SOUTH CAROLINA
PUBLIC SERVICE AUTHORITY

1994 INTEGRATED RESOURCE PLANNING ANALYSIS

VOLUME I

Santee Cooper

January 1995
Metzler & Associates

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

TABLE OF CONTENTS

VOLUME I

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

TABLE OF CONTENTS (cont'd.)

VOLUME I (cont'd.)

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

TABLE OF CONTENTS (cont'd.)

VOLUME I (cont'd.)

VOLUME II

I. INTRODUCTION AND EXECUTIVE SUMMARY

I. INTRODUCTION AND EXECUTIVE SUMMARY

This report has been prepared for the South Carolina Public Service Authority (generally referred to as Santee Cooper) by Metzler & Associates, in cooperation with Energy Management Associates, the Utilities Division of EDS. Metzler & Associates (M&A) was the lead consultant on the assignment, while Energy Management Associates (EMA) provided software and analytical support for all of the studies performed. The purpose of this report is to document the results of a detailed and lengthy analysis of the resource planning options and decisions facing Santee Cooper over the next twenty years.

The planning outlook of Santee Cooper's Corporate Planning Committee is reflected throughout this analysis, and all major assumptions and techniques used have been reviewed by Santee Cooper. The report does not, however, constitute the integrated resource plan of Santee Cooper, but is the independent work product of the project consulting team. While key decisions are analyzed and alternative resource paths are discussed herein, the judgment of Santee Cooper management ultimately will determine the preferred expansion path.

The report describes the methodology used to arrive at a "reference expansion plan." The reference plan is M&A's assessment of the most cost-effective expansion path available to Santee Cooper, based upon the assumptions and policies articulated by Santee Cooper management. Also contained in the report are alternative expansion plans based on different assumptions and policies. The major resource decisions confronting Santee Cooper are described in detail.

This chapter provides an overview of the integrated resource planning analysis performed. The report is divided into nine chapters and two appendices. Subsequent chapters will discuss the planning process used to perform this study, the demand and energy forecast used, the demand-side management (DSM) options considered, the supply-side options considered, Clean Air Act compliance issues, the integrated planning results, sensitivity analyses performed, and a recommended near-term action plan. The appendices provide detailed descriptions of the generation technologies studied and the DSM programs analyzed.

BACKGROUND ON THE SANTEE COOPER SYSTEM

The South Carolina Public Service Authority was formed in 1934 by the legislature of South Carolina. The original purpose of the Authority, now commonly known as Santee Cooper, was to construct and acquire flood control, navigation, and reclamation works on the Cooper, Santee, and Conagree Rivers, and to produce, distribute and sell electric power. Electric power operations were initiated in 1942 with the completion of the Santee Cooper Hydroelectric Project.

Today Santee Cooper's electric service territory comprises military facilities, approximately thirty large industrial accounts, and approximately 94,000 other residential and commercial customers to whom Santee Cooper provides direct retail service. Additionally, wholesale service is provided to Central Electric Power Cooperative, an association of fifteen electric distribution cooperatives serving some 400,000 residential and commercial retail customers, and two municipal utilities–the City of Georgetown and the Town of Bamberg.

At the start of this IRP, the peak electric demand in 1994 was projected to be 2,954 MW comprising both firm and non-firm customers, while installed and contracted generating capacity amounts to 3,279 MW. Available capacity includes 2,864 MW of owned or leased generating capability from hydroelectric, steam, and nuclear facilities. Another 215 MW is available under contract through the Southeastern Power Administration. Table I-1 identifies each of the existing Santee Cooper generating units by size and fuel type.

Table I-1

Summary of Existing Generating Resources

Unit Name	Type	Capacity (MW)	Retirement Date
Jefferies 1	Coal	46	2000
Jefferies 2	Coal	46	2000
Jefferies 3	Coal	153	2015
Jefferies 4	Coal	153	2015
Grainger 1	Coal	85	2011
Grainger 2	Coal	85	2011
Winyah 1	Coal	270	N/A
Winyah 2	Coal	270	N/A
Winyah 3	Coal	270	N/A
Winyah 4	Coal	270	N/A
Cross 1	Coal	540	N/A
Cross 2	Coal	520	N/A
Myrtle Beach 1-5	Oil	90	N/A
Hilton Head 1-3	Oil	97	N/A
Sumner Nuclear	Nuclear	295	N/A
Spillway Hydro	Hydro	2	N/A
Jefferies Hydro	Hydro	128	N/A
St. Stephen Hydro	Hydro	64	N/A

Future load growth for Santee Cooper is largely dependent upon external factors outside the control of management. The largest swing factor involves a single industrial customer which accounts for 300 MW of firm and interruptible load. This customer has the option of leaving the system in the year 2000 by giving notice in 1997. Changes of this magnitude in the total system load forecast will obviously influence the selection of resource expansion plans. As a result, Santee Cooper's plans need to include planning contingencies for both the loss of this load as well as its continuation.

THE CURRENT RESOURCE PLANNING OUTLOOK

The current resource planning outlook is summarized in Exhibit I-1. As shown, there is a wide range of future planning scenarios to be considered. Resource requirements depend upon the level of demand growth ultimately experienced on Santee Cooper's system, an outcome which will be influenced heavily by the decision of one industrial customer (ALUMAX) on whether to leave Santee Cooper's system or not. Six forecasts were analyzed, as summarized below.

- Under the *Base Case Forecast* (Case 1), Santee Cooper has sufficient generation to meet the needs of its customers until the year 2003. The Base Case Forecast assumes average growth in demand of 0.7 percent over the first ten years of the twenty-year planning horizon, including the loss of the ALUMAX load. The same forecast including the ALUMAX load (Case 2) shows growth of 1.8 percent over the first ten years and a need for new capacity in the year 2000. The addition of the recommended DSM programs will result in the delay of the required in-service date of the first unit by one year, and a reduction in new capacity required of 160 to 200 MW over the study period.

- The *High Case Forecasts* (Cases 3 and 4, without ALUMAX and with ALUMAX) show an immediate need for new capacity. The High Case Forecast without ALUMAX calls for average growth in demand of 1.1 percent over the first ten years of the planning horizon, based on higher than expected demand across all customer segments. New capacity resources are required to meet this load forecast in 1997. Including ALUMAX, the High Case Forecast calls for a growth rate in demand of 2.0 percent over the first ten years of the planning horizon. New capacity resources are required to meet this load forecast in 1997. In both of these cases, the 1997 requirement reflects the earliest possible date for Santee Cooper to complete a new generation resource. However, the load in the earlier years (1994 to 1996) exceeds existing capacity resulting in the need for purchasing short- or long-term capacity. The additional DSM programs that are recommended will not result in a delay of the first year of need; however, it will reduce the new capacity required by 160-200 MW during the study period.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

STUDY SUMMARY

	Case 1 Base Load Forecast Without ALUMAX	Case 2 Base Load Forecast With ALUMAX	Case 3 High Load Forecast Without ALUMAX	Case 4 High Load Forecast With ALUMAX	Case 5 Low Load Forecast Without ALUMAX	Case 6 Low Load Forecast With ALUMAX
Summary of Demand Forecast						
1994 Peak Demand Requirements	2,954	2,954	3,340	3,340	2,568	2,568
1994 - 2003 Demand Growth (%)	0.7%	1.8%	1.1%	2.0%	0.2%	1.5%
2004 - 2015 Demand Growth (%)	2.2%	2.1%	2.8%	2.6%	2.5%	2.2%
1994 - 2015 Demand Growth (%)	2.1%	2.0%	2.0%	2.3%	1.5%	1.9%
Supply Side Resource Summary (w/o New DSM Programs)						
First Year of Need	2,003	2,000	1,997	1,997	2,012	2,007
First Year Capacity Requirement	1-80 MW CT	1-80 MW CT	3-80 MW CTs	3-80 MW CTs	4-80 MW CTs	1-80 MW CT
1994 - 1999 Resource Additions (MW)	-	-	320	320	-	-
2000 - 2009 Resource Additions (MW)	640	960	400	560	-	240
2010 - 2015 Resource Additions (MW)	720	800	800	1,040	640	800
Total Resource Additions 1994 - 2015 (MW)	1,360	1,760	1,520	1,920	640	1,040
Sulfur Dioxide Compliance Plans (w/o New DSM Programs						
Required Timing of First Scrubber *	2,012	2,000	2,005	2,000	N/A	2,004
Required Timing of Second Scrubber	N/A	N/A	N/A	2,010	N/A	N/A
Supply Side Resources Summary (w/Recommended DSM Programs**)						
First Year of Need	2004	2001	1997	1,997	2012	2008
First Year Capacity Requirement	1-80 MW CT	2-80 MW CTs	3-80 MW CTs	3-80 MW CTs	1-80 MW CT	80 MW CT
1994-1999 Resource Additions (MW)	-	-	320	320	-	-
2000-2009 Additions (MW)	480	880	320	560	-	80
2010-2015 Resource Additions (MW)	720	680	720	960	480	720
Total Resource Additions 1994-2015 (MW)	1,200	1,560	1,360	1,840	480	800
Sulfur Dioxide Compliance Plans (w/Recommended DSM Programs**						
Required Timing of First Scrubber	2012	2000	2006	2,000	N/A	2005
Required Timing of Second Scrubber	N/A	N/A	N/A	2,010	N/A	N/A

* Scrubber in-service requirements post 2000 assume one year scrubber deferral utilizing environmentally affected dispatching.

**Recommended DSM Programs include: High Efficiency Lighting, Premium Efficiency Motors, Commercial Air Conditioning, Duct Testing and Repair, Residential Good Cents, and Commercial Good Cents.

