costs between a hypothetical "No DSM" case and the IRP base case. Initially, customer rates are lower for the case without DSM, reflecting the DSM reduction in energy sales in the IRP as well as the fact that DSM costs are incurred before the benefits accrue. Eventually, assuming DSM efforts are successful, the lower construction requirements of the IRP base case should result in lower customer rates.

Company financial planners examined the IRP from the perspectives of other stakeholders as well, and confirmed that fixed charges should be adequately covered and that earnings should provide both internal generation of funds and a consistent flow of dividends, assuming appropriate rate relief.

The ability of the Company to meet future demands for electricity will depend upon its ability to attract the necessary financial capital on reasonable terms. The cost associated with attracting this capital as well a the cost of providing utility services are recovered through rates charged to customers. As inflation occurs and the Company expands its DSM and construction programs, it will be required to seek increases in rates. Therefore, the Company's future financial position could be impacted by its ability to obtain adequate and timely rate relief.

CHART ES-8: CUSTOMER COST vs. CONSUMER INFLATION

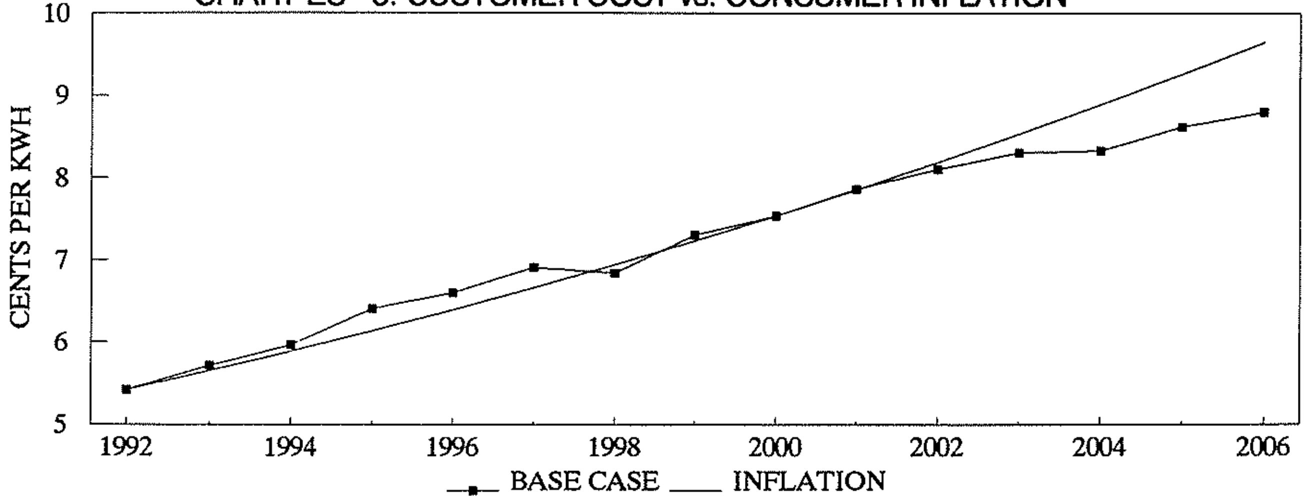
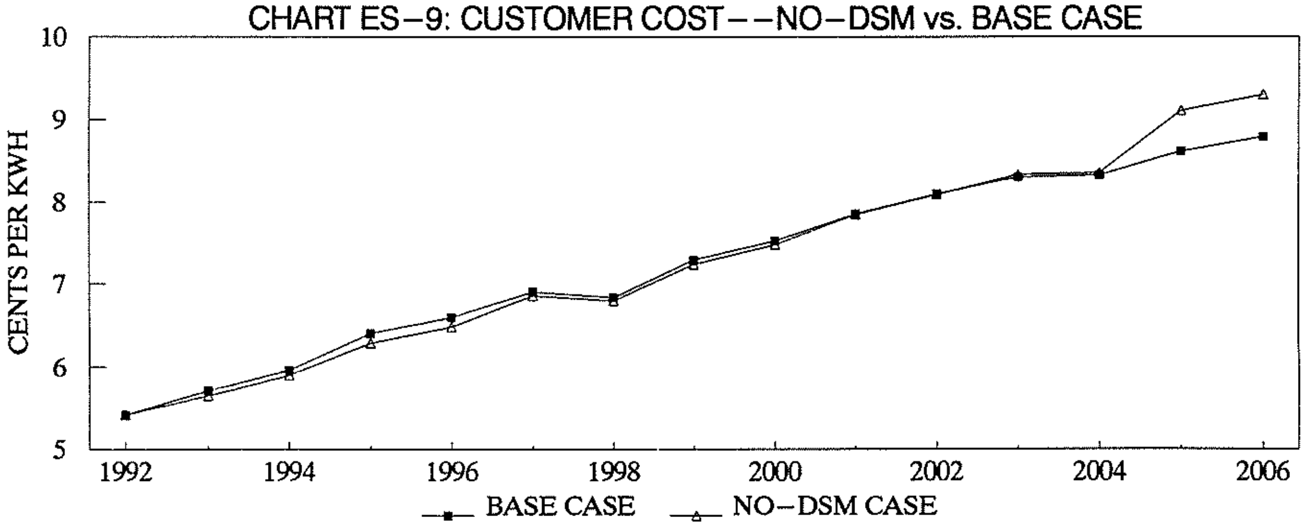


CHART ES-9: CUSTOMER COST--NO-DSM vs. BASE CASE



1992 Integrated Resource Plan

SCE&G

A SCANA Company

INTEGRATED RESOURCE PLAN

Table of Contents

1.0 INTRODUCTION

1.0 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, 1992 through 2011, 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 makes the planning process very complex because a simultaneous solution in all three components is required as opposed to a sequentially derived solution.

There are six chapters in this document. Chapter 1.0 contains the Introduction which will present general information about the Company, an overview of the planning process and the goals and objectives of the IRP. The forecast and forecasting methodology is contained in Chapter 2.0. The demand-side planning component of the IRP is discussed in Chapter 3.0 and the supply-side component in Chapter 4.0. A review of the IRP from a financial perspective is presented in Chapter 5.0. This review includes a discussion of the possible need to iterate through the planning process again, the impact of the IRP on customers and the ability of the Company to finance the plan. The final Chapter 6.0 presents other components of the planning process such as the environmental component, transmission and distribution planning and a technology review. The Executive Summary for the document is published as a separate document.

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 19,000 square miles. Total estimated population of the counties representing the Company's combined service area is approximately 2.2 million.

The Company purchases all of the electric generation of Williams Station, owned by South Carolina Generation 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 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 and Savannah Electric & Power Company and the Southeastern Power Administration's Clark Hill Project.

The Company operates 3,912,000 KW of net generating capability with 56% fueled by coal, 15% by nuclear, 20% hydro and 9% oil and natural gas. The sources of energy in 1991 were 69% coal, 21% nuclear and 10% other.

The Company owns 427 substations having an aggregate transformer capacity of 18,422,620 KVA. The transmission system consists of 3,003 pole miles of lines and the distribution system consists of 14,698 pole miles of overhead lines and 2,719 trench miles of underground lines.

2. The Planning Process

There are three phases to the planning process with each phase containing several steps. The goal of the first phase is to establish the reference plan by which to evaluate new DSM efforts. If no new DSM efforts are found to be cost-effective, the reference plan would be the optimal plan under which the Company would operate. The goal of the second phase of the process is to try to improve on the reference plan by altering our customers' needs for energy through new and/or expanded demand-side programs. The end result of the second phase would be the optimal supply-side plan subject to financial verification. The third phase of the process is essentially a verification of the results of the second phase. There are two goals to this verification: one is to re-evaluate the DSM analysis to verify that the expected benefits are reflected in the optimal plan and the second goal is to make certain that the Company can finance the optimal plan. If the optimal plan fails verification in the third phase, the process returns to phase two to develop an alternate plan. Following is a general discussion of each step within each phase of the planning process.

Phase 1 - Establish The Reference Plan

Step 1. The first step in establishing the reference plan 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 programs, a revised forecast of penetration levels and demand and energy impacts is prepared. This DSM plan represents the demand-side of the reference plan.

Step 2. 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.

Step 3. The reference 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 would run through the complete generation planning cycle. This cycle includes: gathering current information on all supply resources; performing generation planning studies which use dynamic programming techniques to develop optimal expansion plan strategies; and performing financial studies to fine tune expansion plans through detailed calculations.

The final expansion plan which emerges from a multitude of generation planning and financial runs represents the supply-side of the reference plan.

Step 4. Demand and energy credits are calculated based on the supply-side reference plan for evaluating new DSM efforts. These credits are used in Phase 2 of the planning process.

Phase 2 - Establish The Base Plan

Step 1. The reference plan represents the Company's course of action and future expectations without further DSM efforts. Using the demand and energy credits calculated in Phase 1, the Marketing

Department determines whether there are other cost-effective DSM opportunities available to the Company. If there are such opportunities, the Company would be able to change the reference plan in a cost-effective manner by developing and implementing programs that capture these opportunities. The Company uses four benefit/cost tests to evaluate DSM options. These are: the Participant Test, the Total Resource Cost Test (TRC), the Ratepayer Impact Measure Test (RIM), and the Utility Cost Test.

Step 2. Based on the expanded DSM efforts, a new forecast of demand and energy is prepared.

Step 3. A new supply-side plan is developed to meet the new forecast. This requires running through the generation planning cycle of making planning studies to develop potential plans and financial studies to confirm those results. The resulting expansion plan becomes the supply-side base plan subject to financial verification in Phase 3 of the planning process.

Step 4. The final step in Phase 2 is to compute new demand and energy credits based on the new supply-side plan. These will be used in the financial verification phase to judge the need for re-evaluation of the DSM benefit/cost tests.

Phase 3 - Financial Verification

Step 1. The first step of financial verification is to decide if the demand and energy credits used to evaluate DSM programs changed significantly during the process of incorporating DSM system impacts. If so, then it would be necessary to re-evaluate the DSM programs in a sequential manner so that the costs of each program or group of programs are being valued with the correct credits.

Step 2. The second step of verification is to analyze the financial stability and condition of the Company under the plan. The Company must be able to maintain adequate interest coverage ratios, internal generation of funds, earnings growth, etc. to remain financially sound. Financial strength is a prerequisite for a reliable source of electricity for our customers.

Step 3. The final step in the financial analysis phase of the planning process is to calculate the net benefits of the demand-side portion of the optimal plan. This is the amount of savings that the Company expects will accrue to our customers because of the Company's DSM efforts.

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:

1. <u>Develop and maintain an adequate and reliable source of power</u>: It is the Company's goal to have sufficient generation on-line to satisfy the 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.

2. <u>Encourage energy conservation</u>: 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.

3. <u>Protect the environment</u>: The Company will meet and, if possible, exceed 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.

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

5. 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.

6. 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.

2.0 THE FORECAST

2.1 ELECTRIC SALES FORECAST

1. Econometric Methodology
2. Economic Assumptions
3. Forecast Ranges
4. Historical Economic Data
5. Forecast Economic Data
6. Electric Sales Assumptions
7. Demand-Side Management
8. Electric Forecast Equations
9. Historical Electric Sales Data
10. Final Electric Sales Forecast

2.2 PEAK DEMAND FORECAST

1. Summer Peak Demand
2. Weather Impacts
3. Load Factor Development
4. Energy Projections
5. Unadjusted Peak Demands
6. Adjusted Peak Demands
7. Comparison of Peak Demand With and Without DSM
8. Winter Peak Demand
9. Scenario Analysis

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. 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 90% 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 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 8 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:

1. 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.

2. One way to incorporate the effects of "conservation", was to incorporate the real price of electricity. Models selected for the major classes would include this variable, if significant.

3. The remaining variables to be included in the models for the major classes would come from four categories:

   A. Demographic variables - Population.

   B. Measures of economic well-being or activity - real personal income, real per capita income, employment variables, and industrial production indices.

   C. Weather variables - average summer/winter temperature.

   D. Variables identified through residual analysis or knowledge of political changes, major economic events, etc. - such as the foreign oil price increases in 1979 and recession versus non-recession years, etc.

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 1990 and competitive models were evaluated on the basis of:

1. 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.

2. An examination of the model results for 1991. 1991 historical sales data was the basis for this evaluation.

3. 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.

4. 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 8.

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

1. Service Area population;
2. Service Area real per capita income;
3. Service Area real personal income;
4. State industrial production indices;
5. The real price of electricity;
6. Average summer temperature; and,
7. Average winter temperature.

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties which account for 85% 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 GNP 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 55%

probability that the economy will closely resemble the trend, a 25% chance that it will resemble the optimistic scenario, and a 20% 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 2.1% between 1991 and 2011 with consumer prices averaging 4.1% annually over the same time frame. In the 1990's, growth in real output is constrained by slower population growth, averaging .7% from 1991 to 2000 and .5% thereafter, a marked deceleration from the 1.0% average since 1966. Slower population growth leads to a period of softening in housing and other consumer goods markets. Real interest rates remain high by pre-1979 standards and the civilian unemployment rate deviates only slightly from its 5.8% 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. This scenario also assumes that inflation never exceeds 4.0% and averages only 3.0%. The pessimistic scenario makes the opposite assumptions: higher inflation which rises steadily through the first half of the forecast, eventually leveling off around 6.5% 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 4.5% annually from 1993 to 2010. This expectation is based on the Company's most recent Integrated Resource Plan. With inflation projected at a rate close to 4.0% over this time period, the real price of electricity should remain fairly flat 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 -.3% with a high of 13.0% and a low of -9.2%. For forecasting, growth in the real price of electricity is assumed to be zero which is consistent with the historical data and expectations for future policy decisions. 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 +13.01% to -9.19%. 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 in Table 2.1.1.

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 -.1, a 1% increase in the real price of electricity would result in a .1% decline in total territorial sales. Similarly, a 1% increase in real personal income would result in a .8% increase in total territorial sales. In terms of temperature, if the average summer temperature is 81.1 degrees instead of the mean value of 80.3

degrees, a 1.0% increase, sales would be expected to be .5% higher. If the average winter temperature is 46.7 degrees instead of the mean value of 47.7 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 2.2. In the trend scenario, real personal income in the service area grows at a 2.5% annual rate from 1994 to 2011. In the pessimistic and optimistic scenarios, the growth is 1.9% 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 1.8% and 2.7% in the pessimistic and optimistic scenarios respectively, compared to the trend of 2.2%. As noted earlier, the trend scenario has a 55% probability of occurring compared to 20% for the pessimistic and 25% for the optimistic.

TABLE 2.1.1

ELASTICITY COEFFICIENTS

Variable	Coefficient
Real Personal Income	.8
Real Price of Electricity	-.1
Average Summer Temperature	.5
Average Winter Temperature	-.2

TABLE 2.1.2

A FORECAST SCENARIO FOR 2011

	Base Case	Pessimistic	Optimistic
SCE&G Real Personal Income	22.878	20.911	25.075
% Change to Base		-8.60	+9.60
Elasticity		.80	.80
% Change in Sales *		-6.88	+7.68
Total Territorial Sales	24.250	22.582	26.112
Annual % Change (1994 - 2011)	2.2	1.80	2.70

*Calculated based on the following formula:

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

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	949.6	8780	8337.1	49.3	77.9	0.05160	0.05989	0.04738	0.03255
1977	963.6	8943	8617.7	43.3	81.0	0.05583	0.06479	0.05179	0.03342
1978	984.0	9233	9085.2	42.7	79.7	0.05531	0.06380	0.05132	0.03505
1979	1002.1	9333	9352.9	46.8	78.5	0.05527	0.06300	0.05070	0.03547
1980	1018.8	9345	9520.8	45.7	80.2	0.05502	0.06051	0.05009	0.03475
1981	1037.1	9525	9878.4	45.1	80.8	0.05816	0.06486	0.05379	0.03835
1982	1051.0	9519	10004.0	46.1	79.3	0.06382	0.06817	0.05604	0.03964
1983	1065.5	9763	10402.5	48.2	80.7	0.06582	0.07000	0.05676	0.04369
1984	1078.5	10398	11213.9	46.8	79.5	0.06647	0.07126	0.05762	0.04722
1985	1085.5	10661	11572.6	48.4	79.5	0.06744	0.07071	0.05679	0.04623
1986	1105.8	10961	12121.5	47.5	82.6	0.06488	0.06752	0.05422	0.04364
1987	1120.5	11132	12474.1	47.5	82.1	0.05922	0.06167	0.04915	0.03508
1988	1134.1	11492	13033.0	46.6	80.3	0.05438	0.05677	0.04497	0.03399
1989	1152.7	11420	13164.0	51.1	80.9	0.05261	0.05491	0.04340	0.03350
1990	1184.2	11800	13974.3	51.2	82.1	0.05076	0.05279	0.04156	0.03133

1 1982 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	1.070	1.016	0.9150	1.114	1.090	1.481	0.988	1.2206
1977	1.157	1.059	0.9745	1.159	1.171	1.919	1.083	1.4076
1978	1.209	1.050	1.0385	1.203	1.253	2.175	1.144	1.5702
1979	1.267	1.097	1.0385	1.242	1.320	2.416	1.140	1.6772
1980	1.265	1.093	1.0340	1.249	1.257	2.539	1.028	1.7476
1981	1.283	1.072	1.0375	1.269	1.251	3.113	1.053	1.8784
1982	1.210	0.939	0.9810	1.253	1.153	3.197	0.953	1.7568
1983	1.343	1.057	1.1100	1.488	1.370	3.381	1.041	1.9840
1984	1.417	1.051	1.1710	1.595	1.413	3.578	1.107	2.4230
1985	1.397	0.997	1.1665	1.625	1.400	3.659	1.107	2.4878
1986	1.492	1.056	1.1840	1.839	1.558	3.950	1.197	2.5924
1987	1.641	1.166	1.2745	1.916	1.727	4.328	1.201	3.0504
1988	1.714	1.111	1.3110	1.974	1.946	4.605	1.267	3.4926
1989	1.792	1.154	1.2905	1.994	2.131	4.856	1.272	3.6408
1990	1.811	1.122	1.2940	2.056	2.261	5.138	1.191	3.7494

1 1973:1=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
1992	1246.0	11312	14094
1993	1257.0	11466	14414
1994	1266.3	11794	14935
1995	1276.7	11959	15268
1996	1288.1	12080	15560
1997	1302.2	12221	15915
1998	1317.9	12339	16262
1999	1333.3	12496	16661
2000	1349.0	12655	17071
2001	1364.7	12808	17479
2002	1380.9	12934	17861
2003	1396.7	13037	18208
2004	1412.4	13176	18610
2005	1428.0	13300	18993
2006	1443.6	13366	19295
2007	1459.9	13421	19593
2008	1476.8	13492	19925
2009	1493.7	13559	20252
2010	1510.8	13620	20578
2011	1528.4	13682	20911

1 1982 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
1992	1246.0	11472	14294.4
1993	1257.0	11700	14707.8
1994	1266.3	11949	15131.3
1995	1276.7	12178	15547.4
1996	1288.1	12415	15992.1
1997	1302.2	12625	16440.7
1998	1317.9	12813	16886.4
1999	1333.3	13017	17354.8
2000	1349.0	13196	17800.9
2001	1364.7	13369	18245.1
2002	1380.9	13515	18663.4
2003	1396.7	13680	19106.4
2004	1412.4	13870	19589.4
2005	1428.0	14060	20076.9
2006	1443.6	14219	20526.8
2007	1459.9	14369	20978.0
2008	1476.8	14523	21447.8
2009	1493.7	14674	21918.0
2010	1510.8	14821	22391.3
2011	1528.4	14969	22878.3

1 1982 DOLLARS

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
1992	1246.0	11530	14366
1993	1257.0	11888	14943
1994	1266.3	12176	15419
1995	1276.7	12446	15889
1996	1288.1	12775	16456
1997	1302.2	13042	16983
1998	1317.9	13274	17494
1999	1333.3	13563	18084
2000	1349.0	13816	18638
2001	1364.7	14038	19157
2002	1380.9	14245	19671
2003	1396.7	14473	20215
2004	1412.4	14730	20804
2005	1428.0	15002	21422
2006	1443.6	15229	21984
2007	1459.9	15461	22572
2008	1476.8	15700	23185
2009	1493.7	15951	23825
2010	1510.8	16184	24451
2011	1528.4	16406	25075

1 1982 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
1992	1.812	1.136	1.237	2.134	2.399	5.320	1.052	3.611
1993	1.874	1.138	1.292	2.202	2.475	5.597	1.133	3.885
1994	1.933	1.143	1.373	2.272	2.542	5.808	1.226	4.088
1995	1.973	1.147	1.433	2.325	2.581	6.014	1.316	4.213
1996	2.000	1.138	1.460	2.353	2.598	6.142	1.367	4.329
1997	2.040	1.142	1.498	2.392	2.644	6.388	1.405	4.450
1998	2.095	1.153	1.540	2.449	2.713	6.731	1.444	4.636
1999	2.141	1.157	1.574	2.489	2.771	7.017	1.465	4.799
2000	2.190	1.163	1.607	2.537	2.836	7.321	1.487	4.965
2001	2.247	1.172	1.643	2.593	2.906	7.691	1.514	5.155
2002	2.303	1.177	1.673	2.642	2.968	8.067	1.536	5.348
2003	2.352	1.177	1.695	2.689	3.028	8.420	1.546	5.543
2004	2.404	1.180	1.727	2.741	3.092	8.773	1.555	5.726
2005	2.446	1.181	1.761	2.788	3.145	9.117	1.566	5.876
2006	2.483	1.178	1.778	2.829	3.193	9.426	1.566	6.013
2007	2.519	1.176	1.810	2.867	3.243	9.737	1.578	6.142
2008	2.554	1.175	1.840	2.902	3.290	10.069	1.591	6.266
2009	2.587	1.174	1.872	2.936	3.333	10.392	1.606	6.380
2010	2.618	1.171	1.901	2.970	3.373	10.717	1.617	6.499
2011	2.647	1.163	1.930	3.003	3.412	11.041	1.627	6.625

1 1973:1=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
1992	1.838	1.152	1.255	2.164	2.433	5.396	1.067	3.662
1993	1.912	1.161	1.318	2.247	2.526	5.711	1.156	3.964
1994	1.958	1.158	1.391	2.302	2.575	5.884	1.242	4.142
1995	2.009	1.168	1.459	2.368	2.628	6.124	1.340	4.290
1996	2.055	1.170	1.501	2.418	2.670	6.312	1.405	4.449
1997	2.107	1.180	1.548	2.471	2.731	6.599	1.451	4.597
1998	2.176	1.197	1.599	2.543	2.817	6.990	1.499	4.814
1999	2.230	1.205	1.640	2.593	2.886	7.309	1.526	4.999
2000	2.284	1.213	1.676	2.645	2.957	7.634	1.551	5.177
2001	2.346	1.223	1.715	2.707	3.033	8.028	1.580	5.381
2002	2.406	1.230	1.748	2.761	3.101	8.429	1.605	5.588
2003	2.468	1.235	1.779	2.822	3.177	8.835	1.622	5.816
2004	2.530	1.242	1.818	2.885	3.255	9.235	1.637	6.027
2005	2.586	1.248	1.861	2.947	3.324	9.637	1.655	6.211
2006	2.641	1.253	1.891	3.010	3.397	10.028	1.666	6.397
2007	2.697	1.259	1.938	3.070	3.472	10.425	1.689	6.576
2008	2.749	1.265	1.981	3.124	3.541	10.838	1.713	6.745
2009	2.800	1.271	2.026	3.177	3.607	11.247	1.738	6.905
2010	2.849	1.274	2.069	3.232	3.670	11.662	1.760	7.072
2011	2.896	1.272	2.112	3.286	3.733	12.080	1.780	7.248

1 1973:1=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
1992	1.847	1.158	1.261	2.175	2.445	5.423	1.072	3.680
1993	1.943	1.180	1.339	2.283	2.566	5.802	1.174	4.027
1994	1.995	1.180	1.417	2.346	2.624	5.996	1.266	4.221
1995	2.053	1.194	1.491	2.420	2.686	6.259	1.369	4.384
1996	2.115	1.204	1.545	2.488	2.747	6.495	1.446	4.578
1997	2.177	1.219	1.599	2.553	2.821	6.817	1.499	4.749
1998	2.254	1.240	1.657	2.635	2.918	7.242	1.553	4.987
1999	2.324	1.256	1.709	2.702	3.007	7.616	1.590	5.209
2000	2.391	1.270	1.755	2.769	3.096	7.993	1.624	5.420
2001	2.463	1.284	1.801	2.842	3.185	8.429	1.659	5.650
2002	2.536	1.296	1.842	2.910	3.268	8.884	1.692	5.890
2003	2.611	1.307	1.882	2.986	3.361	9.347	1.716	6.153
2004	2.687	1.319	1.931	3.064	3.457	9.808	1.738	6.401
2005	2.759	1.332	1.986	3.144	3.547	10.283	1.766	6.627
2006	2.829	1.342	2.025	3.224	3.638	10.740	1.784	6.851
2007	2.902	1.355	2.085	3.303	3.736	11.217	1.817	7.076
2008	2.972	1.367	2.141	3.377	3.828	11.716	1.852	7.291
2009	3.044	1.382	2.202	3.453	3.921	12.225	1.889	7.506
2010	3.111	1.391	2.259	3.529	4.008	12.735	1.922	7.723
2011	3.174	1.394	2.315	3.601	4.091	13.240	1.951	7.944

1 1973:1=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 2.1.10. Total territorial sales are expected to increase at an annual rate of 2.2% from 1994 to 2011. Most of the 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 2.1% 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 3.0% and in the non-space heating sector, sales increase at .9%.

Residential customers are expected to increase at a 1.7% annual rate, averaging 8,171 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 10% of new customer growth has been non electric heating. However, from 1989 to 1991 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 fifteen 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 50% of new customers would be single family, 30% multi-family and 20% mobile homes. The respective percentages for non-electric heating are 70%, 15% and 15%.

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 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 three years of available historical data.

For Rate 1, we assumed 83% would be single family homes with 33% non-electric heating and 50% electric heating. The remainder would be multi-family homes with 7% non-electric heating and 10% electric heating. For Rate 7, we assumed 38% would non-space heating with 24% single family, 13% multi-family and 1% mobile homes. The remaining 62% would be electric heating with the housing type percentages 46%, 14%, and 2%, respectively. Average use for these customers was based on 1991 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 1.37%, .83%, and 1.38% for single family, multi-family, and mobile homes, respectively. The respective percentages for space heating were 1.02%, .87%, and 1.02%. 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, with a slight increase in space heating, +.1%, and a slight increase in non-space heating of .3%. 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 applied and average use for each subgroup was recalculated.

Commercial

The forecast for commercial sales is a compound annual rate of 2.8% over the 17 year period. Commercial customers are expected to increase about 1,833 per year. As indicated by the model specification the main factor influencing commercial sales over the forecast will be economic activity, although summer temperature and price explain some variation in the sales data.

Industrial

The long-range annual rate of growth forecast for industrial sales is 1.5%. This incorporates a base load of 408 GWH for 1994-2011 for the Savannah River Project forecast. This is 67% of the expected contract amount of 70 MW from 1994 - 2011. This Forecast was based on information supplied by Industrial Relations. 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 two exceptions were the chemical products (SIC 28) which tend to be textile related and 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.

Street Lighting and Other Public Authorities

Street lighting sales are expected to grow at 1.8%. The consensus averages about a 1.1 GWH a year increase. The forecast for OPA sales is a 2.6% annual rate.

Municipal and Cooperatives

Municipal sales are expected to increase 2.2% and cooperative sales are expected to increase 2.0% from 1994 to 2011.

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 process. The forecast was adjusted for both existing programs and new programs. The existing demand side programs that impact the electric sales forecast were great appliance trade-up, home energy check, residential thermal storage, commercial ice storage, commercial high efficiency chillers and commercial relamping. The new programs that impact the electric sales forecast were variable speed motor drives, high efficiency fluorescent ballasts, high efficiency motors, off-peak water heating, roof-top package units, and high efficiency duel fuel heat pumps. The adjustments for these demand side programs were provided by the Marketing Department. For the existing programs, the long-term impact of the program was reduced by the 1992 amount based on the assumption that this was already reflected in the data.

The adjustments to the forecast are shown in Tables 2.1.3 and 2.1.4. Table 2.1.3 shows the existing programs and Table 2.1.4 shows the new programs with the total for both shown in Table 2.1.5. In 1994, these programs reduce the electric sales forecast by 164.5 GWH. By the year 2011, the adjustment was -563.5 GWH.

TABLE 2.1.3

DEMAND SIDE MANAGEMENT
ADJUSTMENTS TO ELECTRIC SALES FOR EXISTING PROGRAMS

(GWH)

YEAR	RESIDENTIAL GREAT APPL TRADE UP	RESIDENTIAL HOME ENERGY CHECK	RESIDENTIAL THERMAL STORAGE	COMMERCIAL ICE STORAGE	COMMERCIAL HIGH EFF. CHILLER	COMMERCIAL RELAMPING	TOTAL EXISTING PROGRAMS ADJUSTMENT
1992	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1993	-5.3	-19.3	6.6	0.3	-0.5	-14.0	-32.1
1994	-10.5	-38.8	12.3	0.7	-1.1	-28.0	-65.4
1995	-15.8	-43.6	18.9	1.0	-1.3	-29.4	-70.2
1996	-21.0	-48.4	26.0	1.3	-1.6	-30.8	-74.5
1997	-26.3	-53.1	33.4	1.6	-1.9	-32.2	-78.4
1998	-31.5	-57.9	40.8	2.0	-2.1	-33.6	-82.5
1999	-36.8	-62.7	48.4	2.3	-2.4	-35.0	-86.1
2000	-42.0	-67.5	55.7	2.6	-2.7	-36.4	-90.1
2001	-47.3	-70.6	63.0	2.9	-2.9	-37.8	-92.6
2002	-52.5	-73.8	70.0	3.3	-3.2	-39.2	-95.4
2003	-57.8	-77.0	77.2	3.6	-3.4	-40.6	-97.9
2004	-63.0	-80.2	84.9	3.9	-3.7	-42.0	-100.1
2005	-68.3	-83.4	92.6	4.2	-4.0	-43.4	-102.1
2006	-73.5	-86.5	99.8	4.6	-4.2	-44.8	-104.7
2007	-78.8	-89.7	107.1	4.9	-4.5	-46.2	-107.2
2008	-84.0	-92.9	114.6	5.2	-4.7	-47.6	-109.4
2009	-89.3	-96.1	122.1	5.5	-5.0	-49.0	-111.7
2010	-94.5	-99.3	129.6	5.9	-5.3	-50.4	-113.9
2011	-99.8	-102.4	137.3	6.2	-5.5	-51.8	-115.9

TABLE 2.1.4

DEMAND SIDE MANAGEMENT
ADJUSTMENTS TO ELECTRIC SALES FOR NEW PROGRAMS

(GWH)

YEAR	VARIABLE SPEED MOTOR DRIVES	HIGH EFF FLUOR BALLASTS	HIGH EFF MOTORS	OFF-PEAK WATER HEATING	ROOFTOP PACKAGE UNITS	HIGH EFF DUEL FUEL HP	TOTAL NEW PROGRAMS ADJUSTMENTS
1992	-0.1	-9.8	-1.4	1.4	-0.9	-1.3	-12.2
1993	-2.6	-39.2	-11.4	3.2	-2.6	-2.8	-55.4
1994	-5.2	-68.5	-21.7	4.8	-4.7	-4.0	-99.1
1995	-7.8	-71.4	-32.4	6.2	-6.2	-4.8	-116.5
1996	-10.6	-74.4	-43.4	7.5	-7.8	-5.7	-134.3
1997	-13.4	-77.3	-54.7	9.0	-9.5	-6.6	-152.5
1998	-16.3	-80.3	-66.2	10.4	-11.1	-7.6	-171.1
1999	-19.3	-83.2	-78.1	11.9	-12.8	-8.5	-190.0
2000	-22.3	-86.1	-90.3	13.4	-14.5	-9.5	-209.3
2001	-25.4	-89.1	-102.8	14.9	-15.4	-10.4	-228.3
2002	-28.6	-92.0	-115.6	16.4	-17.1	-11.3	-248.3
2003	-31.9	-94.9	-128.6	17.9	-18.9	-12.2	-268.7
2004	-35.2	-97.9	-142.0	19.5	-20.8	-13.2	-289.7
2005	-38.7	-100.8	-155.7	21.1	-22.7	-14.2	-311.1
2006	-42.2	-103.7	-169.7	22.6	-24.6	-15.2	-332.8
2007	-45.7	-106.7	-184.0	24.2	-26.5	-16.1	-354.9
2008	-49.4	-109.6	-198.7	25.8	-28.5	-17.1	-377.5
2009	-53.1	-112.6	-213.6	27.5	-30.6	-18.1	-400.4
2010	-56.9	-115.5	-228.8	29.1	-32.6	-19.1	-423.8
2011	-60.8	-118.4	-244.4	30.8	-34.7	-20.1	-447.6

TABLE 2.1.5

DEMAND SIDE MANAGEMENT
TOTAL ADJUSTMENTS TO ELECTRIC SALES

(GWH)

YEAR	TOTAL EXISTING PROGRAMS ADJUSTMENT	TOTAL NEW PROGRAMS ADJUSTMENT	TOTAL ALL PROGRAMS ADJUSTMENT
1992	0.0	-12.2	-12.2
1993	-32.1	-55.4	-87.5
1994	-65.4	-99.1	-164.5
1995	-70.2	-116.5	-186.7
1996	-74.5	-134.3	-208.8
1997	-78.4	-152.5	-230.9
1998	-82.5	-171.1	-253.6
1999	-86.1	-190.0	-276.1
2000	-90.1	-209.3	-299.4
2001	-92.6	-228.3	-320.9
2002	-95.4	-248.3	-343.7
2003	-97.9	-268.7	-366.6
2004	-100.1	-289.7	-389.8
2005	-102.1	-311.1	-413.2
2006	-104.7	-332.8	-437.5
2007	-107.2	-354.9	-462.1
2008	-109.4	-377.5	-486.9
2009	-111.7	-400.4	-512.1
2010	-113.9	-423.8	-537.7
2011	-115.9	-447.6	-563.5

8. 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

I. Residential Class

A. Total Customers

$$\ln(CUST) = 6.5403 + .5536*\ln(RYPI) + .3266 * \ln(POP)$$

t-statistic: (7.156) (6.324) (1.503)

R^2 = .9958
Mean Square Error = .00006
Durbin-Watson = 1.838 with first order autocorrelation = .009
Number of Observations = 15, 1976-1990

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 1992, X = .80, Y = .50, Z = .30, P = .70 and Q = .15

B. Space Heating Average Use

1. Single Family Homes

$$\ln(AVG) = \underset{(24.446)}{13.0006} - \underset{(-4.309)}{.3063} * \ln(Price) - \underset{(-8.095)}{1.0261} * \ln(WTMP) - \underset{(-2.648)}{.0664} * YR88$$

t-statistic shown in parentheses.

where YR88 = 1, if year = 1988
= 0, otherwise

R^2 = .8978
Mean Square Error = .00056
Durbin-Watson = 1.822 with first order autocorrelation = .019
Number of Observations = 14, 1977 - 1990

2. Multi-Family Homes

$$\ln(AVG) = \underset{(25.874)}{11.4557} - \underset{(-5.001)}{.3263} * \ln(Price) - \underset{(-6.882)}{.7866} * \ln(WTMP) - \underset{(-2.672)}{.0607} * YR88$$

t-statistic shown in parentheses.

where YR88 = 1, if year = 1988
= 0, otherwise

R^2 = .8624
Mean Square Error = .00044
Durbin-Watson = 1.706, with first order autocorrelation = .068
Number of Observations = 14, 1977-1990

3. Mobile Homes

$$\ln(AVG) = \underset{(7.066)}{10.0472} - \underset{(-10.182)}{.5243} * \ln(Price) - \underset{(-10.207)}{.9846} * \ln(WTMP) + \underset{(1.244)}{.4287} * \ln(STMP) - \underset{(-3.346)}{.0612} * YR88$$

t-statistic shown in parentheses.

where YR88 = 1, if year = 1988
= 0, otherwise

R^2 = .9585
Mean Square Error = .00029
Durbin-Watson = 2.385, with first order autocorrelation = -.291
Number of Observations = 14, 1977-1990

C. Non-Space Heating Average Use

1. Single Family Homes

```
     ln(AVG) = -1.1441 + .1718 * ln(RPCI) + 1.9181 * ln(STMP)
t-statistic:   (-.794)    (1.897)                (5.080)

             -.1423 * ln(Price) - .1819 * ln(WTMP)
                  (-2.482)          (-1.239)
```

R^2 = .8990

Mean Square Error = .00028

Durbin-Watson = 2.419, with first order autocorrelation = -.223

Number of Observations = 14, 1977-1990

2. Multi-Family Homes

```
     ln(AVG) = -3.6829 + .3719 * ln(RPCI) + 1.5721 * ln(STMP)
t-statistic:   (-2.390)   (6.385)                (4.250)

             -.1671 * ln(Price)      -.0307 * YR79
                 (-3.299)              (-1.677)
```

where YR79 = 1, if year = 1979
= 0, otherwise

R^2 = .9661

Mean Square Error = .00022

Durbin-Watson = 1.832 with first order autocorrelation = -.037

Number of Observations = 14, 1977-1990

3. Mobile Homes

```
     ln(AVG) = -6.3651 + .5511 * ln(RPCI) + 1.6027 * ln(STMP)
t-statistic:   (-4.887)   (11.343)               (5.087)

             -.3043 * ln(Price)      -.0381 * YR79
                 (-7.024)              (-2.449)
```

where YR79 = 1, if year = 1979
= 0, otherwise

R^2 = .9871

Mean Square Error = .00016

Durbin-Watson = 1.198 with first order autocorrelation = .247

Number of Observations = 14, 1977-1990

D. Residential Street Lighting

$$\ln(KWH) = \underset{(13.181)}{9.6582} + \underset{(10.170)}{.7970} * \ln(RYPI) - \underset{(-2.952)}{.0842} * YRL80$$

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

R^2 = .9614
Mean Square Error = .00107
Durbin-Watson = 1.049 with first order autocorrelation = .261
Number of Observations = 14, 1977-1990

II. COMMERCIAL CLASS

A. Total Customers

$$\ln(CUST) = \underset{(13.409)}{3.812036} + \underset{(24.504)}{.985849} * \ln(RYPI)$$

t-statistic: (13.409) (24.504)

R^2 = .9869
Mean Square Error = .00021
Durbin-Watson = 1.872, with first order autocorrelation = .040
Number of Observations = 10, 1981-1990

B. Total Sales

$$\ln(SALES) = \underset{(3.415)}{4.158569} + \underset{(35.037)}{1.140756} * \ln(RYPI) + \underset{(2.331)}{.709654} * \ln(STMP)$$
$$\underset{(-4.047)}{-.17232} * \ln(Price)$$

t-statistic: (3.415) (35.037) (2.331) (-4.047)

R^2 = .9958
Mean Square Error = .00022
Durbin-Watson = 2.680, with first order autocorrelation = -.377
Number of Observations = 15, 1976-1990

From autocorrelation:

$$\ln(SALES) = 4.01601 + 1.13763 * \ln(RYPI) + .75128 * \ln(STMP) - .18327 * \ln(PRICE)$$

III. INDUSTRIAL CLASS (EXCLUDING SAVANNAH RIVER PROJECT)

A. Total Sales

1. Textile Mill Products (SIC=22)

ln(SALES) = 20.3266 + .9185 * ln(JQIND22)
t-statistic: (1596.760) (6.386)

R^2 = .8535
Mean Square Error = .00068
Durbin-Watson = 1.288, with first order autocorrelation = .336
Number of Observations = 9, 1982-1990

From autocorrelation:

ln(SALES) = 20.3347 + .7915 * ln(JQIND22)

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

ln(SALES) = 18.7685 + .3287 * ln(JQIND245) -.8108 * YRL80
t-statistic: (437.179) (1.379) (-15.007)

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

R^2 = .9762
Mean Square Error = .0051
Durbin-Watson = 1.258, with first order autocorrelation = .262
Number of Observations = 15, 1976-1990

3. Paper and Allied Products (SIC=26)

ln(SALES) = 18.6091 + .8945 * ln(JQIND26) - .0985 * YR87
t-statistic: (924.154) (19.555) (-2.512)

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

R^2 = .9706
Mean Square Error = .00130
Durbin-Watson = 2.151, with first order autocorrelation = -.186
Number of Observations = 15, 1976-1990

4. Chemical and Allied Products (SIC=28)

$$\ln(SALES) = 20.3670 + .2791 * \ln(JQIND28) - .1198 * YR90$$
t-statistic: (946.741) (5.659) (-3.428)

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

R^2 = .8010
Mean Square Error = .00078
Durbin-Watson = 1.765, with first order autocorrelation = .096
Number of Observations = 11, 1980-1990

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

$$\ln(SALES) = 17.9546 + .6098 * \ln(JQIND30) + .2003 * YR8184$$
t-statistic: (343.368) (14.678) (7.606)

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

R^2 = .9610
Mean Square Error = .00198
Durbin-Watson = 1.603, with first order autocorrelation = .095
Number of Observations = 14, 1977-1990

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

$$\ln(SALES) = 19.4194 + 1.0028 * \ln(JQIND32)$$
t-statistic: (973.713) (7.661)

R^2 = .8670
Mean Square Error = .00158
Durbin-Watson = 1.702, with first order autocorrelation = .090
Number of Observations = 11, 1980-1990

7. Primary metal, Fabricated metal products, electric and non-electronic machinery, equipment and supplies and transportation equipment (SIC=33, 34, 35, 36 and 37)

$$\ln(SALES) = 19.4385 + .5737 * \ln(JQIND337)$$
t-statistic: (964.605) (26.571)

R^2 = .9860
Mean Square Error = .00050
Durbin-Watson = 1.626, with first order autocorrelation = -.066
Number of Observations = 12, 1979-1990

8. Governmental (SIC=91)

$$\ln(\text{SALES}) = 17.9397 + .6547 * \ln(\text{JQIND30}) - .1296 * \text{YRGR86}$$

t-statistic: (427.564) (15.950) (-4.342)

where YRGR86 = 1, if year is greater than or equal to 1986
= 0, otherwise

R^2 = .9681
Mean Square Error = .00141
Durbin-Watson = 2.191, with first order autocorrelation = -.162
Number of Observations = 15, 1976-1990

9. Other large industrials or Unclassified

$$\ln(\text{SALES}) = 18.8162 + 1.8835 * \ln(\text{JQIND})$$

t-statistic: (243.640) (10.287)

R^2 = .9297
Mean Square Error = .00574
Durbin-Watson = 1.691, with first order autocorrelation = .140
Number of Observations = 10, 1981-1990

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

$$\ln(\text{SALES}) = 18.4059 + 1.2566 * \ln(\text{JQIND26})$$

t-statistic: (61.026) (2.786)

R^2 = .7213
Mean Square Error = .00123
Durbin-Watson = 2.618, with first order autocorrelation = -.457
Number of Observations = 5, 1986-1990

From autocorrelation:

$$\ln(\text{SALES}) = 18.3015 + 1.4079 * \ln(\text{JQIND26})$$

B. Average Use

1. Small Industrial Customers

$$\ln(\text{AVG}) = 12.9185 + .6168 * \ln(\text{JQIND})$$

t-statistic: (337.935) (6.806)

R^2 = .8527
Mean Square Error = .00141
Durbin-Watson = 1.348, with first order autocorrelation = .257
Number of Observations = 10, 1981-1990

C. Customers

Small industrial customers decrease by 7 per year.
Large industrial customers were set equal to there 1993 Forecast value for the Forecast interval - at 112 per year.