EXHIBIT I-1

- The *Low Case Forecasts* (Cases 5 and 6, without ALUMAX and with ALUMAX) reduce the load growth rate over the first ten years of the planning horizon to 0.2 percent without ALUMAX and 1.5 percent per year with ALUMAX. Without ALUMAX the Low Case Forecast shows no need for new capacity until the year 2012. With ALUMAX the year of need in 2007. The DSM programs that are recommended result in a possible one year delay in the initial year of need and an overall reduction of new capacity requirements ranging between 160 and 240 MW over the study period.

With a projected year of need in the year 2003 or before under base case conditions, Santee Cooper must approach its planning decisions carefully to ensure that it is pursuing the necessary steps to plan for and acquire needed capacity in a timely fashion. Assuming a five-year lead time to construct new peaking capacity, Santee Cooper needs to begin to take action in 1995 in the event that ALUMAX remains on the system. ALUMAX must give notice in 1997 if it intends to leave the system. The period 1995 to 1997, therefore, represents a time of some uncertainty in which contingency plans need to be implemented in parallel to ensure that the system is not caught short of needed capacity.

THE PLANNING PROCESS

As mentioned above, this study was performed by an independent group of consultants and does not in itself constitute the integrated resource plan of Santee Cooper. A number of key decisions described in this report need to be made in the months ahead to determine the final shape of the official IRP.

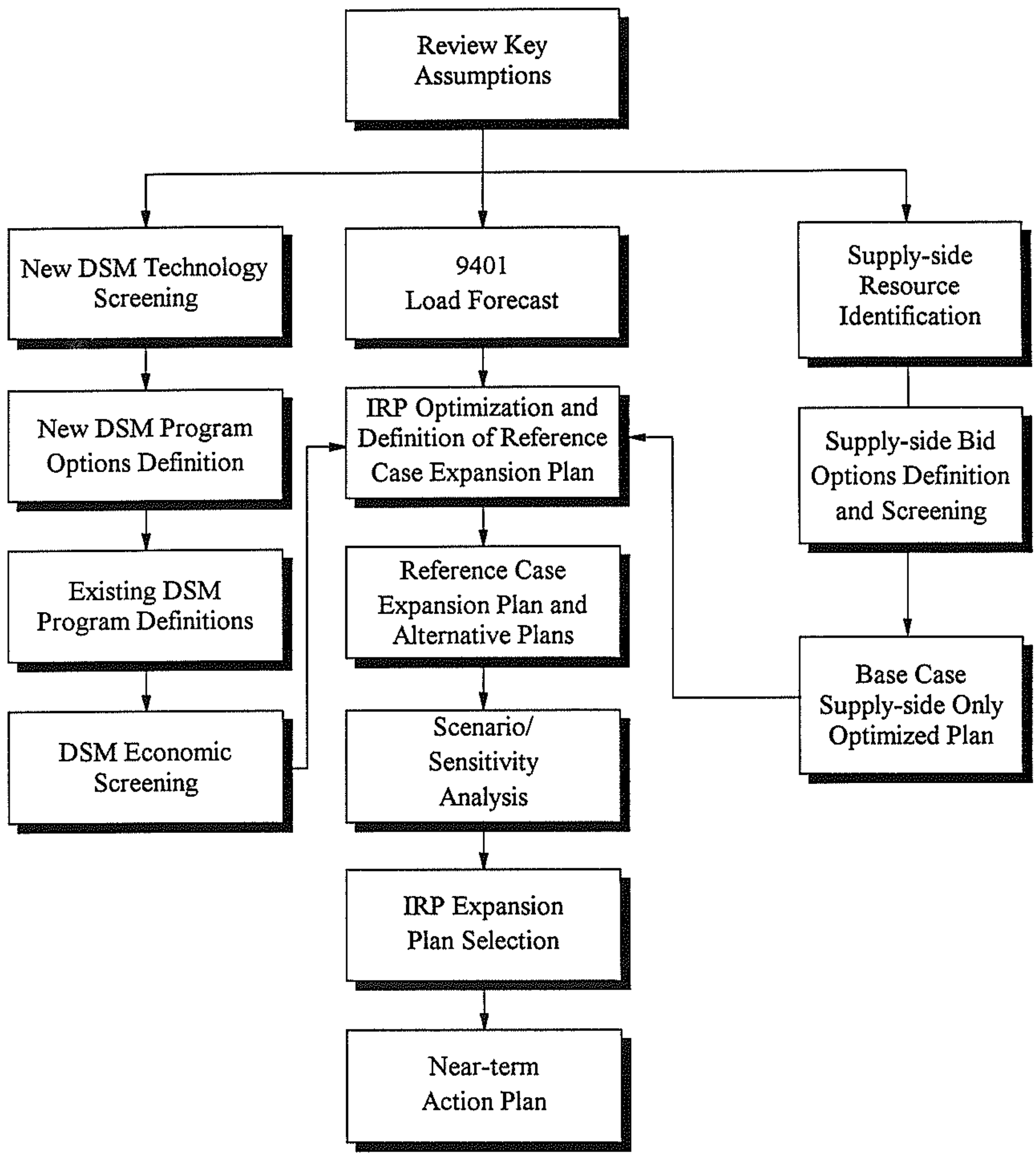
The planning process used to conduct this study for Santee Cooper is depicted in Exhibit I-2. The process, the components of which are explained in greater detail in Chapters II, III, IV, and V, began with a review of the planning assumptions and forecasts used by Santee Cooper. These were adopted as the basis for the IRP study.

Demand and supply options were then analyzed and screened in parallel before being fully integrated into a supply and demand optimization analysis. A total of 227 demand-side options were considered as well as 58 supply-side options. DSM options were first screened for economics and practicality, with a resulting total of nine new DSM programs being considered in the final optimization analysis.

These demand and supply options were considered solely from the perspective of the economic impact to Santee Cooper. In the case of Central, Santee Cooper can recommend a particular action, but Central will need to perform its own economic analysis to determine if the action is economically favorable to its customers.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

INTEGRATED RESOURCE PLANNING PROCESS



The PROSCREEN II™ family of planning models was used to perform all of the economic analysis of demand and supply options. DSVIEW, a module of PROSCREEN II, was used to screen DSM programs for economic performance. DSVIEW was also used to calculate the four major DSM economic tests employed in the study: the Participant Test, the Utility Cost Test, the Total Resource Cost Test, and the Rate Impact Measure Test.

Supply-side options were analyzed first through traditional screening curves comparing cost versus capacity utilization by type of supply option. Then dynamic optimization analysis used the PROVIEW™ module of PROSCREEN II. PROVIEW was also used to perform the overall integration of supply and demand options.

Environmental compliance was analyzed primarily in terms of the Clean Air Act Amendments of 1990, especially Title IV requirements on sulfur dioxide and nitrogen oxide emissions. Secondarily, the possible effects of carbon tax and BTU tax legislation was investigated, although neither of these proposals is expected to become law. Carbon tax impacts were analyzed on the basis of proposed 1991 legislation before the U.S. House of Representatives. The proposed BTU tax in President Clinton's 1993 proposal to Congress was also analyzed.

A wide range of other sensitivity analyses was performed to assess the ability of various expansion plans to respond to unforeseen changes in the future. All of the expansion plans studied were analyzed under six load forecast projections, several different alternative fuel cost assumptions, varying levels of demand-side management impacts, alternative environmental legislation impacts, and differing capital cost assumptions for new supply-side options.

Action planning recommendations were then prepared, including a discussion of the key decisions facing Santee Cooper in the years ahead. The action plan recommendations point out that it will be important to proceed along parallel paths in the near future to anticipate alternative future demand and supply needs. The last step in the planning process was to document the analysis and recommendations in this formal report.

SUPPLY-SIDE ANALYSIS

A comprehensive review of supply options was conducted to first identify and then screen the possible generation technologies available to Santee Cooper. In all, fifty-two generation technologies were identified for screening. Of these only eight advanced to the economic analysis stage, while the remaining technologies were rejected for a number of environmental, regulatory, and/or commercial reasons.

The available technologies were classified as either conventional technology (i.e. proven technologies already widely employed in the industry) or emerging technology

(technology in the development stage, with few existing power plant applications). A total of four conventional and four emerging supply technologies were selected for economic analysis within the resource optimization phase of the study.

Table I-2 lists the eight technologies selected for economic consideration within the IRP analysis.

Table I-2

Supply-side Technologies Selected for Economic Analysis

Conventional Technologies	Emerging Technologies
1. Oil-Fired Combustion Turbine (80 MW)	5. Atmospheric Fluidized Bed Combustion - Bubbling Bed Boiler (200 MW)
2. Oil-fired Combined Cycle (240 MW, 80-MW Increments)	6. Atmospheric Fluidized Bed Combustion - Circulating Bed Boiler (200 MW)
3. Pulverized Coal (560, 400, and 240 MW sizes)	7. Pressurized Fluid Bed Combustion - Bubbling Bed Boiler/Subcritical (320 MW)
4. Advanced Cycle Pulverized Coal (300 MW supercritical)	8. Integrated Coal Gasification Combined Cycle - Entrained Flow/Med. Integration (500 MW)

All eight of the above technologies were considered in the optimization analysis. A series of supply-only optimization analyses under Base Case assumptions showed that three supply options were clearly the most economical: the 80-MW combustion turbine (option 1), the combined cycle unit (selected as a phased construction in 80-MW increments, option 2), and the 400-MW pulverized coal unit (option 3). The earliest that an intermediate or base load option was selected was 2012; nothing other than a combustion turbine unit was selected prior to the year 2012. A string of combustion turbines was selected under the Base Case assumptions starting in the year of need, 2003.