IV. Street Lighting Class - Total Sales

ln(SALES) = 5.6710 + .7131 * ln(RYPI) + .1049 * ln(YR8486)
t-statistic: (37.271) (32.610) (12.060)

where YR8486 = 1, if year = 1984, 1985, or 1986
= 0, otherwise

R^2 = .9921
Mean Square Error = .00017
Durbin-Watson = 1.608, with first order autocorrelation = .053
Number of Observations = 15, 1976-1990

V. Other Public Authority Class - Total Sales

ln(SALES) = 5.3149 + 1.0571 * ln(RYPI)
t-statistic: (36.887) (51.196)

R^2 = .9951
Mean Square Error = .00016
Durbin-Watson = 2.493, with first order autocorrelation = -.290
Number of Observations = 15, 1976-1990

VI. Municipal Class - Total Sales

ln(SALES) = -2.1260 + .95126 * ln(SUM2)
t-statistic: (-3.675) (26.743)

R^2 = .9889
Mean Square Error = .00016
Durbin-Watson = .953, with first order autocorrelation = .287
Number of Observations = 10, 1981-1990

VII. Cooperative Class - Total Sales

ln(SALES) = 5.2778 + .8637 * ln(SUM2) - .5317 * ln(Price)
t-statistic: (2.789) (7.402) (-3.914)

R^2 = .8516
Mean Square Error = .00465
Durbin-Watson = 1.408, with first order autocorrelation = .195
Number of Observations = 15, 1976-1990

9. Historical Electric Sales Data

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 1

ACTUAL RESIDENTIAL SPACE HEATING DETAIL BY HOUSING TYPE
1987 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 7

ACTUAL RESIDENTIAL SPACE HEATING DETAIL BY HOUSING TYPE
1982 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 8 AND OTHER NON STREET LIGHTING RATES

ACTUAL RESIDENTIAL SPACE HEATING DETAIL BY HOUSING TYPE
1977 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 1

ACTUAL RESIDENTIAL NON-SPACE HEATING DETAIL BY HOUSING TYPE
1987 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 7

ACTUAL RESIDENTIAL NON-SPACE HEATING DETAIL BY HOUSING TYPE
1982 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RATE 8 AND OTHER NON STREET LIGHTING RATES

ACTUAL RESIDENTIAL NON-SPACE HEATING DETAIL BY HOUSING TYPE
1977 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL STREET LIGHTING SALES

1977 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

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

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

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

ACTUAL SALES DATA BY CLASS
1976 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

ACTUAL SALES DATA BY CLASS
1976 -- 1990

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

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

ACTUAL SALES DATA BY CLASS
1976 -- 1990

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

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 1990 THE SALES WOULD BE AS FOLLOWS: 87 , 107 , 107 , 106 , 111 , 112 , 109 , 116 , 96 , 103, 110 , 120 , 143 , 150 , 160

10. Final Electric Sales Forecast

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SPACE HEATING SALES FORECAST SUMMARY

TOTAL

YEAR	SINGLE FAMILY HOMES			MULTI FAMILY HOMES			MOBILE HOMES		
	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1992	81,448	19,588	1,595	64,516	11,001	710	19,041	15,654	298
1993	84,380	19,536	1,648	66,276	10,995	729	20,213	15,851	320
1994	87,347	19,472	1,701	68,056	10,985	748	21,400	15,851	339
1995	90,292	19,492	1,760	69,823	10,980	767	22,578	15,851	358
1996	93,435	19,514	1,823	71,709	10,976	787	23,835	15,852	378
1997	96,697	19,535	1,889	73,666	10,972	808	25,139	15,852	398
1998	99,987	19,553	1,955	75,640	10,967	830	26,456	15,852	419
1999	103,381	19,569	2,023	77,677	10,963	852	27,814	15,852	441
2000	106,646	19,580	2,088	79,636	10,960	873	29,119	15,852	462
2001	109,893	19,595	2,153	81,584	10,956	894	30,418	15,852	482
2002	112,991	19,606	2,215	83,442	10,953	914	31,657	15,852	502
2003	116,194	19,615	2,279	85,364	10,950	935	32,938	15,852	522
2004	119,610	19,627	2,348	87,414	10,947	957	34,305	15,852	544
2005	123,029	19,636	2,416	89,466	10,944	979	35,673	15,852	565
2006	126,224	19,641	2,479	91,382	10,941	1,000	36,950	15,852	586
2007	129,453	19,645	2,543	93,320	10,938	1,021	38,242	15,852	606
2008	132,798	19,649	2,609	95,327	10,935	1,042	39,580	15,852	627
2009	136,125	19,650	2,675	97,323	10,933	1,064	40,911	15,852	649
2010	139,477	19,651	2,741	99,334	10,931	1,086	42,252	15,852	670
2011	142,913	19,652	2,809	101,396	10,928	1,108	43,626	15,852	692

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SPACE HEATING SALES FORECAST SUMMARY

RATE 1

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
1992	4,417	18,025	80	678	8,699	6
1993	6,066	18,026	109	862	8,699	7
1994	7,645	18,026	138	1,178	8,699	10
1995	8,455	18,026	152	1,340	8,699	12
1996	9,319	18,026	168	1,513	8,699	13
1997	10,216	18,026	184	1,692	8,699	15
1998	11,121	18,026	200	1,873	8,699	16
1999	12,054	18,026	217	2,060	8,699	18
2000	12,952	18,026	233	2,239	8,699	19
2001	13,845	18,026	250	2,418	8,699	21
2002	14,697	18,026	265	2,588	8,699	23
2003	15,578	18,026	281	2,764	8,699	24
2004	16,517	18,026	298	2,952	8,699	26
2005	17,457	18,026	315	3,140	8,699	27
2006	18,336	18,026	331	3,316	8,699	29
2007	19,224	18,026	347	3,494	8,699	30
2008	20,144	18,026	363	3,678	8,699	32
2009	21,059	18,026	380	3,861	8,699	34
2010	21,981	18,026	396	4,045	8,699	35
2011	22,925	18,026	413	4,234	8,699	37

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC 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
1992	8,224	20,028	165	3,760	9,666	36	191	15,964	3
1993	8,620	20,029	173	3,830	9,666	37	209	16,165	3
1994	8,940	20,029	179	3,927	9,666	38	223	16,165	4
1995	9,278	20,029	186	4,030	9,666	39	238	16,165	4
1996	9,603	20,029	192	4,129	9,666	40	252	16,165	4
1997	9,941	20,029	199	4,232	9,666	41	266	16,165	4
1998	10,282	20,029	206	4,336	9,666	42	281	16,165	5
1999	10,633	20,029	213	4,443	9,666	43	297	16,165	5
2000	10,971	20,029	220	4,546	9,666	44	311	16,165	5
2001	11,307	20,029	226	4,648	9,666	45	326	16,165	5
2002	11,627	20,029	233	4,745	9,666	46	340	16,165	5
2003	11,959	20,029	240	4,846	9,666	47	354	16,165	6
2004	12,313	20,029	247	4,954	9,666	48	370	16,165	6
2005	12,667	20,029	254	5,062	9,666	49	385	16,165	6
2006	12,997	20,029	260	5,162	9,666	50	399	16,165	6
2007	13,331	20,029	267	5,264	9,666	51	414	16,165	7
2008	13,678	20,029	274	5,369	9,666	52	429	16,165	7
2009	14,022	20,029	281	5,474	9,666	53	444	16,165	7
2010	14,369	20,029	288	5,580	9,666	54	459	16,165	7
2011	14,725	20,029	295	5,688	9,666	55	474	16,165	8

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
1992	68,807	19,636	1,351	60,078	11,110	667	18,850	15,651	295
1993	69,694	19,607	1,366	61,584	11,110	684	20,004	15,848	317
1994	70,762	19,558	1,384	62,951	11,110	699	21,177	15,848	336
1995	72,559	19,595	1,422	64,453	11,110	716	22,340	15,848	354
1996	74,513	19,634	1,463	66,067	11,110	734	23,583	15,848	374
1997	76,540	19,673	1,506	67,742	11,110	753	24,873	15,848	394
1998	78,584	19,707	1,549	69,431	11,110	771	26,175	15,848	415
1999	80,694	19,739	1,593	71,174	11,110	791	27,517	15,848	436
2000	82,723	19,764	1,635	72,851	11,110	809	28,808	15,848	457
2001	84,741	19,794	1,677	74,518	11,110	828	30,092	15,848	477
2002	86,667	19,817	1,717	76,109	11,110	846	31,317	15,848	496
2003	88,657	19,839	1,759	77,754	11,110	864	32,584	15,848	516
2004	90,780	19,864	1,803	79,508	11,110	883	33,935	15,848	538
2005	92,905	19,886	1,847	81,264	11,110	903	35,288	15,848	559
2006	94,891	19,901	1,888	82,904	11,110	921	36,551	15,848	579
2007	96,898	19,913	1,930	84,562	11,110	939	37,828	15,848	600
2008	98,976	19,926	1,972	86,280	11,110	959	39,151	15,848	620
2009	101,044	19,937	2,014	87,988	11,110	978	40,467	15,848	641
2010	103,127	19,945	2,057	89,709	11,110	997	41,793	15,848	662
2011	105,263	19,954	2,100	91,474	11,110	1,016	43,152	15,848	684

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC NON-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
1992	174,042	12,045	2,096	27,613	7,503	207	29,905	11,439	342
1993	175,069	12,100	2,118	27,906	7,578	211	30,052	11,737	353
1994	176,108	12,079	2,127	28,128	7,619	214	30,275	11,875	360
1995	177,137	12,102	2,144	28,349	7,662	217	30,495	12,002	366
1996	178,239	12,127	2,161	28,585	7,706	220	30,731	12,131	373
1997	179,380	12,149	2,179	28,829	7,743	223	30,976	12,245	379
1998	180,531	12,168	2,197	29,077	7,774	226	31,222	12,346	385
1999	181,719	12,191	2,215	29,331	7,809	229	31,477	12,456	392
2000	182,862	12,210	2,233	29,576	7,837	232	31,722	12,551	398
2001	183,999	12,235	2,251	29,819	7,865	235	31,965	12,643	404
2002	185,082	12,255	2,268	30,052	7,886	237	32,197	12,720	410
2003	186,204	12,279	2,286	30,293	7,911	240	32,438	12,806	415
2004	187,400	12,309	2,307	30,548	7,941	243	32,694	12,905	422
2005	188,596	12,339	2,327	30,805	7,971	246	32,951	13,003	428
2006	189,715	12,365	2,346	31,044	7,994	248	33,190	13,086	434
2007	190,844	12,390	2,364	31,286	8,016	251	33,432	13,163	440
2008	192,015	12,416	2,384	31,537	8,037	253	33,683	13,242	446
2009	193,180	12,443	2,404	31,787	8,058	256	33,932	13,318	452
2010	194,354	12,470	2,424	32,038	8,078	259	34,184	13,393	458
2011	195,555	12,499	2,444	32,295	8,097	262	34,442	13,467	464

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
1992	2,738	14,716	40	740	5,686	4
1993	4,021	14,861	60	1,290	5,776	7
1994	5,063	14,915	76	1,511	5,822	9
1995	5,597	14,964	84	1,624	5,863	10
1996	6,168	15,014	93	1,745	5,905	10
1997	6,760	15,058	102	1,871	5,942	11
1998	7,357	15,096	111	1,998	5,975	12
1999	7,973	15,138	121	2,128	6,011	13
2000	8,565	15,173	130	2,254	6,042	14
2001	9,155	15,208	139	2,379	6,071	14
2002	9,717	15,236	148	2,498	6,096	15
2003	10,299	15,268	157	2,622	6,123	16
2004	10,919	15,304	167	2,753	6,155	17
2005	11,539	15,340	177	2,885	6,186	18
2006	12,119	15,371	186	3,008	6,213	19
2007	12,705	15,399	196	3,132	6,237	20
2008	13,312	15,427	205	3,261	6,262	20
2009	13,916	15,454	215	3,389	6,286	21
2010	14,525	15,481	225	3,518	6,309	22
2011	15,148	15,508	235	3,650	6,333	23

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
1992	2,580	16,351	42	1,207	6,317	8	98	15,766	2
1993	2,809	16,512	46	1,365	6,418	9	107	16,175	2
1994	2,976	16,572	49	1,455	6,468	9	114	16,364	2
1995	3,152	16,627	52	1,551	6,515	10	121	16,537	2
1996	3,322	16,682	55	1,643	6,562	11	128	16,714	2
1997	3,498	16,731	59	1,738	6,603	11	136	16,870	2
1998	3,676	16,774	62	1,835	6,639	12	143	17,008	2
1999	3,859	16,820	65	1,934	6,679	13	151	17,157	3
2000	4,036	16,859	68	2,029	6,713	14	158	17,288	3
2001	4,211	16,897	71	2,124	6,746	14	165	17,413	3
2002	4,378	16,929	74	2,215	6,773	15	172	17,517	3
2003	4,551	16,964	77	2,309	6,804	16	180	17,635	3
2004	4,736	17,005	81	2,409	6,839	16	187	17,770	3
2005	4,920	17,045	84	2,509	6,874	17	195	17,904	3
2006	5,093	17,078	87	2,602	6,903	18	202	18,017	4
2007	5,267	17,109	90	2,696	6,930	19	209	18,122	4
2008	5,448	17,141	93	2,794	6,958	19	217	18,229	4
2009	5,628	17,172	97	2,892	6,984	20	224	18,333	4
2010	5,809	17,201	100	2,990	7,010	21	232	18,434	4
2011	5,994	17,231	103	3,090	7,037	22	240	18,536	4

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
1992	168,724	11,936	2,014	25,666	7,611	195	29,807	11,424	341
1993	168,239	11,960	2,012	25,251	7,732	195	29,945	11,721	351
1994	168,069	11,914	2,002	25,162	7,793	196	30,161	11,858	358
1995	168,388	11,922	2,007	25,174	7,849	198	30,374	11,984	364
1996	168,749	11,932	2,013	25,197	7,905	199	30,603	12,112	371
1997	169,122	11,938	2,019	25,220	7,955	201	30,840	12,225	377
1998	169,498	11,941	2,024	25,244	7,999	202	31,079	12,325	383
1999	169,887	11,947	2,030	25,269	8,046	203	31,326	12,433	389
2000	170,261	11,951	2,035	25,293	8,088	205	31,564	12,528	395
2001	170,633	11,960	2,041	25,316	8,127	206	31,800	12,618	401
2002	170,987	11,965	2,046	25,339	8,160	207	32,025	12,694	407
2003	171,354	11,975	2,052	25,362	8,197	208	32,258	12,779	412
2004	171,745	11,989	2,059	25,386	8,240	209	32,507	12,877	419
2005	172,137	12,003	2,066	25,411	8,281	210	32,756	12,974	425
2006	172,503	12,015	2,073	25,434	8,317	212	32,988	13,056	431
2007	172,872	12,025	2,079	25,458	8,349	213	33,223	13,132	436
2008	173,255	12,037	2,085	25,482	8,383	214	33,466	13,209	442
2009	173,636	12,048	2,092	25,506	8,415	215	33,708	13,285	448
2010	174,020	12,061	2,099	25,530	8,446	216	33,952	13,358	454
2011	174,413	12,075	2,106	25,555	8,478	217	34,202	13,432	459

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL STREET LIGHTING SALES FORECAST SUMMARY

YEAR	TOTAL GWH
1992	42
1993	42
1994	43
1995	44
1996	45
1997	46
1998	47
1999	48
2000	49
2001	49
2002	50
2003	51
2004	52
2005	53
2006	54
2007	55
2008	56
2009	57
2010	58
2011	59

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

RESIDENTIAL ELECTRIC SALES FORECAST SUMMARY

BY HEATING TYPE

YEAR	NON SPACE HEATING			SPACE HEATING			TOTAL RESIDENTIAL		
	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH	AVERAGE CUSTOMERS	AVERAGE USE IN KWH	TOTAL GWH
1992	231,560	11,425	2,646	165,005	15,776	2,603	396,565	13,340	5,290
1993	233,027	11,512	2,683	170,869	15,787	2,698	403,896	13,424	5,422
1994	234,511	11,518	2,701	176,803	15,767	2,788	411,314	13,448	5,531
1995	235,981	11,555	2,727	182,693	15,789	2,885	418,674	13,507	5,655
1996	237,555	11,595	2,755	188,979	15,812	2,988	426,534	13,568	5,787
1997	239,185	11,630	2,782	195,502	15,835	3,096	434,687	13,626	5,923
1998	240,830	11,660	2,808	202,083	15,855	3,204	442,913	13,679	6,059
1999	242,527	11,695	2,836	208,872	15,874	3,316	451,399	13,734	6,199
2000	244,160	11,725	2,863	215,401	15,889	3,422	459,561	13,782	6,334
2001	245,783	11,758	2,890	221,895	15,906	3,529	467,678	13,831	6,469
2002	247,331	11,784	2,915	228,090	15,919	3,631	475,421	13,874	6,596
2003	248,935	11,816	2,941	234,496	15,932	3,736	483,431	13,919	6,729
2004	250,642	11,854	2,971	241,329	15,946	3,848	491,971	13,968	6,872
2005	252,352	11,892	3,001	248,168	15,959	3,960	500,520	14,015	7,015
2006	253,949	11,925	3,028	254,556	15,968	4,065	508,505	14,056	7,147
2007	255,562	11,955	3,055	261,015	15,976	4,170	516,577	14,094	7,281
2008	257,235	11,988	3,084	267,705	15,985	4,279	524,940	14,133	7,419
2009	258,899	12,019	3,112	274,359	15,992	4,387	533,258	14,171	7,557
2010	260,576	12,051	3,140	281,063	15,998	4,496	541,639	14,207	7,695
2011	262,292	12,084	3,169	287,935	16,004	4,608	550,227	14,243	7,837

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

COMMERCIAL AND INDUSTRIAL CUSTOMERS FORECAST SUMMARY

YEAR	COMMERCIAL FORECAST	INDUSTRIAL FORECAST
1992	59,144	697
1993	60,191	682
1994	61,900	675
1995	63,578	668
1996	65,371	661
1997	67,182	654
1998	68,977	647
1999	70,860	640
2000	72,655	633
2001	74,446	626
2002	76,127	619
2003	77,906	612
2004	79,849	605
2005	81,809	598
2006	83,615	591
2007	85,429	584
2008	87,315	577
2009	89,200	570
2010	91,100	563
2011	93,058	556

SOUTH CAROLINA ELECTRIC & GAS CO: INDUSTRIAL DETAIL FORECAST

INDUSTRIAL SALES-(GWH) SALES	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
SIC 22	662	641	637	639	638	641	646	648	650	652
SIC 24	150	149	151	153	154	155	157	157	158	159
SIC 26	250	257	261	267	271	276	282	287	291	296
SIC 28	832	835	835	838	839	842	847	850	854	857
SIC 30	160	161	163	167	169	173	179	184	188	194
SIC 32	325	323	346	372	389	400	413	419	425	431
SIC 33	661	714	729	741	755	767	786	801	815	831
GOVERNMENTAL	153	154	157	160	163	168	174	178	183	189
OTHER LARGE	478	509	528	551	572	597	632	659	686	719
WESTVACO	266	272	280	291	299	307	319	327	335	345
S R P	408	408	408	408	408	408	408	408	408	408
OTHER SMALL	354	358	359	360	360	361	364	365	365	366
TOTAL INDUSTRIAL SALES	4697	4781	4853	4948	5019	5096	5206	5282	5357	5447

SOUTH CAROLINA ELECTRIC & GAS CO: INDUSTRIAL DETAIL FORECAST

INDUSTRIAL SALES-(GWH) SALES	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
SIC 22	653	654	655	655	656	657	657	658	657	655
SIC 24	159	160	161	162	162	163	164	164	165	166
SIC 26	301	306	311	316	321	326	331	335	339	343
SIC 28	861	864	868	871	874	877	879	881	883	885
SIC 30	199	204	209	214	219	224	229	233	238	242
SIC 32	437	441	443	447	449	454	459	465	469	473
SIC 33	847	865	880	893	906	918	930	940	950	961
GOVERNMENTAL	194	200	205	211	216	221	226	231	236	240
OTHER LARGE	751	785	819	851	882	915	945	975	1004	1032
WESTVACO	354	364	374	384	395	405	414	423	432	441
S R P	408	408	408	408	408	408	408	408	408	408
OTHER SMALL	367	368	368	368	367	367	366	364	362	360
TOTAL INDUSTRIAL SALES	5531	5617	5702	5780	5855	5933	6006	6076	6144	6207

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

TERRITORIAL LOAD-(GWH)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
RESIDENTIAL	5290	5422	5531	5655	5787	5923	6059	6199	6334	6469
COMMERCIAL	4604	4689	4807	4955	5114	5275	5436	5605	5767	5930
INDUSTRIAL -EX SRP	4289	4373	4445	4540	4611	4688	4798	4874	4949	5039
SAVANNAH RIVER PLANT	408	408	408	408	408	408	408	408	408	408
INDUSTRIAL - TOTAL	4697	4781	4853	4948	5019	5096	5206	5282	5357	5447
STREET LIGHTING	51	51	52	53	54	55	56	58	59	60
OTHER PUBLIC AUTHORITY	462	478	493	507	523	538	554	570	585	601
MUNICIPALS	763	786	805	1026	1052	1079	1108	1136	1163	1191
COOPERATIVES	180	183	187	191	195	200	204	209	213	217
TOTAL TERRITORIAL SALES	16047	16390	16729	17335	17744	18167	18623	19058	19478	19914
COMPANY USE	99	102	105	108	111	115	118	122	125	129
UNACCOUNTED FOR	803	819	836	867	887	908	931	953	974	996
TOTAL TERRITORIAL LOAD	16948	17311	17670	18310	18742	19190	19672	20133	20577	21039

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

TERRITORIAL LOAD-(GWH)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
RESIDENTIAL	6596	6729	6872	7015	7147	7281	7419	7557	7695	7837
COMMERCIAL	6082	6244	6422	6603	6769	6937	7112	7287	7465	7649
INDUSTRIAL -EX SRP	5123	5209	5294	5372	5447	5525	5598	5668	5736	5799
SAVANNAH RIVER PLANT	408	408	408	408	408	408	408	408	408	408
INDUSTRIAL - TOTAL	5531	5617	5702	5780	5855	5933	6006	6076	6144	6207
STREET LIGHTING	61	62	63	64	65	66	67	68	69	70
OTHER PUBLIC AUTHORITY	615	631	648	665	680	696	713	729	746	763
MUNICIPALS	1217	1245	1273	1302	1329	1356	1383	1411	1437	1463
COOPERATIVES	221	226	230	234	239	243	247	251	256	260
TOTAL TERRITORIAL SALES	20324	20753	21210	21663	22084	22512	22947	23380	23811	24250
COMPANY USE	133	137	141	145	150	154	159	163	168	173
UNACCOUNTED FOR	1016	1038	1061	1083	1104	1126	1147	1169	1191	1212
TOTAL TERRITORIAL LOAD	21473	21928	22412	22891	23338	23792	24253	24712	25170	25635

2.2 PEAK DEMAND FORECAST

This section describes the procedures used to create the long-range summer and winter peak demand forecasts. It also discusses the results of an analysis of weather impacts on summer peak demand. The winter peak forecast utilized the summer peak projections as an input, so development of summer peak demands will be discussed initially. This is followed by the weather analysis, and concludes with a review of winter peak demand projections.

The forecast of summer peak demands was developed with a load factor methodology, whereas earlier demand projections utilized an econometric/simulation approach. This represents a significant change in forecasting methodology. With load factors, construction of territorial peak demand may be characterized as a building-block approach because class, rate, and some individual customer peaks are separately determined and then summed. In contrast, the econometric/simulation technique used daily, monthly, and seasonal territorial peaks as dependent variables, so customer responses were aggregrated prior to the estimation process.

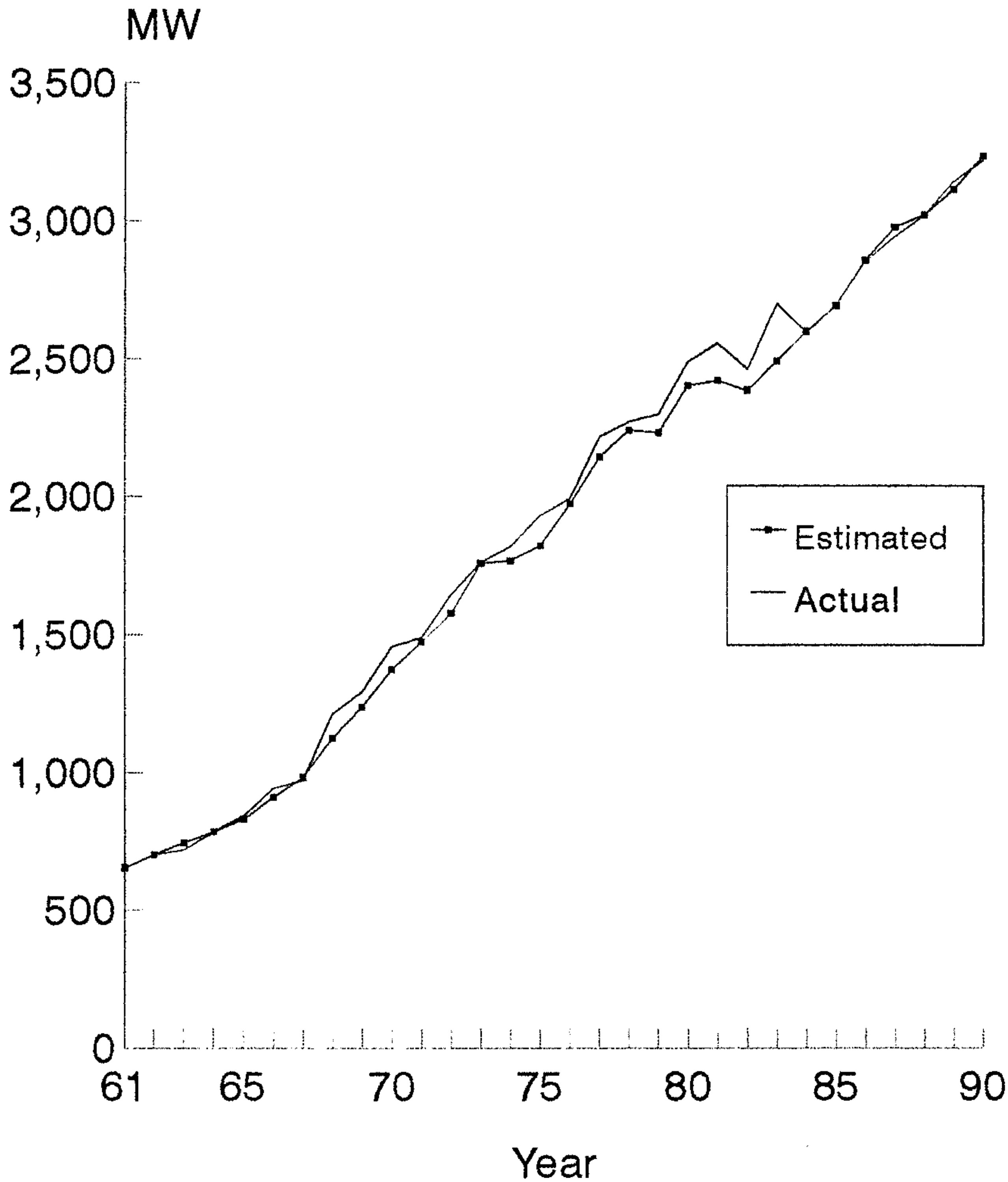
1. Summer Peak Demand

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 four 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.

A check on the validity of this forecasting process was performed by conducting a backcast with constant class load factors. The historical accuracy of the load factor method could thus be examined. Results of the backcast indicated that a load factor methodology was quite accurate over the period 1961-1990, despite the rapidly changing nature of SCE&G's loads over that time. For example, in the last year of the forecast, the difference between the two methods was under 100 MW, or less than 2 percent.

Chart 2.2.1 shows a comparison of the actual summer peaks and the estimated constant class load factor peak for the period 1961-1990. Inspection of this chart clearly shows how well the estimate tracks actual demand. In fact, the Pearson correlation coefficient between actual and estimated load was 0.9979, and was significant at the .01% level. The value of the correlation coefficient implies that over 99% of the variation in historic peak demand is explained by the load factor estimate. The root mean square error (RMSE) of the estimate was 53.9 MW, compared to a mean for actual

CHART 2.2.1
CLASS LOAD FACTOR DEVELOPMENT VS. ACTUAL PEAK DEMANDS



demand of 1,922 MW. Also, the mean absolute percent error (MAPE) was 2.5%. It was therefore concluded that the use of a load factor methodology to forecast peak demand would provide valid results.

2. Weather Impacts

One source of actual variation in actual peak demand not captured through the load factor method is abnormal daily temperatures. To determine the magnitude of this effect and judge whether or not an adjustment to forecast peak demands was required, a regression model was calculated. Actual annual summer peaks were regressed against two explanatory variables. The first of these was the weather occurring on the peak day, measured as the average of cooling degree days (CDD) in Columbia and Charleston. The estimated summer peak based on 1990 load factors was also included. Finally, a dummy variable was incorporated to allow for a changing regression coefficient. This was used to account for the growth in air-conditioning use over the estimation period 1961-1990. The final version of the regression equations tested is shown below as Equation 2.2.1.

EQUATION 2.2.1

$$SPEAK = -191.120 + 1.003*LPEAK + 0.046*ADDFAC + 8.037*CDD$$
$$(-3.01) \quad (118.01) \quad (6.35) \quad (2.50)$$

Estimation Period:
1961-1990

ADDFAC=ADDFAC*LPEAK
where
ADDFAC=1 for years prior to 1984, 0 otherwise

F-statistic: 5673.975
R^2: 0.998
Root MSE: 33.938
Dependent Mean: 1922.433
DW: 1.889

Where: SPEAK=Summer peak
LPEAK=Estimated summer Peak based on actual energy and average 1990 load factors
CDD=Average of cooling Degree Days for summer peak day, Columbia and Charleston

All of the independent variables were significant and the explanatory power of the overall equation was high, with an adjusted R^2 value of 0.998. The mean absolute percent error (MAPE) was 1.51%, representing as expected an improvement over the historic explanatory power of the load factor methodology alone.

For forecasting purposes, as opposed to explaining historic fluctuations in peak demand, the key coefficient in Equation 2.2.1 was that associated with the calculated load factor peak. The value of 1.003 indicated that an upward adjustment of 0.3% to the load factor peak was valid over the estimation period, which would translate into an increase of 10 to 14 MW for the forecast years 1992-2011.

In addition to the load factor adjustment, each additional CDD on the peak day added 8 MW to peak demand, so using the estimation period median value of 21 CDD (See Table 2.2.1) as a proxy for normal peak day weather, an additional 168 MW would be added to the forecast peak. However, when the negative intercept value of -191 was combined with these two positive adjustments the net result was a decrease to peak demand of 9 to 13 MW throughout the forecast horizon. This extremely small adjustment to the estimated load factor peaks implied that any revisions to the forecast values would be insignificant for planning purposes. Therefore, no changes were made as a result of explicitly incorporating weather, and the planning peaks remained as before.

TABLE 2.2.1

WEATHER STATISTICS FOR SUMMER PEAK DAYS

(1961-1990)

	Cooling Degree Days (CDD)
Maximum	26.5
75th Percentile	21.5
Median	21.0
Mean	20.9
25th Percentile	20.0
Minimum	16.0

NOTE: Cooling Degree Days are the average of Columbia and Charleston.

3. 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:

$$\text{Load Factor} = \text{Energy}/(\text{Demand}*8760)$$

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. These were provided by the Load Research Department, which developed load factors by class and/or rate as required. Values were based on calendar year 1990, the most recent period for which load factors have been determined.

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 2.2.2.

TABLE 2.2.2

SYSTEM-LEVEL LOAD FACTORS USED TO DEVELOP CLASS/RATE PEAK DEMANDS

Class/Rate	Annual Load Factor
Residential:	
Good Cents	0.458
Conservation Rate	0.458
Regular Non-Space Heating	0.382
Regular Space Heating	0.411
Commercial	0.579
Industrial[1]	0.826
Municipalities	0.584
Cooperatives	0.491
Miscellaneous (OPA and Company use)	0.668

[1]Excludes customers that were directly forecasted.

Inspection of Table 2.2.2 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 were assumed to have similar load factors in all cases. It should also be noted that the industrial sector load factor excluded four 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.

4. 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.

5. Unadjusted Peak Demands

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The four large industrial customers whose peak demands were developed separately were also added to this estimate. Finally, any new loads not contained in the energy sales projections were added. The complete unadjusted peak demand forecast is shown as part of Table 2.2.3.

6. 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 was assumed to already incorporate 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 1992 as the base year, the difference was calculated between each year's reduction and the 1992 value, for all programs which were in effect prior to 1992. 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 1992 were used to determine the adjusted peak demands from existing programs. Conversely, all of the savings from new DSM programs introduced in 1992 and thereafter were included as reductions to peak demand.

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. Finally, the sum of all included DSM program impacts was determined, and this accumulated value was used to reduce the unadjusted peak demand to its final adjusted peak demand. These estimates are also shown in Table 2.2.3, and are the values used to represent the planning peak.

TABLE 2.2.3
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
TERRITORIAL SUMMER PEAK DEVELOPMENT BY CLASS
(MW)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
RESIDENTIAL										
GOOD CENTS	32	46	58	64	71	78	85	92	99	106
CONSERVATION RATE	64	67	70	73	76	79	82	85	88	91
REGULAR	1,403	1,426	1,445	1,470	1,497	1,524	1,552	1,580	1,607	1,633
RESIDENTIAL TOTAL	1,499	1,539	1,573	1,607	1,644	1,681	1,718	1,757	1,794	1,830
COMMERCIAL TOTAL	910	934	964	994	1,027	1,060	1,092	1,127	1,160	1,193
REGULAR INDUSTRIALS	534	541	552	565	575	585	600	611	621	634
LARGE INDUSTRIALS (INCLUDING SRP)	147	156	156	156	156	156	156	156	156	156
TOTAL INDUSTRIAL	681	697	708	720	730	741	756	767	777	790
MUNICIPALITIES	149	154	157	203	208	213	218	223	228	233
COOPERATIVES	42	43	43	44	45	46	47	48	49	50
MISCELLANEOUS	96	99	102	105	108	112	115	118	121	125
UNADJUSTED DEMAND	3,377	3,465	3,548	3,717	3,806	3,897	3,992	4,086	4,177	4,269
LESS:										
DSM PROGRAMS	6	38	70	88	106	124	142	161	180	197
STAND-BY GENERATORS	17	25	34	38	42	46	50	55	59	63
INTERRUPTIBLE CUSTOMERS	48	48	48	48	54	54	54	54	54	54
TOTAL DEMAND REDUCTIONS	71	111	152	173	202	224	247	270	293	314
ADJUSTED DEMAND	3,306	3,354	3,396	3,544	3,604	3,673	3,745	3,816	3,884	3,955

TABLE 2.2.3
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
TERRITORIAL SUMMER PEAK DEVELOPMENT BY CLASS
(MW)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
RESIDENTIAL										
GOOD CENTS	112	119	127	134	141	148	155	162	169	177
CONSERVATION RATE	94	97	100	103	106	109	112	115	118	121
REGULAR	1,658	1,685	1,713	1,741	1,767	1,793	1,820	1,847	1,874	1,902
RESIDENTIAL TOTAL	1,865	1,901	1,939	1,978	2,014	2,050	2,087	2,125	2,162	2,200
COMMERCIAL TOTAL	1,224	1,257	1,293	1,330	1,363	1,398	1,433	1,469	1,505	1,542
REGULAR INDUSTRIALS	646	657	669	680	691	702	713	723	733	743
LARGE INDUSTRIALS (INCLUDING SRP)	156	156	156	156	156	156	156	156	156	156
TOTAL INDUSTRIAL	801	813	825	836	847	858	868	879	889	899
MUNICIPALITIES	238	243	248	254	259	264	269	274	279	284
COOPERATIVES	51	52	53	54	55	56	57	58	59	60
MISCELLANEOUS	128	131	135	138	142	145	149	152	156	160
UNADJUSTED DEMAND	4,356	4,448	4,545	4,642	4,733	4,825	4,919	5,013	5,107	5,203
LESS:										
DSM PROGRAMS	215	234	252	271	290	309	328	347	367	386
STAND-BY GENERATORS	67	71	75	80	84	88	92	96	100	105
INTERRUPTIBLE CUSTOMERS	54	54	54	54	54	54	54	54	54	54
TOTAL DEMAND REDUCTIONS	337	359	382	405	428	451	474	498	521	545
ADJUSTED DEMAND	4,020	4,089	4,163	4,237	4,305	4,374	4,445	4,515	4,586	4,658

7. Comparison of Peak Demand With and Without DSM

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 1992. 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 2.2.4 shows the results of these calculations. By 2011, the peak demand forecast would be 600 MW, or 13% higher than currently projected without the Company's DSM programs.

TABLE 2.2.4

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

Year	Peak Before DSM	DSM Impacts	Peak After DSM
1992	3,377	71	3,306
1993	3,470	116	3,354
1994	3,557	161	3,396
1995	3,687	185	3,502
1996	3,777	216	3,561
1997	3,870	241	3,629
1998	3,967	267	3,700
1999	4,063	293	3,770
2000	4,155	318	3,837
2001	4,249	342	3,907
2002	4,338	367	3,971
2003	4,431	392	4,039
2004	4,530	418	4,112
2005	4,629	444	4,185
2006	4,721	469	4,252
2007	4,815	495	4,320
2008	4,911	521	4,390
2009	5,006	547	4,459
2010	5,103	574	4,529
2011	5,200	600	4,600

8. 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 26-year period 1965-1990. Actual winter peak demands were related to three primary explanatory variables. These were the summer peak, 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 the summer peak 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 153,000 in 1990, a 15.2% 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 also added for the years 1984 and 1985, which experienced severe winter weather. The results of the regression analysis are shown following in Equation 2.2.2.

8. 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 26-year period 1965-1990. Actual winter peak demands were related to three primary explanatory variables. These were the summer peak, 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 the summer peak 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 153,000 in 1990, a 15.2% 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 also added for the years 1984 and 1985, which experienced severe winter weather. The results of the regression analysis are shown following in Equation 2.2.2.

EQUATION 2.2.2

$$WPEAK = \underset{(-1.58)}{-129.375} + \underset{(11.52)}{0.694*SPEAK} + \underset{(6.25)}{306.430*D8485} + \underset{(4.89)}{8.720*HDD} + \underset{(3.63)}{0.003*CUSTSH}$$

Estimation Period:
1965-1990

F-statistic: 991.026
R^2: 0.994
Root MSE: 55.259
Dependent Mean: 1858.615
DW: 1.695

Where: WPEAK=Winter Peak
SPEAK=Summer Peak
D8485=1 for years 1984 and 1985, 0 otherwise
HDD=Average of Heating Degree Days for winter peak day, Columbia and Charleston
CUSTSH=Residential space-heating customers

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. The MAPE over the estimation period was 2.6%, showing a close fit of actual to predicted winter peak demands.

Forecasting the winter peak demand utilizing the above equation required projections of summer peak, heating degree days, and residential space-heating customers. The planning peaks shown in Table 2.2.3 were used for the summer peak, while heating degree days were based on the median for the estimation period 1965-1990, which was 31 HDD (see Table 2.2.5). Finally, the projections of

TABLE 2.2.5

WEATHER STATISTICS FOR WINTER PEAK DAYS

(1965-1990)

	Heating Degree Days (HDD)
Maximum	50.5
75th Percentile	38.0
Median	31.0
Mean	33.5
25th Percentile	28.5
Minimum	23.0

NOTE: Heating Degree Days are the average of Columbia and Charleston.

residential space-heating customers shown earlier in Section 2.1.10 of this chapter were used as the that variable's forecast input. The result of this process is shown in Table 2.2.6. Winter peak demand is expected to grow from 2,969 MW in 1992 to 4,264 MW in 2011, a compound annual growth rate of 1.9%. The slightly higher rate of increase in winter peak demand causes the ratio of winter to summer peaks to grow from 0.898 in 1992 to 0.927 by 2011. As discussed above, this results from the projected growth in space-heating customers.

TABLE 2.2.6

WINTER TERRITORIAL PEAK DEMANDS

(MW)

Year	Winter Peak
1992	2,969
1993	3,021
1994	3,069
1995	3,162
1996	3,223
1997	3,291
1998	3,362
1999	3,432
2000	3,500
2001	3,569
2001	3,634
2002	3,634
2003	3,702
2004	3,774
2005	3,847
2006	3,914
2007	3,982
2008	4,053
2009	4,122
2010	4,192
2011	4,264

9. Scenario Analysis

The Company develops forecast scenarios through the use of elasticities. As discussed earlier in the chapter, elasticity relates the percent change in an independent variable to that of the dependent variable. The income elasticity associated with territorial sales was 0.8, i.e., each one percent drop in real personal income results in a 0.8 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 approximate income effect on summer peak demand. Table 2.2.6 below shows the result for 2011 under pessimistic and optimistic scenario outcomes for real income. Recall that DRI associates a 55% probability of occurrence with its baseline projections, and a 20% and 25% probability to the pessimistic and optimistic projections, respectively.