DEMAND-SIDE ANALYSIS

The demand-side analysis addressed a wide range of available DSM alternatives. A list of 227 measures was developed from industry literature, DSM plans from other utilities, and the experience of the consulting team. Of these, 81 were residential, 98 were commercial, and 48 were industrial. Residential measures include many types of heat pumps, passive and active solar heat, and energy-efficient refrigerators and freezers, among other measures. Examples of commercial and industrial measures include fluorescent lighting, thermal energy storage, and heat recovery from exhaust air.

A preliminary screening methodology was applied to weed out those measures with limited applicability. Measures not appropriate to Santee Cooper's service area, electrical system, and customer mix were identified by the application of three qualitative criteria:

- *Technical Feasibility* - This criterion assesses the availability of the technology in the marketplace.

- *Customer Acceptance* - This criterion assesses the willingness of Santee Cooper customers to accept a particular measure. Measures which result in adverse lifestyle changes or are inappropriate for the South Carolina climate are rejected.

- *Load Shape Objectives* - This criterion assesses the impact of measures on electric energy consumption and peak demand requirements. Acceptable load shape objectives for DSM screening are conservation, peak clipping and load shifting.

In total, 156 of the 227 measures initially identified were screened out in the preliminary screening process. Appendix B lists all of the measures and groups of measures that were screened out and the reasons for rejecting them.

The next step was to combine those measures which passed the qualitative screening process into DSM programs. The task was to balance the objectives of packaging as many of the measures into programs as possible with the need to design each program to be purposeful, marketable, and manageable.

Eleven new programs were developed:

- *Residential*
  - Load Control for Air Conditioning
  - Ground Source Heat Pump
  - Good Cents Manufactured Home Heat Pump Program
  - High Efficiency Heat Pumps
  - Swimming Pool Load Control
  - Duct Testing and Repair

- *Commercial/Industrial*
  - Thermal Energy Storage
  - Standby Generation
  - High Efficiency Lighting
  - Premium Efficiency Motors
  - Commercial Air Conditioning

The next step in the DSM analysis was to take the program data gathered for the above programs and assess the economic benefits and costs for each potential new program. Each program was modeled in the DSVIEW economic evaluation module of PROSCREEN. Preliminary screening used static avoided costs. Final optimization runs were performed with a dynamic avoided cost calculation in which the avoided cost changed with each year and each scenario studied.

DSVIEW utilizes specific program costs along with Santee Cooper system-specific inputs to assess the costs and benefits of the projected hourly demand and energy impacts of each program concept. The results are expressed as benefit-to-cost ratios. Ratios greater than 1.0 indicate that the program offers net benefits under the rules of the test being addressed. These ratios are briefly described below.

- *Participant Test*: A measure of the quantifiable benefits and costs of a DSM program from the point of view of the participating customer. Essentially a measure of market feasibility, it is designed to indicate whether the program is economically attractive to the customer. The test includes the benefits associated with reduced electric bills and incentive payments weighed against the increased costs due to the purchase of equipment required to participate in the program (e.g., a new heat pump).

- *Utility Cost Test*: A measure of the change in total costs to the utility that is caused by a DSM program. This test evaluates a DSM program from the point of view of a utility's total costs. The test includes the benefits associated with reduced production costs and deferred generation capacity capital costs. These benefits are weighed against increases in the utility's total costs, including DSM program costs, utility costs, and incentives.

- *Ratepayer Impact Measurement (RIM) Test*: A measure of the difference between the change in total revenues recovered through rates by a utility and the change in total costs resulting from the DSM program. If the change in revenues is larger or smaller than the change in total costs, then rate levels may need to be changed to obtain proper revenue recovery. Thus, this test in effect evaluates the impact on rates resulting from a particular DSM program. Impacts on individual classes can be analyzed if costs and demand reductions are allocated in the same method used to determine rates. To fully determine rate impacts on a particular rate class resulting from a particular DSM program, a detailed analysis will be required. For the purposes of this study, the RIM test considered revenue changes resulting from the estimated change in energy sales (kWh); revenue changes resulting from changes in demand (kW) were considered minimal, and were not included in the screening.

- *Total Resource Cost (TRC) Test*: A measure of the overall economic efficiency of a program from the point of view of the utility and its ratepayers taken as a whole. Resource costs include changes in supply costs, utility costs, and participant costs. Since the utility and its ratepayers are taken as a whole, changes in the dollar amounts that flow between them are ignored.

The results of the static economic screening process for the six residential programs and the five commercial/industrial programs appear in Table I-3.

Table I-3

Results of DSM Economic Screening - Combined Analysis*

Program	Participant	TRC	Utility	RIM
		Name of Test		
New Programs				
Standby Generators	Inf.**	13.24	0.51	0.50
High Efficiency Lighting	3.28	2.88	4.91	1.07
Premium Efficiency Motors	3.57	2.62	4.20	1.03
Good Cents Manufactured Home Heat Pump	5.74	1.83	0.47	0.35
Air Conditioning Direct Load Control	Inf.**	1.39	0.54	0.53
Commercial Air Conditioning	1.36	1.37	3.62	1.07
Duct Testing and Repair	1.70	1.00	1.41	0.67
Thermal Energy Storage	1.02	0.51	1.15	0.50
Swimming Pool Direct Load Control	Inf.**	0.54	0.34	0.33
High Efficiency Heat Pump	0.95	0.47	0.73	0.50
Ground Source Heat Pump	0.50	0.34	1.32	0.62
Existing Programs				
Residential Good Cents	Inf.**	6.69	0.64	0.49
Commercial Good Cents	Inf.**	1.02	0.83	0.63
H_2O Advantage	Inf.**	0.82	0.19	0.19

*Note: The results of this screening ignore the differences between retail and wholesale costs and benefits.

**Infinite, since participant cost is assumed to be zero.

ANALYSIS OF PROPOSED DSM PROGRAMS

As can be seen from Table I-3, only three of the new programs pass under all four tests, which indicates that these may be very cost effective programs. The results of the screening of the new programs can be grouped into four categories:

1. **Programs which pass all tests**

   These programs appear to be cost effective from all perspectives and should be pursued further. Three programs fit this category:

   - High Efficiency Lighting
   - Premium Efficiency Motors
   - Commercial Air Conditioning.

2. **Programs which pass the Participant and TRC tests but fail the RIM and/or Utility Cost tests**

   These programs pass the TRC largely because of their high benefit-to-cost ratio for individual participants. The programs in some cases may be redesigned to improve the results of the RIM and Utility Cost tests. Four programs fit this category:

   - Standby Generators
   - Good Cents Manufactured Home Heat Pump
   - Air Conditioning Direct Load Control
   - Duct Testing and Repair.

3. **Programs which fail the TRC and RIM tests but pass the Utility Cost test**

   These programs lower Santee Cooper's revenue requirements but offer marginal benefits to participants as currently designed:

   - Thermal Energy Storage
   - Ground Source Heat Pump.

4. **Programs which fail the TRC test as well as the utility and RIM tests**

   These programs, as currently designed, are failing to meet multiple standards of economic efficiency and should not be implemented unless their results can be improved. Two programs fit this category:

   - High Efficiency Heat Pump
   - Swimming Pool Direct Load Control.

From these economic screening results, a total of nine new DSM programs were included for consideration in the final optimization analyses. The nine new programs included the seven programs which passed the TRC test (groups 1 and 2 above) plus those programs which passed the Utility Cost Test only (group 3 above).

ANALYSIS OF EXISTING DSM PROGRAMS

Santee Cooper currently has three DSM programs in place. These three programs are:

- Residential Good Cents
- Commercial Good Cents
- H_2O Advantage

Each of these three existing programs were also screened using the economic tests described above. Of these three programs the two Good Cents programs provide the best economic benefits. The H_2O Advantage program failed all tests other than the Participant Test. The Residential Good Cents program clearly passed the TRC test, although it failed the Utility Cost test. The Commercial Good Cents program marginally passed the TRC test with a 1.02 ratio. Based on these results, both Good Cents programs were included with the nine new programs in the final integration stage of the IRP analysis, resulting in a total of 11 possible DSM programs.

OPTIMIZATION ANALYSIS

In the optimization analysis, all of the surviving supply and demand options were included in a simultaneous resource optimization using the PROVIEW economic optimization model. Using a dynamic programming algorithm, this model assesses literally all combinations of resources possible and selects that mix which best matches the optimization criteria established. In this case the plan was optimized on the present value of revenue requirements (PVRR). The results under Base Case assumptions yielded the Reference Expansion Plan shown in Exhibit I-3a. Also included in Exhibit I-3a is the Supply-Only/Base Case Plan, which incorporates existing DSM program impacts but no new DSM programs.