TABLE 2.2.7

PEAK DEMAND FORECAST SCENARIO FOR 2011

(MW)

	Base Case	Pessimistic	Optimistic
SCE&G Real Personal Income	22.878	20.911	25.075
% Change to Base		-8.60	+9.60
Elasticity		.80	.80
% Change in Sales		-6.88	+7.68
Territorial Summer Peak Demand	4,658	4,337	5,015
Annual % Change 1994-2011	1.9	1.4	2.3

3.0 DEMAND-SIDE PLANNING

CHAPTER 3.0

DEMAND-SIDE MANAGEMENT ACTIVITIES AT SCE&G

This chapter describes South Carolina Electric & Gas Company's Demand-Side Management (DSM) activities. The first section examines the DSM concept and the factors in its applicability to today's utility operating environment. Included in this section will be an overview of Demand-Side Management objectives at SCE&G and associated market strategies.

Section Two review the process used to evaluate Demand-Side Management options. This section will highlight the evaluation process and the results of this analysis for both current programs, and programs in various stages of development.

Demand-Side options for the 1992 Least Cost Integrated Resource Plan are presented in the third section.

The fourth section presents the current status of all Demand-Side options at SCE&G. This section includes a summary and technical description of the DSM programs and an estimate of the impact of these programs on peak load over the twenty year planning horizon. The Company estimates that the cumulative impact of its DSM efforts by 2011 will result in reduced customer demands of 615 MW's and lower energy consumption by 843 million kWh.

3.1 THE DEMAND-SIDE MANAGEMENT CONCEPT

Demand-Side Management is focused on the concept of actively influencing the demand for electricity by direct intervention in the marketplace. Demand-Side Management is designed to optimize the utility's operational objectives by influencing customers to utilize the Company's product in a desired way through various incentives, including customer education, trade ally cooperation, direct incentives and alternative pricing through rates. The net result of the intervention in the marketplace is to influence the utility's load shape in a direction consistent with the operating environment of the utility.

Utilities are advocating an increased emphasis on Demand-Side options as a part of their resource plans largely due to the increased need for resource flexibility, customer concerns regarding rising prices and the substantial capital requirements of new generating plants.

Demand-Side Management can offer utilities an increased ability to improve customer relations by forming partnerships with customers. These "partnerships" are established on a proactive consideration of customer needs which are translated into increased options and control for utility customers.

Utility activities in DSM have been accelerating rapidly over the past several years. As of July, 1991, 31 states have adopted a working framework or integrated resource plan for formal consideration of Demand-Side Management options. According to The Electric Power Research Institute (EPRI) report on DSM impacts approximately 30% of new U.S. capacity requirements over this decade will be provided by DSM activities and these efforts are also projected to reduce electricity use by 107 billion kWh.

3.2 DEMAND-SIDE OBJECTIVES & STRATEGIES

SCE&G's Demand-Side Management load shape objectives fall into four major categories which are featured in Chart 3.2.1. Each of these changes in load shape has a distinct effect on the system. Some are effective in reducing the need for future generation capacity by targeting system growth of peak loads, while others improve system load factor. Both of these generalized effects have a common goal; to reduce the frequency and relative magnitude of rate increases.

Demand-Side Management objectives at SCE&G are incorporated in a broader strategy which is expressed in SCE&G's marketing mission; to influence customers in a manner which enhances the perceived value of our energy services. A critical element in our strategy is a focus on offering energy options designed to give our customers both increased understanding and control regarding their energy decisions/operations and to provide appropriate price signals to direct our customers toward the "best" utilization of our existing capacity. Our focus includes an active effort to build partnerships with our customers by cooperating in efforts to improve our mutual competitiveness.

These efforts span a broad spectrum from energy education at the Energy Info Centers to a portfolio of 25 Demand-Side Management programs. (See Chart 3.2.2)

CHART 3.2.1

DEMAND-SIDE LOAD SHAPE OBJECTIVES

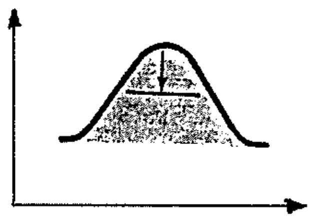
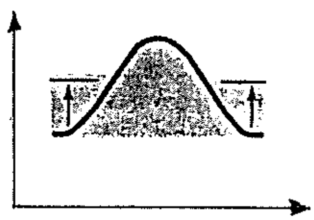
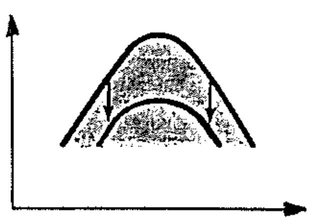
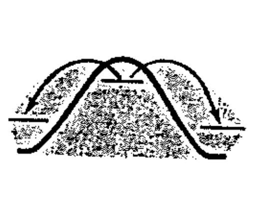
Load Shape Example Objective	Illustration	Definition
Peak Clipping		Reduction of system peak loads
Valley Filling		Building off-peak system loads
Strategic Conservation		Reduction of system load across all periods
Load Shifting		Shifting of system peak loads to off-peak periods

Chart 3.2.2
DSM Program Portfolio

Program	Load Shape Impact	Markets
Comm. Heat Pump Pool Heaters	VF	C
Fluorescent Ballast New	PC, SC	C/I
Fluorescent Ballast Retro	PC, SC	C/I
High Efficiency Motors	PC, SC	I
Adjustable Frequency Drives	SC	I
Compact Fluorescent Lamps	SC	R/C/I
Gas Air Conditioning	PC, SC	C/I
GATU Dual Fuel	PC, SC	R/C/I
GATU Financing	PC, SC	R/C/I
Residential Heat Pump Pool Heaters	VF	R
Off-Peak Water Heating	VF	R/C
Commercial Heat Pump Water Heaters	VF, SC	C
Commercial Electric Cooking	VF	C

Program	Load Shape Impact	Markets
Commercial HVAC	PC, SC	C/I
High Efficiency Lighting	PC, SC	C/I
Thermal Storage (OPAC)	PC, VF, LS	C/I
Lighting	VF	R/C/I
GATU	PC, SC	R/C/I
HEC	PC, SC	R/C
Good Cents	PC, SC	R
Rate 07	PC, SC	R
Rate 05	LS	R
Rate 27	PC	I
Residential Thermal Storage	PC, VF, LS	R
Standby Generator	PC	C/I

3.3 ENERGY EDUCATION AT SCE&G

One of the major thrusts in SCE&G's energy education efforts has been a continued focus and commitment on the Energy Info Centers. The primary goal of the Energy Info Centers is to provide energy education and information to customers to enable them to make informed decisions for energy choices to reduce their costs and the Company's peak load. Two centers were opened in the major metropolitan markets of Columbia and Charleston in 1984 and 1985, respectively. The Centers are located in high traffic retail settings and feature exhibits and interactive displays. The Centers provide a centralized source of detailed information to our customers on the full range of energy conservation and efficiency alternatives available. Included in the Centers is a variety of tools to enable homeowners to make informed decisions about their energy lifestyles and to understand how they can make cost-beneficial changes in their homes related to energy usage.

Educating the customer...making them aware of new technology...helping them to understand that they have a variety of choices which can control their energy purchases. These are some of the initial thoughts that sparked the creation of SCE&G's two Energy Info Centers.

Our Energy Info Centers were the first facilities of their type, that we know of, to bring together the combined strengths and talents of a public utility company, Home Builders Associations and energy appliance/product manufacturers and distributors with the expressed purpose of energy educating the public. To support this mission, emphasis has been placed on communicating "the technical" in lay terms. We feel an integral part of motivating customers to action is speaking their language.

More specifically, SCE&G has invited these partners to join together to accomplish several tasks. First, we are providing a unique information environment where the residential electrical and gas customers can learn to conserve energy. Second, we are trying to develop a customer understanding of the value of the home energy products, gas and electricity, they purchase everyday. Also, we want to use the Energy Info Centers as an embassy where the public can come in and meet with people from SCE&G. An important part of our message is communicating warmth and interest in our customers...to engender a feeling that we are caring energy professionals. Finally, we want to establish dialogue with our customers, wherein we collect information as to how our company can better meet their changing needs.

The Energy Info Centers were opened in June of 1984, and since then 1,800,000 people have walked through the doors. The Columbia Energy Info Center is located in Dutch Square Mall and offers a total of 22 energy educational exhibits. The Charleston Energy Info Center is located in Citadel Mall and provides visitors with 21 energy educational exhibits. We feel the mall locations of the centers is innovative in that they are placed in the mainstream of residential consumer activity. As we maintain "retailer hours," consumers are free to browse and study at their leisure.

In essence, we are retailing energy education and we feel that concept is truly unique. To quote A.G.A. Monthly, "Some busy companies try to avoid their customers, South Carolina Electric & Gas Co. went looking for theirs."

The Centers are open from 11:00 AM until 9:00 PM, six days a week and from 9:00 AM until 7:00 PM Saturdays. Both Centers contain a 1400 square foot, 100 seat auditorium where energy related seminars and a variety of other workshops are conducted. since opening, we have conducted over 1,000 workshops and seminars on topics ranging from "How to Build an Energy Efficient Home" to Energy Conservation for the Elementary School Student." Also, a permanent staff of six Energy Education Representatives are at the Centers to assist customers.

We employ a multi-media approach in presenting energy products and concepts. Live, installed and metered high efficiency heat pumps, gas furnaces, and household appliances with easily understood displays explaining the benefits of their state-of-the-art technology help customers develop a clear understanding of what these products can offer them through touching, seeing, feeling and hearing. This technique is used also in our model home with its "cut-away-construction."

We also offer a service to consumers who are building homes which involves computer modeling. This is to assist them in the selection of energy efficient heating and cooling equipment as well as the selection of optimum cost effective levels of insulation.

Customers are shown how to build their homes to comply with SCE&G's Energy Conservation Rate, which lowers their electricity kWh costs between 2% and 9% ompared with the standard electric rate...a real incentive to build in savings and increased comfort.

Customers are also able to receive in depth analyses of their last 12 months electricity and gas bills. Based on the records of their consumption plus additional information they provide us regarding their homes and lifestyles, we can generate a computerized projection of what their total bills should be and identify specific target areas where they may be able to conserve.

We feel that our Energy Info Centers fill a public need for objective, reliable, readily available energy information and expertise that can help them understand the energy purchases they make daily and the many choices they have in controlling them.

A second energy education initiative was developed and implemented in response to a series of customer research efforts. Our customers consistently indicated that SCE&G is the most credible source of information for energy related matters and that SCE&G should take a proactive role in informing customers about energy conserving options.

As a result, the "Energy Experts" campaign was developed and implemented featuring a host of energy conservation tips. (See Chart 3.3.1) this educational effort has also been strongly tied to the Energy Info Centers and to our DSM product mix.

CHART 3.3.1

ENERGY EXPERTS CONSERVATION TOPICS

* Weatherstripping, caulking, Insulation
* Water heater operations and settings
* Air conditioning operation and settings
* Package fluorescent lamps
* High pressure sodium lamps
* Fan use for space conditioning
* Oven operation
* Washer & Dryer operation

3.4 DSM EVALUATION

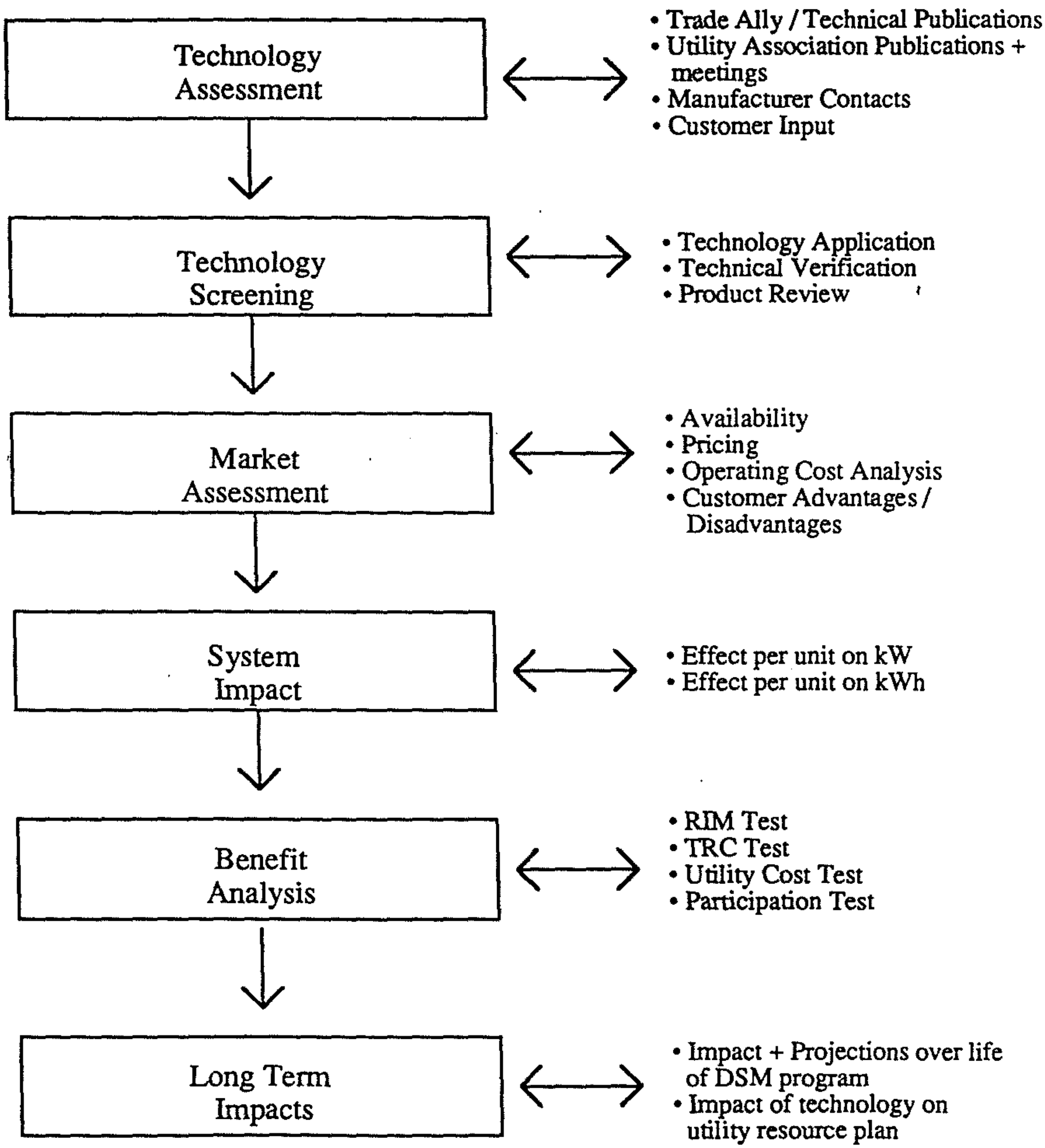
The Demand-Side Management evaluation process has undergone significant evolution over the past several years and will continue to be a dynamic process for the foreseeable future.

Demand-Side Management analysis is a process that integrates a number of qualitative and quantitative steps in establishing the applicability of a technology to meet our resource needs. Our analysis process is based on a Demand-Side Management decision matrix that is depicted in Chart 3.4.1. The Demand-Side Decision Matrix - six stages of evaluation are defined as follows:

Technology Assessment: This stage of the evaluation process involves the initial exposure to a modified or new technology. Technologies with DSM potential are introduced through a variety of means to the marketing function including various publications, trade ally/manufacturers solicitations, customer research or through utility associations.

Technology Screening: In this stage an initial technology screening is performed which explores the characteristics of the proposed technology by examining manufacturers' specifications and performance claims. This stage attempts to verify the technical viability of the proposed technology as indicated by independent review, units in commercial operation or through verification of sample/prototype testing.

Chart 3.4.1
DSM Flow Chart Decision Matrix



Market Assessment: The market assessment stage is designed to establish reasonable estimates of local product availability and market pricing. Performance analysis and pricing information are combined to produce an operating cost estimate. This estimate is used for comparison purposes to evaluate customer advantages/disadvantages relative to competitive or current technologies in use.

System Impact: This stage focuses on the per-unit impact of the technology on system energy and demand.

Benefit Analysis: Cost/benefit analyses are conducted at this stage based on the methodologies outlined in the End-Use Technical Assessment guide (TAG) published by EPRI in April 1991. The following four tests are run on each DSM resource option:

(1) Total Resource Cost Test (TRC): Also known as the All Ratepayers Test. This test is a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its rate payers as a whole. Resource costs include changes in supply costs, utility costs, and participant costs. Changes in transfer payments (incentives, revenue changes) are ignored by this test.

(2) Participant Test: This test is a measure of the quantifiable benefits and costs of a DSM program from the perspective of a participant. This test can be modified to establish customer paybacks.

(3) Ratepayer Impact Measure Test (RIM): Also known as the non participant test and the No Losers Test is a measure of the difference between the change in total revenues paid to a utility and the change in total costs to a utility resulting from a DSM program.

(4) utility Cost Test: Also known as the Utility Revenue Requirements Test is a measure of the change in total costs to the utility that is caused by a DSM program.

Programs that emerge with positive net benefits and associated benefits/cost are presented to approval authorities. After approval, the program is subjected to a formal implementation process for integration into company operations. The final stage of the decision matrix is projection of the proposed program on the Company's resource plans. This stage entitled Long Term Impacts is defined as follows:

Long Term Impacts: This stage is focused on calculating the impacts of the DSM resource option in terms of anticipated market penetration rates over the planning horizon. Estimates are generated on current and projected penetrations utilizing forcasted customer growth and historical program performance considerations.

3.5 DSM ANALYSIS RESULTS

A variety of Demand-Side alternatives have been evaluated for possible inclusion in the 1992 DSM portfolio. Chart 3.5.1 depicts a listing of the options that were evaluated for potential as DSM resources for The 1992 Integrated Resource Plan.

Chart 3.5.2 shows TAG test results for the DSM resources which were evaluated for The 1992 Integrated Resource Plan. The charts are followed by TAG test results showing net benefits for various evaluated programs organized on the same basis as Chart 3.5.2. Chart 3.5.3 features a summary of DSM program analysis components including equipment costs, incentives and customer paybacks expressed in years.

Chart 3.5.1

DSM Technologies

Photovoltaics
Magnetic Fluorescent Ballasts
Residential Air Conditioner Desuperheaters
Solar Water Heating
Heat Pump Water Heating
High Efficiency Freezers/Refrigerators
Radiant Barriers
Setback Thermostats
Low Flow Shower heads
Commercial Dual Fuel Heat Pumps
High Efficiency Water Heating
High Efficiency Motors
Electronic Fluorescent Ballast (Retro)
Electronic Fluorescent Ballast (New)
Compact Fluorescent Lamps
Gas Absorption Cooling
High Efficiency Dual Fuel Heat Pump
Off-Peak Water Heating
High Efficiency Commercial HVAC (Rooftop)
Adjustable Frequency Drives
High Efficiency Chillers
Commercial Ice Storage
Home Energy Check
Residential Thermal Storage
Good Cents Home
Rate 07
High Efficiency Lighting
Great Appliance Trade-up
Storm Windows
Attic Insulation (R-11 - R-30)
Gas Absorption Cooling (engine driven)
Standby Generators

Chart 3.5.2

DSM Benefit / Cost Test Results

Implemented Programs:

	TAG Tests			
Program	TRC	RIM	UCT	PCT
High. Eff. Chillers	3.19	1.00	11.39	3.60
Thermal Storage (OPAC)	1.97	1.50	2.55	1.09
Home Energy Check	2.95	1.37	10.59	2.31
Res. Thermal Storage	1.16	.89	1.33	1.31
Good Cents	1.92	.99	4.83	2.58
Rate 07	1.69	1.01	8.54	1.84
High. Eff. Lighting	7.65	1.34	11.29	11.25
Great Appliance Trade-up	2.32	1.42	4.05	1.74
Standby Generators	2.66	1.41	1.71	1.99
Rate 27	7.87	3.11	7.87	2.31

PROGRAM: HIGH EFFICIENCY CHILLERS 10-Apr-92

Participant Test	Bill Reductions	$4,138,057	Bill Increases	$0	B/C Ratio	3.60
	Avoided Participant Cost	$0	Participant Costs	$1,201,150		
	Incentives	$180,172	Participant Charges	$0		
					Net	
	Total Benefit	$4,318,230	Total Costs	$1,201,150	Benefits	$3,117,080

Total Resource Cost Test	Avoided Supply Cost	$4,520,133	Increased Supply Cost	$0	B/C Ratio	3.19
	Net Avoided Part. Cost	$0	Net Participant Cost	$1,201,150		
			Utility Cost	$216,639		
					Net	
	Total Benefits	$4,520,133	Total Costs	$1,417,789	Benefits	$3,102,344

Ratepayer Impact Measure Test	Avoided Supply Cost	$4,520,133	Increased Supply Cost	$0	B/C Ratio	1.00
	Revenue Gain	$0	Revenue Loss	$4,138,057		
	Participation Charge	$0	Incentives	$180,172		
			Utility Cost	$216,639		
					Net	
	Total Benefits	$4,520,133	Total Costs	$4,534,869	Benefits	($14,736)

Utility Cost Test	Avoided Supply Cost	$4,520,133	Increased Supply Costs	$0	B/C Ratio	11.39
	Participation Charges	$0	Incentives	$180,172		
			Utility Costs	$216,639		
					Net	
	Total Benefits	$4,520,133	Total Costs	$396,812	Benefits	$4,123,321

PROGRAM: COMMERCIAL ICE STORAGE 10–Apr–92

Participant Test	Bill Reductions	$11,414,039	Bill Increases	$7,707,548	B/C Ratio	1.09
	Avoided Participant Cost	$0	Participant Costs	$3,974,528		
	Incentives	$1,324,843	Participant Charges	$0		
	Total Benefit	$12,738,882	Total Costs	$11,682,076	Net Benefits	$1,056,806

Total Resource Cost Test	Avoided Supply Cost	$22,880,494	Increased Supply Cost	$6,804,183	B/C Ratio	1.97
	Net Avoided Part. Cost	$0	Net Participant Cost	$3,974,528		
			Utility Cost	$853,994		
	Total Benefits	$22,880,494	Total Costs	$11,632,704	Net Benefits	$11,247,790

Ratepayer Impact Measure Test	Avoided Supply Cost	$22,880,494	Increased Supply Cost	$6,804,183	B/C Ratio	1.50
	Revenue Gain	$7,707,548	Revenue Loss	$11,414,039		
	Participation Charge	$0	Incentives	$1,324,843		
			Utility Cost	$853,994		
	Total Benefits	$30,588,042	Total Costs	$20,397,058	Net Benefits	$10,190,984

Utility Cost Test	Avoided Supply Cost	$22,880,494	Increased Supply Costs	$6,804,183	B/C Ratio	2.55
	Participation Charges	$0	Incentives	$1,324,843		
			Utility Costs	$853,994		
	Total Benefits	$22,880,494	Total Costs	$8,983,019	Net Benefits	$13,897,475

PROGRAM: HOME ENERGY CHECK 10-Apr-92

Participant Test	Bill Reductions	$9,730,185	Bill Increases	$0	B/C Ratio	2.31
	Avoided Participant Cost	$0	Participant Costs	$4,562,091		
	Incentives	$820,455	Participant Charges	$0		
	Total Benefit	$10,550,640	Total Costs	$4,562,091	Net Benefits	$5,988,549

Total Resource Cost Test	Avoided Supply Cost	$15,331,406	Increased Supply Cost	$0	B/C Ratio	2.95
	Net Avoided Part. Cost	$0	Net Participant Cost	$4,562,091		
			Utility Cost	$627,242		
	Total Benefits	$15,331,406	Total Costs	$5,189,333	Net Benefits	$10,142,073

Ratepayer Impact Measure Test	Avoided Supply Cost	$15,331,406	Increased Supply Cost	$0	B/C Ratio	1.37
	Revenue Gain	$0	Revenue Loss	$9,730,185		
	Participation Charge	$0	Incentives	$820,455		
			Utility Cost	$627,242		
	Total Benefits	$15,331,406	Total Costs	$11,177,883	Net Benefits	$4,153,523

Utility Cost Test	Avoided Supply Cost	$15,331,406	Increased Supply Costs	$0	B/C Ratio	10.59
	Participation Charges	$0	Incentives	$820,455		
			Utility Costs	$627,242		
	Total Benefits	$15,331,406	Total Costs	$1,447,697	Net Benefits	$13,883,708

PROGRAM: RESIDENTIAL THERMAL STORAGE 10-Apr-92

Participant Test	Bill Reductions	$22,991,443	Bill Increases	$13,749,258	B/C Ratio	1.31
	Avoided Participant Cost	$0	Participant Costs	$9,149,957		
	Incentives	$6,955,204	Participant Charges	$0		
	Total Benefit	$29,946,647	Total Costs	$22,899,216	Net Benefits	$7,047,432

Total Resource Cost Test	Avoided Supply Cost	$20,608,457	Increased Supply Cost	$6,760,719	B/C Ratio	1.16
	Net Avoided Part. Cost	$0	Net Participant Cost	$9,149,957		
			Utility Cost	$1,791,805		
	Total Benefits	$20,608,457	Total Costs	$17,702,481	Net Benefits	$2,905,976

Ratepayer Impact Measure Test	Avoided Supply Cost	$20,608,457	Increased Supply Cost	$6,760,719	B/C Ratio	0.89
	Revenue Gain	$13,749,258	Revenue Loss	$22,991,443		
	Participation Charge	$0	Incentives	$6,955,204		
			Utility Cost	$1,791,805		
	Total Benefits	$34,357,716	Total Costs	$38,499,171	Net Benefits	($4,141,456)

Utility Cost Test	Avoided Supply Cost	$20,608,457	Increased Supply Costs	$6,760,719	B/C Ratio	1.33
	Participation Charges	$0	Incentives	$6,955,204		
			Utility Costs	$1,791,805		
	Total Benefits	$20,608,457	Total Costs	$15,507,728	Net Benefits	$5,100,729

PROGRAM: GOOD CENTS HOME 10-Apr-92

Participant Test	Bill Reductions	$32,034,180	Bill Increases	$0	B/C Ratio	2.58
	Avoided Participant Cost	$0	Participant Costs	$12,405,574		
	Incentives	$0	Participant Charges	$0		
	Total Benefit	$32,034,180	Total Costs	$12,405,574	Net Benefits	$19,628,606

Total Resource Cost Test	Avoided Supply Cost	$39,659,121	Increased Supply Cost	$0	B/C Ratio	1.92
	Net Avoided Part. Cost	$0	Net Participant Cost	$12,405,574		
			Utility Cost	$8,215,057		
	Total Benefits	$39,659,121	Total Costs	$20,620,631	Net Benefits	$19,038,491

Ratepayer Impact Measure Test	Avoided Supply Cost	$39,659,121	Increased Supply Cost	$0	B/C Ratio	0.99
	Revenue Gain	$0	Revenue Loss	$32,034,180		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$8,215,057		
	Total Benefits	$39,659,121	Total Costs	$40,249,237	Net Benefits	($590,115)

Utility Cost Test	Avoided Supply Cost	$39,659,121	Increased Supply Costs	$0	B/C Ratio	4.83
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$8,215,057		
	Total Benefits	$39,659,121	Total Costs	$8,215,057	Net Benefits	$31,444,065

PROGRAM: RATE 7 10-Apr-92

Participant	Bill Reductions	$21,944,031	Bill Increases	$0	B/C Ratio	1.84
Test	Avoided Participant Cost	$0	Participant Costs	$11,901,107		
	Incentives	$0	Participant Charges	$0		
					Net	
	Total Benefit	$21,944,031	Total Costs	$11,901,107	Benefits	$10,042,925

Total	Avoided Supply Cost	$25,076,036	Increased Supply Cost	$0	B/C Ratio	1.69
Resource	Net Avoided Part. Cost	$0	Net Participant Cost	$11,901,107		
Cost			Utility Cost	$2,935,065		
Test					Net	
	Total Benefits	$25,076,036	Total Costs	$14,836,172	Benefits	$10,239,864

Ratepayer	Avoided Supply Cost	$25,076,036	Increased Supply Cost	$0	B/C Ratio	1.01
Impact	Revenue Gain	$0	Revenue Loss	$21,944,031		
Measure	Participation Charge	$0	Incentives	$0		
Test			Utility Cost	$2,935,065		
					Net	
	Total Benefits	$25,076,036	Total Costs	$24,879,096	Benefits	$196,940

Utility	Avoided Supply Cost	$25,076,036	Increased Supply Costs	$0	B/C Ratio	8.54
Cost	Participation Charges	$0	Incentives	$0		
Test			Utility Costs	$2,935,065		
					Net	
	Total Benefits	$25,076,036	Total Costs	$2,935,065	Benefits	$22,140,971

PROGRAM: HIGH EFFICIENCY LIGHTING 10-Apr-92

Participant Test	Bill Reductions	$6,450,709	Bill Increases	$0	B/C Ratio	11.25
	Avoided Participant Cost	$0	Participant Costs	$589,114		
	Incentives	$175,367	Participant Charges	$0		
	Total Benefit	$6,626,076	Total Costs	$589,114	Net Benefits	$6,036,962

Total Resource Cost Test	Avoided Supply Cost	$9,805,933	Increased Supply Cost	$0	B/C Ratio	7.65
	Net Avoided Part. Cost	$0	Net Participant Cost	$589,114		
			Utility Cost	$692,840		
	Total Benefits	$9,805,933	Total Costs	$1,281,954	Net Benefits	$8,523,978

Ratepayer Impact Measure Test	Avoided Supply Cost	$9,805,933	Increased Supply Cost	$0	B/C Ratio	1.34
	Revenue Gain	$0	Revenue Loss	$6,450,709		
	Participation Charge	$0	Incentives	$175,367		
			Utility Cost	$692,840		
	Total Benefits	$9,805,933	Total Costs	$7,318,916	Net Benefits	$2,487,016

Utility Cost Test	Avoided Supply Cost	$9,805,933	Increased Supply Costs	$0	B/C Ratio	11.29
	Participation Charges	$0	Incentives	$175,367		
			Utility Costs	$692,840		
	Total Benefits	$9,805,933	Total Costs	$868,207	Net Benefits	$8,937,726

PROGRAM: GREAT APPLIANCE TRADE UP 10–Apr–92

Participant Test	Bill Reductions	$12,580,152	Bill Increases	$0	B/C Ratio	1.74
	Avoided Participant Cost	$0	Participant Costs	$10,242,597		
	Incentives	$5,222,871	Participant Charges	$0		
	Total Benefit	$17,803,023	Total Costs	$10,242,597	Net Benefits	$7,560,426

Total Resource Cost Test	Avoided Supply Cost	$27,363,557	Increased Supply Cost	$0	B/C Ratio	2.32
	Net Avoided Part. Cost	$0	Net Participant Cost	$10,242,597		
			Utility Cost	$1,534,682		
	Total Benefits	$27,363,557	Total Costs	$11,777,279	Net Benefits	$15,586,278

Ratepayer Impact Measure Test	Avoided Supply Cost	$27,363,557	Increased Supply Cost	$0	B/C Ratio	1.42
	Revenue Gain	$0	Revenue Loss	$12,580,152		
	Participation Charge	$0	Incentives	$5,222,871		
			Utility Cost	$1,534,682		
	Total Benefits	$27,363,557	Total Costs	$19,337,706	Net Benefits	$8,025,851

Utility Cost Test	Avoided Supply Cost	$27,363,557	Increased Supply Costs	$0	B/C Ratio	4.05
	Participation Charges	$0	Incentives	$5,222,871		
			Utility Costs	$1,534,682		
	Total Benefits	$27,363,557	Total Costs	$6,757,553	Net Benefits	$20,606,004

PROGRAM: STANDBY GENERATORS 27-Apr-92

Participant Test	Bill Reductions	$226	Bill Increases	$0	B/C Ratio	1.99
	Avoided Participant Cost	$0	Participant Costs	$602		
	Incentives	$974	Participant Charges	$0		
	Total Benefit	$1,200	Total Costs	$602	Net Benefits	$598

Total Resource Cost Test	Avoided Supply Cost	$1,786	Increased Supply Cost	$0	B/C Ratio	2.66
	Net Avoided Part. Cost	$0	Net Participant Cost	$602		
			Utility Cost	$69		
	Total Benefits	$1,786	Total Costs	$671	Net Benefits	$1,115

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,786	Increased Supply Cost	$0	B/C Ratio	1.41
	Revenue Gain	$0	Revenue Loss	$226		
	Participation Charge	$0	Incentives	$974		
			Utility Cost	$69		
	Total Benefits	$1,786	Total Costs	$1,269	Net Benefits	$517

Utility Cost Test	Avoided Supply Cost	$1,786	Increased Supply Costs	$0	B/C Ratio	1.71
	Participation Charges	$0	Incentives	$974		
			Utility Costs	$69		
	Total Benefits	$1,786	Total Costs	$1,043	Net Benefits	$743

PROGRAM: RATE 27; SIX CONT HRS, SUMMER ONLY 27-Apr-92

Participant Test	Bill Reductions	$5,173,824	Bill Increases	$2,238,149	B/C Ratio	2.31
	Avoided Participant Cost	$0	Participant Costs	$0		
	Incentives	$0	Participant Charges	$0		
	Total Benefit	$5,173,824	Total Costs	$2,238,149	Net Benefits	$2,935,674

Total Resource Cost Test	Avoided Supply Cost	$22,880,494	Increased Supply Cost	$2,053,855	B/C Ratio	7.87
	Net Avoided Part. Cost	$0	Net Participant Cost	$0		
			Utility Cost	$853,994		
	Total Benefits	$22,880,494	Total Costs	$2,907,849	Net Benefits	$19,972,646

Ratepayer Impact Measure Test	Avoided Supply Cost	$22,880,494	Increased Supply Cost	$2,053,855	B/C Ratio	3.11
	Revenue Gain	$2,238,149	Revenue Loss	$5,173,824		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$853,994		
	Total Benefits	$25,118,644	Total Costs	$8,081,673	Net Benefits	$17,036,971

Utility Cost Test	Avoided Supply Cost	$22,880,494	Increased Supply Costs	$2,053,855	B/C Ratio	7.87
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$853,994		
	Total Benefits	$22,880,494	Total Costs	$2,907,849	Net Benefits	$19,972,646

1992 Programs:

Program	TRC	RIM	UCT	PCT
	TAG Tests			
Gas Absorption Cooling	4.27	1.06	9.89	1.33
Comm. HP Water Heaters	1.89	1.29	5.39	1.59
High Eff. Motors	10.19	1.20	15.70	11.66
Fluorescent Ballast (Retro)	1.95	1.23	6.35	1.64
Fluorescent Ballast (New)	1.95	1.29	8.45	1.55
Compact Fluorescent	2.83	1.13	16.25	2.83
Dual Fuel HP	2.50	2.11	2.11	1.20
Off Peak Water Heating	1.42	1.13	1.22	1.32
High Eff. Rooftop HP	1.91	1.53	9.72	1.28
Adjustable Freq. Drives	3.61	1.19	6.06	3.50

PROGRAM: GAS ABSORPTION COOLING 27-Apr-92

Participant Test	Bill Reductions	$1,585	Bill Increases	$918	B/C Ratio	1.33
	Avoided Participant Cost	$0	Participant Costs	$350	Payback (years)	7.93
	Incentives	$100	Participant Charges	$0		
	Total Benefit	$1,685	Total Costs	$1,268	Net Benefits	$417

Total Resource Cost Test	Avoided Supply Cost	$1,882	Increased Supply Cost	$0	B/C Ratio	4.27
	Net Avoided Part. Cost	$0	Net Participant Cost	$350		
			Utility Cost	$90		
	Total Benefits	$1,882	Total Costs	$440	Net Benefits	$1,441

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,882	Increased Supply Cost	$0	B/C Ratio	1.06
	Revenue Gain (Gas)	$918	Revenue Loss	$1,585		
	Participation Charge	$0	Incentives	$100		
	Net Revenue Gain	($918)	Utility Cost	$90		
	Total Benefits	$1,882	Total Costs	$1,776	Net Benefits	$106

Utility Cost Test	Avoided Supply Cost	$1,882	Increased Supply Costs	$0	B/C Ratio	9.89
	Participation Charges	$0	Incentives	$100		
			Utility Costs	$90		
	Total Benefits	$1,882	Total Costs	$190	Net Benefits	$1,691

PROGRAM: HEAT PUMP WATER HEATER

Participant Test	Bill Reductions	$749	Bill Increases	$0	B/C Ratio	1.59
	Avoided Participant Cost	$0	Participant Costs	$534		
	Incentives	$100	Participant Charges	$0		
	Total Benefit	$849	Total Costs	$534	Net Benefits	$315

Total Resource Cost Test	Avoided Supply Cost	$1,267	Increased Supply Cost	$0	B/C Ratio	1.89
	Net Avoided Part. Cost	$0	Net Participant Cost	$534		
			Utility Cost	$135		
	Total Benefits	$1,267	Total Costs	$669	Net Benefits	$598

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,267	Increased Supply Cost	$0	B/C Ratio	1.29
	Revenue Gain	$0	Revenue Loss	$749		
	Participation Charge	$0	Incentives	$100		
			Utility Cost	$135		
	Total Benefits	$1,267	Total Costs	$984	Net Benefits	$283

Utility Cost Test	Avoided Supply Cost	$1,267	Increased Supply Costs	$0	B/C Ratio	5.39
	Participation Charges	$0	Incentives	$100		
			Utility Costs	$135		
	Total Benefits	$1,267	Total Costs	$235	Net Benefits	$1,032

PROGRAM: HIGH EFFICIENCY MOTORS 10-Apr-92

Participant Test	Bill Reductions	$2,232	Bill Increases	$0	B/C Ratio	11.66
	Avoided Participant Cost	$0	Participant Costs	$200		
	Incentives	$100	Participant Charges	$0		
	Total Benefit	$2,332	Total Costs	$200	Net Benefits	$2,132

Total Resource Cost Test	Avoided Supply Cost	$2,904	Increased Supply Cost	$0	B/C Ratio	10.19
	Net Avoided Part. Cost	$0	Net Participant Cost	$200		
			Utility Cost	$85		
	Total Benefits	$2,904	Total Costs	$285	Net Benefits	$2,619

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,904	Increased Supply Cost	$0	B/C Ratio	1.20
	Revenue Gain	$0	Revenue Loss	$2,232		
	Participation Charge	$0	Incentives	$100		
			Utility Cost	$85		
	Total Benefits	$2,904	Total Costs	$2,417	Net Benefits	$487

Utility Cost Test	Avoided Supply Cost	$2,904	Increased Supply Costs	$0	B/C Ratio	15.70
	Participation Charges	$0	Incentives	$100		
			Utility Costs	$85		
	Total Benefits	$2,904	Total Costs	$185	Net Benefits	$2,719

PROGRAM: ELECTRONIC FLUORESCENT BALLAST; RETROFIT 27–Apr–92

Participant Test	Bill Reductions	$1,389	Bill Increases	$0	B/C Ratio	1.64
	Avoided Participant Cost	$0	Participant Costs	$1,000		
	Incentives	$248	Participant Charges	$0		
	Total Benefit	$1,637	Total Costs	$1,000	Net Benefits	$637

Total Resource Cost Test	Avoided Supply Cost	$2,112	Increased Supply Cost	$0	B/C Ratio	1.95
	Net Avoided Part. Cost	$0	Net Participant Cost	$1,000		
			Utility Cost	$85		
	Total Benefits	$2,112	Total Costs	$1,085	Net Benefits	$1,027

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,112	Increased Supply Cost	$0	B/C Ratio	1.23
	Revenue Gain	$0	Revenue Loss	$1,389		
	Participation Charge	$0	Incentives	$248		
			Utility Cost	$85		
	Total Benefits	$2,112	Total Costs	$1,722	Net Benefits	$390

Utility Cost Test	Avoided Supply Cost	$2,112	Increased Supply Costs	$0	B/C Ratio	6.35
	Participation Charges	$0	Incentives	$248		
			Utility Costs	$85		
	Total Benefits	$2,112	Total Costs	$333	Net Benefits	$1,779

PROGRAM: ELECTRONIC FLUORESCENT BALLAST; NEW

10-Apr-92

Participant Test	Bill Reductions	$1,389	Bill Increases	$0	B/C Ratio	1.55
	Avoided Participant Cost	$0	Participant Costs	$1,000		
	Incentives	$165	Participant Charges	$0		
	Total Benefit	$1,554	Total Costs	$1,000	Net Benefits	$554

Total Resource Cost Test	Avoided Supply Cost	$2,112	Increased Supply Cost	$0	B/C Ratio	1.95
	Net Avoided Part. Cost	$0	Net Participant Cost	$1,000		
			Utility Cost	$85		
	Total Benefits	$2,112	Total Costs	$1,085	Net Benefits	$1,027

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,112	Increased Supply Cost	$0	B/C Ratio	1.29
	Revenue Gain	$0	Revenue Loss	$1,389		
	Participation Charge	$0	Incentives	$165		
			Utility Cost	$85		
	Total Benefits	$2,112	Total Costs	$1,639	Net Benefits	$473

Utility Cost Test	Avoided Supply Cost	$2,112	Increased Supply Costs	$0	B/C Ratio	8.45
	Participation Charges	$0	Incentives	$165		
			Utility Costs	$85		
	Total Benefits	$2,112	Total Costs	$250	Net Benefits	$1,862

PROGRAM: COMPACT FLUORESCENTS

Participant Test	Bill Reductions	$1,141	Bill Increases	$0	B/C Ratio	2.83
	Avoided Participant Cost	$0	Participant Costs	$403		
	Incentives	$0	Participant Charges	$0		
	Total Benefit	$1,141	Total Costs	$403	Net Benefits	$739

Total Resource Cost Test	Avoided Supply Cost	$1,381	Increased Supply Cost	$0	B/C Ratio	2.83
	Net Avoided Part. Cost	$0	Net Participant Cost	$403		
			Utility Cost	$85		
	Total Benefits	$1,381	Total Costs	$488	Net Benefits	$894

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,381	Increased Supply Cost	$0	B/C Ratio	1.13
	Revenue Gain	$0	Revenue Loss	$1,141		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$85		
	Total Benefits	$1,381	Total Costs	$1,226	Net Benefits	$155

Utility Cost Test	Avoided Supply Cost	$1,381	Increased Supply Costs	$0	B/C Ratio	16.25
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$85		
	Total Benefits	$1,381	Total Costs	$85	Net Benefits	$1,296

PROGRAM: HIGH EFFICIENCY DUAL FUEL HEAT PUMP 10–Apr–92

Participant Test	Bill Reductions	$0	Bill Increases	$2,199	B/C Ratio	1.20
	Avoided Participant Cost	$2,729	Participant Costs	$250		
	Incentives	$200	Participant Charges	$0		
	Total Benefit	$2,929	Total Costs	$2,449	Net Benefits	$480

Total Resource Cost Test	Avoided Supply Cost	$0	Increased Supply Cost	$754	B/C Ratio	2.50
	Net Avoided Part. Cost	$2,729	Net Participant Cost	$250		
			Utility Cost	$90		
	Total Benefits	$2,729	Total Costs	$1,094	Net Benefits	$1,635

Ratepayer Impact Measure Test	Avoided Supply Cost	$0	Increased Supply Cost	$754	B/C Ratio	2.11
	Revenue Gain	$2,199	Revenue Loss	$0		
	Participation Charge	$0	Incentives	$200		
			Utility Cost	$90		
	Total Benefits	$2,199	Total Costs	$1,044	Net Benefits	$1,156

Utility Cost Test	Avoided Supply Cost	$0	Increased Supply Costs	$754	B/C Ratio	2.11
	Participation Charges	$0	Incentives	$200		
	Off Peak Revenue	$2,199	Utility Costs	$90		
	Total Benefits	$2,199	Total Costs	$1,044	Net Benefits	$1,156

PROGRAM: OFF PEAK WATER HEATING

10-Apr-92

Participant Test	Bill Reductions	$776	Bill Increases	$776	B/C Ratio	1.32
	Avoided Participant Cost	$583	Participant Costs	$250		
	Incentives	$0	Participant Charges	$0		
	Total Benefit	$1,359	Total Costs	$1,026	Net Benefits	$333

Total Resource Cost Test	Avoided Supply Cost	$1,334	Increased Supply Cost	$230	B/C Ratio	1.42
	Net Avoided Part. Cost	$583	Net Participant Cost	$250		
			Utility Cost	$868		
	Total Benefits	$1,917	Total Costs	$1,348	Net Benefits	$569

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,334	Increased Supply Cost	$230	B/C Ratio	1.13
	Revenue Gain	$776	Revenue Loss	$776		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$868		
	Total Benefits	$2,110	Total Costs	$1,873	Net Benefits	$236

Utility Cost Test	Avoided Supply Cost	$1,334	Increased Supply Costs	$230	B/C Ratio	1.22
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$868		
	Total Benefits	$1,334	Total Costs	$1,098	Net Benefits	$236

PROGRAM: HIGH EFFICIENCY ROOF TOP HEAT PUMPS/ACs 10-Apr-92

Participant Test	Bill Reductions	$884	Bill Increases	$0	B/C Ratio	1.28
	Avoided Participant Cost	$0	Participant Costs	$750		
	Incentives	$75	Participant Charges	$0		
	Total Benefit	$959	Total Costs	$750	Net Benefits	$209

Total Resource Cost Test	Avoided Supply Cost	$1,605	Increased Supply Cost	$0	B/C Ratio	1.91
	Net Avoided Part. Cost	$0	Net Participant Cost	$750		
			Utility Cost	$90		
	Total Benefits	$1,605	Total Costs	$840	Net Benefits	$765

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,605	Increased Supply Cost	$0	B/C Ratio	1.53
	Revenue Gain	$0	Revenue Loss	$884		
	Participation Charge	$0	Incentives	$75		
			Utility Cost	$90		
	Total Benefits	$1,605	Total Costs	$1,049	Net Benefits	$556

Utility Cost Test	Avoided Supply Cost	$1,605	Increased Supply Costs	$0	B/C Ratio	9.72
	Participation Charges	$0	Incentives	$75		
			Utility Costs	$90		
	Total Benefits	$1,605	Total Costs	$165	Net Benefits	$1,440

PROGRAM: VARIABLE SPEED DRIVES 10-Apr-92

Participant Test	Bill Reductions	$1,409	Bill Increases	$0	B/C Ratio	3.50
	Avoided Participant Cost	$0	Participant Costs	$470		
	Incentives	$235	Participant Charges	$0		
	Total Benefit	$1,644	Total Costs	$470	Net Benefits	$1,174

Total Resource Cost Test	Avoided Supply Cost	$2,092	Increased Supply Cost	$0	B/C Ratio	3.61
	Net Avoided Part. Cost	$0	Net Participant Cost	$470		
			Utility Cost	$110		
	Total Benefits	$2,092	Total Costs	$580	Net Benefits	$1,512

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,092	Increased Supply Cost	$0	B/C Ratio	1.19
	Revenue Gain	$0	Revenue Loss	$1,409		
	Participation Charge	$0	Incentives	$235		
			Utility Cost	$110		
	Total Benefits	$2,092	Total Costs	$1,754	Net Benefits	$338

Utility Cost Test	Avoided Supply Cost	$2,092	Increased Supply Costs	$0	B/C Ratio	6.06
	Participation Charges	$0	Incentives	$235		
			Utility Costs	$110		
	Total Benefits	$2,092	Total Costs	$345	Net Benefits	$1,747

Programs Rejected:

Program	TRC	RIM	UCT	PCT
		TAG Tests		
Photovoltaics	.28	.33	.44	.83
Res. A/C Desuperheater	.62	1.34	3.10	.42
Solar Water Heating	.42	.66	6.27	.61
Res. Heat Pump Water Htr.	.48	.36	1.75	1.35
High Eff. Water Heating	.45	.25	1.10	2.35
High Eff. Refig. (Res.)	1.14	.50	4.38	2.42

Programs Under Consideration:

Program	TRC	RIM	UCT	PCT
		TAG Tests		
Hi. Eff. Refrig./Freezer	1.19	.48	3.31	2.72
Magnetic Fluor. Ballasts	1.34	1.23	5.84	1.10
Radiant Barrier	3.13	1.02	10.59	3.13
Setback Thermostat	1.91	.33	11.49	6.71
Low Flow Showerhead	31.50	.33	62.99	192.38
Comm Dual Fuel HP	2.39	1.24	3.16	1.77

PROGRAM: PHOTOVOLTAICS

Participant Test	Bill Reductions	$972	Bill Increases	$0	B/C Ratio	0.83
	Avoided Participant Cost	$0	Participant Costs	$4,800		
	Incentives	$3,000	Participant Charges	$0		
	Total Benefit	$3,972	Total Costs	$4,800	Net Benefits	($828)

Total Resource Cost Test	Avoided Supply Cost	$1,356	Increased Supply Cost	$0	B/C Ratio	0.28
	Net Avoided Part. Cost	$0	Net Participant Cost	$4,800		
			Utility Cost	$100		
	Total Benefits	$1,356	Total Costs	$4,900	Net Benefits	($3,544)

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,356	Increased Supply Cost	$0	B/C Ratio	0.33
	Revenue Gain	$0	Revenue Loss	$972		
	Participation Charge	$0	Incentives	$3,000		
			Utility Cost	$100		
	Total Benefits	$1,356	Total Costs	$4,072	Net Benefits	($2,717)

Utility Cost Test	Avoided Supply Cost	$1,356	Increased Supply Costs	$0	B/C Ratio	0.44
	Participation Charges	$0	Incentives	$3,000		
			Utility Costs	$100		
	Total Benefits	$1,356	Total Costs	$3,100	Net Benefits	($1,744)

PROGRAM: RESIDENTIAL AIR CONDITIONER DESUPERHEATER

Participant Test	Bill Reductions	$506	Bill Increases	$0	B/C Ratio	0.42
	Avoided Participant Cost	$0	Participant Costs	$1,800		
	Incentives	$250	Participant Charges	$0		
	Total Benefit	$756	Total Costs	$1,800	Net Benefits	($1,044)

Total Resource Cost Test	Avoided Supply Cost	$1,194	Increased Supply Cost	$0	B/C Ratio	0.62
	Net Avoided Part. Cost	$0	Net Participant Cost	$1,800		
			Utility Cost	$135		
	Total Benefits	$1,194	Total Costs	$1,935	Net Benefits	($741)

Ratepayer Impact Measure Test	Avoided Supply Cost	$1,194	Increased Supply Cost	$0	B/C Ratio	1.34
	Revenue Gain	$0	Revenue Loss	$506		
	Participation Charge	$0	Incentives	$250		
			Utility Cost	$135		
	Total Benefits	$1,194	Total Costs	$891	Net Benefits	$302

Utility Cost Test	Avoided Supply Cost	$1,194	Increased Supply Costs	$0	B/C Ratio	3.10
	Participation Charges	$0	Incentives	$250		
			Utility Costs	$135		
	Total Benefits	$1,194	Total Costs	$385	Net Benefits	$809

PROGRAM: SOLAR WATER HEATING

Participant Test	Bill Reductions	$4,041	Bill Increases	$0	B/C Ratio	0.61
	Avoided Participant Cost	$0	Participant Costs	$6,660		
	Incentives	$0	Participant Charges	$0		
	Total Benefit	$4,041	Total Costs	$6,660	Net Benefits	($2,619)

Total Resource Cost Test	Avoided Supply Cost	$2,979	Increased Supply Cost	$0	B/C Ratio	0.42
	Net Avoided Part. Cost	$0	Net Participant Cost	$6,660		
			Utility Cost	$475		
	Total Benefits	$2,979	Total Costs	$7,135	Net Benefits	($4,156)

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,979	Increased Supply Cost	$0	B/C Ratio	0.66
	Revenue Gain	$0	Revenue Loss	$4,041		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$475		
	Total Benefits	$2,979	Total Costs	$4,516	Net Benefits	($1,537)

Utility Cost Test	Avoided Supply Cost	$2,979	Increased Supply Costs	$0	B/C Ratio	6.27
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$475		
	Total Benefits	$2,979	Total Costs	$475	Net Benefits	$2,504

PROGRAM: HEAT PUMP WATER HEATER

Participant Test	Bill Reductions	$7,882	Bill Increases	$0	B/C Ratio	1.35
	Avoided Participant Cost	$0	Participant Costs	$7,000		
	Incentives	$1,575	Participant Charges	$0		
	Total Benefit	$9,457	Total Costs	$7,000	Net Benefits	$2,457

Total Resource Cost Test	Avoided Supply Cost	$3,632	Increased Supply Cost	$0	B/C Ratio	0.48
	Net Avoided Part. Cost	$0	Net Participant Cost	$7,000		
			Utility Cost	$495		
	Total Benefits	$3,632	Total Costs	$7,495	Net Benefits	($3,863)

Ratepayer Impact Measure Test	Avoided Supply Cost	$3,632	Increased Supply Cost	$0	B/C Ratio	0.36
	Revenue Gain	$0	Revenue Loss	$7,882		
	Participation Charge	$0	Incentives	$1,575		
			Utility Cost	$495		
	Total Benefits	$3,632	Total Costs	$9,952	Net Benefits	($6,320)

Utility Cost Test	Avoided Supply Cost	$3,632	Increased Supply Costs	$0	B/C Ratio	1.75
	Participation Charges	$0	Incentives	$1,575		
			Utility Costs	$495		
	Total Benefits	$3,632	Total Costs	$2,070	Net Benefits	$1,562

PROGRAM: HIGH EFFICIENCY WATER HEATING

Participant Test	Bill Reductions	$235	Bill Increases	$0	B/C Ratio	2.35
	Avoided Participant Cost	$0	Participant Costs	$100		
	Incentives	$0	Participant Charges	$0		
	Total Benefit	$235	Total Costs	$100	Net Benefits	$135

Total Resource Cost Test	Avoided Supply Cost	$77	Increased Supply Cost	$0	B/C Ratio	0.45
	Net Avoided Part. Cost	$0	Net Participant Cost	$100		
			Utility Cost	$70		
	Total Benefits	$77	Total Costs	$170	Net Benefits	($93)

Ratepayer Impact Measure Test	Avoided Supply Cost	$77	Increased Supply Cost	$0	B/C Ratio	0.25
	Revenue Gain	$0	Revenue Loss	$235		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$70		
	Total Benefits	$77	Total Costs	$305	Net Benefits	($227)

Utility Cost Test	Avoided Supply Cost	$77	Increased Supply Costs	$0	B/C Ratio	1.10
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$70		
	Total Benefits	$77	Total Costs	$70	Net Benefits	$7

PROGRAM: RESIDENTIAL HIGH EFFICIENCY REFRIGERATOR

Participant Test	Bill Reductions	$4,231	Bill Increases	$0	B/C Ratio	2.42
	Avoided Participant Cost	$0	Participant Costs	$1,875		
	Incentives	$313	Participant Charges	$0		
	Total Benefit	$4,544	Total Costs	$1,875	Net Benefits	$2,669

Total Resource Cost Test	Avoided Supply Cost	$2,411	Increased Supply Cost	$0	B/C Ratio	1.14
	Net Avoided Part. Cost	$0	Net Participant Cost	$1,875		
			Utility Cost	$238		
	Total Benefits	$2,411	Total Costs	$2,113	Net Benefits	$298

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,411	Increased Supply Cost	$0	B/C Ratio	0.50
	Revenue Gain	$0	Revenue Loss	$4,231		
	Participation Charge	$0	Incentives	$313		
			Utility Cost	$238		
	Total Benefits	$2,411	Total Costs	$4,781	Net Benefits	($2,371)

Utility Cost Test	Avoided Supply Cost	$2,411	Increased Supply Costs	$0	B/C Ratio	4.38
	Participation Charges	$0	Incentives	$313		
			Utility Costs	$238		
	Total Benefits	$2,411	Total Costs	$550	Net Benefits	$1,861

PROGRAM: RESIDENTIAL HIGH EFFICIENCY FREEZER

Participant Test	Bill Reductions	$6,179	Bill Increases	$0	B/C Ratio	2.72
	Avoided Participant Cost	$0	Participant Costs	$2,500		
	Incentives	$625	Participant Charges	$0		
	Total Benefit	$6,804	Total Costs	$2,500	Net Benefits	$4,304

Total Resource Cost Test	Avoided Supply Cost	$3,477	Increased Supply Cost	$0	B/C Ratio	1.19
	Net Avoided Part. Cost	$0	Net Participant Cost	$2,500		
			Utility Cost	$425		
	Total Benefits	$3,477	Total Costs	$2,925	Net Benefits	$552

Ratepayer Impact Measure Test	Avoided Supply Cost	$3,477	Increased Supply Cost	$0	B/C Ratio	0.48
	Revenue Gain	$0	Revenue Loss	$6,179		
	Participation Charge	$0	Incentives	$625		
			Utility Cost	$425		
	Total Benefits	$3,477	Total Costs	$7,229	Net Benefits	($3,752)

Utility Cost Test	Avoided Supply Cost	$3,477	Increased Supply Costs	$0	B/C Ratio	3.31
	Participation Charges	$0	Incentives	$625		
			Utility Costs	$425		
	Total Benefits	$3,477	Total Costs	$1,050	Net Benefits	$2,427

PROGRAM: MAGNETIC FLUORESCENT BALLAST

Participant Test	Bill Reductions	$1,387	Bill Increases	$0	B/C Ratio	1.10
	Avoided Participant Cost	$0	Participant Costs	$1,500		
	Incentives	$260	Participant Charges	$0		
	Total Benefit	$1,647	Total Costs	$1,500	Net Benefits	$147

Total Resource Cost Test	Avoided Supply Cost	$2,159	Increased Supply Cost	$0	B/C Ratio	1.34
	Net Avoided Part. Cost	$0	Net Participant Cost	$1,500		
			Utility Cost	$110		
	Total Benefits	$2,159	Total Costs	$1,610	Net Benefits	$549

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,159	Increased Supply Cost	$0	B/C Ratio	1.23
	Revenue Gain	$0	Revenue Loss	$1,387		
	Participation Charge	$0	Incentives	$260		
			Utility Cost	$110		
	Total Benefits	$2,159	Total Costs	$1,757	Net Benefits	$402

Utility Cost Test	Avoided Supply Cost	$2,159	Increased Supply Costs	$0	B/C Ratio	5.84
	Participation Charges	$0	Incentives	$260		
			Utility Costs	$110		
	Total Benefits	$2,159	Total Costs	$370	Net Benefits	$1,789

PROGRAM: RADIANT BARRIER

Participant Test	Bill Reductions	$1,979	Bill Increases	$0	B/C Ratio	3.13
	Avoided Participant Cost	$0	Participant Costs	$695		
	Incentives	$195	Participant Charges	$0		
	Total Benefit	$2,174	Total Costs	$695	Net Benefits	$1,479

Total Resource Cost Test	Avoided Supply Cost	$2,224	Increased Supply Cost	$0	B/C Ratio	3.13
	Net Avoided Part. Cost	$0	Net Participant Cost	$695		
			Utility Cost	$15		
	Total Benefits	$2,224	Total Costs	$710	Net Benefits	$1,514

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,224	Increased Supply Cost	$0	B/C Ratio	1.02
	Revenue Gain	$0	Revenue Loss	$1,979		
	Participation Charge	$0	Incentives	$195		
			Utility Cost	$15		
	Total Benefits	$2,224	Total Costs	$2,189	Net Benefits	$36

Utility Cost Test	Avoided Supply Cost	$2,224	Increased Supply Costs	$0	B/C Ratio	10.59
	Participation Charges	$0	Incentives	$195		
			Utility Costs	$15		
	Total Benefits	$2,224	Total Costs	$210	Net Benefits	$2,014

PROGRAM: SETBACK THERMOSTAT

Participant Test	Bill Reductions	$671	Bill Increases	$0	B/C Ratio	6.71
	Avoided Participant Cost	$0	Participant Costs	$100		
	Incentives	$0	Participant Charges	$0		
					Net	
	Total Benefit	$671	Total Costs	$100	Benefits	$571

Total Resource Cost Test	Avoided Supply Cost	$230	Increased Supply Cost	$0	B/C Ratio	1.91
	Net Avoided Part. Cost	$0	Net Participant Cost	$100		
			Utility Cost	$20		
					Net	
	Total Benefits	$230	Total Costs	$120	Benefits	$110

Ratepayer Impact Measure Test	Avoided Supply Cost	$230	Increased Supply Cost	$0	B/C Ratio	0.33
	Revenue Gain	$0	Revenue Loss	$671		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$20		
					Net	
	Total Benefits	$230	Total Costs	$691	Benefits	($461)

Utility Cost Test	Avoided Supply Cost	$230	Increased Supply Costs	$0	B/C Ratio	11.49
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$20		
					Net	
	Total Benefits	$230	Total Costs	$20	Benefits	$210

PROGRAM: LOW FLOW SHOWER HEAD

Participant Test	Bill Reductions	$1,924	Bill Increases	$0	B/C Ratio	192.38
	Avoided Participant Cost	$0	Participant Costs	$10		
	Incentives	$0	Participant Charges	$0		
	Total Benefit	$1,924	Total Costs	$10	Net Benefits	$1,914

Total Resource Cost Test	Avoided Supply Cost	$630	Increased Supply Cost	$0	B/C Ratio	31.50
	Net Avoided Part. Cost	$0	Net Participant Cost	$10		
			Utility Cost	$10		
	Total Benefits	$630	Total Costs	$20	Net Benefits	$610

Ratepayer Impact Measure Test	Avoided Supply Cost	$630	Increased Supply Cost	$0	B/C Ratio	0.33
	Revenue Gain	$0	Revenue Loss	$1,924		
	Participation Charge	$0	Incentives	$0		
			Utility Cost	$10		
	Total Benefits	$630	Total Costs	$1,934	Net Benefits	($1,304)

Utility Cost Test	Avoided Supply Cost	$630	Increased Supply Costs	$0	B/C Ratio	62.99
	Participation Charges	$0	Incentives	$0		
			Utility Costs	$10		
	Total Benefits	$630	Total Costs	$10	Net Benefits	$620

PROGRAM: ROOF TOP DUAL FUEL HEAT PUMPS; COMMERCIAL

Participant Test	Bill Reductions	$2,081	Bill Increases	$841	B/C Ratio	1.77
	Avoided Participant Cost	$0	Participant Costs	$390		
	Incentives	$100	Participant Charges	$0		
	Total Benefit	$2,181	Total Costs	$1,231	Net Benefits	$950

Total Resource Cost Test	Avoided Supply Cost	$2,848	Increased Supply Cost	$711	B/C Ratio	2.39
	Net Avoided Part. Cost	$0	Net Participant Cost	$390		
			Utility Cost	$90		
	Total Benefits	$2,848	Total Costs	$1,191	Net Benefits	$1,656

Ratepayer Impact Measure Test	Avoided Supply Cost	$2,848	Increased Supply Cost	$711	B/C Ratio	1.24
	Revenue Gain	$841	Revenue Loss	$2,081		
	Participation Charge	$0	Incentives	$100		
			Utility Cost	$90		
	Total Benefits	$3,688	Total Costs	$2,982	Net Benefits	$706

Utility Cost Test	Avoided Supply Cost	$2,848	Increased Supply Costs	$711	B/C Ratio	3.16
	Participation Charges	$0	Incentives	$100		
			Utility Costs	$90		
	Total Benefits	$2,848	Total Costs	$902	Net Benefits	$1,946

Chart 3.5.3

DSM Program Analysis Factors (per kW)

Program	Equipment Cost	Incentives	Customer Payback
Implemented Programs:			
High Eff. Chillers	$ 500.00	$ 75.00	2.90
Comm. Ice Storage	$ 300.00	$ 100.00	2.70
Home Energy Check	$ 506.00	$ 91.00	3.90
Res. Thermal Storage	$ 888.00	$ 675.00	.96
Good Cents	$ 870.00	-	5.40
Rate 07	$1320.00	-	7.60
High Eff. Lighting	$ 56.00	$ 16.67	.28
Great Appliance Trade-up	$ 600.00	$ 305.95	4.00
Standby Generators	-	$ 82.80	-
Rate 27	-	-	-
Rejected / Under Consideration:			
Photovoltaics	$4800.00	$3000.00	14.20
Res. High Eff. Refrig.	$1875.00	$ 312.50	2.80
Magnetic Fluor. Ball.	$1500.00	$ 260.00	9.00
Res. A/C Desuperheater	$1800.00	$ 250.00	23.50
Solar Water Heating	$6660.00	-	12.60
Res. HP Water Heater	$7000.00	$1575.00	5.40
Res. Hi. Eff. Freezer	$2500.00	$ 625.00	3.00
Radiant Barrier	$ 695.00	$ 195.00	3.00
Setback Thermostat	$ 100.00	-	1.80
Low Flow Shower Head	$ 10.00	-	.05
Comm. Rooftop Dual Fuel Heat Pumps	$ 650.00	$ 100.00	2.70
High Eff. Water Heating	$ 100.00	-	4.30

Chart 3.5.3

DSM Program Analysis Factors (per kW)

Continued

Program	Equipment Cost	Incentives	Customer Payback
1992 Programs:			
High Eff. Motors	$ 200.00	$ 100.00	.45
Electronic Fluor. Bal. (Retro.)	$1000.00	$ 247.50	5.40
Electronic Fluor. Bal. (New)	$1000.00	$ 165.00	6.00
Compact Fluorescents	$ 402.60	-	2.70
Gas Absorption Cooling	$ 350.00	$ 100.00	1.90
High Eff. Dual Fuel HP	$ 250.00	$ 200.00	-
Off Peak Water Heating	$ 250.00	-	2.50
High Eff. Rooftop HP	$ 750.00	$ 75.00	7.70
Variable Speed Drive	$ 470.00	$ 235.00	1.70
HP Water Heater (Comm)	$ 534.00	$ 100.00	4.50

3.6 DSM EVALUATION DEVELOPMENT EFFORTS

SCE&G has embarked on a number of efforts to strengthen our DSM evaluation capabilities. These efforts include the following:

- An outside audit of our DSM evaluation process performed by Barakat & Chamberlin, Inc. on behalf of the EPRI Customer Assistance Center.
- A pilot project to isolate impacts of DSM on T & D expenditures.
- The development of a formal post implementation process.
- An initiative to increase customer research efforts to assist in establishing both market potentials and incentives.
- Establishment of more formal methods of identifying and screening technology and program options.

Each of these efforts will be briefly summarized below:

Outside Audit: In early 1992 we used Barakat & Chamberlin to review our current activities with the goal of providing direction for strengthening our DSM efforts. This report is in its final stages of preparation and is expected to highlight a number of opportunities to further develop our DSM capabilities.

T & D Pilot Project: This project represents a collaboration between the T & D Engineering and Marketing departments. We are in the process of selecting and modeling several "high growth" substations. The area served by the substation will be analyzed for DSM potential and a comprehensive strategy to forestall substation expansion will be implemented. This project should be very helpful in further establishing impacts of DSM efforts on non-generating facility expansion.

Post Implementation Process: This process is in development and will include a formal evaluation plan for each DSM program to include enhanced load research, statistical billing analysis and customer response measurement.

Customer Research Efforts: This effort will include the development of a number of customer input mechanisms including structured consumer panels and the further development of benchmark studies of market potentials with particular focus on the commercial customer segment.

Identifying and Screening Technologies: This initiative will focus on increasing the formal documentation associated with technology evaluation.

3.7 1992 DSM PORTFOLIO

In 1992, SCE&G substantially increased its portfolio of DSM programs in all three market segments with the addition of 14 new programs. (See Chart 3.7.1) These programs are implemented by three separate field sales functions organized on the following major segments. The residential and small commercial segment composed of 454,000 customers, the commercial market segment composed of 21,100 customers and the industrial market with 973 customers.

The residential and small commercial programs portfolio is marketed under the "Energy Extras" promotional umbrella and a core audit service, the Home Energy Check. The large commercial and industrial programs are marketed under the promotional umbrella, "Competitive Edge" with a core audit service for lighting. Program descriptions are featured in Exhibit 3.7.2.

CHART

3.7.1

IMPLEMENTED MARKETING PROGRAMS 4-24-92							
	High Eff. Elec. Fluores. Ballast - New	Commercial HP Pool Heaters	High Eff. Elec. Fluores. Ballast - Retro.	High Efficiency Motors	Adjustable Frequency Drives	Compact Fluores. Lamps	Gas Air Conditioning
Description	Provides commercial and industrial customers with an incentive for replacing inefficient ballasts with high efficiency units. (New only)	Gives commercial customers incentives for installing high efficiency HP pool heaters.	Provides commercial and industrial customers with an incentive for replacing inefficient ballasts with high efficiency units. (Retrofit only)	Provides an incentive to replace or upgrade small to medium size motors with high efficiency models.	Provides a method for commercial and industrial customers to better match their large drive energy requirement with the process being performed.	Provides an opportunity for residential customers to purchase high efficiency compact fluorescent lamps.	Provides large commercial and industrial customers an incentive to install gas fired chillers.
Incentive	$165/kW deferred or $5/ballast	$120/ton	$247/kW deferred or $7.5/ballast	$100/kW deferred	$235/kW deferred	N/A	$100/kW deferred
Load Shape Effect	Strategic Conserv. Peak Clipping	Valley Filling	Strategic Conserv. Peak Clipping	Strategic Conserv. Peak Clipping	Strategic Conserv.	Strategic Conserv.	Peak Clipping Strategic Conservation
Market	Large Commercial & Industrial customers with lighting systems that require ballasts	Commercial Pools Retrofit and new construction	Large Commercial & Industrial customers with lighting systems that require ballasts	Commercial and Industrial customers.	Commercial &Industrial customers with large drives	Residential customers in the metro areas	Large Commercial & Industrial customers with large space cooling requirements
End Use Device	Fluorescent and HighPressure Sodium Lighting	Heat Pump Pool Heaters	Fluorescent and High Pressure Sodium Lighting	Motors up to 200 + horse power	Large motors and drives with variable loads usually associated w/ fans & pumps	Fluorescent lamps for indoor applications	Gas Fired Chillers
Implementation Date	1992	1992	1992	1992	1992	1992	1992
1992 Goal	10,000 Ballasts	40 Pool Heaters	40,000 Ballasts	500 motors	100 drives	1,500 Fluorescent Lamps	5 HVAC systems

IMPLEMENTED MARKETING PROGRAMS

4-24-92

	High Eff. Lighting	High Eff. Chillers	Thermal Storage (OPAC)	Lighting Tip/Bonus			
Description	Influences decision makers within commercial and industrial facilities to purchase high efficiency lighting equipment for installation during normal maintenance activities.	Utilizes a rebate to customers based on the installation of high efficiency chillers on a kW deferred basis.	Minimizes energy costs by generating cooling capacity during off-peak hours and storing it for use during peak periods.	Gives employees incentives to sell new lights and locate unbilled lights.			
Incentive	$ .10 / 6 watts removed	$100/kW deferred	$100/kW deferred	$5/lead; $10/new sale; $15 / unbilled light			
Load Shape Effect	Strategic Conserv. Peak Clipping	Strategic Conserv. Peak Clipping	Peak Clipping, Valley Filling, Load Shifting	Valley Filling			
Market	Comm. & Indust. facilities w/ large lighting loads	Large Commercial and Industrial customers.	Large Commercial Customers principally in the office building market.	Residential, commercial and industrial customers			
End Use Device	High eff. lamps High eff. reflectors.	Centrifugal Chillers, Reciprocating Chillers, Screw Chillers	Commercial HVAC systems	All lights are eligible			
Implementation Date	1990	1990	1990	1991			
1992 Goal	187,650 lamps	200kW deferred	800 kW deferred	7,000 Lights			

IMPLEMENTED MARKETING PROGRAMS

4-24-92

	GATU Piggyback	GATU Financing	Residential HP Pool Heaters	Off-Peak Water Heating	Comm. HP Water Heaters	Comm. Electric Cooking	Commercial HVAC Equip.
Description	An HVAC system that meets the GATU guidelines and uses a gas heating system for supplemental heat. (Existing gas water heater only)	Incentive addition to current GATU program. Restricted to customers who retrofit HVAC equipment with a minimum SEER of 13.	Gives customers an incentive for installing high efficiency HP pool equipment.	Allows customers to heat water off-peak. Consists of a high capacity hot water storage tank, an electronic timer and insulation jacket.	Gives commercial customers incentives for installing high efficiency water heaters.	Offers customers incentives for purchasing electric cooking equipment.	Provides commercial and industrial customers with an incentive to retrofit current HVAC equipment with high efficiency models.
Incentive	$200/system	Financing up to $10,000 at 9% for a maximum of 48 mths	$120/ton	$6.00 / month	$100/ton	One-time buy down of incremental cost	$50/ton
Load Shape Effect	Strategic Conserv. Peak Clipping	Strategic Conserv. Peak Clipping	Valley Filling	Peak Clipping Load Shifting	Valley Filling	Valley Filling	Strategic Conserv. Peak Clipping
Market	Commercial customers on Rates 01, 07, 08, 09, 20 and 23.	Residential and commercial customers on Rates 01, 07, 08, 09, 20 and 23.	Residential Pools Retrofit and newconstruction	Rate 01, 07, 08 & 09 Residential Customer	Facilities that have waste heat or constant cooling year round	Commercial customers involved in cooking and oven baking	Large Commercial customers on rates 09, 20 & 23.
End Use Device	Heat Pump systems	Heat Pumps, Central AC, Package Systems	Heat Pump Pool Heaters	Electric Water Heaters	Heat Pump Water Heaters	Cooking Equipment	Rooftop HVAC Equipment
Implementation Date - Proposed	1992	1992	1992	1992	1992	1992	1992
Proposed Goal	1,221 HP systems	N/A	10 Pool Heaters	4,626 Water Heaters	250 Water Heaters	100 Cooking Systems	350 HVAC Systems

IMPLEMENTED MARKETING PROGRAMS

4-24-92

	GATU	HEC	Good Cents	Rate 07	Res. Thermal Storage	Standby Generator	Rate 27
Description	Focuses on high efficiency HVAC equipment for Residential and Commercial markets. Minimum efficiency of 11 SEER and maximum capacity of 5 tons to qualify.	Audit customer's home. Make recommendations on efficiency improvements. If homeowner makes improvements, SCE&G provides rebates and financing.	Focuses on energy efficiency measures such as insulation, ventilation, HVAC systems, window and door requirements for new construction. These factors are optimized to lower the customers energy costs.	Energy efficiency measures such as insulation, ventilation, water heater systems, window and door requirements for retrofit. Includes an in-home inspection with recommendations to meet program standards.	Uses Heat Pump driven water bank system to produce off-peak cooling, heating and water heating.	Allows businesses with large capacity standby generators to meet their own electrical requirements during peak hours. SCE&G pays a standby fee for available capacity and a fuel supplement fee based on operation.	An interruptible rate available to customers who can commit at least 1000 kW of interruptible power from June to September. Customers must commit to a 5 year contract.
Incentive	AC $ 50 - $175/ton HP $125 - $300/ton	R11-30 $6.50/100 sqft 0-R30 $10/100 sqft	Good Cents Rate 1	Conservation Rate 7	Time-of-use Rate 5 $675/ton	$2.00/kW/month $ .07/kWh	Demand discounts
Load Shape Effect	Strategic Conserv. Peak Clipping	Strategic Conserv. Peak Clipping	Strategic Conserv. Peak Clipping	Strategic Conserv. Peak Clipping	Peak Clipping, Valley Filling, Load Shifting	Peak Clipping	Peak Clipping
Market	Customers on Rates 01, 07, 08, 09, 20 & 23. New Const. & Replace.	Residential Rate 08; customers with cooling in older homes.	Residential New Construction	Residential retrofit on homes built within last 6 years and new construction	Developers in new construction market	Health care facilities, data centers, waste water & water pumping operations.	Large industrial customers with variable operations.
End Use Device	Heat Pump, Central AC, Through the Wall Heat Pump & Package Systems.	HVAC, Insulation, Windows and Ducts	Various	Insulation, Windows, Duct and Infiltration	HVAC and Water Heating Systems	N/A	N/A
Implementation Date	1987	1988	1986	1982	1990	1990	1990
1992 Goal	5,500 HVAC Systems	Efficiency Retrofits	1,950 households	1,200 households	5 HVAC Systems	7,000 kW standby capacity.	28,000 kW

EXHIBIT

3.7.2

SCE&G

ENERGY EXTRAS

Home Energy Check

Great Appliance Trade-up

Great Appliance Trade-up Piggyback

Great Appliance Trade-up Financing

Good Cents Home

Compact Fluorescent Lamps

Off-Peak Water Heating

Rate 07

Residential Thermal Storage

Program Name	:	The Home Energy Check
Description	:	The Home Energy Check is a retrofit package from SCE&G that starts with a detailed audit of the customer's home. The audit concentrates on the HVAC system, water heating system, insulation, ventilation and air loss around windows and doors. Formal recommendations on efficiency improvements are left with the homeowner. If the homeowner follows the auditor's recommendations SCE&G makes rebates and financing available.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Implementation Date	:	1988
Market	:	Customers on Rate 08 and 09 with cooling in older structures
End Use Devices	:	Heat Pumps, Central AC, Window AC, Window Heat Pumps and Package Systems

Home Energy Check
Current Incentive Structure:

Conservation Activity		Incentive
Storm Windows		$50
Duct Insulation	R2 - R6	$75
Ceiling Insulation	R11 - R30	$6.50/100 sq. ft.
Ceiling Insulation	R0 - R30	$10.00/100 sq. ft.
Wall Insulation	R0 - R11	$125

Program Name	:	Great Appliance Trade-up
Description	:	The Great Appliance Trade-up Program is focused on high efficiency cooling devices for the residential and commercial markets. It is structured with a minimum threshold of efficiency to qualify and an incentive in the form of a bill credit.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Implementation Date	:	1987
Market	:	Residential and commercial customers on Rates 07, 08, 09, 20 and 23 in the new construction and replacement market for cooling using unitary systems less than 5 tons.
End Use Devices	:	Heat Pumps, Central AC, Through the Wall Heat Pumps Package Systems

Great Appliance Trade-up
1992 Incentive Structure:

SEER Level	Air Conditioner Bill Credit	Heat Pump Bill Credit
*11.0 - 11.99	*$ 50/Ton	*$125/Ton
12.0 - 12.99	$ 75/Ton	$200/Ton
13.0 - 13.99	$100/Ton	$225/Ton
14.0 - 14.99	$125/Ton	$250/Ton
15.0 - 15.99	$150/Ton	$275/Ton
16.0 +	$175/Ton	$300/Ton

*Replacement Market Only

Program Name : GATU - Piggyback

Description : The GATU - Piggyback is an HVAC system that meets the GATU guidelines and uses a gas heating system for supplemental heat. A $200 bonus incentive would be given to customers for using gas as supplemental heat. The supplemental heat is delivered via a hot water coil charged by a gas hot water heater.

Load Shape Effect : Strategic Conservation, Peak Clipping

Market : Residential and commercial customers on Rates 07, 08, 09, 20 and 23 in the new construction and replacement market for cooling using unitary systems less than 5 tons.

End Use Devices : Heat Pumps, Heat Pump Package systems

Incentive Structure :

- $200 bonus for using gas as supplemental heat

Good Cents Home

Thermal and Equipment Guidelines:

- 12 BTUH heat gain for houses over 1,350 square feet
- 14 BTUH heat gain for houses under 1,350 square feet

Minimum Thermal Requirements:

- R30 attic insulation
- R19 floor insulation
- R5 slab insulation
- Double glazed windows
- R6 duct insulation
- ASHRAE 90 water heaters
- Controlled infiltration

Minimum Equipment Specifications:

- Sized up to 125% of cooling load using ACCA's Manual J
- Minimum SEER of 11.00
- Minimum HSPF of 7.0
- Minimum AFUE of 80%
- No AFUE requirement for package units

Program Name : <u>Compact Package Fluorescent Lamps</u>

Description : This program provides an opportunity for residential customers to purchase high efficiency compact fluorescent lamps. The program will be launched on a pilot basis in the two major metro markets and will be marketed via bill inserts. The lamps will be offered in three wattage options and payment will be requested by check. Lamps will be priced at cost plus a small margin to cover overhead expenses. Once payments have cleared customers may pick up their lamp at the Energy Info Centers.

Load Shape Effect : Strategic Conservation

Market : Metro Charleston and Columbia residential customers

End Use Device : High power factor package fluorescent lamps for indoor applicators

Program Name	:	Off Peak Water Heating
Description	:	The off-peak water heating program consists of a high capacity hot water storage tank, an electronic timer and insulation jacket. Customers who select thermal storage for water heating will automatically receive a $6 a month credit on their electric bills.
Load Shape Effect	:	Load Shifting
Market	:	Residential Customers on rates 07 and 08
End use Devices	:	Electric Water Heater

Program Name	:	<u>Residential Service Conservation Rate 07)</u>
Description	:	The Rate 07 offering from SCE&G is a program that offers a discounted rate structure for customers that meet strict thermal requirements in their homes. The program features an in-home inspection and recommendations on meeting the program standards.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Implementation Date	:	1982
Market	:	Residential retrofit on homes built within the last 6 years and new construction
Minimum Requirements	:	

Item	Thermal Requirements
Ceilings	R-30
Walls	R-11
Slab Insulation	R-5
Floors	R-19
Duct Insulation	R-6
Water Heater	R-8
Windows	Double Insulated Glass

Program Name	:	Residential Thermal Storage
Description	:	This technology is focused on utilizing a heat pump driven water bank system to produce off-peak cooling, heating and water heating. This program will utilize time-of-use rate 05 and shift participating customers' heating and cooling loads to off-peak periods.
Load Shape Effect	:	Peak Clipping, Valley Filling, Load Shifting
Implementation Date	:	1990
Market	:	Developers in new construction market
End Use Devices	:	TES Systems

SCE&G COMPETITIVE EDGE

High Efficiency Chillers

Thermal Energy Storage

Standby Generators

High Efficiency Lighting

Demand Rate Opportunities

Rooftop HVAC Equipment

High Efficiency Equipment Programs

Program Name	:	High Efficiency Chillers
Description	:	This program closely parallels the Great Appliance Trade-Up in the residential market. It utilizes a rebate to customers based on the installation of high efficiency chillers on a KW deferred basis.
Load Shape Effect	:	Peak Clipping, Strategic Conservation
Implementation Date	:	1990
Market	:	The program is targeted at large industrial and commercial customers and is applicable to both the retrofit and new construction markets. This program is promoted to the trade allies via seminars and direct mail.
End Use Devices	:	Centrifugal Chillers, Reciprocating Chillers, Screw Chillers
Participation Requirement Standards	:	

Technology	Minimum KW/Ton	ARI Reference
Centrifugal	.67	550-86
Reciprocating:		
Air cooled	1.15	590-86
Water cooled	.85	590-86
Screw	.71	550-86

Program Name	:	Thermal Energy Storage (TES)
Description	:	Technologically advanced Thermal Energy Storage systems minimize energy costs by generating cooling capacity during off-peak hours and storing it for use during peak periods.
Load Shape Effect	:	Peak Clipping, Valley Filling, Load Shifting
Implementation Date	:	1990
Market	:	Large commercial customers principally in the office building market. Promotional efforts are focused on architects and engineers active in commercial office buildings in the SCE&G service territory.
End Use Devices	:	TES Systems

Program Name	:	<u>Standby Generator</u>
Description	:	The Standby Generator Program allows businesses with larger capacity standby generators to enter into a five year agreement with SCE&G to meet their own electrical requirements during peak hours. SCE&G pays these customers a standby fee for making their capacity available, and a fuel supplement fee based on the cost of operating SCE&G gas turbines.
Load Shape Effect	:	Peak Clipping
Implementation Date	:	1990
Market	:	Health care facilities and data centers with a need for large standby systems. Waste water and water pumping operations.
End Use Devices	:	None
Current Incentive Structure	:	$2.00 per KW /per month (capacity fee) $ .07 per KWH (fuel supplement fee)

Program Name	:	High Efficiency Lighting
Description	:	This program is designed to influence decision makers within large commercial and industrial facilities to purchase high efficiency lighting equipment for installation during their normal lighting maintenance activities.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Market	:	Commercial and industrial facilities with large lighting loads such as office buildings and manufacturing plants.
End Use Devices	:	High efficiency fluorescent and lamps. High efficiency reflectors.