As can be seen in Exhibit I-3a, these nine DSM programs that passed the TRC test (seven new and two existing programs), together with the supply options indicated, comprise the Reference Case Expansion Plan, which results in the lowest long-run revenue requirements. In addition to the Reference Case, an additional expansion plan was evaluated consisting of four new and two existing DSM programs. This plan reflects four new programs that passed both the TRC and Utility Cost Tests, plus the two existing programs that passed the TRC. This plan was designated the TRC/Utility plan. The impact of the DSM programs in the Reference Case is to eliminate the need for four combustion turbine units, and delaying the need for new capacity from 2003 in the Supply-Only/Base Case Expansion Plan to 2005 in the Reference Case Expansion Plan. The plans also call for the deferral of the combined cycle unit to 2014 from 2012.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

COMPARISON OF INTEGRATED PLANS

Year	Supply Only Plan/Base Case Plan (w/o ALUMAX)	Reference Case Plan (w/o ALUMAX)	TRC/Utility Plan (w/o ALUMAX)
1994			
1995			
1996		LIT, STBY, MOT, HP, AC, DLCA, DUC, RESG, COMG	LIT, MOT, AC, DUC, RESG, COMG
1997			
1998			
1999			
2000			
2001			
2002			
2003	One 80-MW CT		
2004	One 80-MW CT		One 80-MW CT
2005	One 80-MW CT	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT	One 80-MW CT
2007	Two 80-MW CTs	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT	One 80-MW CT
2012	Two 80-MW CTs & One 80-MW Phased CC	Three 80-MW CTs	Three 80-MW CTs
2013	Two 80-MW CTs	One 80-MW CT	Two 80-MW CTs
2014	One 80-MW CT	One 80-MW Phased CC	One 80-MW Phased CC
2015	One 80-MW CT	One 80-MW CT	One 80-MW CT
PVRR ($000)	$5,974,907	$5,916,238	$5,922,727
Total New Capacity	1,360 MW	1,040 MW	1,200 MW

LIT: High Efficiency Lighting
STBY: Standby Generation
MOT: Premium Efficiency Motors
HP: Good Cents Manufactured Home Heat Pump
AC: Commercial Air Conditioning
DLCA: Air Conditioning Direct Load Control
DUC: Duct Testing and Repair
RESG: Residential Good Cents
COMG: Commercial Good Cents

The results of the TRC/Utility plan are to eliminate the need for two combustion turbines and delay the need for the combined cycle unit until 2014 from 2012. The first new resource requirement was deferred from 2003 to 2004.

A similar analysis as that presented in Exhibit I-3a is presented in Exhibit I-3b; the only difference is the load assumptions. Exhibit I-3b reflects the resource requirements in the event ALUMAX continues as an industrial customer on Santee Cooper's system.

The deferral of generating capacity of one to two years, depending on the level of DSM is the same with or without ALUMAX. The critical difference shown on Exhibit I-3b is the earlier need date for the higher system load with ALUMAX. With ALUMAX, the first year of need is 2000, shifting up to one year depending on the level of DSM.

It is important to recognize that the DSM programs studied do not necessarily result in the lowest production costs. Since several of the DSM programs failed to pass the RIM test, the impact on the plans is to raise costs over a long-run period. Exhibits I-4a and I-4b depict the annual impact of the DSM programs on system costs. As can be seen, relative to the Supply-Only/Base Case Plan, the Reference Case Plan and TRC/Utility Plan lead to higher average costs initially. Production costs will be approximately one percent higher initially, then the upward impact subsides and then finally turns downward. The timing of the change in direction is dependent on the year of need for new capacity.

SENSITIVITY ANALYSIS

A variety of sensitivity studies was performed on the expansion plans to determine whether alternative expansion paths offer superior stability or other advantages over the Reference Case or Supply-Only Plans. Four basic expansion paths were analyzed: the Supply-Only/Base Case, an Early Combined Cycle Case, a Coal Plant Case, and the Reference Case, including new DSM. A wide range of sensitivities was performed, including demand growth, fuel prices, and capital cost sensitivities.

The results of the sensitivity analyses were unremarkable. The Reference Case survived as the lowest cost option in nearly every analysis, offering the greatest amount of flexibility. The flexibility of the Reference Case Plan is due to the long lead time allowed prior to a major capital commitment other than for a combustion turbine. By calling for a string of relatively low-cost combustion turbine units starting in 2004, the Reference Case Plan allows for deferral of units in the future if need be or, on the other hand, the acceleration of capacity additions if necessary.

CLEAN AIR ACT AMENDMENTS COMPLIANCE

The CAAA of 1990 affects Santee Cooper's plans primarily with respect to SO_2 and NO_x emissions limitations. Exhibit I-5 shows the SO_2 allowance bank under each of the

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

COMPARISON OF INTEGRATED PLANS

Year	Supply Only Plan/Base Case Plan (w/ALUMAX)	Reference Case Plan (w/ALUMAX)	TRC/Utility Plan (w/ALUMAX)
1994			
1995			
1996		LIT, STBY, MOT, HP, AC, DLCA, DUC, RESG, COMG	LIT, MOT, AC, DUC, RESG, COMG
1997			
1998			
1999			
2000	One 80-MW CT		
2001	Two 80-MW CTs	Two 80-MW CTs	Two 80-MW CTs
2002	One 80-MW CT		One 80-MW CT
2003	One 80-MW CT	One 80-MW CT	One 80-MW CT
2004	Two 80-MW CTs	One 80-MW CT	Two 80-MW CTs
2005	One 80-MW CT	One 80-MW CT	
2006	One 80-MW CT	One 80-MW CT	Two 80-MW CTs
2007	One 80-MW CT	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT	One 80-MW CT
2012	One 400-MW PC	One 400-MW PC	One 400-MW PC
2013			
2014	One 80-MW CT		
2015	Two 80-MW CTs	One 80-MW Phased CC	One 80-MW Phase CC
PVRR ($000)	$6,654,110	$6,576,565	$6,596,640
Total New Capacity	1,760 MW	1,360 MW	1,520 MW

LIT: High Efficiency Lighting
STBY: Standby Generation
MOT: Premium Efficiency Motors
HP: Good Cents Manufactured Home Heat Pump
AC: Commercial Air Conditioning
DLCA: Air Conditioning Direct Load Control
DUC: Duct Testing and Repair
RESG: Residential Good Cents
COMG: Commercial Good Cents

CORRECTED COPY

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

PRODUCTION COST IMPACTS FROM DSM PROGRAMS
(without ALUMAX)

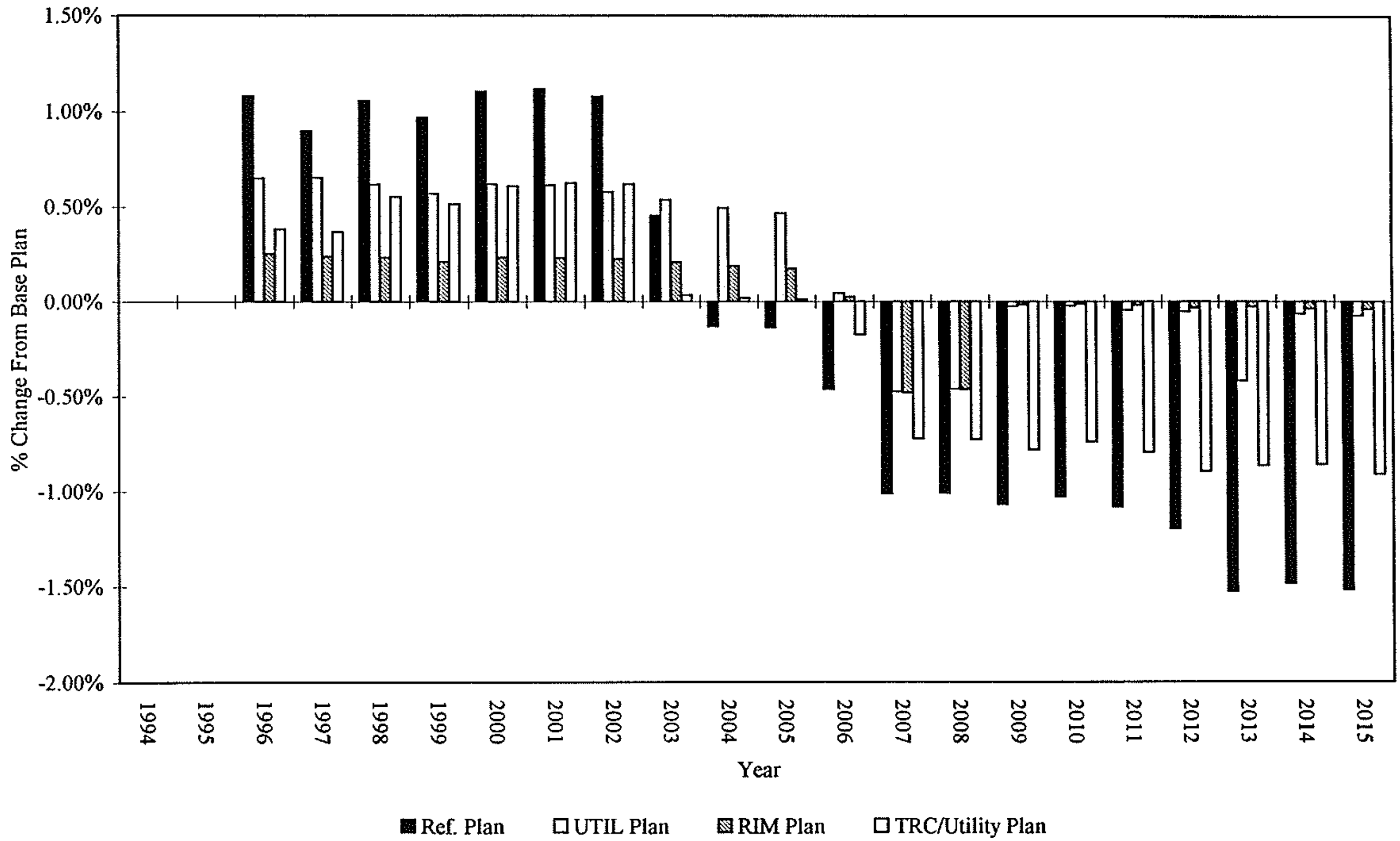


EXHIBIT I-4a

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

PRODUCTION COST IMPACT OF REFERENCE CASE PLAN AND TRC/UTILITY PLAN RELATIVE TO SUPPLY ONLY/BASE CASE PLAN
(with ALUMAX)

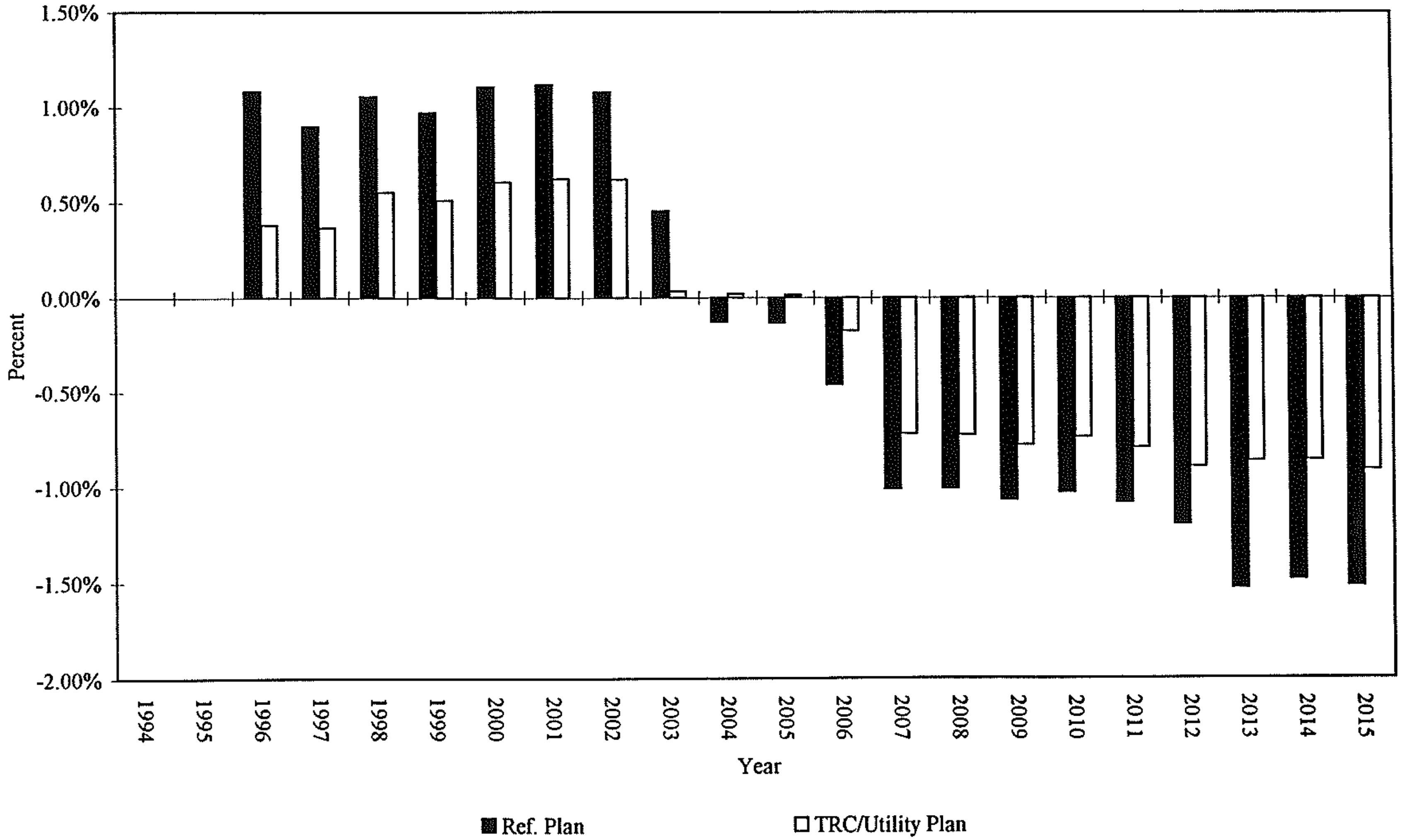


EXHIBIT I-4b

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SO2 ALLOWANCE BANKING

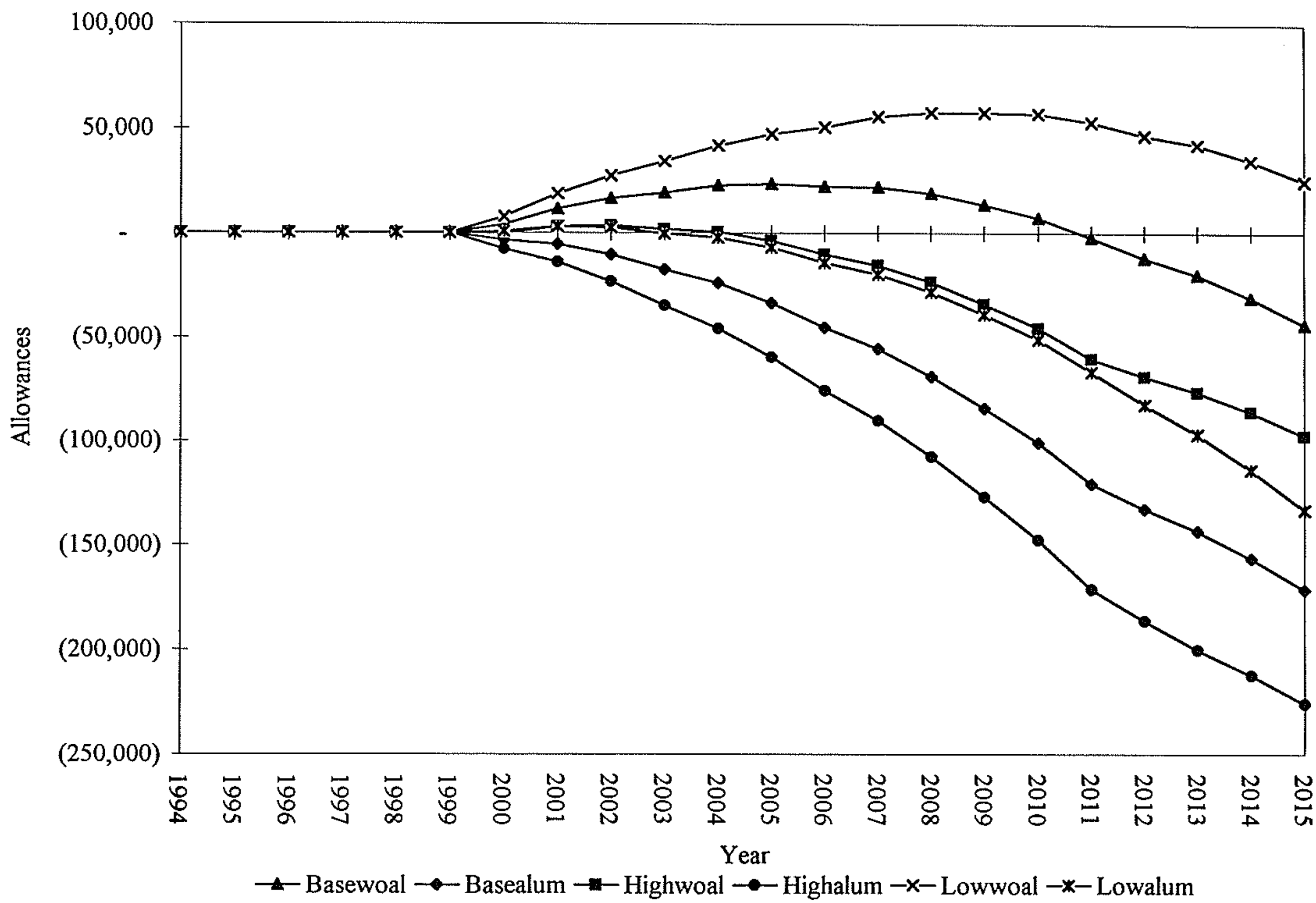


EXHIBIT I-5

six forecast scenarios. This exhibit assumes existing SO_2 removal equipment and does not assume any purchases of allowances. Under the Base Case Forecast assumptions, the allowance bank goes negative in the year 2011. Under higher growth assumptions the allowance bank goes negative in the period 2000 through 2004. Note that the Base Case Forecast with ALUMAX scenario shows a depletion of the allowance bank immediately on January 1, 2000, the beginning of Phase II under the CAAA regulations. The compliance alternatives identified include:

- Purchasing allowances on the open allowance trading market
- Fuel switching to low sulfur coal
- Converting to natural gas from coal
- Environmental dispatch
- Installing a scrubber on an existing coal-fired plant.

The least cost compliance plan under each of the six load forecast scenarios is identified in Table I-4. For the purpose of this analysis it was assumed that allowance trading was not an option.

Table I-4

CAAA Compliance Plans Costs

Case	CAAA Compliance Plans	1994 to 2015 PVRR ($000)
Base Case without ALUMAX	EAD in 2011	5,983,332
	Winyah 1 Scrubber in 2012	
Base Case with ALUMAX	Winyah 1 Scrubber in 2000	6,694,842
High Load without ALUMAX	EAD in 2000	6,709,570
	Winyah 1 Scrubber in 2005	
High Load with ALUMAX	Winyah 1 Scrubber in 2000	7,462,964
	Jefferies 3 Scrubber in 2010	
Low Load without ALUMAX	Plan in compliance	5,514,844
Low Load with ALUMAX	EAD in 2003	6,118,559
	Winyah 1 Scrubber in 2004	

However, an analysis of the value of allowance trading to the plan under alternative scenarios was performed to assess the potential impact such a strategy could have. Depending upon the allowance price projected, the results showed that revenue requirements could be reduced by either selling into or buying from an assumed allowance marketplace. The results showed that at a value of $80 per allowance, it is far cheaper to buy allowances than to comply; at a value of $250 per allowance or higher it is best to install a scrubber immediately in the year 2000 and sell allowances; and at a value of $200 per allowance it is optimum to accelerate installation of a scrubber from the year 2012 (under the Base Case Forecast) to the year 2006.