Program Name	:	Rate 27
Description	:	This is an interruptible rate, available to customers who can commit at least 1000 KW of firm and 1500 KW of interruptible power, from June through September. The rate offers various demand discounts based on the interruptible schedule selected. Customers must commit to a five year contract.
Load Shape Effect	:	Peak Clipping
Implementation Date	:	1990
Market	:	Large industrial customers with variable operations
End Use Devices	:	None

Program Name	:	Commercial HVAC Equipment
Description	:	This program provides commercial and industrial customers with an incentive to retrofit current cooling HVAC equipment with high efficiency models.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Market	:	Large commercial customers on Rates 09, 20 and 23 with HVAC system capacities between 5 and 50 tons. Other customers may qualify if it is verified the HVAC equipment operates on SCE&G system peak.
End Use Devices	:	HVAC equipment
Incentive Structure	:	• Incentives will be based on improvements over efficiency minimums. • $50 / ton

Program Name	:	<u>Variable Speed Motors/Drives</u>
Description	:	The Variable Speed Motor/Drive program provides a method for commercial and industrial customers to better match their large motor/drive energy requirement with the task/process being performed.
Market	:	Commercial and industrial customers using large motors/drives for applications which can be improved through the use of variable speed devices.
End Use Devices	:	Large motors and drives with variable loads
Incentive Structure	:	Cash incentives for kW reduction

Program Name	:	High Efficiency Electronic Fluorescent Ballast
Description	:	The High Efficiency Ballast program allows commercial and industrial customers to substantially reduce their lighting cost by replacing inefficient ballasts with high efficiency units.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Market	:	Commercial and industrial customers with lighting systems that require ballasts and who operate their lights during peak periods of system demand.
End Use Devices	:	All high intensity discharge lighting including fluorescent and high pressure sodium.
Incentive Structure	:	• Reduced energy costs • Cash incentive from SCE&G based on kW reduction

Program Name	:	<u>High Efficiency Motors</u>
Description	:	The High Efficiency Motor program provides commercial and industrial customers the incentive to replace or upgrade small to medium sized motors with higher efficiency models.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Market	:	Large commercial and industrial customers using small to medium sized motors in the process. Could be expanded to include others as warranted.
End Use Device	:	Any equipment using a motor up to about 200 + horse power.
Incentive Structure	:	Incentives based on kW saved by efficiency improvement.

3.8 DSM TECHNICAL CHARACTERISTICS

Exhibit 3.8.1 includes a more in-depth technical review of program qualifications and technical requirements.

EXHIBIT

3.8.1

RESIDENTIAL DUAL FUEL HEAT PUMPS

THE IDEA:

Customers are interested in the energy savings from heat pumps and the warmer supply air associated with gas heat. This is available by replacing the normal resistance heat strips with either a direct fired gas furnace or a hot water coil in the conventional heat pump air handler. The direct fired configuration does not allow the heat pump to operate at the same time as the gas heat. This situation reduces the maximum savings associated with heat pump operation. The hot water coil will allow simultaneous use of the heat pump and gas heating thereby maximizing heat pump savings.

THE EQUIPMENT:

The major component will be the heat pump. The hot water coil will be installed in the heat pump air handler upstream of the air conditioning coil. The gas water heater will be required to provide sufficient hot water to meet normal domestic hot water needs and supply supplemental heating below the balance point. The storage size of the water heater tank is not critical, however, the total BTU input will determine heater acceptance. BTU requirements are shown on the following page.

THE SELLING PROCESS:

The program will be sold in conjunction with the existing Great Appliance Trade Up (GATU) program. The program will be available to all residential class customers. There must be sufficient hot water available to meet supplemental heating needs while supplying domestic needs. The attached sheet provides guidelines for meeting heating and domestic hot water requirements. The customer will be responsible for the purchase and installation of all equipment. The incentive for participation will be enhanced customer satisfaction and a rebate from SCE&G. New construction and retrofit applications can receive a $ 200.00 rebate.

RESIDENTIAL DUAL FUEL HEAT PUMPS

The amount of hot water required for supplemental heating is a function of structure heat loss, tank capacity and maximum BTU input to the water heater. Industry standards size water heaters in the following manner:

Heat loss X 120% = required water heater output

As this program will be for supplemental heating only, we do not need to provide 100% of the heat loss unless the heat pump itself is not operating. If the heat pump is not operating, there needs to be some indication that the customer will recognize as needing attention. To do this, we will require that the water heater provide at least 80% of the whole house heat loss. In this situation, the customer will know quickly if the system needs attention. Indications will be insufficient space heating at design temperatures or insufficient space heating and water heating during other periods. Therefore, water heater BTU output must be at least

Heat loss X 80% = required water heater output

OFF PEAK WATER HEATING

THE IDEA:

Water heating is a year round load that has an impact on our summer peak demand requirement. In order to remove this load from the summer peak, the user will need to ensure the electric heating elements are not energized during that time. This can most easily be accomplished by use of a programmable timer. In addition, by ensuring all water heating is done "off peak" SCE&G is able to offer this energy at a lower cost.

THE EQUIPMENT:

In order to ensure that the customer will have sufficient hot water during the "off" times it is necessary that they have a hot water storage tank large enough to meet their needs. The attached chart shows the minimum acceptable storage sizes based on the number of bedrooms and bathrooms. It will be permissible to parallel water heaters to obtain the necessary storage. SCE&G will provide one timer per customer and one interrupting relay per tank. If the tanks are paralleled, all tanks will be controlled. It will be the customer's responsibility to provide the necessary wiring from the timer to the extra tanks. All water heater tanks will have an external insulation blanket of at least R-3.

THE SELLING PROCESS:

The program is for all electric water heating customers on rates 1, 7, 8 and 9. The program offers the customers the opportunity to reduce their hot water costs by operating the water heater only during off peak times. In return for allowing us to control the timing of water heater use, the customer will receive a monthly water heating credit of $ 6.00 per month. The sales rep will examine the existing hot water storage tank to determine the size. The sales rep will then determine the required minimum tank size using the attached guide chart. Existing customers needing additional storage capacity will be eligible for a one time rebate of $ 200.00 to offset this cost. New construction can, if necessary get a $ 100.00 rebate.

OFF PEAK WATER HEATING STORAGE TANK SIZE REQUIREMENTS

Family Size	Without dishwasher – Bathrooms 1	2	3	With dishwasher – Bathrooms 1	2	3
1	52	52	52	52	52	52
2	52	52	52	52	66	66
3	52	66	66	66	82	82
4	80	80	80	80	120	120
5	80	120	120	120	120	120
6	120	120	120	120	120	120
7	120	120	120	***	***	***
8	***	***	***	***	***	***

Note: If the residence does not have a clothes washer, it is permissible to reduce the storage tank to the next nominal size.

STORAGE TANK SIZING (NOMINAL)

Stated Name Plate Capacity	Nominal Size
28.5 - 37.9	30
38.0 - 49.3	40
49.3 - 62.6	52
62.7 - 75.9	66
76.0 - 113.9	80
> 114.0	120

SIMPLIFIED SIZING TABLE FOR 8 HOURS OF "OFF" TIME

Number of Bedrooms	Number of Baths	Size(gal)
2	1.0 - 1.5	52
	2.0 - 2.5	66
3	1.0 - 1.5	66
	2.0 - 3.5	80
4	2.0 - 2.5	80
	3.0 - 3.5	120
5	2.0 - 3.5	120

COMMERCIAL HEAT PUMP WATER HEATERS

THE IDEA:

Many commercial customers require large amounts of hot water for cooking, clothes washing and production processes. Most of this hot water is provided by non electric sources. Many of these customers could benefit financially by using a heat pump water heater to preheat water before it is heated to the desired temperature by non electric sources. In addition, the use of heat pump water heaters would add electric revenue from a high load factor end use.

THE EQUIPMENT:

Most commercial hot water uses require temperatures of 160° - 180°F. The heat pump water heater can provide output temperatures of 130°-135°F. For this reason, the heat pump water heater would need to be supplemented by a heating source capable of raising temperatures to the needed level. Also, since heat pump water heaters do not have high recovery rates, it will probably be necessary to include a storage tank to ensure peak hot water needs are met economically. Commercial heat pump water heaters have efficiency ratings (COPs) in the 2.5 - >3.0 range. These efficiencies afford economical operation at costs less than conventional non electric sources.

THE SELLING PROCESS:

Customers such as full service restaurants, nursing homes, laundromats and hotels have requirements for large amounts of hot water. The key to a successful heat pump application is a relatively constant need for hot water because the economic benefit is greater when the unit runs the most. An additional feature is space conditioning. If the customer needs air conditioning in the space where the heat pump water heater is installed, then cooling is supplied at no cost. Remember, this unit is basically an air conditioner that uses the hot gas to heat water. In addition to the energy savings, SCE&G will rebate the customer at the rate of $ 100.00 per ton for installed heat pump water heating.

HOT WATER EXPENSE FOR A 200 UNIT HOTEL WITH RESTAURANT

The hotel in question uses on average 10 gallons per unit per day.
The restaurant serves on average 500 meals per day.

Entering water temperature is 65°F and output water is required at 180°F.

The existing gas unit has an e.f. of .55 and gas costs $0.70/therm.

The HPWH has a COP of 2.75 and average energy is $0.055/kWh.

Estimated heat gain in the kitchen area is 80,000 BTUH. Cooling by chiller with efficiency of .8kW/ton (SEER of approximately 15).

Cost to heat water with gas:

$$\frac{\{(10 \text{ gal/day} \times 200 \text{ units})+(2.4 \text{ gal/meal} \times 500 \text{ meals})\} \times 365 \times (180-65)}{.55 \text{ (ef)} \times 100{,}000 \text{ BTU/therm}}$$

= 2442 therms @ $0.70/therm => $ 1709.40/year

Cost to preheat water with heat pump water heater:

$$\frac{\{(10 \text{ gal/day} \times 200 \text{ units})+(2.4 \text{ gal/meal} \times 500 \text{ meals})\} \times 365 \times (135-65)}{2.75 \times 3413 \text{ BTU/kWh}}$$

= 8711 kWh @ $0.055/kWh => $ 479.10/year

Cost to boost water temperature with gas:

$$\frac{\{(10 \text{ gal/day} \times 200 \text{ units})+(2.4 \text{ gal/meal} \times 500 \text{ meals})\} \times 365 \times (180-135)}{.55 \text{ (ef)} \times 100{,}000 \text{ BTU/therm}}$$

= 956 therms @ $0.709/therm => $ 669.20/year

Cooling savings from HPWH:

$$\frac{80{,}000 \text{ BTUH X } 2500 \text{ hrs}}{15 \text{ X } 1000} = 13{,}333 \text{ kWh @ \$0.055/kWh} \Rightarrow \$733.33/\text{year}$$

Water heating savings: $ 1709.40 - ($479.10 + 669.20) = $ 561.10/year

Cooling savings: $733.33/year

ESTIMATED TOTAL ANNUAL SAVINGS: $1,294.43/year

COMMERCIAL ROOF TOP HVAC EQUIPMENT

THE IDEA:

The majority of our commercial customers use roof top HVAC equipment for space conditioning. This segment of the market has not been addressed by any of the current marketing programs. This customer class offers a potentially large demand reduction for air conditioning. While there is not a large variation in the efficiency of roof top package cooling equipment, there are units available that are considered high efficiency.

THE EQUIPMENT:

The majority of roof top package equipment available is in the 8.4 to 8.8 EER range. Older equipment is substantially lower in efficiency than the new equipment. As the "builder model" unit is in this range, we will require something more efficient. The minimum efficiency to be eligible for a rebate is and EER of 9.0. There is a reasonable selection of equipment available in this EER range.

THE SELLING PROCESS:

All customers with outdated roof top cooling equipment are eligible. The concept will be similar to the Great Appliance Trade-up but with the absence of a large dealer community selling the product. Rebates will be offered at the rate of $ 50.00 per ton.

ELECTRONIC FLUORESCENT BALLASTS

THE IDEA:

All fluorescent lamps require a ballast to provide the necessary voltage to ignite the lamp and the current limiting feature to ensure continued operation. Recent federal regulations have established certain efficiency standards for fluorescent ballasts that are significantly better than previous technology. The most efficient of these devices is the high frequency electronic ballast. This ballast will effectively operate with all 4' rapid start fluorescent lamps. Maximum savings are associated with installation of electronic ballasts and T8 fluorescent lamps.

THE EQUIPMENT:

There are many brands of high frequency fluorescent ballast available today. As with any equipment, some are better than others. Specific ballast performance standards are contained in the attachment to this document. Generally all electronic ballasts should meet current federal regulations for Radio Frequency Interference (RFI), category A transients as described in IEEE standard 587, all applicable UL requirements for ballasts, have low third harmonic distortion and a power factor of no less than 90%.

THE SELLING PROCESS:

All customers with fluorescent lighting systems are eligible to participate in this program. In order to ensure maximum energy savings ballast replacement should be accompanied with lamp replacement to T8 lamps. This change ensures that the customer cannot go back to using inefficient F40 lamps and thereby reduce the efficiency and savings of the system. SCE&G is offering a rebate of $ 330.00 per kW for ballast savings. This is in addition to the rebates for replacing F40 lamps with T8, F30 lamps. The rebates and associated energy savings will make selling high efficiency lighting an attractive prospect.

ELECTRONIC FLUORESCENT BALLAST STANDARD

SAFETY:
All electronic ballasts must meet all UL safety standards established for ballasts.

POWER FACTOR:
All electronic ballasts must be of the high power factor classification (power factor > 90%).

BALLAST FACTOR:
This is the measure of the ballasts ability to produce light from the fluorescent lamp. All electronic ballasts must have a ballast factor > .925 when operating a standard 40 Watt rapid start lamp. The ballast factor for high efficiency lamps must be > .88.

INTERNAL FUSING:
All electronic ballasts must have internal fusing to disconnect the ballast from line voltage in the event of internal component failure.

THERMAL PROTECTION:
All electronic ballasts must incorporate Class P thermal protection.

CAPACITORS:
All capacitors incorporated in the electronic ballast must be of the non-PCB type.

RADIO FREQUENCY(RFI) OR ELECTROMAGNETIC (EFI) INTERFERENCE:
Electronic ballasts operate at thigh frequencies which may cause RFI/EFI feedback into the power system. This can affect operation of data processing and communication equipment. All electronic ballasts must meet the requirements of Federal Communications Rules and Regulations, Part 18, Subpart J. They must be certified for Class A (industrial) applications.

SURGE WITHSTAND:
All electronic ballasts must incorporate transient protection equipment designed to withstand a Category A transient as described by IEEE Publication 587.

HARMONICS:
Because high frequency electronic ballasts are non-linear devices, they can generate an excessive level of harmonic current. This current can overload the neutral conductor of the wiring supplying the lighting circuits. For this reason, third harmonic current must not exceed 25% of the input current to the lighting circuit. In addition, harmonics can cause distortion of the nominal voltage/) sine wave. All electronic ballasts must limit this distortion to no more than 10%.

FILAMENT HEATING:
Filaments of rapid start lamps should have continuous heating. All electronic ballasts must meet American National Standards Institute (ANSI) Specification C78.1 regarding filament heating.

HIGH EFFICIENCY MOTORS

THE IDEA:

A significant part of our electrical load is from motors. Most large motors are by design high efficiency devices. However, the vast majority of motors in use today are in the fractional to 10 horsepower range. Significant demand and energy savings can be realized by replacing low efficiency motors with higher efficiency units.

THE EQUIPMENT:

Motor efficiency is determined by many factors among which are the number and type of windings and core materials. Standard efficiencies for motors vary from the 70% range up to 94%. Because better materials are used in high efficiency motors they cost more. However, the marginal first cost is quickly recovered through demand and energy savings. Attached to this document is a listing of motor sizes and standard efficiencies. Also shown is the method of determining the demand savings for higher efficiency motors.

THE SELLING PROCESS:

Almost all electric customers use motors for production, pumping or moving air. Most of these motors are relatively low efficiency devices. There is little reason to think that a customer will replace a working motor. However, if the customer is installing new motors or if a motor fails, there is an excellent opportunity to replace the existing motor with a high efficiency unit. SCE&G will promote the replacement of standard motors with high efficiency units through rebates. Because the "standard" efficiency of motors varies by size the rebate will be based on actual kW saved by using the high efficiency device. The attachment shows a simple method of calculating these savings. Rebates will be based on $ 100.00 per kilowatt deferred.

HIGH EFFICIENCY MOTORS

DEMAND SAVINGS CALCULATIONS

Input power to the motor and nominal (rated) output of the motor in horsepower determine the motor efficiency. Therefore, if the motor efficiency and nominal horsepower is known, input power can be determined. This is important because input power is what we are trying to reduce.

One horsepower is equal to 746 watts. This is constant regardless of the motor efficiency. If a one (1) horsepower motor is 75% efficient, then input power, in watts, is equal to

$$\frac{746}{.75} = 995 \text{ watts}$$

If the motor is 90% efficient, the input power is

$$\frac{746}{.90} = 829 \text{ watts}$$

As can be seen, the demand is reduce by 126 watts while still developing the same rated output (one horsepower). Energy savings can be determined by multiplying the demand savings by the number of operating hours. Since motor design usually sizes motor load at 75% of motor rating, the actual kW saving will generally be 75% of the full load reduction.

Normally you do not need to be concerned with the rated motor current. This value along with rated voltage will give you volt-amps (VA). This is of no value unless you know the power factor. As we are only concerned with demand reduction, you need only be concerned with motor horsepower and efficiency. However, if you are unable to obtain efficiency data for the "old" motor you can estimate the kW demand in the following manner.

Full load rated current (name plate data) X Line voltage X .85 = kW

The value of .85 represents an estimate of the motor power factor. This level of power factor is probably high and should be used only when actual motor data is unavailable.

MOTOR REBATE TABLE

	MOTOR EFFICIENCY														
	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.9	0.91	0.92	0.93	0.94	0.95	MIN EFF
Horsepower															
1	$4	$5	$6	$7											82.0%
2			$8	$9	$11										84.0%
3				$7	$8	$10	$12	$15							85.5%
5						$12	$16	$20	$23	$26					87.0%
7.5								$20	$26	$31	$36				89.0%
10									$20	$27	$33				90.0%
15										$41	$46				91.5%
20											$50	$63			92.0%
25											$48	$64	$80		92.0%
30											$67	$77	$96		92.5%
40											$62	$75	$100	$125	92.5%
50												$97	$129	$160	93.0%
60												$102	$118	$155	93.6%
75													$107	$149	94.1%
100													$156	$212	94.1%
125													$226	$265	94.5%
150													$153	$200	94.5%
200														$240	95.0%
250	CONTACT TECHNICAL SERVICES FOR MOTORS IN THIS RANGE														
300															
350															
400															
500															

All motors must exceed minimum efficiency to receive rebate.

ADJUSTABLE FREQUENCY DRIVES

THE IDEA:

The AC induction motor has proven to be a reliable method for converting electrical energy into mechanical power. The AC motor has been designed to operate at fixed speed by using the fixed frequency (60 HZ) of the AC line. The speed of an AC motor can be changed by changing the frequency to the motor. By using an Adjustable Frequency Drive (AFD) the motor speed can be varied directly with the applied frequency. This is particularly useful on centrifugal pump and fan type loads. Instead of operating an AC motor at full speed and mechanically restricting the flow with a valve, damper or inlet vane, an AFD can be used to match the motor speed to the flow requirements of the system. At less than full flow, systems with AFD's are much more efficient than mechanical systems for controlling flow. Whenever systems operate below maximum flow levels, significant energy savings can be achieved with an AFD.

THE EQUIPMENT:

AFDs are relatively complex devices that vary motor speed. By varying speed of the motor, AFD's provide flow control electrically rather than restricting flow mechanically. Significant energy savings can be achieved during times when full flow is not required.

THE SELLING PROCESS:

Any customer that uses valves, dampers or inlet vanes to control flow is a potentially good candidate for AFDs. This will be the most easily recognizable application. However, since there must be assurance that the AFD will in fact reduce demand, each application will be evaluated on a case by case basis. If the demand can be effectively reduced by AFD's and we can verify that the device will not be on our peak, the customer will be eligible for a rebate of $ 235.00 per kW of load removed. The attached sheet shows a method of determining the rebate values for pumps and fans.

ADJUSTABLE FREQUENCY DRIVES

REBATE AMOUNTS AND REQUIREMENTS

A. Requirements:

1. If system flow exceeds during the peak electrical period, 1300 through 2100 hours, Monday through Friday, June through September, no rebate will be made.

2. Rebates will be based on the maximum system flows during the peak period described above.

B. The kW savings as a function of flow will be calculated by multiplying the kW per horsepower saved by applying the AFD times the number of horsepower. KW savings to be used are shown below:

PUMP SYSTEMS		FAN SYSTEMS	
Maximum Flow	kW/HP	Maximum Flow	kW/HP
90%	.125	90%	.167
80%	.210	80%	.210
70%	.250	70%	.260
*		60%	.310
*		50%	.370

* Pump flow rates below 70% yield about the same savings as noted at 70%.

Interpolation may be sued for flow rates between the values shown.

ADJUSTABLE FREQUENCY DRIVES
REBATE SCHEDULE

PUMP SYSTEMS

Horsepower	MOTOR EFFICIENCY	KW @ 90% LOAD	KW @ 90% WITH AFD	KW DEFERRED	TOTAL REBATE
1	77.0%	0.90	0.76	0.15	$34
2	78.0%	1.78	1.49	0.29	$67
3	79.0%	2.63	2.21	0.42	$100
5	80.0%	4.34	3.64	0.70	$164
7.5	83.0%	6.27	5.26	1.01	$238
10	85.0%	8.16	6.85	1.32	$309
15	87.0%	11.96	10.03	1.93	$453
20	89.0%	15.59	13.08	2.51	$591
30	89.0%	23.39	19.61	3.77	$886
40	89.0%	31.18	26.15	5.03	$1,182
50	90.0%	38.54	32.33	6.22	$1,461
60	90.0%	46.25	38.79	7.46	$1,753
75	90.0%	57.82	48.49	9.33	$2,191
100	91.0%	76.24	63.94	12.30	$2,890
125	92.0%	94.26	79.06	15.20	$3,573
150	92.0%	113.12	94.87	18.24	$4,287
200	94.0%	147.61	123.80	23.81	$5,595
250	94.0%	184.52	154.76	29.76	$6,994
300	94.0%	221.42	185.71	35.71	$8,393
400	94.0%	295.23	247.61	47.62	$11,190
500	94.0%	369.03	309.51	59.52	$13,988

FAN SYSTEMS

Horsepower	MOTOR EFFICIENCY	KW @ 90% LOAD	KW @ 90% WITH AFD	KW DEFERRED	TOTAL REBATE
1	77.0%	0.90	0.71	0.19	$46
2	78.0%	1.78	1.40	0.38	$90
3	79.0%	2.63	2.07	0.57	$133
5	80.0%	4.34	3.40	0.93	$219
7.5	83.0%	6.27	4.92	1.35	$317
10	85.0%	8.16	6.41	1.76	$412
15	87.0%	11.96	9.39	2.57	$605
20	89.0%	15.59	12.24	3.35	$788
30	89.0%	23.39	18.36	5.03	$1,182
40	89.0%	31.18	24.48	6.71	$1,576
50	90.0%	38.54	30.25	8.29	$1,948
60	90.0%	46.25	36.31	9.95	$2,337
75	90.0%	57.82	45.38	12.43	$2,922
100	91.0%	76.24	59.84	16.40	$3,853
125	92.0%	94.26	73.99	20.27	$4,764
150	92.0%	113.12	88.79	24.33	$5,717
200	94.0%	147.61	115.87	31.74	$7,460
250	94.0%	184.52	144.84	39.68	$9,325
300	94.0%	221.42	173.80	47.62	$11,190
400	94.0%	295.23	231.74	63.49	$14,920
500	94.0%	369.03	289.67	79.36	$18,650

If system flow exceeds 90% during SCE&G peak period, no rebate will be offered.

COMPACT FLUORESCENT LAMPS

THE IDEA:

Many customers are interested in ways to not only reduce their energy bills, but also ways to improve the environment. One of the most effective ways of doing this is to reduce the amount of demand and energy required for lighting. All too often customers are interested in purchasing energy conserving lamps such as compact fluorescents, but are unable to find them or are able to find only inefficient models. SCE&G felt it important to provide a convenient way for customers to obtain these lights until the market place is ready to meet this customer need.

THE EQUIPMENT:

There are many manufacturers who provide compact fluorescent lamps in almost any configuration imaginable. They can be a completely self contained, throw away unit like the Sylvania Earth Light, or a separate lamp and ballast unit. They can be placed in flood light housings, in decorative fixtures or in almost any way desired. SCE&G will limit its sales to high efficiency, basic lamp configurations. A list of product will be provided once lamp purchases are made.

THE SELLING PROCESS:

Any SCE&G customer is a prospect. The lamps will be sold by providing information to the customer. If the customer wants to purchase a lamp(s), they need only agree to pay for the lamp on their electric bill. Once this agreement is received in Marketing, the customer will receive a coupon which will be redeemable at either Energy Info Center for the lamp of their choice.

GAS AIR CONDITIONING

THE IDEA

Absorption cooling was the first type of refrigeration available and is still being used widely in many areas. A newer type of gas cooling is an engine driven vapor compression system similar to today's electric air conditioning. Recent advances in these technologies have brought their COPs to a value greater than one (1). That in conjunction with a very attractive gas cooling rate makes this a potential for removing large segments of the electric cooling load.

THE EQUIPMENT

Absorption cooling is accomplished by heating an absorber-refrigerant mixture. Today this is usually water and lithium bromide with the water being the refrigerant. Heating the solution releases the water as a higher pressure, high temperature vapor. The water vapor is cooled and then sent to an evaporator where it changes state and provides the cooling. This water is then preheated and brought together with the absorber and the cycle begins again. The engine driven vapor compression cycle uses a gas fired engine to operate a refrigerant compressor and is thereafter the same as an electric air conditioner. The absorption cooling system requires a larger cooling tower than its electric counterpart. Also, the engine drive system offers the potential for large amounts of hot water as a by product of engine cooling.

THE SELLING PROCESS

Non-electric cooling will be treated the same as OPAC. It offers the customer the opportunity for cooling without demand charges. In addition, the cooling gas rate of $ 0.35 per therm makes it more cost effective than electric cooling. Although these systems cost 2.5 to 3 times what a comparable electric system costs, the paybacks are in the 5 to 7 year range. SEC&G will provide a rebate of $ 100.00 for every kW removed by using gas cooling.

3.9 DSM DEVELOPMENT EFFORTS

The following section includes a description of DSM efforts in program development and research.

1992 MARKETING PROGRAMS In R&D

4-24-92

	Comm. Audit	Materials Handling	Demand Free Days	Low Income Energy Use	Energy Use Indicator		
Description	Provide small and medium service commercial customers with on-site energy audits of their facilities. The analysis will target lighting, HVAC and thermal envelope improvements.	Provides commercial customers an incentive to switch from propane and gas powered materials handling equipment to electric powered equipment.	Customers are provided with 5 mW or larger monthly demands with time periods of free demand.	Designed to help low income customers conserve on their energy bills. Selected options include: education, low income housing construction, community development and any related company programs.	Program will employ a digital display that will show the energy user the real time cost of energy.		
Incentive	Any related DSM programs	A one time buy down TOU rate	Free demand	Any related DSM programs	N/A		
Load Shape Effect	Strategic Conserv. Peak Clipping	Valley Filling	Valley Filling	Strategic Conserv.	Strategic Conserv. Peak Clipping		
Market	Small and medium general service customers on Rates 09 and 20	Large Commercial customers with distribution facilities	Commercial and Industrial customers with 5 mW or larger monthly demand	Low income residential customers on rate 08 and 02.	All electric energy customers		
End Use Device	Lighting and HVAC equipment	Forklifts, tow motors, conveyors and electric vehicles	N/A	N/A	N/A		
Implementation Date Proposed	1992	1992	1992	1992	1992		
Proposed Goal	N/A	N/A	N/A	N/A	N/A		

3.112

Program Name	:	Energy Use Indicator
Description	:	The Energy Use Indicator program will employ a digital display that will show the energy user the real time cost of energy. Allows customer to make choices whenever they perceive their energy costs are too high.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Market	:	Primarily residential and small commercial customers would use this device. Energy Use Indicators could be used by all customers if desired.
End Use Device	:	All electrical energy use devices
Incentive Structure	:	• Allow customers to better manage their energy uses. • Customer purchases equipment from SCE&G. • Reduced energy costs

Program Name	:	Materials Handling/Forklifts
Description	:	Provides commercial customers an incentive to switch from propane and gas powered materials handling equipment to electric powered equipment.
Load Shape Effect	:	Valley Filling
Market	:	Large commercial customers with particular focus on distribution facilities.
End Use Devices	:	Forklifts, Tow Motors, Conveyors and Electric Vehicles
Customer Benefits	:	• Cleaner and safer fuel source • Lower operating costs • Lower maintenance costs
Incentives	:	• TOU Rate • One time buy down

Program Name	:	<u>Low Income Energy Use Alternatives</u>
Description	:	This program provides selected low income customers with energy options through customer education, low income housing construction, community involvement, and company programs. The program will help low income customers conserve on their energy bills. The program will target this group by developing a better relationship with the Farmers Home Administration representatives. Issues such as low income housing construction standards consistent to SCE&G's best residential energy rates will we will pursued. A customer education campaign on company programs will be implemented targeting this group, as well as strong community involvement.
Load Shape Effect	:	Strategic Conservation
Market	:	Low income customers on Rate 8

Program Name	:	<u>Commercial Audit</u>
Description	:	This program will provide on-site visits to the small and medium service commercial customers. The analysis will target lighting improvements, HVAC opportunities, general energy management practices & opportunities, and thermal envelop improvements while at the same time provide an opportunity to identify candidates for other programs. Obviously, supermarkets will need a certain emphasis on refrigeration and restaurants will need assistance on water heating and food preparation.
Load Shape Effect	:	Strategic Conservation, Peak Clipping
Market	:	Small (Rate 9) and Medium General Service (Rate 20) customers whose energy use is primarily lighting and HVAC.
End Use Devices	:	Lighting and HVAC equipment
Incentive Structure	:	• Analysis provided "courtesy of " SCE&G • Reduced energy expenditures by customers • Possible incentives for DSM related measures • Tie in with other Marketing programs in other markets

Program Name	:	<u>Demand Free Days (under development)</u>
Description	:	This program provides selected customers with 5 MW or larger monthly demands with time periods of free demand. The purpose is to increase energy sales during off peak or low demand periods for customers whose production loads cannot be changed or modified to meet TOU rate considerations.
Load Shape Effect	:	Valley filling
Market	:	Commercial or Industrial customers with 5 MW or larger monthly demands unable to take advantage of TOU rate.

3.10 DSM STATUS REPORT

SCE&G has tripled its DSM deferment goal in 1992 to 53,228 kW. This includes substantial efforts in a number of new programs and is broken out by program and market segment in Exhibit 3.10.1.

The march status report for DSM programs is featured in Exhibit 3.10.2. DSM efforts have already deferred over 8 megawatts through the first quarter.

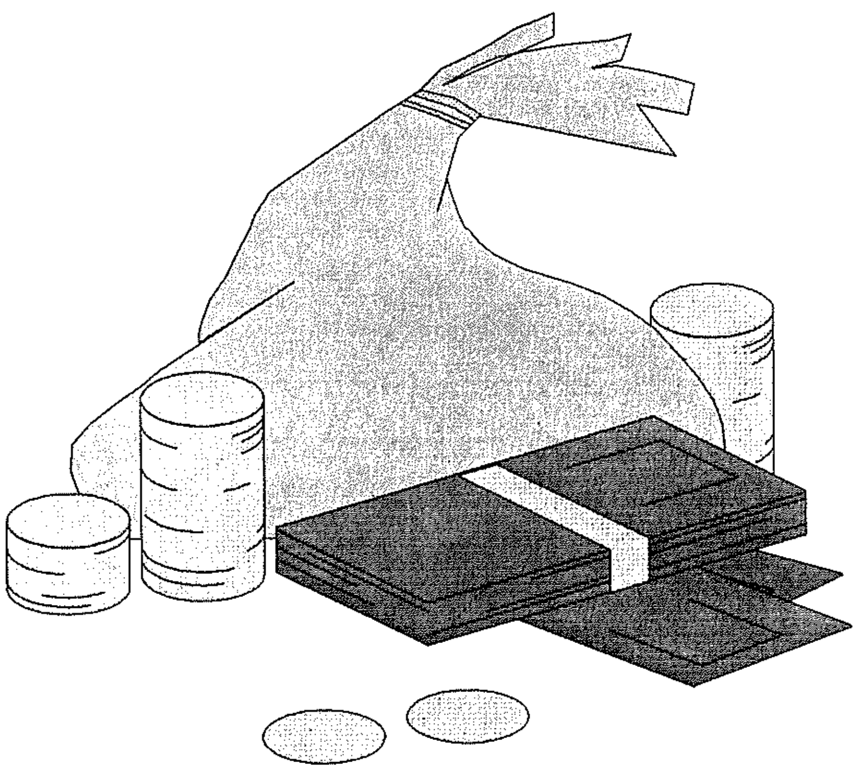
The final Exhibit 3.10.3 is the twenty year projection by market segment and program for DSM activities.

EXHIBIT

3.10.1

1992 GOALS

53,228 kW



Marketing 1992 kW Deferment

Programs	Units	1990 Actuals	1991 Actuals	1992 Goal	1992 kW
Great Appl. Trade-Up	HVAC	6,213	5,733	6,721	6,996
Good Cents	H.H.	2,277	1,989	1,950	2,244
Rate 7	H.H.	1,574	1,490	1,200	636
HEC Incentives	H.H.	496	716	1,600	1,696
RTS	HVAC	0	0	5	15
High Eff. Chillers	kW	157	399	200	200
Ice Storage (OPAC)	kW	503	173	800	800
Standby Generation	kW	3,692	5,850	7,000	7,000
High Eff. Lighting	Lamps	16,402	66,164	187,650	1,351
Electronic F.Ballast	Ballast	0	0	50,000	1,500
Off-Peak W.H.	W.H.	0	0	4,626	1,850
Roof Top Package	HVAC	0	0	350	700
High Eff. Motors	Motors	0	0	500	200
Var. Speed Drives	Motors	0	0	100	40
Interruptible (27)	kW	0	0	28,000	28,000
Total					53,228

Residential & Small Commercial Market:

1992 kW Deferment

Programs	Units	1992 Goal	1992 kW
Great Appl. T-Up	HVAC	6,721	6,996
Good Cents	H.H.	1,950	2,243
Rate 7	H.H.	1,200	636
HEC Incentives	H.H.	1,600	1,696
RTS	HVAC	5	15
High Eff. Lighting	Lamps	20,850	150
Electronic F.Ballast	Ballast	5,000	150
Off-Peak W.H.	W.H.	4,626	1,850
Roof Top Package	HVAC	175	350
Totals			14,086

Commercial Market:

1992 kW Deferment

Programs	Units	1992 Goal	1992 kW
Com. Chillers	kW	100	100
Ice Storage (OPAC)	kW	700	700
Standby Generation	kW	6,000	6,000
High Eff. Lighting	Lamps	118,150	851
Electronic F.Ballast	Ballast	30,000	900
Roof Top Package	HVAC	175	350
Totals			8,901

Industrial Market:

1992 kW Deferment

Programs	Units	1992 Goal	1992 kW
Com. Chillers	kW	100	100
Ice Storage (OPAC)	kW	100	100
Standby Generation	kW	1,000	1,000
High Eff. Lighting	Lamps	48,650	350
Electronic F.Ballast	Ballast	15,000	450
High Eff. Motors	Motors	500	200
Var. Speed Drives	Motors	100	40
Interruptable Rate	kW	28,000	28,000
Total			30,240

EXHIBIT

3.10.2

March Monthly Report

Department Totals

kW Deferment

Programs	Units	System Totals	Current Month	1992 YTD	1992 Goal	1992 kW	Percent of Goal
Great Appl. T-Up	HVAC	19,302	349	1,698	6,721	6,996	25%
Good Cents	H.H.	8,529	252	728	1,950	2,244	37%
Rate 7	H.H.	15,612	53	264	1,200	636	22%
HEC Incentives	H.H.	1,466	57	144	1,600	1,696	9%
RTS	HVAC	0	0	0	5	15	0%
High Eff. Chillers	kW	624	43	68	200	200	34%
Ice Storage (OPAC)	kW	676	0	0	800	800	0%
Standby Generation	kW	10,542	0	1,200	7,000	7,000	17%
Relamping	kW	852	45	258	187,650	1,351	19%
Electronic F.Ballast	Ballast	0	0	0	50,000	1,500	0%
Off-Peak W.H.	W.H.	0	0	0	4,626	1,850	0%
Roof Top Package	HVAC	0	0	0	350	700	0%
High Eff. Motors	Motors	0	0	0	500	200	0%
Var. Speed Drives	Motors	0	0	0	100	40	0%
Interruptible (27)	kW	22,000	0	4,000	28,000	28,000	14%
Totals kW				8,423		53,228	16%

Residential & Small Commercial Market

kW Deferment

Programs	Units	Current Month	1992 YTD	1992 Goal	1992 kW	Percent of Goal
Great Appl. T-Up	HVAC	349	1698	6,721	6,996	25%
Good Cents	H.H.	252	728	1,950	2,243	37%
Rate 7	H.H.	53	264	1,200	636	22%
HEC Incentives	H.H.	57	144	1,600	1,696	9%
RTS	HVAC	0	0	5	15	0%
Relamping	kW	0	0	20,850	150	0%
Electronic F.Ballast	Ballast	0	0	5,000	150	0%
Off-Peak W.H.	W.H.	0	0	4,626	1,850	0%
Roof Top Package	HVAC	0	0	175	350	0%
Totals			2897		14,086	21%

Commercial Market:

kW Deferment

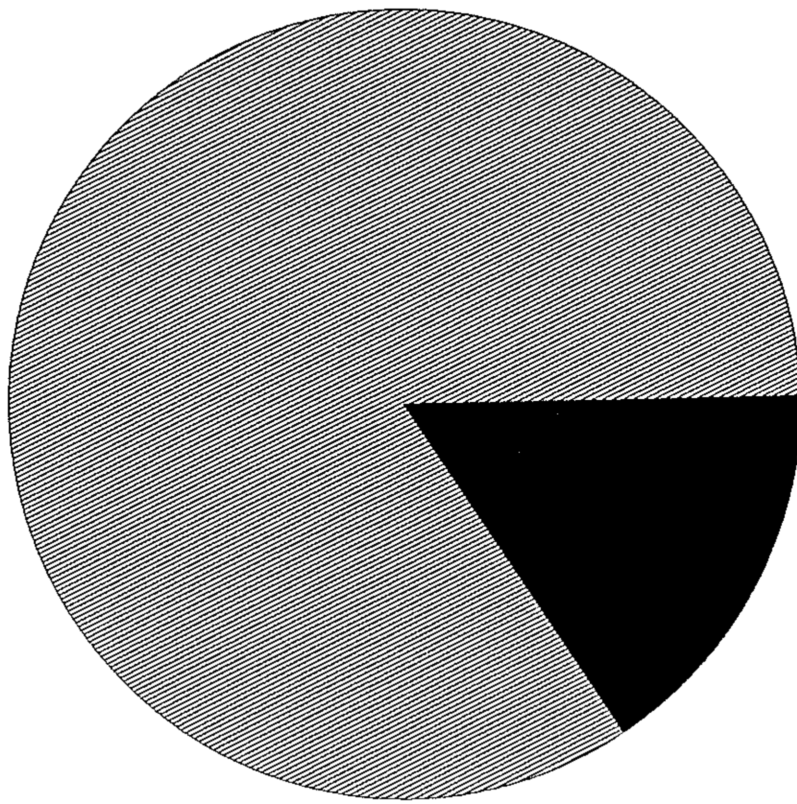
Programs	Units	Current Month	1992 YTD	1992 Goal	1992 kW	Percent of Goal
Com. Chillers	kW	43	68	100	100	68%
Ice Storage (OPAC)	kW	0	0	700	700	0%
Standby Generation	kW	1200	1200	6,000	6,000	20%
Relamping	kW	38	258	118,150	851	30%
Electronic F.Ballast	Ballast	0	0	30,000	900	0%
Roof Top Package	HVAC	0	0	175	350	0%
Totals kW			1,526		8,901	17%