The case with ALUMAX requires compliance at the beginning of Phase II which is January 1, 2000. Given this requirement, the cases discussed above have little bearing on Santee Cooper if ALUMAX remains. At prices for allowances below $200, it would be reasonable to rely on the allowance market for the required number, but at prices over $200, Santee Cooper would be better off adding a scrubber at Winyah 1 as planned.

Based on recent proposed rules promulgated by the EPA in March, 1994, NO_x emissions limits of 0.5 pounds per MMBtu have been proposed. If this level holds, the results of the IRP analysis indicate that Santee Cooper will have no difficulty complying without taking extraordinary action to control NO_x emissions.

KEY DECISIONS AND RECOMMENDATIONS

Three key resource planning decisions confront Santee Cooper management in the years ahead. Each of these decisions is described below along with the actions required to address them.

1. Which DSM programs should be implemented and over what time frame?

Santee Cooper can take a more or less aggressive approach to DSM, the choice depending upon its policies with respect to the environment and customer costs. The TRC/Utility Plan, which includes four new DSM programs, will effectively eliminate the need for one peaking power plant in the year 2003, under Base Case Forecast assumptions. The trade-off is that production costs can be expected to be higher over the next decade as a result, by approximately 0.5 percent.

The more aggressive DSM program reflected in the Reference Plan would accomplish even more plant deferrals or eliminations, but with higher DSM expenditures, and thus with only minimal reductions in revenue requirements.

Santee Cooper management must determine what level of cost increase is tolerable in the interest of pursuing a DSM strategy. Santee Cooper may determine that the advantage of a DSM program is less the economic impacts it brings and more the strategic and customer satisfaction benefits it provides.

M&A Recommendation:

- Begin to pilot the four new DSM programs identified in TRC/Utility Plan analysis:
  - High Efficiency Lighting
  - Premium Efficiency Motors
  - Commercial Air Conditioning
  - Duct Testing and Repair
- Seek to limit the rate impact through financing and other cost reducing techniques.
- Keep total expenditures within a predetermined limit which is assured not to result in an unacceptable rate impact.
- Formulate a long-run marketing and DSM strategy to guide future investments in DSM.

2. How should a possible need for capacity in the year 2000 be addressed, given that ALUMAX will not declare until 1997 and resource bidding preparations should begin in 1995 for capacity additions in 2000?

The period from now to 1997 presents Santee Cooper with a difficult challenge in light of the uncertainty surrounding the ALUMAX decision whether to remain on the system. If ALUMAX ultimately decides to remain on the system in 1997, Santee Cooper will have only three years in which to arrange for new peaking capacity. This should be adequate if the groundwork for acquiring new resources has been laid prior to that time.

For example, to implement a bidding process for new resources, Santee Cooper will need to lay out its bidding strategy and guidelines in advance. As an initial part of this effort, Santee Cooper will need to develop a "utility build" option to identify the costs and benefits of this alternative. These costs and benefits will be necessary in a comparison of Santee Cooper constructing a unit or contracting with an outside firm to construct the resource through a bidding process. Providing less than three years of lead time to potential bidders may limit the responses received. Thus it will be important that a bidding package be readied well in advance of the 1997 date so a bidding plan can be implemented immediately.

M&A Recommendation:

- Begin preparations immediately to put in place a bidding process for new peaking capacity in the event that ALUMAX decides in 1997 to remain on the system. This process will include developing the costs for a utility built unit.
- Begin preparations for a possible scrubber installation in 1999 in the event that ALUMAX decides to remain on the system.

3. How should Santee Cooper address the emissions allowance trading market?

As shown in this study, there are significant potential benefits to Santee Cooper being involved in trading emission allowances *in a known and stable market for allowance prices*. As with any commodity trade, perfect knowledge of the future price of a commodity can be highly lucrative. Since in this case, as with commodity trading generally, the market prices are speculative, a more flexible approach to allowance trades seems appropriate.

The base assumption toward allowance trading in this study was to plan not to utilize the market. Given the flexible nature of the expansion plans developed in this analysis, it is likely that Santee Cooper can maintain its flexibility on this issue for an extended period of time. At some point, however, decisions regarding either an early or delayed investment in control strategies with the allowance trading market in mind will need to be made.

Exhibit I-6 depicts the decision paths which are associated with allowance trading decisions, based on the Base Case Forecast. As shown, if allowance trading is not pursued, a scrubber will be needed in 2012. Under differing assumptions regarding allowance values, Santee Cooper may chose one of several alternative paths.

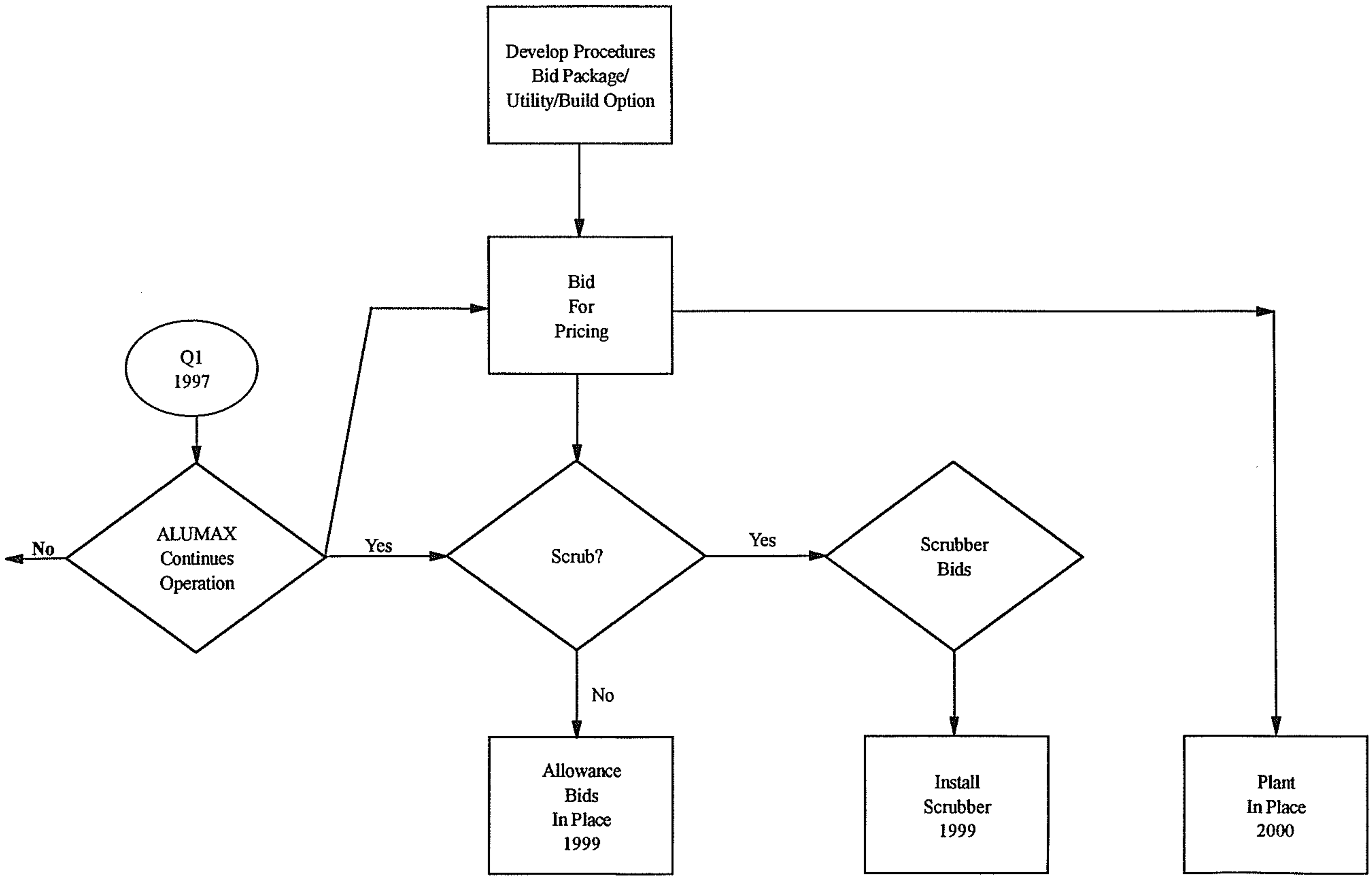
M&A Recommendation:

- Monitor allowance trades in the industry press and develop a forecast of allowance prices to be used in future planning activities. This recommendation does not depend on the future status of ALUMAX.

- Routinely reassess whether to trade allowances as part of future resource planning studies.

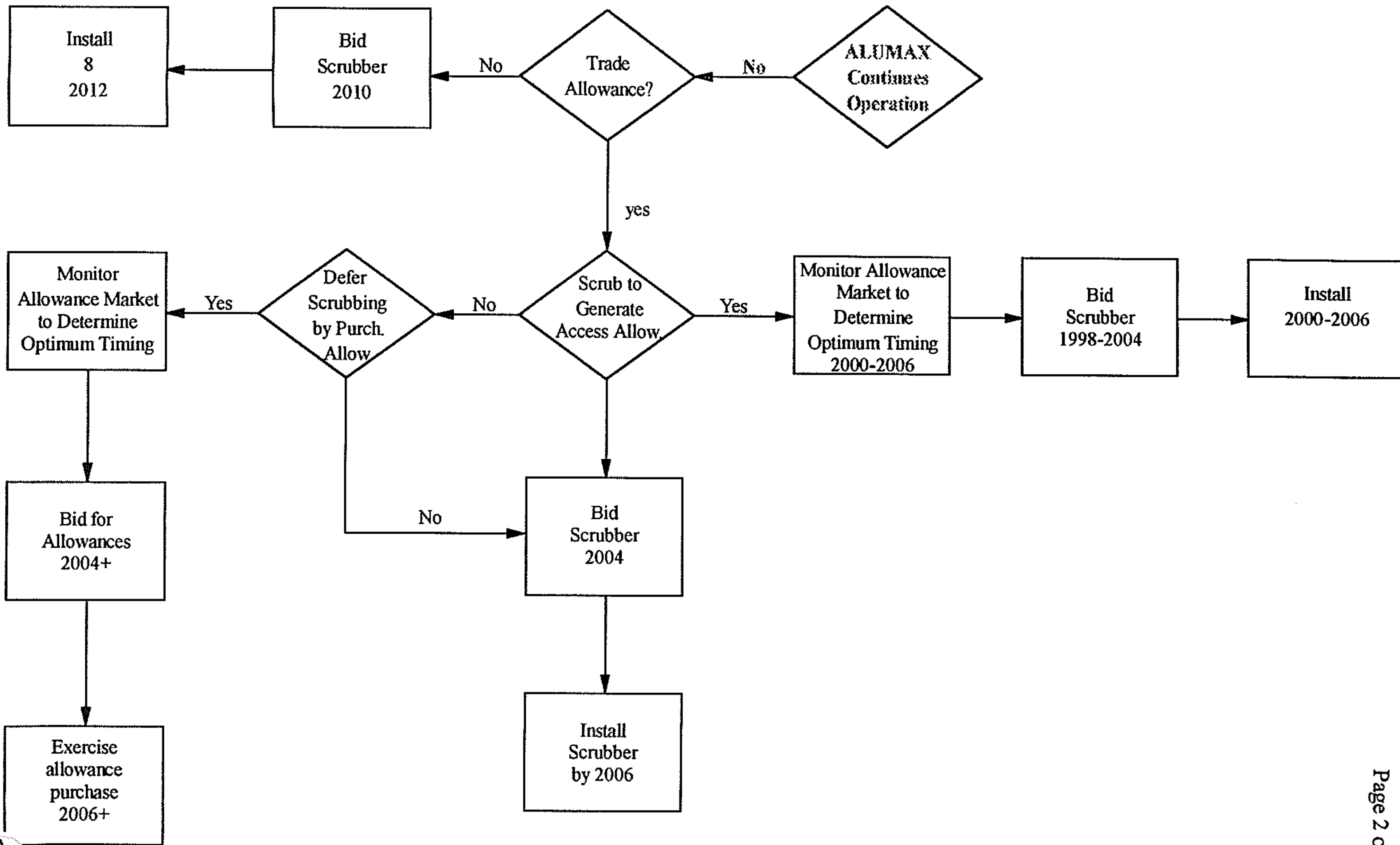
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUPPLY SIDE AND ENVIRONMENTAL COMPLIANCE PLAN STEPS



SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUPPLY SIDE AND ENVIRONMENTAL COMPLIANCE PLAN STEPS



II. INTEGRATED RESOURCE PLANNING PROCESS

II. INTEGRATED RESOURCE PLANNING PROCESS

This integrated resource plan (IRP) was developed for Santee Cooper in a multi-step process in which all viable demand-side and supply-side options were analyzed to arrive at an optimal long-term resource plan. The IRP process is depicted in Exhibit II-1.

The key steps in the process consist of:

- Reviewing key 1994 study assumptions
- Reviewing the 1994 load forecast
- Identifying and screening demand-side management options
- Identifying and screening supply-side resource options
- Identifying environmental regulation compliance plans
- Optimizing the demand-side and supply-side options to determine the reference case
- Performing sensitivity analyses on the base case and alternative scenarios
- Selecting the IRP expansion plan
- Developing a near-term action plan.

Each of these steps involves one or more separate tasks, which are described in the following sections.

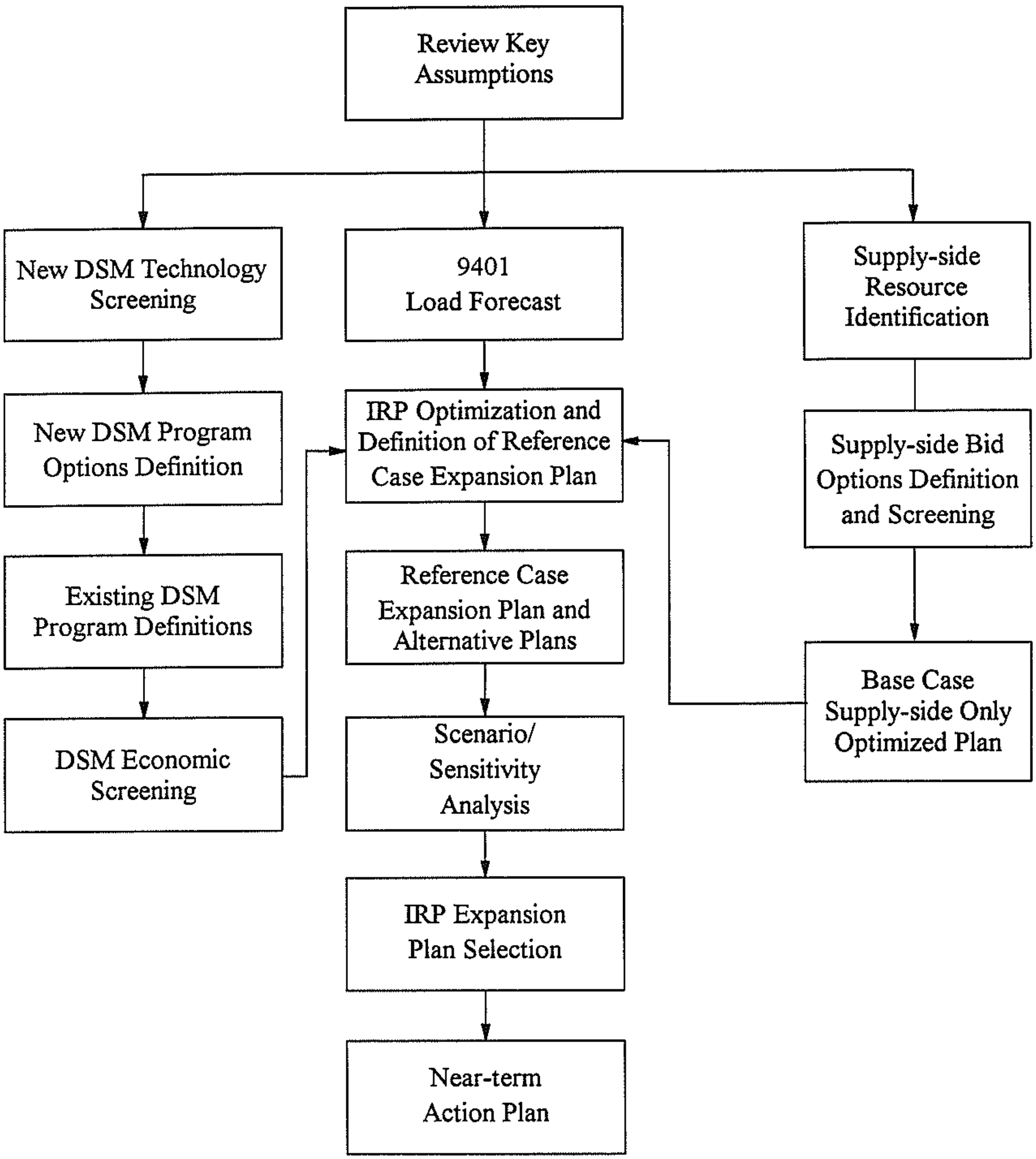
A. REVIEWING KEY 1994 STUDY ASSUMPTIONS

A number of assumptions affecting the operations of Santee Cooper are important in developing the IRP. These assumptions are common to all of the resource plans analyzed. They are:

- Fuel price forecasts and availability
- System reliability
- Economic factors
- Environmental outlook.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

INTEGRATED RESOURCE PLANNING PROCESS



Each of the assumptions is an important element in the analysis and affects the selection of the appropriate resource. A summary of the assumptions used in the 1994 IRP constitutes the rest of this section. A complete set of the base assumptions is provided in Appendix E.

FUEL PRICE FORECASTS AND AVAILABILITY

Fuel price projections were provided by Santee Cooper for the types of generating facilities that it might own and operate. The predominant fuels assumed to be used are coal, No. 6 oil and No. 2 oil. Table II-1 shows the price projections for these fuels in the years 1994-2015.

Table II-1

Fuel Price Projections
(in nominal dollars)

Year	Spot Coal ($/mmBtu)	Contract Coal ($/mmBtu)	No. 6 Oil ($/mmBtu)	No. 2 Oil ($/mmBtu)
1994	1.82	1.40	2.40	4.36
1995	1.89	1.46	2.50	4.48
1996	1.97	1.52	2.60	4.60
1997	2.05	1.58	2.70	4.72
1998	2.13	1.64	2.81	4.84
1999	2.21	1.71	2.92	4.97
2000	2.30	1.78	3.04	5.11
2001	2.39	1.85	3.16	5.24
2002	2.49	1.92	3.29	5.38
2003	2.59	2.00	3.42	5.53
2004	2.69	2.08	3.56	5.67
2005	2.80	2.16	3.70	5.83
2006	2.91	2.25	3.85	5.98
2007	3.03	2.34	4.00	6.14
2008	3.15	2.43	4.16	6.31
2009	3.27	2.53	4.33	6.47
2010	3.41	2.63	4.50	6.65
2011	3.54	2.73	4.68	6.82
2012	3.68	2.84	4.87	7.01
2013	3.83	2.96	5.06	7.19
2014	3.98	3.08	5.27	7.39
2015	4.14	3.20	5.48	7.58

The coal price forecast in Table II-1 reflects Santee Cooper's low sulfur Golden Oak coal at a 1994 delivered price of $1.40 per million British thermal units (mmBtu) for the contract coal, and $1.82 per mmBtu for the spot coal. Santee Cooper receives coal from a total of five different suppliers. The price identified in the table is a representative price of these five contracts. In the modeling of the fuels, each individual contract price is used with the appropriate generating unit. This coal forecast is based on Santee Cooper's existing contracts and the utility's future expectations of the regional coal market.