Industrial Market:

kW Deferment

Programs	Units	Current Month	1992 YTD	1992 Goal	1992 kW	Percent of Goal
Com. Chillers	kW	0	0	100	100	0%
Ice Storage (OPAC)	kW	0	0	100	100	0%
Standby Generation	kW	0	0	1,000	1,000	0%
Relamping	kW	0	0	350	350	0%
Electronic F.Ballast	Ballast	0	0	15,000	450	0%
High Eff. Motors	Motors	0	0	500	200	0%
Var. Speed Drives	Motors	0	0	100	40	0%
Interruptable Rate	kW	0	4000	28,000	28,000	14%
Totals kW			4000		30,240	13%

kW - DEFERRED

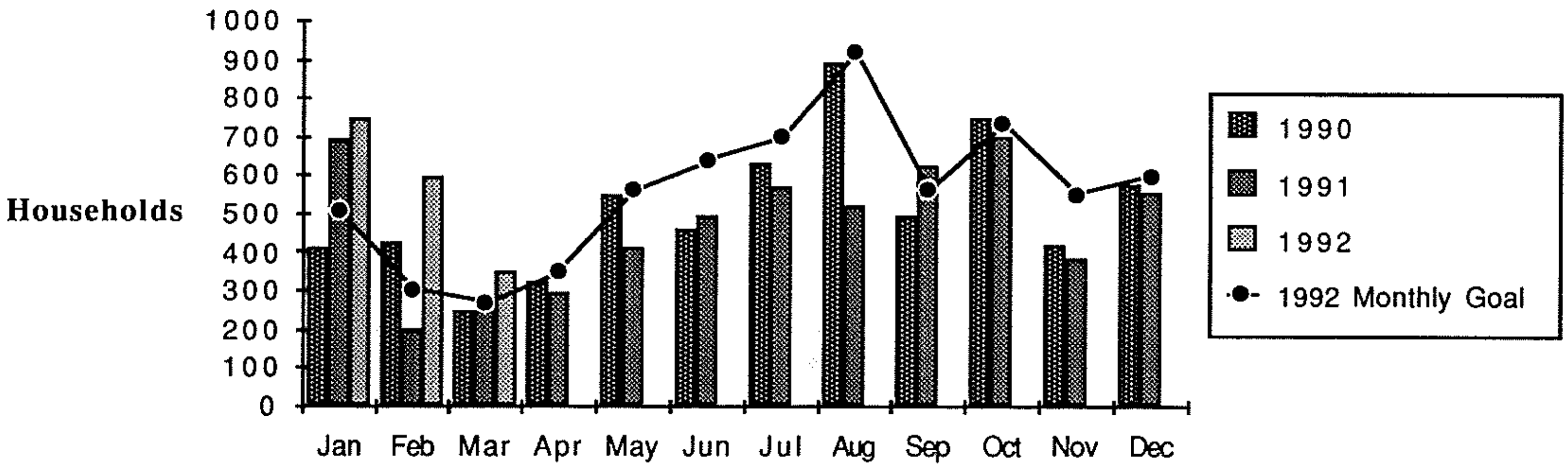


1992 GOAL - 53,228 kW

March 1992

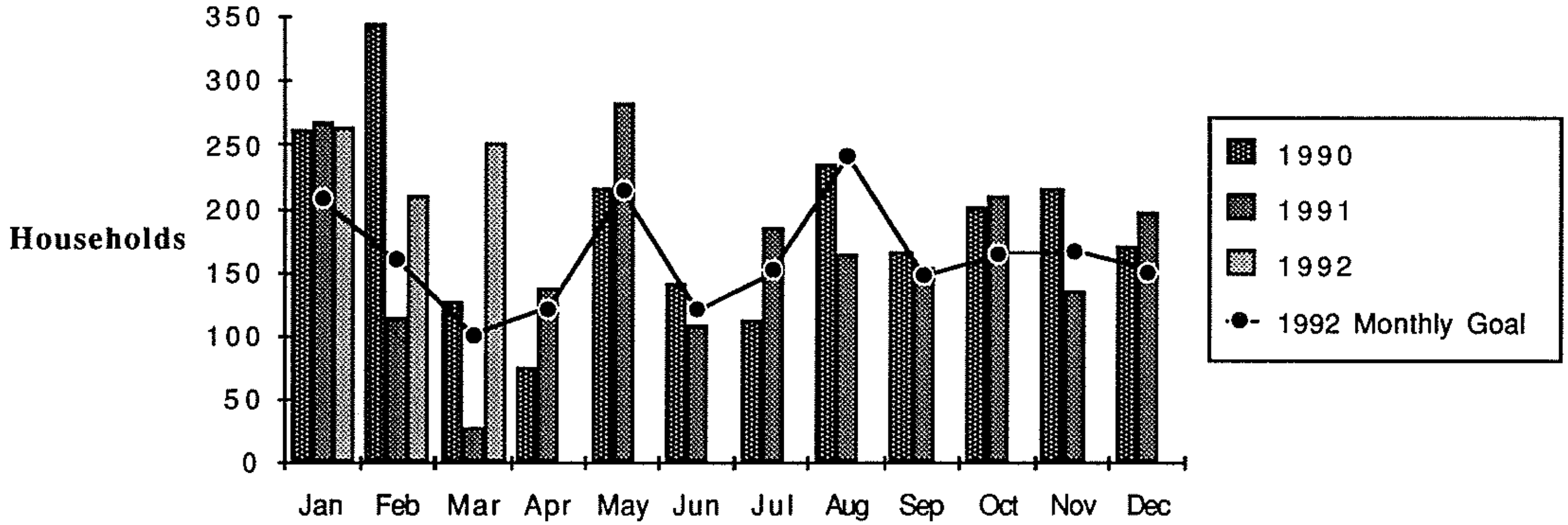
3.130

GREAT APPLIANCE TRADE-UP SYSTEM SALES



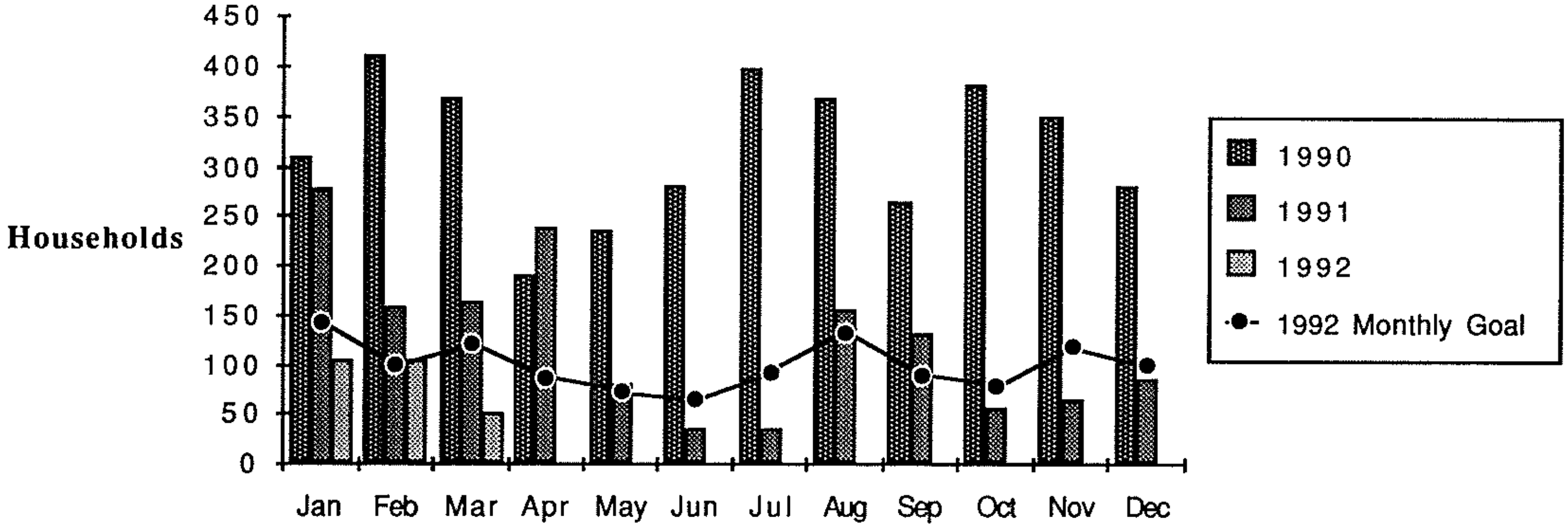
Year To Date - 1,698
1992 Goal - 6,721
Percent of Goal - 25%

GOOD CENTS SYSTEM SALES



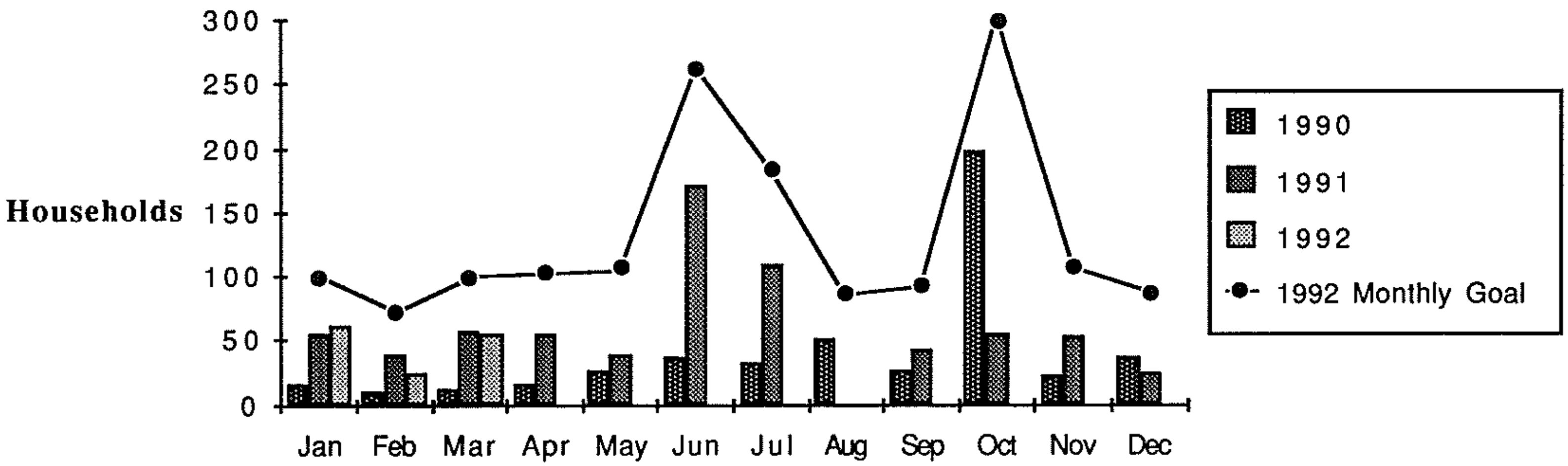
Year To Date - 728
1992 Goal - 1,950
Percent of Goal - 37%

RATE 7
SYSTEM SALES



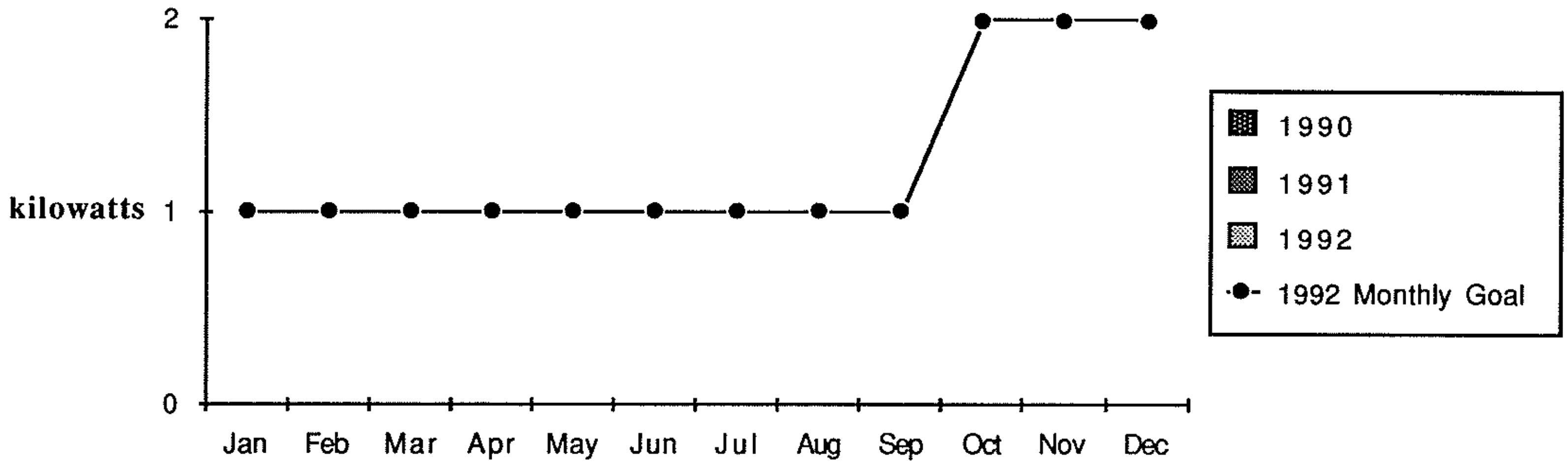
Year To Date - 264
1992 Goal - 1,200
Percent of Goal - 22%

HOME ENERGY CHECK SYSTEM SALES



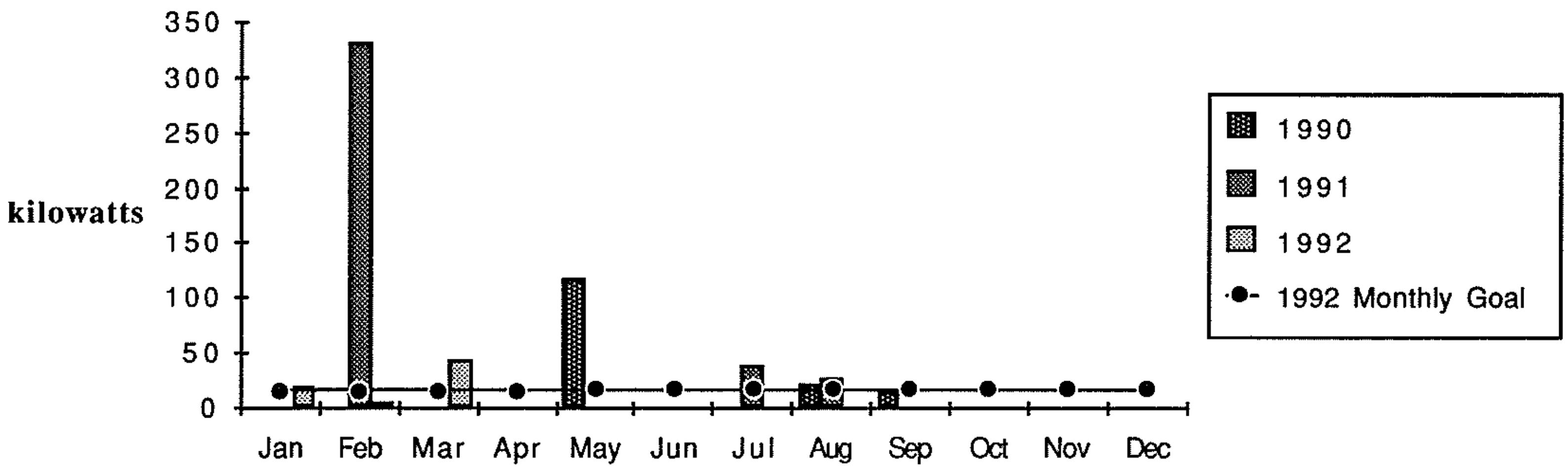
Year To Date - 144
1992 Goal - 1,600
Percent of Goal - 9%

RESIDENTIAL THERMAL STORAGE SYSTEM SALES



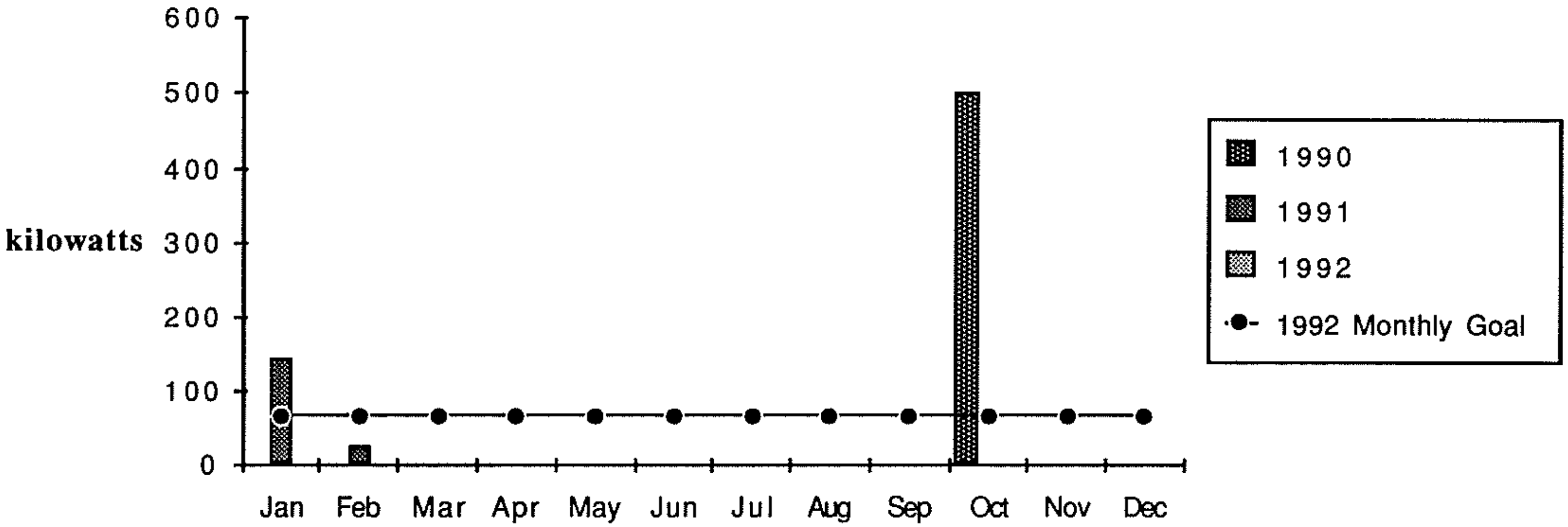
Year To Date - 0
1992 Goal - 15 KW
Percent of Goal - 0%

HIGH EFFICIENCY CHILLERS SYSTEM SALES



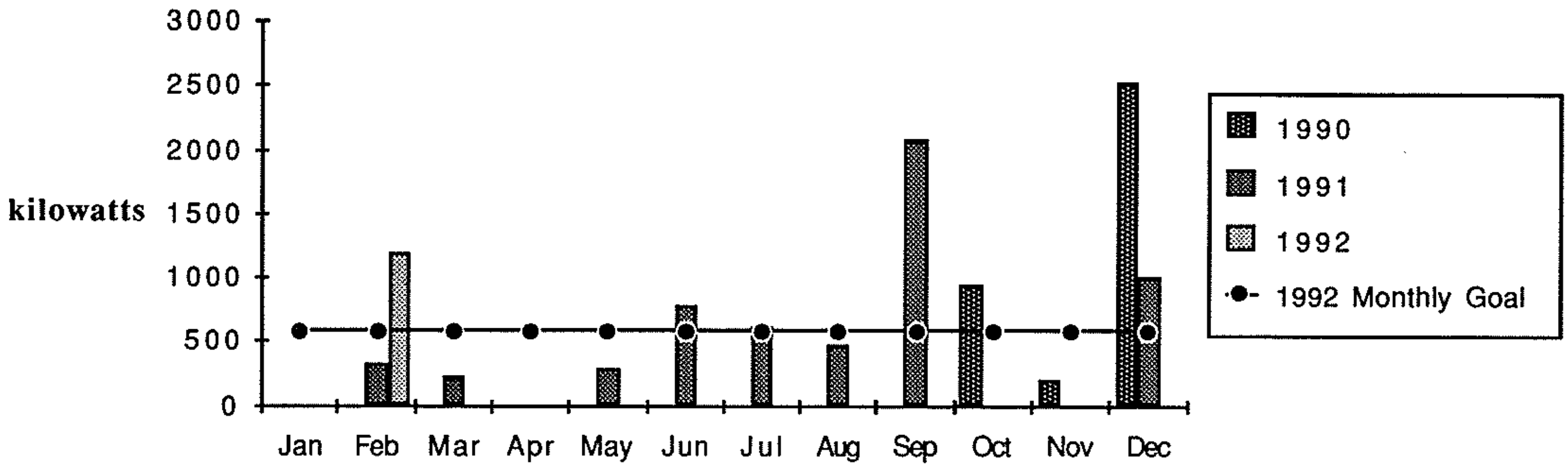
Year To Date - 68 KW
1992 Goal - 200 KW
Percent of Goal - 34%

ICE STORAGE SYSTEM SALES



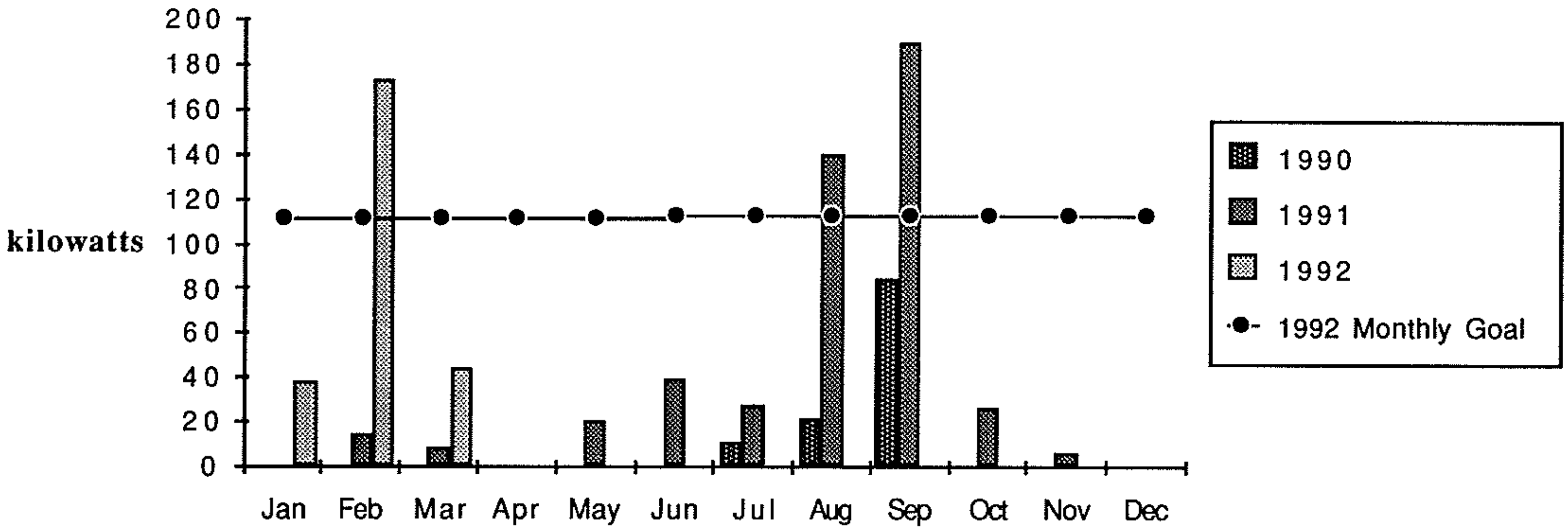
Year To Date - 0 KW
1992 Goal - 800 KW
Percent of Goal - 0%

STANDBY GENERATOR SYSTEM SALES



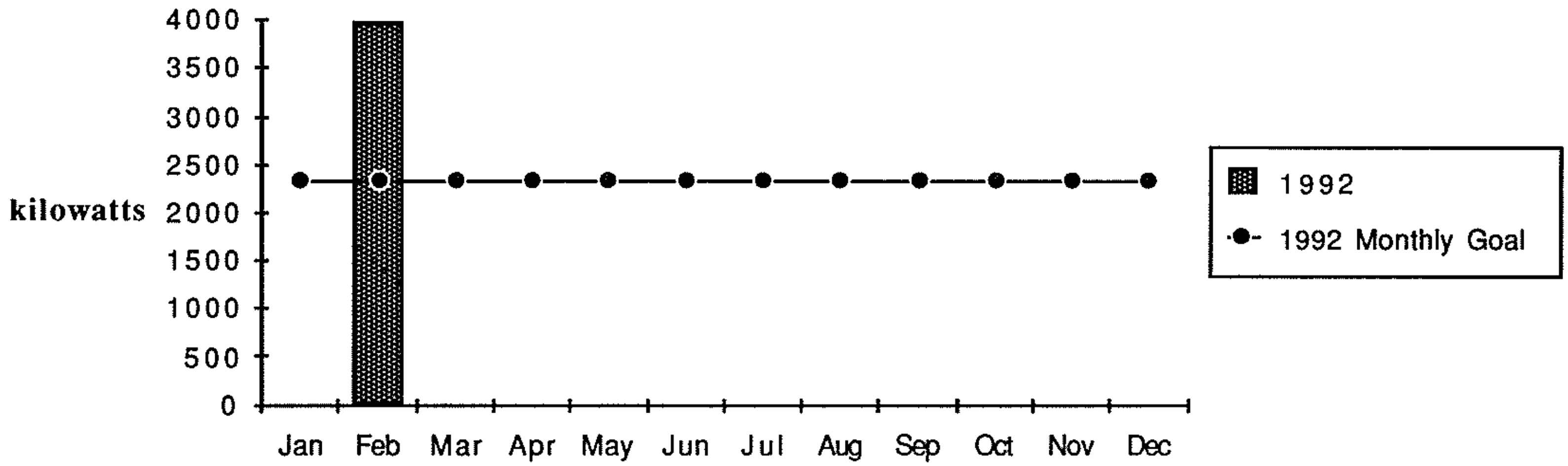
Year To Date - 1,200 KW
1992 Goal - 7,000 KW
Percent of Goal - 17%

RELAMPING SYSTEM SALES



Year To Date - 258 KW
1992 Goal - 1,351 KW
Percent of Goal - 19%

INTERRUPTIBLE RATE (27) SYSTEM SALES

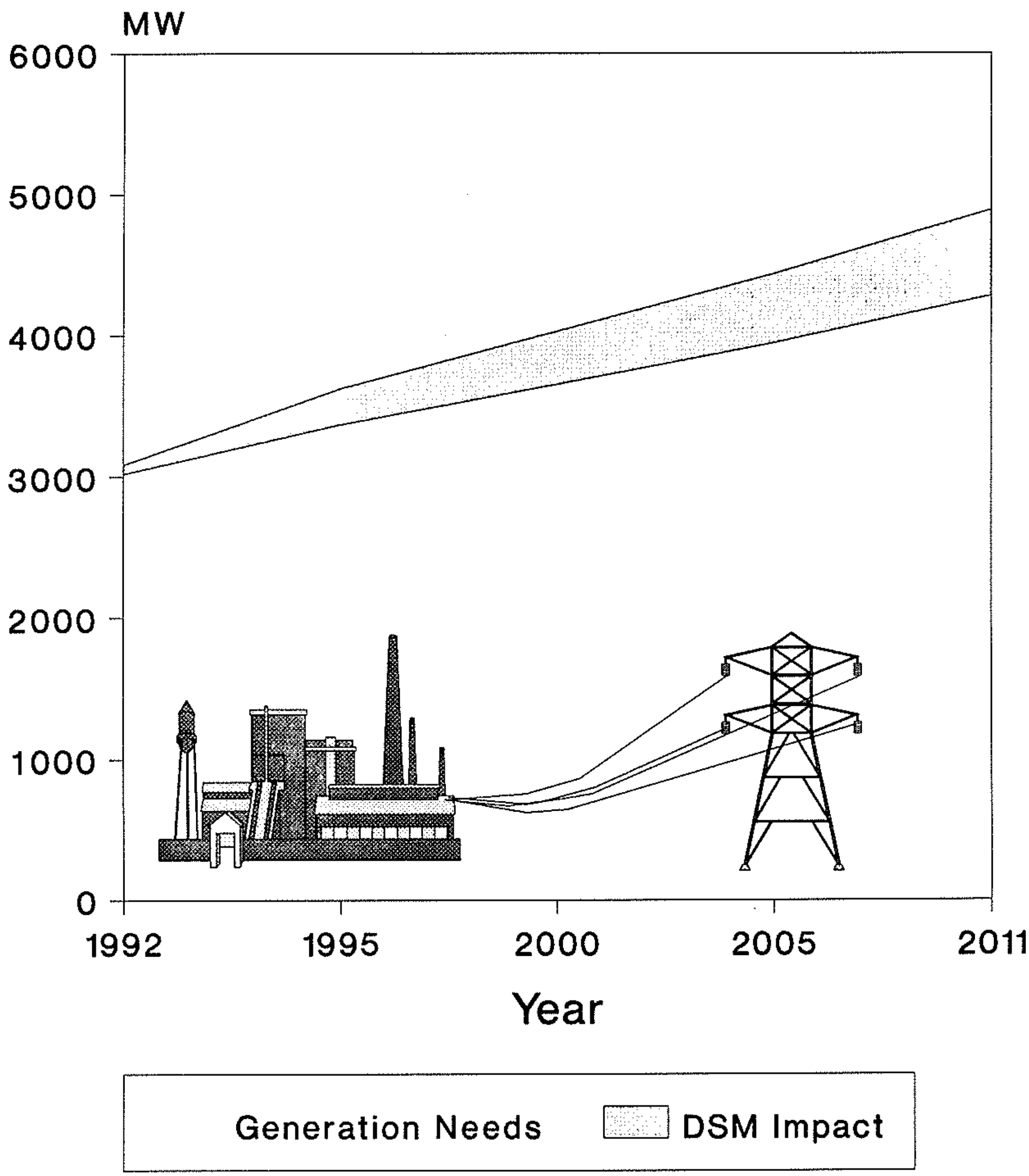


Year To Date - 4,000 KW
1992 Goal - 28,000 KW
Percent of Goal - 14%

EXHIBIT

3.10.3

DSM Impact On Peak



March 1992

PROJECTED 20 YEAR DEMAND IMPACTS

YEAR	RESIDENTIAL & SMALL COMM. PROGRAMS KW REDUCTION	C&I PROGRAMS KW REDUCTION	1992 PROGRAMS KW REDUCTION	ALL PROGRAMS KW REDUCTION
1992	46,981	66,669	5,434	119,084
1993	65,534	79,587	16,793	161,913
1994	83,198	92,505	28,125	203,828
1995	94,499	97,605	34,396	226,500
1996	106,059	108,705	40,918	255,682
1997	117,799	113,805	47,616	279,220
1998	129,578	118,905	54,426	302,909
1999	141,515	124,005	61,428	326,948
2000	153,258	129,105	68,423	350,785
2001	164,444	134,205	74,917	373,567
2002	175,407	139,305	81,989	396,702
2003	186,528	144,405	89,269	420,202
2004	197,968	149,505	96,843	444,316
2005	209,412	154,605	104,543	468,560
2006	220,522	159,705	112,176	492,402
2007	231,678	164,805	119,935	516,419
2008	243,012	169,905	127,894	540,811
2009	254,320	175,005	135,949	565,275
2010	265,664	180,105	144,126	589,895
2011	277,133	185,205	152,476	614,813

PROJECTED 20 YEAR ENERGY IMPACTS

YEAR	RESIDENTIAL & SMALL COMM. PROGRAMS KWH REDUCTION	C&I PROGRAMS KWH REDUCTION	1992 PROGRAMS KWH REDUCTION	ALL PROGRAMS KWH REDUCTION
1992	88,745,658	40,641,700	2,190,978	131,578,336
1993	117,823,925	60,735,936	25,985,422	204,545,283
1994	145,132,257	80,830,172	51,302,166	277,264,595
1995	158,946,891	84,888,572	63,878,305	307,713,768
1996	173,036,064	91,826,972	76,679,466	341,542,502
1997	187,362,566	95,885,372	89,735,396	372,983,335
1998	201,741,282	99,943,772	103,109,589	404,794,643
1999	216,327,265	104,002,172	116,800,206	437,129,643
2000	230,656,932	108,060,572	130,931,633	469,649,138
2001	244,078,082	112,118,972	144,674,772	500,871,826
2002	257,204,943	116,177,372	159,640,330	533,022,645
2003	270,539,072	120,235,772	174,935,559	565,710,403
2004	284,294,066	124,294,172	190,520,959	599,109,196
2005	298,054,597	128,352,572	206,534,126	632,941,295
2006	311,375,277	132,410,972	223,077,096	666,863,345
2007	324,756,872	136,469,372	239,979,598	701,205,842
2008	338,371,841	140,527,772	257,196,512	736,096,125
2009	351,953,585	144,586,172	274,819,093	771,358,849
2010	365,581,211	148,644,572	292,816,866	807,042,649
2011	379,374,178	152,702,972	311,159,607	843,236,757

RESIDENTIAL AND SMALL COMMERCIAL MARKET

PROJECTED 20 YEAR KW PENETRATIONS

YEAR	GREAT APPLIANCE TRADE-UP	GOOD CENTS PROGRAM	HOME ENERGY CHECK	RATE 7	RESIDENTIAL THERMAL STORAGE	TOTAL REDUCTION OF KW
1992	23933	11101	3172	8761	15	46981
1993	29183	15317	9593	9227	2214	65534
1994	34433	18947	16115	9596	4107	83198
1995	39683	20810	17705	9986	6316	94499
1996	44933	22798	19295	10361	8673	106059
1997	50183	24862	20885	10750	11120	117799
1998	55433	26942	22475	11142	13587	129578
1999	60683	29089	24065	11547	16132	141515
2000	65933	31153	25655	11936	18581	153258
2001	71183	33207	26715	12323	21016	164444
2002	76433	35167	27775	12693	23340	175407
2003	81683	37193	28835	13075	25742	186528
2004	86933	39354	29895	13482	28304	197968
2005	92183	41516	30955	13890	30868	209412
2006	97433	43538	32015	14271	33266	220522
2007	102683	45579	33075	14656	35686	231678
2008	107933	47695	34135	15055	38195	243012
2009	113183	49800	35195	15452	40691	254320
2010	118433	51920	36255	15851	43205	265664
2011	123683	54093	37315	16261	45781	277133

RESIDENTIAL AND SMALL COMMERCIAL MARKET

PROJECTED 20 YEAR KWH PENETRATIONS

YEAR	GREAT APPLIANCE TRADE-UP	GOOD CENTS PROGRAM	HOME ENERGY CHECK	RATE 7	RESIDENTIAL THERMAL STORAGE	TOTAL REDUCTION OF KWH
1992	23932650	33302850	5233008	26282700	-5550	88745658
1993	29182650	45950550	15828450	27681455	-819180	117823925
1994	34432650	56842200	26590047	28786950	-1519590	145132257
1995	39682650	62429958	29213547	29957508	-2336772	158946891
1996	44932650	68393421	31837047	31081845	-3208899	173036064
1997	50182650	74584584	34460547	32249111	-4114326	187362566
1998	55432650	80825841	37084047	33425823	-5027079	201741282
1999	60682650	87265956	39707547	34640026	-5968914	216327265
2000	65932650	93460155	42331047	35807865	-6874785	230656932
2001	71182650	99621717	44080047	36969551	-7775883	244078082
2002	76432650	105500931	45829047	38078004	-8635689	257204943
2003	81682650	111579003	47578047	39223949	-9524577	270539072
2004	86932650	118060863	49327047	40446023	-10472517	284294066
2005	92182650	124548036	51076047	41669098	-11421234	298054597
2006	97432650	130613205	52825047	42812610	-12308235	311375277
2007	102682650	136736817	54574047	43967141	-13203783	324756872
2008	107932650	143084334	56323047	45163886	-14132076	338371841
2009	113182650	149399973	58072047	46354622	-15055707	351953585
2010	118432650	155759634	59821047	47553656	-15985776	365581211
2011	123682650	162277926	61570047	48782599	-16939044	379374178

RESIDENTIAL AND SMALL COMMERCIAL MARKET

PROJECTED 20 YEAR UNIT PENETRATIONS

YEAR	GREAT APPLIANCE TRADE-UP	GOOD CENTS PROGRAM	HOME ENERGY CHECK	RATE 7	RESIDENTIAL THERMAL STORAGE
1992	22793	9653	2992	16530	5
1993	27793	13319	9050	17410	738
1994	32793	16476	15203	18105	1369
1995	37793	18096	16703	18841	2105
1996	42793	19824	18203	19548	2891
1997	47793	21619	19703	20282	3707
1998	52793	23428	21203	21023	4529
1999	57793	25294	22703	21786	5377
2000	62793	27090	24203	22521	6194
2001	67793	28876	25203	23251	7005
2002	72793	30580	26203	23948	7780
2003	77793	32342	27203	24669	8581
2004	82793	34221	28203	25438	9435
2005	87793	36101	29203	26207	10289
2006	92793	37859	30203	26926	11089
2007	97793	39634	31203	27652	11895
2008	102793	41474	32203	28405	12732
2009	107793	43304	33203	29154	13564
2010	112793	45148	34203	29908	14402
2011	117793	47037	35203	30681	15260

COMMERCIAL & INDUSTRIAL MARKET

PROJECTED 20 YEAR KW PENETRATIONS

YEAR	HIGH EFFICIENCY CHILLER	COMMERCIAL ICE STORAGE (OPAC)	INTERRUPTIBLE RATE 28	STAND-BY GENERATOR	HIGH EFF. COMMERCIAL LIGHTING	TOTAL REDUCTION OF KW
1992	756	1476	46000	16492	1945	66669
1993	1174	1976	46000	24492	5945	79587
1994	1592	2476	46000	32492	9945	92505
1995	1792	2976	46000	36492	10345	97605
1996	1992	3476	52000	40492	10745	108705
1997	2192	3976	52000	44492	11145	113805
1998	2392	4476	52000	48492	11545	118905
1999	2592	4976	52000	52492	11945	124005
2000	2792	5476	52000	56492	12345	129105
2001	2992	5976	52000	60492	12745	134205
2002	3192	6476	52000	64492	13145	139305
2003	3392	6976	52000	68492	13545	144405
2004	3592	7476	52000	72492	13945	149505
2005	3792	7976	52000	76492	14345	154605
2006	3992	8476	52000	80492	14745	159705
2007	4192	8976	52000	84492	15145	164805
2008	4392	9476	52000	88492	15545	169905
2009	4592	9976	52000	92492	15945	175005
2010	4792	10476	52000	96492	16345	180105
2011	4992	10976	52000	100492	16745	185205

COMMERCIAL & INDUSTRIAL MARKET

PROJECTED 20 YEAR KWH PENETRATIONS

YEAR	HIGH EFFICIENCY CHILLER	COMMERCIAL ICE STORAGE (OPAC)	INTERRUPTIBLE RATE 28	STAND-BY GENERATOR	HIGH EFF. COMMERCIAL LIGHTING	TOTAL REDUCTION OF KWH
1992	984312	-2225808	22080000	12995696	6807500	40641700
1993	1528548	-2979808	22080000	19299696	20807500	60735936
1994	2072784	-3733808	22080000	25603696	34807500	80830172
1995	2333184	-4487808	22080000	28755696	36207500	84888572
1996	2593584	-5241808	24960000	31907696	37607500	91826972
1997	2853984	-5995808	24960000	35059696	39007500	95885372
1998	3114384	-6749808	24960000	38211696	40407500	99943772
1999	3374784	-7503808	24960000	41363696	41807500	104002172
2000	3635184	-8257808	24960000	44515696	43207500	108060572
2001	3895584	-9011808	24960000	47667696	44607500	112118972
2002	4155984	-9765808	24960000	50819696	46007500	116177372
2003	4416384	-10519808	24960000	53971696	47407500	120235772
2004	4676784	-11273808	24960000	57123696	48807500	124294172
2005	4937184	-12027808	24960000	60275696	50207500	128352572
2006	5197584	-12781808	24960000	63427696	51607500	132410972
2007	5457984	-13535808	24960000	66579696	53007500	136469372
2008	5718384	-14289808	24960000	69731696	54407500	140527772
2009	5978784	-15043808	24960000	72883696	55807500	144586172
2010	6239184	-15797808	24960000	76035696	57207500	148644572
2011	6499584	-16551808	24960000	79187696	58607500	152702972

COMMERCIAL & INDUSTRIAL MARKET

PROJECTED 20 YEAR UNIT PENETRATIONS

YEAR	HIGH EFFICIENCY CHILLER	COMMERCIAL ICE STORAGE (OPAC)	INTERRUPTIBLE RATE 28	STAND-BY GENERATOR	HIGH EFF. COMMERCIAL LIGHTING
1992	756	1476	46000	16492	1945
1993	1174	1976	46000	24492	5945
1994	1592	2476	46000	32492	9945
1995	1792	2976	46000	36492	10345
1996	1992	3476	52000	40492	10745
1997	2192	3976	52000	44492	11145
1998	2392	4476	52000	48492	11545
1999	2592	4976	52000	52492	11945
2000	2792	5476	52000	56492	12345
2001	2992	5976	52000	60492	12745
2002	3192	6476	52000	64492	13145
2003	3392	6976	52000	68492	13545
2004	3592	7476	52000	72492	13945
2005	3792	7976	52000	76492	14345
2006	3992	8476	52000	80492	14745
2007	4192	8976	52000	84492	15145
2008	4392	9476	52000	88492	15545
2009	4592	9976	52000	92492	15945
2010	4792	10476	52000	96492	16345
2011	4992	10976	52000	100492	16745

1992 PROGRAMS

PROJECTED 20 YEAR KW PENETRATIONS

YEAR	VARIABLE SPEED MOTOR DRIVES	HIGH EFF. FLUOR. BALLASTS	HIGH EFFICIENCY MOTORS	OFF-PEAK WATER HEATING	TOTAL REDUCTION OF KW
1992	40	1500	200	1850	3590
1993	726	6000	1596	4100	12423
1994	1438	10500	3026	6210	21174
1995	2184	10950	4517	7889	25540
1996	2950	11400	6049	9652	30051
1997	3737	11850	7623	11480	34689
1998	4544	12300	9238	13346	39428
1999	5374	12750	10897	15268	44288
2000	6224	13200	12597	17172	49192
2001	7095	13650	14339	19089	54173
2002	7985	14100	16119	20982	59186
2003	8896	14550	17941	22925	64311
2004	9829	15000	19807	24951	69587
2005	10785	15450	21719	26996	74950
2006	11762	15900	23673	28993	80328
2007	12759	16350	25668	31018	85796
2008	13779	16800	27707	33099	91385
2009	14820	17250	29790	35195	97055
2010	15883	17700	31917	37318	102818
2011	16969	18150	34088	39488	108696

1992 PROGRAMS

PROJECTED 20 YEAR KW PENETRATIONS

YEAR	ROOF TOP PACKAGE UNITS	HIGH EFFICIENCY DUEL FUEL HP	TOTAL REDUCTION OF KW
1992	700	1143	1843
1993	2008	2362	4370
1994	3576	3375	6951
1995	4760	4096	8856
1996	6005	4862	10867
1997	7272	5655	12927
1998	8541	6456	14997
1999	9857	7282	17140
2000	11147	8084	19230
2001	11860	8884	20745
2002	13148	9656	22804
2003	14506	10452	24958
2004	15960	11296	27257
2005	17450	12143	29593
2006	18904	12944	31848
2007	20386	13754	34140
2008	21918	14591	36509
2009	23467	15427	38894
2010	25038	16270	41308
2011	26647	17133	43780

1992 PROGRAMS

PROJECTED 20 YEAR KWH PENETRATIONS

YEAR	VARIABLE SPEED MOTOR DRIVES	HIGH EFF. FLUOR. BALLASTS	HIGH EFFICIENCY MOTORS	OFF-PEAK WATER HEATING	TOTAL REDUCTION OF KWH
1992	143400	5250000	1434000	-1443312	5384088
1993	2602710	21000000	11446188	-3198312	31850586
1994	5156664	36750000	21699288	-4843488	58762464
1995	7828398	38325000	32386225	-6153512	72386110
1996	10574405	39900000	43370252	-7528715	86315942
1997	13395433	41475000	54654363	-8954331	100570465
1998	16290816	43050000	66235898	-10410001	115166714
1999	19264215	44625000	78129494	-11908953	130109756
2000	22311970	46200000	90320513	-13393909	145438575
2001	25433914	47775000	102808290	-14889746	161127458
2002	28625474	49350000	115574526	-16365632	177184368
2003	31890723	50925000	128635525	-17881301	193569947
2004	35236483	52500000	142018565	-19461525	210293523
2005	38663461	54075000	155726475	-21056840	227408096
2006	42165251	55650000	169733638	-22614720	244934169
2007	45742188	57225000	184041384	-24194304	262814268
2008	49397265	58800000	198661691	-25816971	281041985
2009	53130440	60375000	213594392	-27451769	299648063
2010	56942337	61950000	228841982	-29108188	318626131
2011	60835369	63525000	244414109	-30800877	337973601

1992 PROGRAMS

PROJECTED 20 YEAR KWH PENETRATIONS

YEAR	ROOFTOP PACKAGE UNITS	HIGH EFFICIENCY DUEL FUEL HP	TOTAL REDUCTION OF KWH
1992	911400	-4104510	-3193110
1993	2614416	-8479580	-5865164
1994	4655952	-12116250	-7460298
1995	6197400	-14705206	-8507806
1996	7818431	-17454906	-9636475
1997	9467907	-20302975	-10835068
1998	11120718	-23177843	-12057125
1999	12834288	-26143838	-13309550
2000	14513147	-29020088	-14506941
2001	15442254	-31894941	-16452687
2002	17119255	-34663293	-17544037
2003	18887118	-37521506	-18634388
2004	20780446	-40553010	-19772564
2005	22720202	-43594172	-20873970
2006	24612655	-46469728	-21857073
2007	26542032	-49376703	-22834671
2008	28537398	-52382871	-23845473
2009	30554325	-55383294	-24828970
2010	32599816	-58409081	-25809266
2011	34693787	-61507781	-26813994

1992 PROGRAMS

PROJECTED 20 YEAR UNIT PENETRATIONS

YEAR	VARIABLE SPEED MOTOR DRIVES	HIGH EFF. FLUOR. BALLASTS	HIGH EFFICIENCY MOTORS	OFF-PEAK WATER HEATING
1992	100	50000	500	4626
1993	1815	200000	3991	10251
1994	3596	350000	7566	15524
1995	5459	365000	11292	19723
1996	7374	380000	15122	24130
1997	9341	395000	19057	28700
1998	11360	410000	23095	33365
1999	13434	425000	27242	38170
2000	15559	440000	31493	42929
2001	17736	455000	35847	47724
2002	19962	470000	40298	52454
2003	22239	485000	44852	57312
2004	24572	500000	49518	62377
2005	26962	515000	54298	67490
2006	29404	530000	59182	72483
2007	31898	545000	64171	77546
2008	34447	560000	69268	82747
2009	37051	575000	74475	87986
2010	39709	590000	79791	93295
2011	42424	605000	85221	98721

1992 PROGRAMS

PROJECTED 20 YEAR UNIT PENETRATIONS

YEAR	ROOF TOP PACKAGE UNITS	HIGH EFFICIENCY DUEL FUEL HP
1992	350	1143
1993	1004	2362
1994	1788	3375
1995	2380	4096
1996	3002	4862
1997	3636	5655
1998	4271	6456
1999	4929	7282
2000	5573	8084
2001	5930	8884
2002	6574	9656
2003	7253	10452
2004	7980	11296
2005	8725	12143
2006	9452	12944
2007	10193	13754
2008	10959	14591
2009	11734	15427
2010	12519	16270
2011	13323	17133

4.0 SUPPLY-SIDE PLANNING

4.0 SUPPLY-SIDE PLANNING

1. Introduction
2. Need for Capacity and Energy Resources
3. Existing Resources
4. Maintenance and Refurbishment Plan
5. Purchased Power
6. Utility Joint Planning
7. Owned Resource Options
8. Supply-Side Process
9. Assumptions and Inputs
10. The Supply-Side Plan and Alternative Plans
11. Flexibility and Risks
12. Technology Review -- Conventional

4.0 SUPPLY-SIDE PLANNING

1. Introduction

Although SCE&G is accelerating its conservation and demand-side management programs, the fact yet remains that the growth of population and economic activity in its service territory require the Company to expand its supply-side capabilities as well. Since the V. C. Summer nuclear plant began commercial operations in 1983, the Company has replaced three old oil-burning steam plants with a modern internal combustion turbine (ICT), but it has not increased its capabilities.

In 1991 the Company contracted with Duke/Fluor Daniel to engineer, procure, and construct a 385-MW pulverized coal-fired steam plant, to come on line by the summer peak season of 1996. The unit will be equipped with flue gas desulfurization (FGD or "scrubber"), and will be located near Cope, South Carolina, between the midlands and low country load centers. The Company hopes to avoid construction of other generation resources during this period by means of conservation/DSM, and by making limited-term purchases of capacity. This strategy implies, however, that the Company's need for additional permanent supply resources will only just be met when the Cope unit comes on line. The task of supply-side planning is to identify a plan that provides the necessary additional capacity and energy, and that minimizes the present worth of all the streams of revenue required to do so.

2. Need for Capacity and Energy Resources

According to current projections, SCE&G will have a reserve margin of slightly less than 20% of projected planning peak after the Cope unit comes on line in 1996. (Planning peaks are the peak demands the Company's customers are expected to present, minus the Company's dispatchable demand-side resources, such as industrial interruptible load and dispatchable customer stand-by generation.) Since planning peaks are expected to continue to grow by about 70 MW per year, the Company expects to need additional resources, and since annual energies are expected to grow proportionally faster than peak demands, the Company must be prepared to meet some additional steady load and not just occasional peak loads. This implies a mix of capacity types.

Capacity resources are usually characterized 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 loads that is much higher than their share of the Company's capacity, because the high fixed costs per kilowatt 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).

Peaking resources typically provide a much smaller proportion of energy loads 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-turbine (ICT) technologies, since ICTs burn more expensive fuels and are generally less efficient at converting heat energy in the fuel into electrical energy than baseload plants. For some other types of peaking resources, the low capacity factor results from limitation of 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 do contribute a great deal to system reliability, because they can be started either instantly (in the case of our Saluda hydro) or very quickly (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 fill the gaps.

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. A quality frame-built ICT, engineered to high utility standards, will still cost less than half what a baseload plant will cost per kilowatt of capacity.

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 is less flexible in start-up than the same capacity in an ICT would be. And 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 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 start up quickly, a combined cycle is more flexible in its energy supply than a baseload plant.

At SCE&G the intermediate energy-supply niche is filled by the eight 64-MW pumped-storage hydro units at Fairfield. This resource is more flexible than a baseload resource, since it can be started instantly, and its output can be varied over a wide range without efficiency penalty. But its energy is more costly than baseload energy, since pumping is done with off-peak baseload generation and there are efficiency losses in the double conversion of the energy. Pumped-storage energy is 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 day, 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 72% baseload (including nuclear, coal, and run-of-river hydro), about 13% intermediate (pumped-storage hydro), and about 15% peaking (Saluda hydro and gas/oil-fired units). The exact balance among these capacity types will change as new units are added. Conceptions about the optimal balance are subject to constant change, since the optimal balance is a 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 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 baseload, intermediate, and peaking resources in a menu from which the supply-side aspect of IRP will make choices.

3. Existing Resources

SCE&G's peak electric generating capability as of the end of 1991 was 3,912 MW. This capability is composed of coal-fired, nuclear, hydroelectric, and oil- and natural gas-fired generating resources. Coal-fired generation contributes 56% of the system capability, nuclear 15%, hydroelectric 19%, and oil and natural gas 10% . A detailed listing of generating units is provided at the end of Section 4.3. 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.

TABLE 4.3.1

Generating Station Capability

	First and Last Unit In Service	Rating in Kilowatts Net Capability Summer	Winter
Steam:			
Canadys – Canadys, SC	1962 – 1967	430,000	430,000
Hagood – Charleston, SC	1947 – 1951	20,000	20,000
McMeekin – near Irmo, SC	1958 – 1959	252,000	254,000
Urquhart – Beech Island, SC	1953 – 1955	250,000	254,000
Wateree – Eastover, SC	1970 – 1971	700,000	720,000
Williams – Goose Creek, SC	1973	560,000	565,000
Total Steam Capacity		2,212,000	2,243,000
Nuclear:			
V. C. Summer – Parr, SC	1984	590,000	596,000
I. C. Turbines: (1)			
Burton, SC	1961	9,500	10,000
Charleston, SC	1961	9,500	10,000
Burton, SC	1963	9,500	10,000
Burton, SC	1963	9,500	10,000
Hardeeville, SC	1968	14,000	14,000
Canadys, SC	1968	14,000	15,000
Urquhart (14 MWs, 12MWs) – Beech Is., SC	1969	26,000	32,000
Coit (2 X 15 MWs) – Columbia, SC	1969	30,000	36,000
Parr Turbines (2 X 13 MWs)	1970	26,000	34,000
Parr Turbines (2 X 17 MWs)	1971	34,000	42,000
Parr Heat Recovery – Parr, SC	1925 – 1929	28,000	28,000
Williams (2 X 24.5 MWs) – Goose Creek, SC	1972	49,000	58,000
Hagood – Charleston, SC	1991	95,000	112,000
Total I. C. Turbines Capacity		354,000	411,000
Hydro:			
Columbia – Columbia, SC	1927 – 1929	10,000	10,000
Neal Shoals – Carlisle, SC	1905	5,000	5,000
Parr Shoals – Parr, SC	1914 – 1921	14,000	14,000
Saluda – Near Irmo, SC	1930 – 1971	206,000	206,000
Stevens Creek – Near Martinez, GA	1914 – 1926	9,000	9,000
Fairfield Pumped Storage – Parr, SC	1978	512,000	512,000
Total Hydro Capacity		756,000	756,000
Grand Total:		3,912,000	4,006,000

Notes:

(1) I. C. Turbines net capability for summer is based on a 100o F day.

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 (72 %) and peaking/intermediate (28 %) 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 Chart 4.4.1 at the end of this chapter section. For long-range planning purposes the maintenance of existing coal-fired and ICT units is extended into the future using a five-year cycle for major maintenance outages. For four years of this five-year cycle routine inspection and maintenance is performed on the generating units. In the fifth year 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 Chart 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.

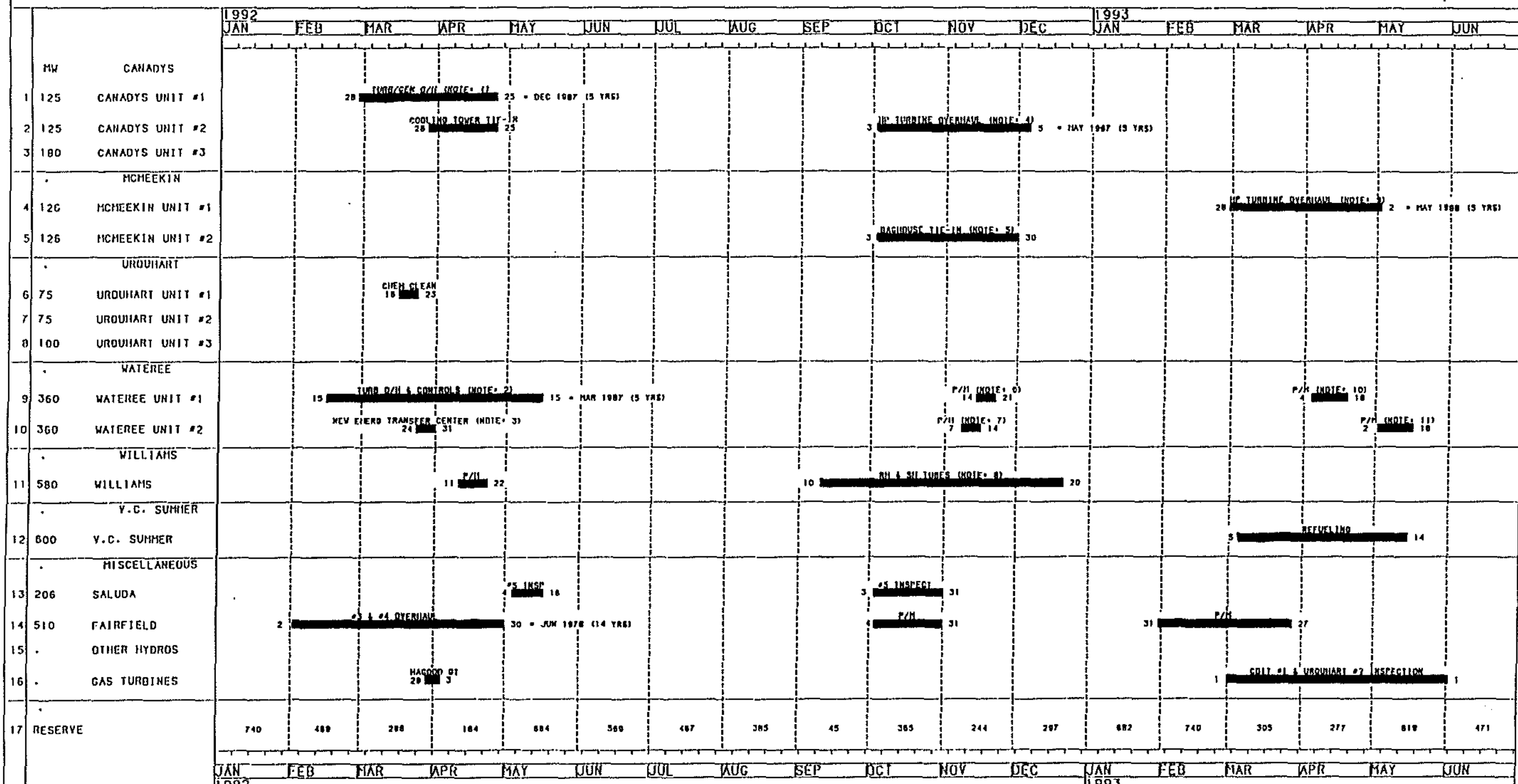
The two largest generating units on SCE&G's system are the A. M. Williams coal-fired facility in Charleston and the V. C. Summer Nuclear Station in Jenkinsville. For reliability purposes these two generating facilities do not have their scheduled maintenances at the same time. This significant operating 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 typically last for fifty-six days. The current outage projection calls for a ten-year inservice inspection outage in 1993, which should last approximately sixty-five days. A major maintenance project will be undertaken during the Fall 1994 refueling outage. This project will consist of the replacement of the steam generators and will extend the outage to approximately one hundred 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. Current maintenance plans for the Williams unit include the installation of a scrubber in the late 1990's. 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 the existing coal-fired units. Once the Environmental Protection Agency has provided the details of acceptable techniques for NOx reduction, SCE&G will then prepare a maintenance plan to implement these methods in its coal-fired units.

CHART 4.4.1.a

PLANNED MAJOR MAINTENANCE SCHEDULE



APPROVALS
D.R. MOORE
H.O. LORICK
S.U. KIDWAI
W.E. MOORE
D.J. BULLWINKEL

INSPECTION NOTES:

* = DATE OF LAST TURBINE INSPECTION

SPRING 1992

1. CAN #1 - A. DA INSP
   B. STEAM LINE INSP
   C. AIR RECIEVER INSP
   D. HANGER INSP
   E. BOILER INSP
2. WAT #1 - A. DA TANK/RECEIVER INSP
   B. HANGER INSP
   C. MS. RH LINE INSP
   D. CHEMICAL CLEANING
   E. BOILER INSP
3. WAT #2 - A. CHEMICAL CLEANING

FALL 1992

4. CAN #2 - A. DA TANK/RECEIVER INSP
   B. STEAM LINE INSP
   C. HANGER INSP
   D. BOILER INSP
5. MCM #2 - A. RECEIVER INSP
   B. HANGER INSP
   C. CHEMICAL CLEANING
6. WAT #1 - A. CHEMICAL CLEANING
7. WAT #2 - A. HTRH OUTLET TEE INSP
8. WIL #1 - A. RECEIVER INSP
   B. HANGER INSP
   C. CHEMICAL CLEANING

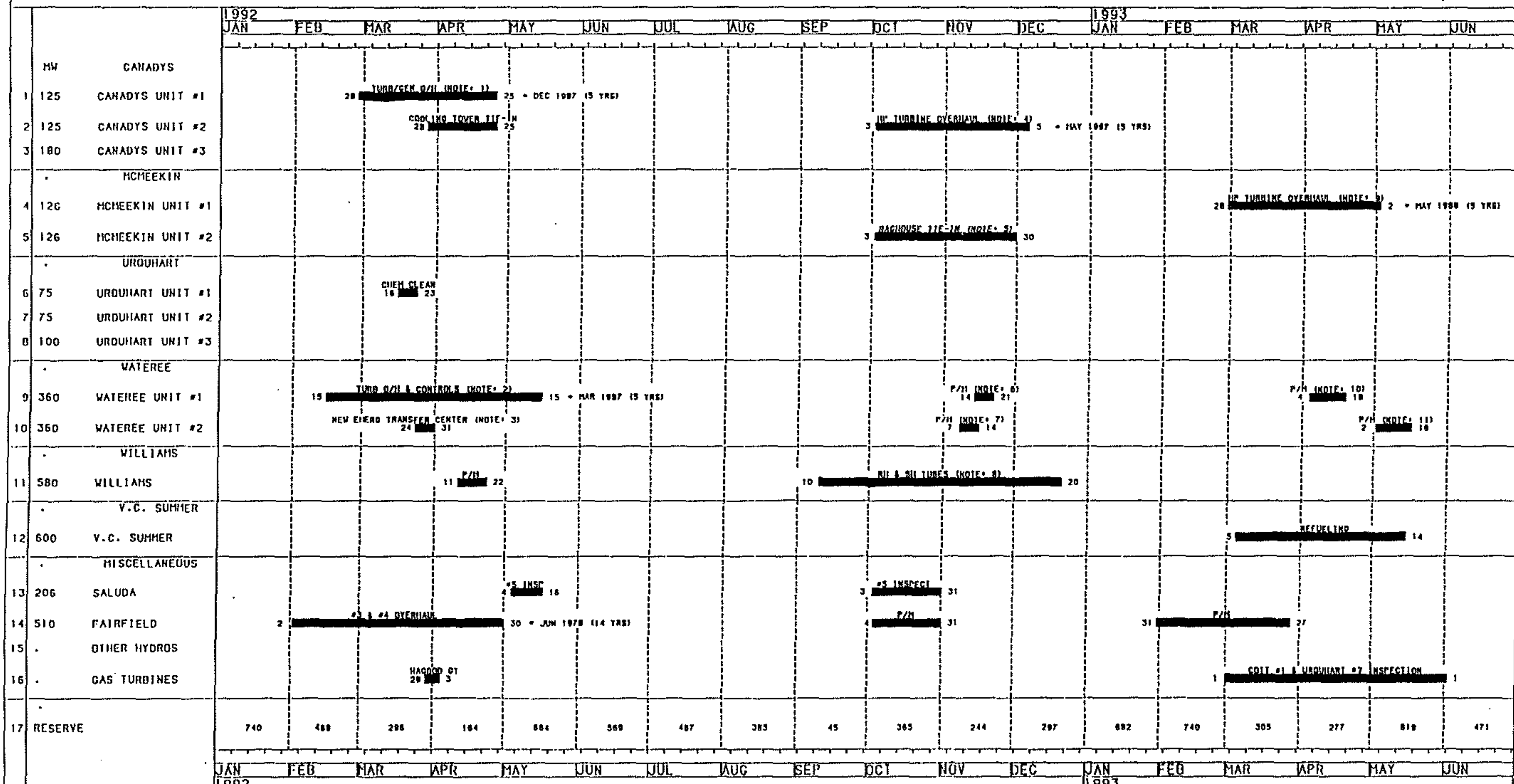
SPRING 1993

9. MCM #1 - A. BOILER INSP
   B. AIR RECEIVER INSP
   C. STEAM LINE INSP
   D. HANGER INSP
   E. CHEMICAL CLEANING
10. WAT #1 - A. HANGER INSP
11. WAT #2 - A. AIR RECEIVER INSP
   B. HANGER INSP

REVISION 1. 2 MAR 92

CHART 4.4.1.b

PLANNED MAJOR MAINTENANCE SCHEDULE



APPROVALS

D.R. MOORE
M.D. LORICK
S.U. KIDWAI
W.E. MOORE
O.J. BULLWINKEL

INSPECTION NOTES:

* DATE OF LAST TURBINE INSPECTION

SPRING 1992

1. CAN #1 - A. DA INSP
   B. STEAM LINE INSP
   C. AIR RECIEVER INSP
   D. HANGER INSP
   E. BOILER INSP
2. WAT #1 - A. DA TANK/RECEIVER INSP
   B. HANGER INSP
   C. MS. IN LINE INSP
   D. CHEMICAL CLEANING
   E. BOILER INSP
3. WAT #2 - A. CHEMICAL CLEANING

FALL 1992

4. CAN #2 - A. DA TANK/RECEIVER INSP
   B. STEAM LINE INSP
   C. HANGER INSP
   D. BOILER INSP
5. MCM #2 - A. RECEIVER INSP
   B. HANGER INSP
   C. CHEMICAL CLEANING
6. WAT #1 - A. CHEMICAL CLEANING
7. WAT #2 - A. HIGH OUTLET TEE INSP
8. WIL #1 - A. RECEIVER INSP
   B. HANGER INSP
   C. CHEMICAL CLEANING

SPRING 1993

9. MCM #1 - A. BOILER INSP
   B. AIR RECEIVER INSP
   C. STEAM LINE INSP
   D. HANGER INSP
   E. CHEMICAL CLEANING
10. WAT #1 - A. HANGER INSP
11. WAT #2 - A. AIR RECEIVER INSP
    B. HANGER INSP

REVISION 1. 2 MAR 92

EXISTING UNIT SCHEDULED MAINTENANCE

CHART 4.4.2

Unit	Normal Spring/Fall (Days/Year)	Major (Days/Year)	Major Cycle Interval (Years)	Cycle Start Year
Williams	28	70	5	1997
Wateree 1 Wateree 2	28 28	70 70	5 5	1997 1996
Canadys 1 Canadys 2 Canadys 3	14 14 24	70 70 70	5 5 5	1997 1997 1996
McMeekin 1 McMeekin 2	14 14	70 70	5 5	1993 1997
Urquhart 1 Urquhart 2 Urquhart 3	14 14 14	70 70 70	5 5 5	1996 1994 1995
V.C. Summer	65 (Spring 1993) 100 (Fall 1994) 56 (After 1994)			
I.C. Turbines	10	90	5	
Hagood 2	14			

5. Purchased Power

SCE&G's capability reserves are not more than adequate in 1992, and customer loads will be growing against that capability. Nevertheless, SCE&G hopes to avoid building other supply resources while the Cope unit is being constructed, and intends to maintain its reliability by purchasing limited-term capacity from other utilities with whom we are interconnected or who can make reasonable arrangements for wheeling. SCE&G has already contracted to purchase 100 MW of capacity during the months of June through September of 1993 and of 1994. Based on discussions we have had with other potential suppliers, we believe that we will be able to contract for as much as 350 MW in 1995 on terms that will be more advantageous to our customers than construction of peaking capacity concurrent with construction of a baseload plant.

SCE&G has not included any long-term purchased power options in its menu of choices for the base-case supply-side IRP plan. The Company does not mean to imply that such transactions are not eligible for consideration as part of the Company's future supply mix, but merely that any such transaction must be judged in part against the economics of what the Company can accomplish by constructing, owning, and operating its own supply resources.

Like many other utilities in high-growth regions of the country, SCE&G has had many representations made to it by owners, prospective owners, brokers, or other representatives of blocks of power for sale by contract. Because the Company is not currently in the market for long-term power supply, it is taking the opportunity to review and overhaul its policies and procedures with respect to offers of power from non-utility generation sources (NUGs). While these procedures are under review, the Company is declining to receive offer-specific information from any non-utility source. When the Company receives unsolicited communications, the source is asked to provide information about itself (corporate information, financial strength and arrangements, relevant experience), but not about its proposed project at this time.

In the meantime, the Company intends to prepare procedures and a sample specification package that might be used as a model to initiate and guide a process of resource acquisition by bidding. The intention of this initiative is to stimulate Company thinking about such a process, to develop channels of communication and methods of analysis that would be useful in conducting such a process and in evaluating received bids, and to prepare for some potential consequences and opportunities that may arise from national energy legislation currently taking shape.

By undertaking this study the Company is not committing itself to future acquisition of NUG sources, by bidding or any other means, anymore than it is ruling NUG sources out by not including them in the base-case supply-side IRP plan. The IRP plan considers type and timing of future supply resources considering systemwide needs and conventional technologies and methods of cost recovery. Nevertheless, very local circumstances (such as support for transmission in a particular load center or cogeneration involving an already existing steam host) may make consideration of NUG sources the course of wisdom, and changes in methods of cost recovery resulting from national or state legislative and/or regulatory action may make consideration of NUGs mandatory.

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). These are all levels of voluntary 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 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 except for Oglethorpe Power (SCE&G expects to have an interchange agreement with Oglethorpe by the end of 1992). 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.

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, however, may become competitive with conventional approaches. Two of these include coal gasification and solar photovoltaic cells. Recent advancements in these technologies have been lowering their capital and operating costs to some extent. The future potential of coal gasification 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:

1. 385 MW scrubbed coal unit to be built by Duke/Fluor Daniel, and owned and operated by SCE&G (Cope);
2. 400 MW scrubbed coal unit (SCE&G built);

3. 300 MW scrubbed coal unit (SCE&G built);

4. 200 MW scrubbed coal unit (SCE&G built);

5. 297 MW combined cycle unit;

6. 99 MW simple cycle internal combustion turbine; and

7. 99 MW simple cycle internal combustion turbine with selective catalytic reduction device (SCR).

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 385 MW coal-fired unit (Cope) was used as a basis for a first 400 MW unit on site for costs and operating characteristics because of the currency of the Cope project data.

The combined cycle unit considered as a viable conventional supply technology consisted of two 99 MW internal combustion turbines (ICT) with 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 (297 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. Operating costs were based upon 3,000 to 4,000 hours of operation per year.

The simple cycle internal combustion turbine was included as a conventional supply technology in two different configurations, with and without selective catalytic reduction. The generating output of both versions of the ICTs, based upon a 105 degree F ambient temperature, was 99 MW. The Hagood ICT was the basis for modeling specifications for the simple cycle ICT since the ICT at Hagood is the newest ICT on SCE&G's system and is approximately the same MW rating.

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 may not be necessary with generating units typically operating as peaking capacity at approximately 1000 hours of operation annually.

8. Supply-Side Process

SCE&G supply-side planners participate in many phases of the entire IRP process, including the development of reference values for avoidable generation resources to be used in valuing demand-side resources. After demand-side targets are set and forecasts of future loads are revised, the supply-side planners use their information, methods, and models to accomplish their primary mission: to identify a base-case supply-side IRP plan that provides supply and reserves to serve the remaining growth in system capacity and energy needs in a way that minimizes the sums of the present worths of all 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.

Supply-side IRP planning determines the timing of resource additions, considering only the growth in capacity and energy needs. Supply-side IRP planning determines the type of each resource addition, considering one consistent set of assumptions about future costs of all kinds. And supply-side IRP planning determines timing and types of resources considering a scope of obligation 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 planned resources by some neighbor utility, is very likely to be able to produce a better plan than a process that looks only at the timing of load growth. A series of decisions made over time, under changing expectations about various future prices, will likely yield a better result than making all those decisions 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 members of regional electric reliability councils, will probably produce a better result than a plan that has only a service-territory scope.

The facts of life in the preceding paragraph should not be regarded as disparaging of the IRP supply-side base-case plan, however it may seem. The base-case plan does not take advantage of all the information used in a particular 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 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 capacity type is added. But a process that schedules several resources over a long planning horizon will identify a mix that achieves or maintains a good balance of capacity 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-run objective.

Supply-side planners at SCE&G concentrate on providing the long-run perspective in developing the IRP supply-side base-case plan. Planners develop plans over twenty-year horizons, and model the dispatch of those systems for ten or more years beyond installation of the last unit, 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 use a variety of commercial and custom software products, but two in particular play a large role in developing long-range plans:

> EGEAS is a package of models developed initially by the Electric Power Research Institute (EPRI) and now maintained by Stone and Webster. The EGEAS application most useful to 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. 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 an extremely useful mode. The analyst must be very careful in using and depending on EGEAS, however, for several reasons. There are several refinements of unit operation or description which EGEAS may not model very reliably--fuels that are available only part of the year, for instance, or capacity additions that are not permanent, such as a limited-term purchase. And there are some circumstances, especially when more than a small number of resource types are included in the choice menu, when EGEAS may produce a solution that is not optimal. Use of EGEAS requires much testing, experience with the model, and experience in supply planning work. And EGEAS results require validation in other models, especially PROSCREEN.

PROSCREEN is a package of interdependent models devised and maintained by Energy Management Associates. Two modules in particular are employed in development of IRP plans: GAF ("Generation and Fuel") models the dispatch of the current and a given future system to future loads, subject to many kinds of operating constraints, such as maintenance schedules and expected exposure to forced outages. GAF collects information about fixed operating and maintenance costs, fuel costs, and other variable costs, and passes this information to CER ("Capital Expenditure and Recovery"). CER models the flows of costs to construct the given future units, taking financing and tax considerations into account; it also models the flows of revenues required to cover all costs of ownership, return of investment through depreciation, return on investment at an input rate, and all operating, maintenance, and fuel costs. The revenue requirements of all kinds are summed up by year, discounted back to the present using a proxy for the opportunity cost of capital, and summed. That sum, the Accumulated Present Worth of Revenue Requirements (APWRR) is a figure of merit that allows comparison of whole plans.

PROSCREEN is not an optimizing program; it calculates the cost consequences of meeting a particular set of loads with a particular plan, so the analyst must make repeated runs, making slight variations in the input plans, to find the optimal version of a particular strategy. And although PROSCREEN can model atypical or constrained resources more accurately than EGEAS, the analyst must often use a great deal of ingenuity to model the constraints, and must do much testing to be sure that ingenuity does not have consequences that were never intended. Nevertheless, the results of a validated PROSCREEN run have a great deal of merit, and PROSCREEN results can be taken to the Company's Financial Planning department as a starting point for analysis to determine what a plan will mean for the Company's ratepayers and financial stakeholders.

SCE&G supply-side planners also construct alternative plans to the base-case plan, either to provide a basis for testing the base-case plan, or to meet alternative future circumstances. Both the base-case plan and alternative plans will be discussed later in this chapter.

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 1992 IRP process should be identified.

First among the givens is the 385-MW Cope unit, scheduled to be on line before the summer peak of 1996. Other capacity-related givens include the retirement of 48 MW of Parr Steam and remaining Hagood Steam capacity after 1992. Net capability at Williams will be reduced by 2 MW whenever new cooling tower pumps are being operated; they are scheduled to be installed by 1994. SCE&G and SCPSA plan to replace the V. C. Summer nuclear plant steam generators during a long refueling/maintenance outage in late 1994, and SCE&G currently assumes that there will then be an increase of 10 MW in its two-thirds share of the plant's output.

An additional specific assumption is that a limited-term purchase strategy will allow the Company to avoid constructing any other new generation resource during the construction period for the Cope plant.

Other assumptions are more general. One such assumption is that the Company will not retire any plants besides Hagood Steam and Parr Steam during the planning horizon. That may be an optimistic assumption, since the three coal-fired units at Urquhart, for instance, are all nearly forty years old. Nevertheless, the current assumption is that construction of new generation will be limited to that necessary for load growth, and not for capacity replacement. Another general assumption is that for general planning purposes a target reserve margin of 20% of expected peak will continue to be an appropriate guideline, and that limited-term purchases will be available to lead in to baseload additions after the Cope unit, to minimize capacity "bulges."

SCE&G is not constrained by Phase I of the 1990 Clean Air Act Amendments. The Company is in the process of developing a strategy to meet its obligations under Phase II, which will be effective after the end of 1999. While the final strategy has not yet been determined, supply-side planners are assuming a mix of responses to coming limits on SO2 emissions: all future coal plants will be equipped with scrubbers, one current coal plant will have a scrubber retrofitted, all unscrubbed plants will be fueled with low-sulfur coal (possibly requiring baghouses to replace electrostatic precipitators), and the Company will have some opportunity to co-fire low-priced summer-season natural gas in some of its coal plants. The current assumption is that the Williams plant will be retrofitted with a scrubber, with a net capacity reduction of about 10 MW because of station service load to operate the scrubber equipment.

Initial PROSCREEN runs for a plan assume that coal plants will not co-fire natural gas, and that all plants will be dispatched according to system and plant economics. Annual SO2 emissions for years after 1999 are estimated in a spreadsheet model and compared with an estimate of our SO2 "cap." If emissions do not exceed the cap, or if they do not exceed the cap by more than the Company believes it will be able to manage by co-firing gas with coal during non-heating seasons, then the economic dispatch is deemed appropriate. If, however, emissions are higher than may be managed by a co-firing strategy, then dispatch constraints must be applied to force plants with lower emissions (but higher costs) to higher levels of dispatch. This environmental constraint on economic dispatch had a direct bearing on the rejection, for the time being, of one candidate technology for the supply-side base-case IRP plan.

10. The Supply-Side Plan and Alternative Plans

The IRP base-case supply-side plan meets future capacity and energy needs with a balance of about 1000 MW of baseload and about 700 MW of peaking capacity. The plan assumes a strategy of limited-term purchases of capacity and energy leading up to the commercial operation of the Cope plant in 1996. After 1996 the plan schedules 99-MW simple-cycle internal combustion turbines at the rate of one a year through 2001 and another in 2003. A 300 MW coal-fired plant in 2005 is led up to by means of a limited-term purchase in 2004. The plan concludes with an ICT in 2007, a limited-term purchase in 2009, and a second 300 MW coal-fired plant in 2010. (For a detailed schedule of this plan see Table 4.10.1.)

This plan keeps reserve margins in a very narrow band ranging from 19% to 23% of projected peaks. The ordering of the units aims at keeping a balance between baseload and intermediate/peaking capacity. Studies indicate that SCE&G's long-run supply costs are minimized when the baseload proportion of the Company's total capacity is at about two-thirds of total system capacity. The Cope plant will add a large block of baseload capacity and raise the Company's baseload proportion to 74%. As ICTs are added over the next several years that proportion will decline to 65% by 2003. The baseload proportion will be 68% in the last year of the twenty-year plan, assuming that no existing plants are retired.

The non-peaking resources chosen were two 300 MW coal plants, chosen over 200 MW coal plants, 400 MW coal plants, and 297 MW dual-fuel combined-cycle plants. Studies previous to this IRP would have chosen the greater economies of scale achievable with the 400 MW plant size, but the accelerated DSM efforts have reduced the projected growth of peaks and energies enough that smaller incremental additions of baseload yield lower study-period costs, under plan assumptions.

Studies substituting 297 MW dual-fuel combined-cycle plants for the 300 MW coal plants initially showed a long-run accumulated present worth of revenue requirements (APWRR) advantage of about 0.9% for the combined-cycle plan. Examination of the dispatch patterns revealed that the combined-cycle units were dispatched much less than the scrubbed coal units they replaced, since the combined-cycle fuels (No. 2 oil during the heating season, and natural gas otherwise) were more costly than coal. Because the CC units were dispatched so little, unscrubbed coal units were dispatched much more heavily, and post-1999 SO2 emissions were much greater than the Company expects to be allowed. When the CC units were constrained to dispatch at a higher level to bring total system emissions down to base-case levels, the combined-cycle case APWRR was about 1.1% higher than the base-case APWRR. Although the scrubbed coal units have higher capacity costs, they produce low-cost and low-emissions energy. Energy from the low-emissions combined-cycle units, even at the current projections for gas and oil prices, is not yet inexpensive enough to displace scrubbed coal energy.

Supply-side planners also produced a plan fitted to future peak demands and annual energies that would be expected if the Company ceased all DSM promotion after 1991. The higher growth rates required a much greater expansion plan--about 1100 MW of baseload capacity and about 1300 MW of peaking capacity, including 99 MW ICTs in 1994 and 1995, before the Cope unit. The baseload proportion of total capacity in this plan settles out at about 62%. This is a reasonable outcome because the loads this plan meets are "peakier," with lower daily, seasonal, and annual load factors. One consequence of DSM load-leveling is that a higher proportion of total customer load is made eligible to be served by baseload generation, so the optimum baseload proportion is higher for a system with loads altered by DSM.

TABLE 4.10.1

Supply–Side of the Integrated Resource Plan

YEAR	PEAK (MW)	CAPACITY CHANGES ONE YEAR (MW)	LONG TERM (MW)	DESCRIPTION	CAPACITY (MW)	RESERVE MARGIN
1992	3,306	50		SPOT CAPACITY PURCHASES	3,962	19.84%
1993	3,354	100		4 MONTH LIMITED TERM PURCHASE	4,014	19.68%
		50		4 MONTH LIMITED TERM PURCHASE		
			−28	RETIRE PARR STEAM		
			−20	RETIRE HAGOOD STEAM		
1994	3,396	100		4 MONTH LIMITED TERM PURCHASE	4,062	19.61%
		100		4 MONTH LIMITED TERM PURCHASE		
			−2	WILLIAMS COOLING TOWER		
1995	3,501	350		4 MONTH LIMITED TERM PURCHASE	4,222	20.59%
			10	VCSN STEAM GENERATOR UPGRADE		
1996	3,561		385	COPE UNIT	4,257	19.55%
1997	3,628		99	ICT	4,356	20.07%
1998	3,700		99	ICT	4,455	20.41%
1999	3,770		99	ICT	4,554	20.80%
2000	3,837		99	ICT	4,643	21.01%
			−10	SCRUBBER AT WILLIAMS		
2001	3,907		99	ICT	4,742	21.37%
2002	3,972				4,742	19.39%
2003	4,038		99	ICT	4,841	19.89%
2004	4,112	100		4 MONTH LIMITED TERM PURCHASE	4,941	20.16%
2005	4,185		300	PULVERIZED COAL UNIT	5,141	22.84%
2006	4,252				5,141	20.91%
2007	4,320		99	ICT	5,240	21.30%
2008	4,390				5,240	19.36%
2009	4,460	100		4 MONTH LIMITED TERM PURCHASE	5,340	19.73%
2010	4,528		300	PULVERIZED COAL UNIT	5,540	22.35%
2011	4,600				5,540	20.43%

11. Flexibility and Risks

The 1992 base-case IRP plan is intended to provide the Company with supply-side flexibility to manage either higher or lower growth in customer requirements than is posited.

Flexibility to manage growth that is lower than expected is generally accomplished by not committing to supply-side resources ahead of need or earlier than construction lead times allow.

Flexibility to manage growth higher than forecast is necessary as well. Although SCE&G is pursuing DSM aggressively, and holds as an objective the postponement of construction needs by promoting conservation to its customers, customers nevertheless will make their own choices and decisions. Customers make both long-run and moment-to-moment 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 needs 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.

Flexibility is desirable not merely because loads cannot be predicted with certainty, however, but also because temporary or immediate circumstances may make short-run variations in the long-run plan advantageous or even necessary. The early part of the supply-side plan presents an example: supply-side planners had identified a need for capacity in the years preceding the Cope plant, but investigation of the market for limited-term purchases led to an alternative supply-side strategy. Both avenues are actively being explored at the present. SCE&G is proceeding with the task of identifying sites and preparing for the permitting process for ICT units that might be brought on line before the Cope unit, but the Company currently expects to provide adequate service in a less costly way by using purchases to postpone those units until after 1996. Because of the preliminary permitting work, the Company retains the capability of constructing ICT units if load growth should accelerate or if adequate capacity should not be available for purchase at advantageous terms. The current expectation, however, is that the Company will rely on purchases for capacity requirements before the Cope plant.

Immediately after 1996 the supply-side base-case plan includes a succession of ICT units. This phase of the plan derives most of its flexibility from the relative ease with which ICT units can be postponed or even advanced, if the siting and permitting groundwork has been prepared. As this period approaches the Company will explore whether it may be possible to capture some procurement and construction economies by building more than one unit at a time, staging phases of construction to use the same crews.

During this period the Company will also have to consider the relative advantages of dispersed vs. concentrated locations for ICTs. ICTs dispersed about the transmission system but located near load centers can provide local generation and transmission support during transmission disruptions, but total site-related costs and staffing costs will be higher. ICTs located together in parks will have lower site-related costs and staffing costs, and if the park is located at a current coal plant site or where coal could be delivered, then some coal-gasification process could eventually provide a hedge against natural gas price or deliverability problems. Coal-gasification for dispersed ICTs will likely not be feasible because site-related costs will be high and because economies of scale do not favor small gasification plants. Each of these siting strategies for ICTs provides an enhanced flexibility of one sort, but only at the cost of reduced flexibility of another sort; it is possible that each strategy could be followed with some of the planned units.

The ICT units scheduled after the Cope baseload plant will provide capacity and reliability, but they are not expected normally to be called upon to provide much energy. Under the assumptions of this IRP process about the effectiveness of DSM, the Company will not need another high-capacity-factor resource before 2005. And under current assumptions about relative fuel prices and the Company's probable response to requirements of the 1990 Clean Air Act Amendments, the resource with the lowest total cost in the long run is a scrubbed coal plant of about 300 MW.

The decision date for this resource is at least seven years away, and during this period the Company will be watching the factors and circumstances that might make a dual-fuel combined-cycle plant a serious competitor to a scrubbed coal plant. At present, the advantages of coal include less uncertainty about supply and deliverability over a period as long as the life of a base-load plant, and less uncertainty about the cost of controlling system SO2 emissions. Capital and operating costs for flue-gas desulfurization are known with a fair degree of certainty, so the total cost of providing baseload energy within SO2 emissions limits is less uncertain for a scrubbed coal plant than for a dual-fuel combined-cycle plant.

Capital costs and operating costs other than fuel are as well known for combined-cycle plants as for coal plants. The greater uncertainty about the total combined-cycle cost of providing baseload energy within emissions limits results from uncertainty about fuel prices and natural gas deliverability. Such a plant would presumably be fueled with natural gas except during heating-season months, when the available fuel would be No. 2 oil.

Natural gas prices have remained low for longer than would have been the case if the only downward pressure on prices had been the necessity to work through the "gas bubble." In years past, prices for gas offered to SCE&G as a fuel for generation of electricity during summer months had been capped only by the competing fuel, No. 2 oil for ICTs. Recently, however, intrafuel competition has kept gas prices lower than interfuel competition ever did, and many forecasts of future gas prices reflect the pressures of intrafuel competition.

Can natural gas prices remain low? One natural limit is the cost of replacing reserves, the exploration and development costs involved in extending supply of a limited and non-renewable resource. If prices are too low, exploration and development will slow or cease, but then supplies will tighten up. Assuming that demand remains the same, gas users will bid prices up until they are high enough to support exploration and development and increase supply. A primary intention of deregulation of natural gas markets over the last several years has been to reestablish the clarity of price signals throughout the range of gas markets.

Since gas prices must in the long run cover costs of exploration and development they cannot rise less than inflation unless there are productivity gains in this industry greater than those in other industries. This is possible, but not predictable. And since the more obvious and accessible possibilities are the first to be explored, costs are likely to rise at least proportionately with the difficulties and risks of exploring what remains. The conclusion is that the likelihood of gas prices remaining as relatively low as they are now for the life of a power plant is not very great.

Long-term gas contracts are being offered now to owners of power plants, with prices preset for as long as fifteen years. This is an interesting development, but not the complete solution to fuel price predictability that it might seem. Prices for continued supplies after the end of the contract will reflect market conditions at that time, so price uncertainty remains for any plant expected to be in service for more than fifteen years. Contracts include constraining conditions of supply, such as take-or-pay terms and minimum rates of gas take that disregard electric load patterns, and the lower prices are associated with more restrictive conditions. If a gas-fired resource is dispatched out of normal economic order because its fuel cannot be cut back, then some other resource must be cut back when electric loads are low. Long-term contracts are typically for supply at the source; deliverability is still an issue and a risk, and rates for gas transmission are not fixed for the long term. A final consideration for a long-term contract at set prices is the risk that if the set prices diverge too far from current market prices for transactions that occur every day for years, the contract is likely at some point not to be honored. If the seller is tied to contracts with prices too low, he may use bankruptcy to avoid the contract or he may have reorganization forced on him. Any customer would lose either the supply or the price or both; in any case the customer would lose the predictability that the contract apparently offered.

Natural gas deliverability will continue to be a source of uncertainty for utility and industry planners. Lower gas prices lead to greater demand for gas transportation services, and deregulation of the gas transportation industry will likely result in transportation capacity's being expanded, but only as transportation prices are bid up. The length of time required for pipeline permitting and construction may result in problems for utilities or industrial gas customers, especially if their individual plans conflict.

Another issue that relates to both gas supply and deliverability is the difference in gas and electric industry attitudes toward reliability of service. Historically, electric utilities have built reserve capacities to minimize service interruptions, while gas suppliers and pipelines have used interruption as a strategy to minimize unproducing reserve capacities. Whatever is undertaken to reconcile these attitudes will create some costs somewhere, and these costs will ultimately fall on energy end-users.

One strategy an electric utility can use to hedge against gas price rise and deliverability uncertainties is to retain the potential to develop coal-gasification. At current natural gas price levels coal-gasification would not be a primary strategy, but it could be a fall-back strategy if a utility installed gas-fired plants together in a park where coal delivery and gasification could be permitted and constructed. If the fall-back strategy were implemented, the ultimate result would be a plant that could convert the energy in coal into electricity at a somewhat higher cost than if the plant had been built as a scrubbed coal-fired steam plant in the first place, but that still might be preferable to a continuing reliance on high-cost natural gas. (A fallback strategy of No. 2 oil is probably not a good long-term strategy, since although oil prices provide a cap for gas prices, the level of the cap is less predictable than that provided by coal gas. Current forecasts of oil prices are lower than in years past, but this optimism does not result from any permanent gain in oil industry productivity, but rather from world political developments, which are less predictable in their permanence.)

For all these reasons, supply-side planners at SCE&G could not at this time recommend a choice of dual-fuel combined-cycle over a scrubbed coal plant for a high-capacity-factor supply resource. The Company will watch developments in the natural gas and coal-gasification industries carefully over the next several years, however, and it is possible that by the time a decision must be made about building or replacing a baseload-capable plant, some factors will have changed and some uncertainties will have been resolved.

In the meantime, the Company will look for opportunities to use low-cost interruptible gas during non-heating season months as a mitigation strategy to help accomplish various environmental objectives. Recently, the Company has burned natural gas in steam plant boilers, either alone or co-fired with coal, to reduce particulate emissions, and the Company anticipates that displacing coal with interruptible gas during some months will be one part of a complex strategy to meet our customers' demands within our annual SO2 emissions constraints after 1999.

One very large area of uncertainty is yet to be discussed. SCE&G, South Carolina Generating Company (owner of the A. M. Williams coal-fired plant), and SCANA, the holding company for both of these companies along with other subsidiaries, are all subject to governmental regulation of one kind or another, and there are regulatory uncertainties at the state and especially at the federal level.

At the state level, questions about the treatment of DSM costs have yet to be settled. The Company feels encouraged to pursue the programs and thus to incur the costs, but if the question of cost recovery goes too long unanswered, financial markets may begin to see a degree of risk that could be reflected in bond ratings and share values.

At the federal level, as this IRP is being prepared, major pieces of energy legislation are being debated in each house of Congress. Each bill is comprehensive, including many energy-related issues. At this time, before either bill has passed in its house and before the process of mark-up in a House-Senate Conference Committee, it is not possible to predict the final form of the legislation, but it seems certain that some major work of national energy legislation will be passed this year. Some of the issues under debate are consistent with the forms and intentions of IRP, as practiced in South Carolina. But some issues have very large implications for the structure, division of responsibilities, permissible modes of ownership and operation, and distribution of risks and opportunities for revenues of the electric utility industry in the United States. Federal legislation could nullify results of IRP processes in this state and many others by redefining, not just the rules of the game, but the game itself and all its players.

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 het, 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 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%.

Type of Plant:	Cope – Pulverized Coal	
Capacity (MW):	Maximum	385
	Minimum	100
Capital Cost ($/KW, 1992$):	First Unit	
	Second Unit	
Construction Lead Time (Years):		6

Annual % Breakout for Construction Expenditures

Beginning Balance	3.4 %
1992	8.8 %
1993	26.6 %
1994	41.3 %
1995	16.9 %
1996	3.0 %

Expected Life (Years):		44
Heat Rate (BTU/KWH):	@Maximum	9,550
	@Minimum	11,000
Forced Outage Rate:	Immature	10 %
	Mature	7 %
Fixed O&M ($000/Year, 1996$)	First Unit	12,603
	Second Unit	N/A
Variable O&M ($/MWH, 1996$)		2.29
Maintenance (Days per Year/Spring–Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

Type of Plant:	Pulverized Coal		
Capacity (MW):		Maximum	400
		Minimum	100
Capital Cost ($/KW, 1992$):		First Unit	1,074
		Second Unit	1,025
Construction Lead Time (Years):			7

Annual % Breakout for Construction Expenditures

	First Unit	Second Unit
Year #1	0.1 %	0.3 %
Year #2	3.2 %	3.5 %
Year #3	8.8 %	6.7 %
Year #4	26.5 %	24.4 %
Year #5	41.3 %	44.5 %
Year #6	16.9 %	17.5 %
Year #7	3 %	3.1 %
Year #8	%	%

Expected Life (Years):		44
Heat Rate (BTU/KWH):	@Maximum	9,550
	@Minimum	11,000
Forced Outage Rate:	Immature	10 %
	Mature	7 %
Fixed O&M ($000/Year, 1992$)	First Unit	10,877
	Second Unit	8,525
Variable O&M ($/MWH, 1992$)		1.98
Maintenance (Days per Year/Spring–Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

Type of Plant:	**Pulverized Coal**		
Capacity (MW):		Maximum	300
		Minimum	75
Capital Cost ($/KW, 1992$):		First Unit	1,171
		Second Unit	1,117
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):		44
Heat Rate (BTU/KWH):	@Maximum	9,599
	@Minimum	11,292
Forced Outage Rate:	Immature	10 %
	Mature	7 %
Fixed O&M ($000/Year, 1992$)	First Unit	9,963
	Second Unit	7,815
Variable O&M ($/MWH, 1992$)		2.16
Maintenance (Days per Year/Spring–Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

Type of Plant: Pulverized Coal

Capacity (MW):	Maximum	200
	Minimum	50
Capital Cost ($/KW, 1992$):	First Unit	1,343
	Second Unit	1,281
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):		44
Heat Rate (BTU/KWH):	@Maximum	9,694
	@Minimum	11,388
Forced Outage Rate:	Immature	10 %
	Mature	7 %
Fixed O&M ($000/Year, 1992$)	First Unit	8,788
	Second Unit	6,932
Variable O&M ($/MWH, 1992$)		2.44
Maintenance (Days per Year/Spring–Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

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 exhause 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).

Type of Plant: Combined Cycle – Full Unit

Capacity (MW):	Maximum	297
	Minimum	50
Capital Cost ($/KW, 1992$):	First Unit	646
	Second Unit	N/A
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):		30
Heat Rate (BTU/KWH):	@Maximum	7,990
	@Minimum	15,150
Forced Outage Rate:	Immature	15 %
	Mature	10 %
Fixed O&M ($000/Year, 1992$)	First Unit	2,440
	Second Unit	N/A
Variable O&M ($/MWH, 1992$)		2.34
Maintenance (Days per Year/Spring–Fall Outage)	Normal	28
	Major	70
Interval for Major Maintenance (Years):		5

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.

Type of Plant:	ICT – Simple Cycle		
Capacity (MW):		Maximum	99
		Minimum	50
Capital Cost ($/KW, 1992$):		First Unit	380
		Second Unit	N/A
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):		30
Heat Rate (BTU/KWH):	@Maximum	12,571
	@Minimum	15,150
Forced Outage Rate:	Immature	10 %
	Mature	8 %
Fixed O&M ($000/Year, 1992$)	First Unit	415
	Second Unit	N/A
Variable O&M ($/MWH, 1992$)		1.34
Maintenance (Days per Year/Spring–Fall Outage)	Normal	10
	Major	21
Interval for Major Maintenance (Years):		5

Type of Plant: ICT – Simple Cycle with SCR

Capacity (MW):	Maximum	99
	Minimum	50
Capital Cost ($/KW, 1992$):	First Unit	483
	Second Unit	N/A
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):		30
Heat Rate (BTU/KWH):	@Maximum	12,571
	@Minimum	15,150
Forced Outage Rate:	Immature	10 %
	Mature	9 %
Fixed O&M ($000/Year, 1992$)	First Unit	1,378
	Second Unit	N/A
Variable O&M ($/MWH, 1992$)		2.01
Maintenance (Days per Year/Spring–Fall Outage)	Normal	15
	Major	21
Interval for Major Maintenance (Years):		5

5.0 FINANCIAL ANALYSIS

5.0 FINANCIAL ANALYSIS

1. Sequential Evaluation of DSM Programs
2. Financial Viability of the IRP Base Plan
3. Benefits of Demand-Side Management

5.0 FINANCIAL ANALYSIS

The purpose of the financial analysis section is threefold: (1) to ascertain the need to re-evaluate the DSM programs in a sequential manner, that is, one program at a time or one subgroup of programs at a time; (2) to evaluate the financial condition of the Company under the base plan; and (3) to calculate the overall net benefit of the Company's DSM efforts.

1. Sequential Evaluation of DSM Programs

The Company initiates IRP by establishing a reference supply plan to use in developing new DSM targets and hurdles. There was concern that it might be inappropriate to use a single reference plan as a basis for evaluating all new DSM potential. If the final supply-side base plan differed significantly in character from the original reference plan, that would indicate the need to analyze DSM programs one or several at a time and at each iteration to establish a new reference supply plan for evaluation in subsequent iterations. The Company opted not to analyze its DSM programs in this iterative manner, for several reasons. First, the character of the supply-side base case plan was similar to that of the reference plan. This can be seen in the percent of incremental baseload and peaking capacity required under each plan. The table below compares these plans:

INCREMENTAL LONG-TERM CAPACITY (20-YEAR PLANS)

	Reference Plan		Base Plan	
	(MW)	%	(MW)	%
Baseload	1300	59	985	57
Peaking	990	41	693	43
Total	2290	100	1678	100

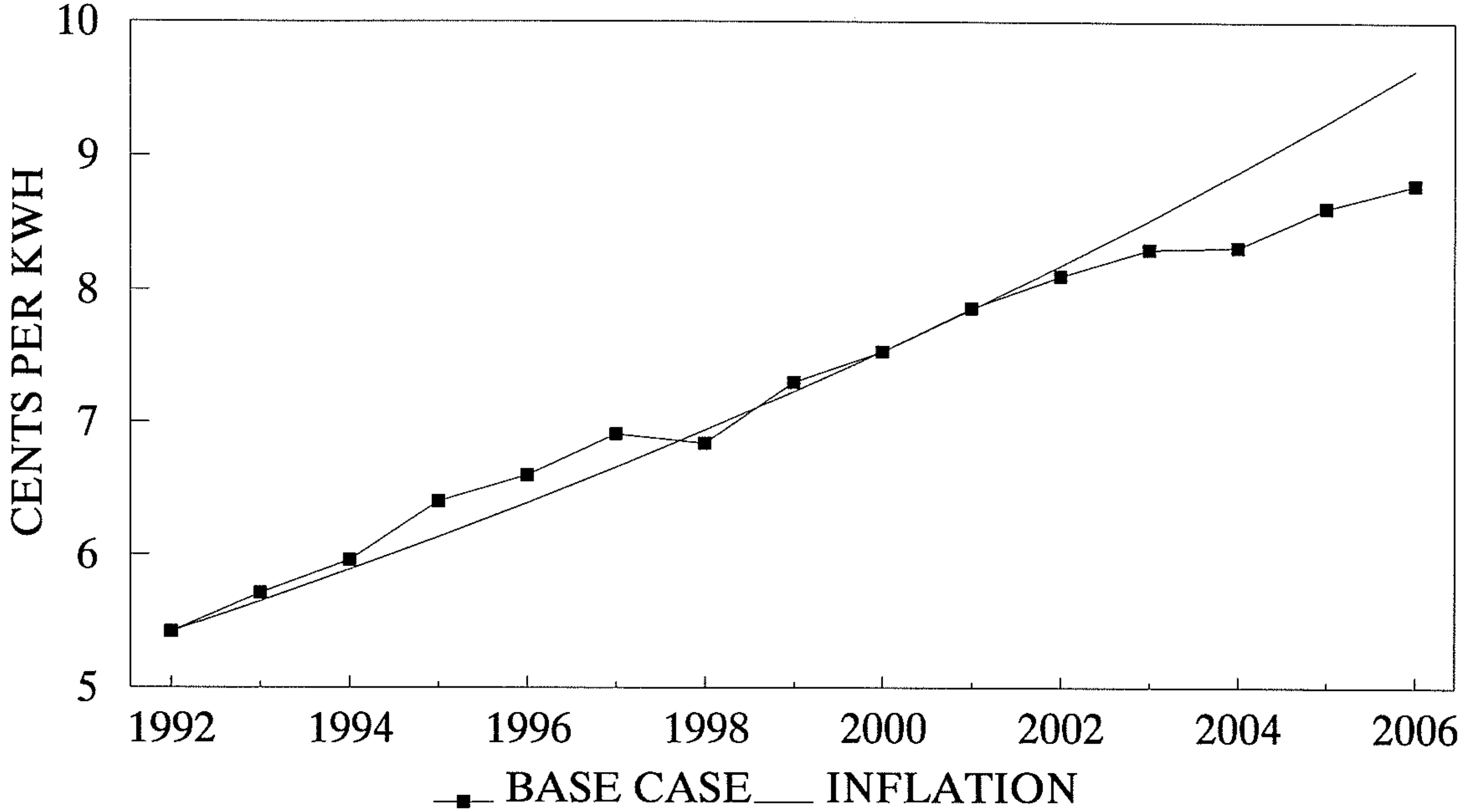
Secondly, the Company's DSM program, in total, was projected to have a significant and desirable effect on the demand and energy forecasts. It was projected to be cost-effective and to represent a comprehensive effort spanning all classes of customers. Finally, the Company felt that it was making a significantly larger effort in the area of DSM, and it would be prudent to gain more experience with the scale of this effort before adding or deleting programs.

2. Financial Viability of the IRP Base Plan

The IRP base plan must be financially viable. This requires an analysis of the cost of energy to our customers as well as estimation of effects on shareholder interests.

For the IRP base case, the estimated annual average cost per KWH, over all customers, is compared with a forecast of consumer inflation in Chart 5.2.1. This analysis indicates that the Company is doing a good job of keeping the growth in costs down, considering that there are large costs for new plants, for new DSM, and for large environmental projects during the years included in the analysis.

CHART 5.2.1: CUSTOMER COST vs. CONSUMER INFLATION



From an investor's perspective, capital will be needed to fund a construction program for not only new generation facilities, but also environmental remediation expenditures to comply with the Clean Air Act, and ongoing system improvements and expansion to meet forecasted customer growth. Investor considerations must be balanced with those of customers. Financial stability and strength are essential in maintaining the necessary flexibility to respond to the changing utility environment. Major construction expenditures, issuances of common stock and debt securities, and long-term commitments all can have a significant impact on the financial flexibility of the Company. Also of importance in the evaluation of financial and investor concerns is the Company's ratio of earnings to fixed charges. Scrutiny of this ratio becomes particularly important when analyzing purchased power strategies which obligate the Company to make long-term fixed payments to another company such as a non-utility generator (NUG).

The Company has analyzed these financial considerations in the IRP base case and feels confident that under the assumptions of cost recovery and adequate and timely rate relief, it will retain sufficient financial flexibility to protect the interest of investors.

3. Benefits of Demand-Side Management

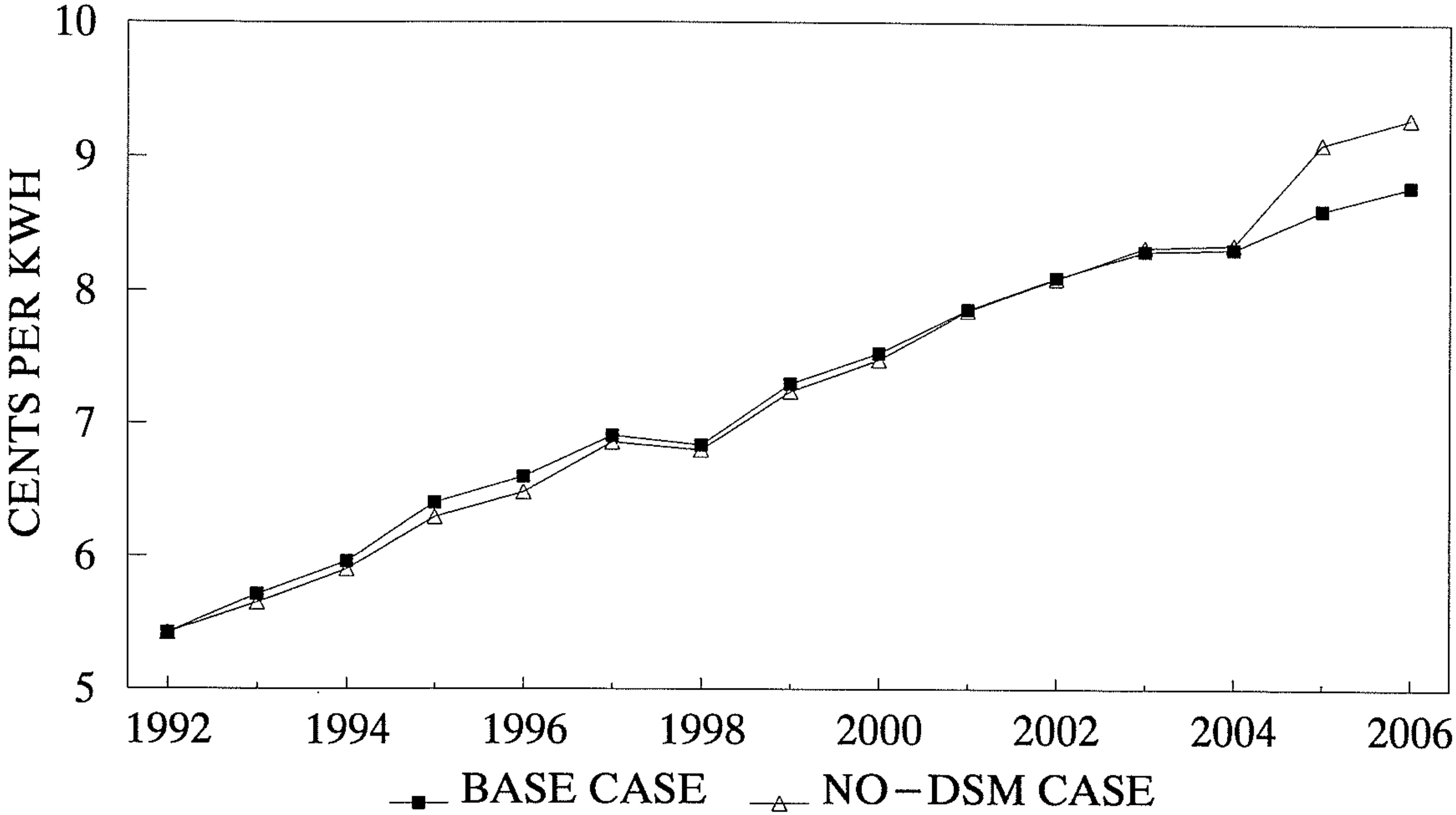
As a test of the value of the DSM programs in the IRP, the Company constructed a case in which all outlays for DSM were halted after 1991, with no DSM effects on loads except for the embedded effects of such programs as Good Cents and Great Appliance Trade-Up. Forecasts of peak demands and annual energy sales were higher for the no-DSM case, and so were construction requirements for new generation. Total revenue requirements were higher for the no-DSM case than for the IRP base case in every year.

Nevertheless, as Chart 5.3.1 illustrates, annual average cost per KWH would be slightly lower for a no-DSM case, for perhaps a decade. There are two reasons for this result. The first is that the reduction in annual KWH sales in the IRP base case relative to the no-DSM case is proportionally greater than the reduction in revenue requirements, so rates would have to be slightly higher for full revenue recovery. The second reason is that the costs of DSM appear before the benefits accrue. The higher rates in the IRP base plan may be thought of as an investment by the Company's customers, looking forward to a return in the future, when large construction outlays can be postponed. That this customer investment will pay off is predicted by the relative rate advantage of the IRP base case in the later years of the analysis.

In summary, the Company estimates that its DSM program will save $191 million in accumulated present worth revenue requirements over the next fifteen years. The table below highlights some of the major components of this savings.

	Change in Present Worth Revenue Requirements (000)
DSM Expenses	$ +89,345
Non-Fuel Revenue	-201,258
Fuel Revenue	-78,498
Total Change	$ -190,521

CHART 5.3.1: CUSTOMER COST--NO-DSM vs. BASE CASE



6.0 OTHER CONSIDERATIONS

6.1 ENVIRONMENTAL PLANNING

1. Introduction
2. Air
3. Cooling Towers
4. Environmental Support Services
5. Hazardous Waste
6. Low and High Level Nuclear Waste
7. Hydro Power
8. Land and Lake Management
9. Transmission Lines
10. Impact of Demand-Side Management

6.2 TRANSMISSION AND DISTRIBUTION PLANNING

1. Mission Statement
2. Transmission Planning
3. Substation Planning
4. Interconnection Planning
5. Distribution Planning

6.3 TECHNOLOGY REVIEW

1. Photovoltaics
2. Compressed Air Energy Storage
3. Advanced Light-Water Nuclear Reactors
4. Fluidized-Bed Combustion
5. Coal Gasification
6. Fuel Cells
7. Refuse Derived Fuel
8. Wind Turbines
9. Geothermal
10. Ocean Energy

6.0 OTHER CONSIDERATIONS

6.1 ENVIRONMENTAL PLANNING

1. Introduction

Forecasting environmental expenses fifteen years into the future implies knowledge of laws and regulations that will be implemented during these years. Even minor changes in definitions or limits can have an enormous effect on actual costs. For example, fifteen years ago, no one anticipated the complexity of the Clean Air Act Amendments of 1990 and its associated costs. Today we are no better qualified to forecast the future.

Because future predictions 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.

SCE&G's environmental activities encompass many things and many people. The SCE&G Environmental Policy (Attachment I) effectively summarizes those activities and their goals.

The commitment outlined in the SCE&G Environmental Policy is reflected in the fact that SCE&G has invested $271,209,487 in capital improvements for environmental control through 1991. Environmental construction work in progress for 1991 alone totaled $15,382,211. Table 6.1.1 shows projected capital and operating costs for the next 20 years for environmental compliance and programs. An Environmental Services Department (ESD) was established several years ago to support and ensure environmental compliance in all areas of operations. Future needs of the company will encompass employees with some environmental specialization within the various functional areas.

Environmental Policy Statement

South Carolina Electric & Gas 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 and, if possible, exceed 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, and
* To aggressively oversee all company activities to ensure compliance with these tenets and with all legal and regulatory requirements.

TABLE 6.1.1

PROJECTED ENVIRONMENTAL COSTS

YEAR	CAPITAL COST		O&M COST	
1992	$ 35,432,800		$ 7,736,700	
1993	49,816,000		9,208,900	
1994	36,931,000		9,588,500	
1995	64,038,000		10,081,000	
1996	148,925,000	(1)	10,602,400	
1997	59,850,000		11,381,500	
1998	81,806,600		12,215,700	
1999	69,155,000	(2)	12,731,700	
2000	2,230,000		43,334,900	(3)
2001	2,761,000		44,807,200	
2002	200,000		47,094,500	
2003	297,648,000	(4)	47,954,100	
2004	200,000		48,277,300	
2005	200,000		51,986,600	
2006	200,000		55,653,800	
2007	200,000		51,894,700	
2008	200,000		57,140,600	
2009	200,000		60,862,500	
2010	200,000		61,627,400	
2011	200,000		56,201,800	
2012	200,000		59,413,200	

(1) COPE PLANT

(2) COMPLETION OF COMPLIANCE TO CLEAN AIR ACT AMENDMENT

(3) COMPLIANCE COAL AT CANADYS, MCMEEKIN, URQUHART, AND WATEREE STATIONS; SCRUBBER AT WILLIAMS STATION AND COPE PLANT

(4) NEW FOSSIL PLANT

2. Air

On November 15, 1990, President Bush signed into law a massive overhaul of the Clean Air Act (CAA) which sets a timetable for more stringent regulations to go into effect over the next 10 years. The biggest impact to the electric utility industry is connected to the control of gases and particulate stack emissions associated with fossil burning generating facilities. As a result, major capital and operating costs will increase as continuous emission monitors and nitrogen oxide and sulfur dioxide control equipment are installed by 1995 and 2000, respectively. Additionally, where switching to lower sulfur coal is an option, upgrades to particulate collection systems and other plant equipment may be required.

In order to meet the deadlines established under the CAAA, SCE&G retained EBASCO Services Incorporated to develop an initial assessment of its impact upon SCE&G's coal-fired steam electric-generating facilities. This assessment will assist SCE&G in developing and coordinating its long-range emission compliance plan for its coal-fired units on a least cost basis. Further, the assessment includes the development of a computer model, which permits SCE&G to refine its emission compliance plan over the near- and long-term to reflect changes in the economics of control technologies and the cost of energy as the impact of the CAAA are felt through the nation. The study involved the examination of the CAAA identifying key provisions which would directly affect SCE&G.

The study then assembled SCE&G system economic parameters and projected unit capacity factors, load growth, fuel changes, planned retirements and additions. These data were utilized in establishing potential emissions of sulfur dioxide, nitrogen oxides and particulate matter for SCE&G's fossil-fired generating facilities.

The study found that the SCE&G least cost emission compliance plan would consist of two stages (i.e., those activities commencing prior to the year 2000 and those thereafter). Stage 1 of the plan requires the installation of continuous emission monitors and low NO_x burners at all units. Further, in anticipation of future particulate emission regulations and potential use of low sulfur coal to reduce SO2 emissions, fabric filters may be installed on all units of the Canadys, Urquhart and Wateree Stations. The estimated investment required during Stage 1 of the emission compliance plan is summarized in Table 6.1.2 attached.

Stage 2 of the emission compliance plan addresses the requirements of the CAAA for the control of sulfur dioxide emissions from SCE&G's system. The plan incorporates the use of low sulfur compliance coals, commencing in the year 2000, on all unit of the Canadys, McMeekin, Urquhart and Wateree Stations, and the installation of a lime/limestone wet scrubbing system at the Williams Station in the year 1999. The plan would require an estimated investment of $103.5 million for the Williams wet scrubbing system.

TABLE 6.1.2

1990 CLEAN AIR ACT AMENDMENT

INVESTMENT ESTIMATES
(THOUSANDS OF DOLLARS)

	1993	1994	1995	1996	1997	1998	1999
CANADYS UNIT 1							
– Particulate control					13737		
– Low NO_x burners			5663				
CANADYS UNIT 2							
– Particulate control						14286	
– Low NO_x burners				5890			
CANADYS UNIT 3							
– Particulate control							21395
– Low NO_x burners					2917		
MCMEEKIN UNIT 1							
– Low NO_x burners					6125		
MCMEEKIN UNIT 2							
– Low NO_x burners						6370	
URQUHART UNIT 1							
– Particulate control			9586				
– Low NO_x burners	5286						
URQUHART UNIT 2							
– Particulate control				9970			
– Low NO_x burners		5497					
URQUHART UNIT 3							
– Particulate control					13824		
– Low NO_x burners			5717				
WATEREE UNIT 1							
– Particulate control						34194	
– Low NO_x burners							6467
WATEREE UNIT 2							
– Particulate control							35562
– Low NO_x burners					3938		
WILLIAMS UNIT 1							
– Low NO_x burners							14196
YEARLY INVESTMENT Thousands of Dollars	5286	5497	20966	15860	40541	54850	77620
PRESENT WORTH VALUE Thousands of Dollars	4572	4425	15704	11054	26271	33074	43545

The cumulative 1991 present worth value of the first stage of the emission compliance plan is $138.645 million.

Also to be noted is that control emission monitors will cost $2.5 million per unit.

3. Cooling Towers

Water releases to the environment are controlled by the Federal Water Pollution Control Act of 1972, the Clean Water Act of 1977 and the Water Quality Act of 1987. These Acts protect the "chemical, physical and biological integrity of the nation's waters." Under these acts the EPA established water quality standards, technology based effluent limitation guidelines, pretreatment standards and a national permit program (e.g., NPDES) to regulate the discharge of pollutants. In South Carolina, EPA has delegated this authority to the state and is administered by the South Carolina Department of Health and Environmental Control.

Thermal discharge is the principal water pollutant resulting from the generation of power. Water is vital to the operation of steam turbines to cool steam as it leaves the turbine to form condensate. Cooling towers and spray ponds are used by SCE&G at some of its facilities to remove this heat from the water through evaporation. An additional cooling tower is being constructed for 1992 operation.

4. Environmental Support Services

The ESD staff coordinates and performs in many areas of SCE&G's environmental concerns, including but not limited to:

* Wastewater (NPDES) and Air Quality Permits
* Evaluation of Environmental Concerns with New Construction
* Wetlands Analysis and Mitigation
* Underground Storage Tank Program Management
* PCB Program Management
* Environmental Property Assessments
* Fish Studies
* Archeological/Historical Studies
* Waste Handling and Recycling
* Hazardous Material Coordination
* Spill Prevention Control and Countermeasures
* Solid Waste Disposal
* Coordination of Best Management Practices in all Aspects of Environmental Issues
* Environmental Audits and Evaluations
* Environmental Sampling
* Environmental Testing
* Resource Center for Knowledge and Dissemination of Environmental Information
* Environmental Training
* Remediation of Environmental Problems
* Prevention of Environmental Problems

SCE&G's Environmental Services Departments (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 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. The ESD performs audits 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.

5. Hazardous Waste

Hazardous waste is controlled under the Resource Conservation and Recovery Act (RCRA). All manufacturing generates some hazardous waste as part of maintenance operations. With the difficulty in siting new disposal and treatment facilities and the pressure to close existing ones, costs will undoubtedly increase. There is also a popular concept that increasing the taxes on this waste is a painless way of raising revenue. These tax increases cannot be estimated. A major unknown which prevents meaningful long-term estimates of hazardous waste disposal costs is the uncertainty over what will be defined as hazardous waste in new laws and regulations.

6. Low and High Level Nuclear Waste

Low-level nuclear waste is controlled by 1985 Amendments to the Low-Level Nuclear Waste Policy which established regional sites. The cost estimate of burial for low level radioactive waste in a secure landfill has to be based on present costs even though the disposal site is scheduled to close.

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 pools which "temporarily" store the spent fuel.

7. Hydro Power

Even hydro power, an environmentally favored renewable resource, has added environmental costs 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.

8. 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.

9. 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 maintenance costs are attributed to the specialized maintenance practices implemented in the sensitive habitat areas.

10. Impact of Demand-Side Management

As discussed in detail elsewhere in this document, SCE&G has made and will continue to make significant commitments to the implementation of demand-side management (DSM) programs and anticipates large reductions in our customers' need for energy. The monetary benefits of these DSM programs have already been discussed, but there are significant qualitative benefits as well. The table below highlights our estimate of the reduction in the amount of air pollution and solid waste over the next fifteen years that result from the Company's DSM initiatives.

Pollutant	Tons Reduced
Particulate	7,812
SO_2	34,875
NO_x	19,015
Ash	114,286

6.2 TRANSMISSION AND DISTRIBUTION PLANNING

1. Mission Statement

The mission of the Transmission and Distribution Planning Department is to develop and coordinate a program which provides for timely modifications to our transmission and distribution system to insure an economical and reliable delivery of power.

2. Transmission Planning

The need for spending all capital money and some limited maintenance money on the SCE&G transmission system (all facilities operating at a voltage of 33 KV or higher) is initiated and evaluated in the Transmission and Substation Planning Department.

Transmission and Distribution Planning evaluates the existing and future transmissions system to determine all service and reliability problems (line overloads, transformer overloads, low voltages, high voltages, 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 the load flow program to predict the performance of the existing system and the planned system for each of the next ten years. 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 and/or buses, building new lines, upgrading existing substations, building new substations, retiring lines or substations, installing capacitors, installing power circuit breakers, installing sectionalizing switches (manual or radio-controlled), changing transformer tap settings, reconfiguring the system (i.e., different line terminations on a given bus or different switch settings). All alternatives are discussed with Relaying, Substation and Transmission Engineering, Distribution Planning, Operations, and System Control to address any considerations they might have. Upon approval of the final recommendation, the project is entered into the Budget.

Other transmission planning activities conducted by Transmission and Substation Planning are: 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 the transmission facilities rated 125 KV or above that the Company will need to construct over the next ten years.

TABLE 6.2.1

SCE&G TRANSMISSION FACILITY ADDITIONS

125 KV AND ABOVE

1991-2000

TRANSMISSION LINES

	VOLTAGE	CAPACITY	COMPLETION & OPERATION
Cope-Orangeburg	230	720	9/94
Cope-Canadys	230	720	5/96
Ridgeland-Okeetee	230	480	5/98

TRANSMISSION TRANSFORMERS

Goose Creek	230/115	336	12/94
Summerville #2	230/115	224	5/94
Cope	230/115	224	9/94
Burton	230/115	225	5/95
Orangeburg	230/115	336	5/95
Pineland #2	230/115	336	5/97
Mt. Pleasant	230/115	224	5/97
Okeetee	230/46	100	5/98
Saluda	230/115	336	5/99

3. Substation Planning

Distribution Substation Planning is coordinated with the Distribution Planning Department. Transmission and Substation Planning analyzes load data and Distribution Planning makes recommendations to identify the need for additional distribution transformer capacity on our system. The best alternative for serving this capacity from the transmission system is then chosen. Considerations would include cost, transmission substation capacity (230-115 KV, 1115-46 KV, 115-33 KV, 230-46 KV), proximity to a given transmission line, relaying concerns, system losses, and reliability. Relaying, Substation and Transmission Engineering, Distribution Planning, Operations, and district personnel are consulted for their input. Transmission and Substation Planning conducts similar evaluations for industrial customer service.

4. Interconnection Planning

The Transmission and Substation 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 system 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 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 25 KV 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, 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 various computer programs to predict the performance of the existing system and the planned system for the next several years. Using the results of these studies 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 Relaying and Customer Operations to address any concerns and considerations they might have. 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, Stability Studies, Motor Start Studies, and circuit coordination studies. The department provides technical support to Customer Operations on a daily basis helping them to solve problems.

Distribution Engineering and Planning uses Scott and Scott Distribution Primary Analysis Systems, D-Coord, CYME, Dawalibi, Motor Start, Radial Voltage Drop and Short Circuit, Lotus and Auto Cad computer programs to perform various department studies.

6.3 TECHNOLOGY REVIEW

1. Photovoltaics

Of all the solar energy technologies, photovoltaics (PV) shows 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 semi-conductors 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.

Charted below are current average costs for photovoltaic electricity, as well as predicted reasonable costs for the mid-to-late 1990's.

Cost of Electricity Produced ($/KWH)

	Present	Mid-to-Late 1990's
Desert Southwest	0.28	0.10
Southern US	0.35	0.12
Middle US	0.43	0.15
Northern US	0.47	0.16

As a result of the expected enhancement in the development of solar cells and associated equipment, SCE&G has planned and designed a photovoltaic test facility. This facility will consist of two 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.

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.

2. 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 AECs 545 MW Lowman coal-fired plant 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. The salt reservoirs are found in Louisiana, Eastern Texas, and Alabama.

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 AECs 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 when the air in the caverns is exhausted, the unit stops. 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.

3. Advanced Light-Water Nuclear Reactors (ALWR)

An agreement between the Department of Energy (DOE) and the commercial nuclear power industry was recently announced. As described in the Public Utilities FORTNIGHTLY recently, the agreement provides for $200 million in funding over the next five years 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.

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 Compubsion (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 basically 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.

Type: Atmospheric Fluidized-Bed Combustion Coal (circulating-bed)

Current capital cost (1991 $): $1260-$1580/kw

Type: Pressurized Fluidized-Bed Combustion Coal

Current capital cost (1991 $): $1350-$1750/kw

More than 1000 MWs of existing coal-fired capacity are being converted to the AFBC technology.

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 (1991$): $1200-$2350/kw

Size: 500 MW

Operating and maintenance costs: 6 to 12 mills/KWH

Places Installed

- Cool Water Project, California
  (100 MW ICGCC, Shell gasifier demonstration,1984)
- Successfully operated since 1984, meeting stringent California pollution standards

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, as shown below:

ENVIRONMENTAL PERFORMANCE

LBS./MMBTU

	Cool Water-Actual	U. S. EPA Standards
High Sulfur Coal - SO_2	0.076	0.6
Low Sulfur Coal - SO_2	0.018	0.24
NOx	0.07	0.6
Particulates	0.008	0.03

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. At the 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.

6. 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. (for example: natural gas and air). The output of the fuel cell 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 3-phase a-c for use on a utility system. There are three types of fuel cells being considered for use by utilities:

a. Phosphoric Acid Fuel Cells (PAFC)

International Fuel Cells Co. Connecticut has a 200 KW PAFC available for commercial use. The plant is self-contained (includes all auxiliaries), and sells for $600,000. The first unit was recently shipped. The company has orders for 60 additional units. This product must be considered somewhat experimental. A previous 11 MW plant in Japan consisting of multiple PAFC cells manufactured by IFC has run into unexpected technical problems.

b. Molten Carbonate Fuel Cells (MCFC)

This technology has strong backing by EPRI. The Fuel Cell Manufacturing Company is in the process of erecting a factory in Connecticut for producing 200 KW cells which will be assembled into a 2 MW plant for commercial use by utilities. The first plant is scheduled to go into service in Santa Barbara, California in 1996. EPRI believes that the cost of these plants can come down to $1500/KW. However, this is based on an optimistic assumption that there will be no unexpected technical problems.

c. Solid Oxide Fuel Cells (SOFC)

This technology is being actively pursued by Westinghouse. A 25 KW unit has been developed, and a 100 KW unit is under development. Cost per KW has not been disclosed.

Fuel Cells and SCE&G

Fuel cells hold great promises because of very low emission of pollutants, and because of high thermal efficiency. However, the technology is not 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.

7. 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 into pellets and is 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 and increase of flexibility in the sulfur content of coal
* Can use existing boiler

Disadvantages to the Utility

* Possible boiler explosions
* Increased Forced Outage Rates and start-up time
* Contamination of saleable bottom ash and its disposal
* Variation of bottom ash characteristics
* Increased difficulty to control boiler operations
* Potential for chloride corrosion
* Higher Heat Rate (1-3%) and economic dispatch
* Degradation of Electrostatic Precipitator operation
* The effects of co-firing RDF with coal is dependent upon the type of plant and type of coal
* Exact quantity of excess air required to reduce NOx emissions is uncertain
* Problems of handling RDF

Costs

Average cost: 7 cents/KWH

Conclusion

SCE&G is engaged in a study to see if it is feasible to burn old tires in one of its boilers. Also, SCE&G has entertained the idea of working with a county planning group in disposing of waste.

8. Wind Turbines

Background

Wind power is the solar energy technology closest to being economically competitive in the bulk power market. In 1989, wind power plants generated over 2 billion KWH of 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. 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.

Pacific Gas & Electric, Niagara Mohawk Power Corp., and EPRI are developing a variable speed turbine that captures the energy of wind gusts, according to Power Line. This innovation and others would bring wind power's costs to five cents per kilowatt-hour, making it a highly competitive option. 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.

Additional Information

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.

9. Geothermal

Background

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 turn 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. Also, most geothermal resources are located in the western third of the country.

Conclusion

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.

10. Ocean Energy

Technologies deriving electric power from the ocean are broken down into six technologies.

Ocean Thermal Energy Conversion

Ocean Thermal Energy Conversion (OTEC) works by utilizing different temperature gradients in the ocean to generate electric generation. This technology has been demonstrated to be possible 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

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.

Wavepower

There are two wavepower technologies that have been designed by Norwegian companies. One design 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.

Ocean Current Turbines

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

Salinity Gradient Devices use the energy different that exists between fresh and salt water. So far, no test facilities have been built.

Ocean Wind Turbines

So far, no Ocean Wind Turbines have been built.

Conclusion

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.