SYSTEM RELIABILITY

Santee Cooper uses a 20 percent minimum summer peak reserve margin for planning purposes. The 20 percent reserve margin criterion represents a signal to Santee Cooper that new resources may be required. However, recommendations for new resources are timed for projected drops to a 17 percent reserve margin. This reduced level of reserve margin is judged by Santee Cooper to represent a reasonable balance between having sufficient reserve capacity to provide reliable service and the added cost of increased reserve capacity. For the purpose of this study, the 17 percent reserve margin was used to time the addition of new resources.

MAJOR ECONOMIC ASSUMPTIONS

The quantitative economic criteria of the IRP center around the calculation of the present value of incremental revenue requirements (PVRR) for each of the resource plans. The key economic inputs utilized in calculating revenue requirements include construction costs, operating and maintenance expenses, general price escalators and the cost of capital. Table II-2 details the major economic input assumptions that are common to each resource option analyzed.

Table II-2

Major Economic Assumptions

Planning Period (PROVIEW™)	1994-2015
End-effects Period (PROVIEW)	2016 and Beyond
General Price Escalation Rate	3.0%
Cost of Capital (Long-term Tax Free Debt Rate)	6.5%

The planning period covered 1994-2015. An extended analysis period to capture the economic end-effects was added to ensure that all of the costs of supply- and demand-side options were captured over their useful lives. This extension period is contained in the PROVIEW model, which was used to develop much of the IRP economic analysis.

B. REVIEWING THE 1994 LOAD FORECAST

The 1994 load forecast which was provided by Santee Cooper is the critical assumption in the IRP that will drive the overall resource plan. Included in the forecast are three key components:

- 1994 Peak Demand Forecast
- ALUMAX Load
- Interruptible Load.

Each component is briefly identified and discussed below.

1994 PEAK DEMAND FORECAST

Santee Cooper reviews and revises its demand and energy forecasts on an annual basis. Details of the forecast used in the IRP are provided in Chapter III. During the forecasting process, Santee Cooper produces a most probable forecast along with alternative high and low forecasts based on different scenarios of economic growth, customer growth, price levels and weather. The probable forecast, one in which there exist equal probabilities that sales and demands will fall above or below the projection, is used in development of the base case IRP. The high and low forecasts are used in sensitivity analyses to assess the impact of load growth on alternative resource acquisition scenarios. Table II-3 shows the demand values in megawatts (MW) for these alternative forecasts.

Table II-3

1994 Demand Forecast Sensitivities (MW)

Year	Base	High	Low
1994	2,954	3,340	2,568
1995	3,056	3,453	2,653
1996	3,085	3,496	2,666
1997	3,161	3,588	2,726
1998	3,179	3,623	2.729
1999	3,196	3,655	2,730
2000	2,938	3,663	2,439
2001	3,009	3,498	2,511
2002	3,079	3,585	2,566
2003	3,150	3,673	2,622
2004	3,249	3,787	2,704
2005	3,321	3,873	2,758
2006	3,399	3,971	2,819
2007	3,479	4,065	2,880
2008	3,556	4,161	2,942
2009	3,635	4,257	3,002
2010	3,713	4,353	3,063
2011	3,786	4,448	3,122
2012	3,873	4,615	3,224
2013	3,961	4,782	3,326
2014	4,051	4,947	3,427
2015	4,143	5,113	3,529

ALUMAX

In addition to the load forecast sensitivities, another critical element in Santee Cooper's future load uncertainties is ALUMAX of South Carolina, Inc. The ALUMAX facility employs an aluminum reduction process with a demand of approximately 300 MW and an energy requirement of approximately 2,630 gigawatt-hours per year. In 1990, ALUMAX signed its tenth amendment to its agreement with Santee Cooper. As part of this agreement, ALUMAX is served through Santee Cooper's Large Light and Power Curtailable Supplemental Power Rider (L-94-SP).

The term of the current agreement extends through March 31, 2000. The agreement may be renewed automatically for two consecutive five-year periods. As part of this agreement, ALUMAX is to provide notice to Santee Cooper at least three years in advance if there is an intent to terminate the agreement in the year 2000 or at the end of the first subsequent period.

Since ALUMAX represents over 10 percent of Santee Cooper's total requirements, this load and its possible termination in the year 2000 will be a critical factor in the IRP prepared for Santee Cooper. Therefore, this 300-MW load remained as a retail customer in the three load sensitivities beyond the year 2000, resulting in a total of six load sensitivity cases to be evaluated.

INTERRUPTIBLE LOAD

In many of Santee Cooper's agreements with its industrial customers, the customer may choose an interruptible service at a reduced cost of power. In return, Santee Cooper has the option to interrupt the customer during peak conditions. However, instead of the customer being required to reduce its energy consumption, Santee Cooper will offer to purchase energy on the economy market and pass this energy on to the customer. This allows the customer to continue to operate its process if the energy is available, yet relieves Santee Cooper of the requirement to add resources to meet the total peak demand of this customer. This interruptible demand is 152 MW in 1994, 156 MW in 1995, and 119 MW thereafter in the study period.

C. DEMAND-SIDE MANAGEMENT OPTIONS ANALYSIS

The identification and screening of demand-side management options for the IRP consists of the following three critical steps:

- DSM technology screening
- DSM program options definition
- DSM economic screening.

This process is described in detail in Chapter IV; a summary is presented here.

DSM TECHNOLOGY SCREENING

The technology screening phase begins with the development of a comprehensive list of DSM measures created after thorough review of industry literature, studies by Santee Cooper marketing and sales personnel and discussions with trade allies. The purpose is to identify all technologies and products which could influence the amount of energy that Santee Cooper customers use.

Once the list of DSM measures is developed, it is screened to exclude those measures that could not practically be included in a DSM program. In order to screen those measures and eliminate them from further study, Santee Cooper applied a test based on the following three criteria:

- *Technical Feasibility* - the availability of the technology in the marketplace.

- *Customer Acceptance* - the willingness of Santee Cooper customers to accept significant amounts of a particular measure. Unacceptability is typically due to a measure's resulting in adverse lifestyle changes or performing poorly in a climate as varied as that of South Carolina.

- *Load Shape Objectives* - DSM measures that, if promoted, would tend to increase electric energy consumption and/or peak demand requirements.

PROGRAM OPTIONS DEFINITION

Measures which pass the qualitative screen are combined into programs. The objective is to package as many of the remaining DSM measures into programs as is practical while ensuring that each major end-use within each customer class is addressed by measures within the programs. Each program is designed to maintain sufficient flexibility to include as many measures as possible.

DSM ECONOMIC SCREENING

Each program is modeled in the DSM economic evaluation model of PROSCREEN™ called DSVIEW. DSVIEW analyzes specific program costs along with Santee Cooper system inputs to assess the benefits of each program. The results are expressed as benefit-cost ratios. These ratios are briefly described below:

- *Participant Test* - a measure of the quantifiable benefits and costs of a DSM program from the point of view of the participating customer. It indicates whether the program is economically attractive to the customer. If the test results in a ratio greater than 1.0, it indicates the proposed program would provide the ratepayer with benefits from decreased electric bills and incentive payments for participating in the program that combined would exceed the costs to the participant.

- *Total Resource Cost Test* - a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. Resource costs include changes in supply costs, utility costs, and participant costs. Since the utility and its ratepayers are taken as a whole, changes in the dollar amounts that flow between them are ignored. If this test results in a ratio of greater than 1.0, it is an indication that the program's combined benefits are greater than all of the combined costs to both the ratepayer and the utility.

- *Utility Cost Test* - a measure of the change in total costs to the utility that is caused by a DSM program. This test evaluates a DSM program from the point of view of a utility's total costs. Total costs include changes in supply costs, utility costs, and incentives. If this test results in a ratio of greater than 1.0, it is an indication that the program's benefits are greater than the costs to implement the program.

- *Ratepayer Impact Measurement (RIM) Test*: A measure of the difference between the change in total revenues recovered through rates by a utility and the change in total costs resulting from the DSM program. If the change in revenues is larger or smaller than the change in total costs, then rate levels may need to be changed to obtain proper revenue recovery. Thus, this test in effect evaluates the impact on rates resulting from a particular DSM program. Impacts on individual classes can be analyzed if costs and demand reductions are allocated in the same method used to determine rates. To fully determine rate impacts on a particular rate class resulting from a particular DSM program, a detailed analysis will be required. For the purposes of this study, the RIM test considered revenue changes resulting from the estimated change in energy sales (kWh); revenue changes resulting from changes in demand (kW) were considered minimal, and were not included in the screening.

Once the analysis of economic results of each DSM program is completed, the DSM programs which pass the screening tests with scores greater than 1.0 will be selected for integration with the supply-side options in the IRP optimization step.

SCREENING OF EXISTING DSM PROGRAMS

Santee Cooper currently has three DSM programs in various stages of implementation. The incremental costs and benefits of continuing these three programs were included in the DSM program screening analysis. Any of the existing DSM programs with benefit to cost ratios greater than 1.0 were passed to the integration phase of the IRP.

D. SUPPLY-SIDE OPTIONS ANALYSIS

The supply-side options analysis included supply-side resource identification and supply-side options definition and screening. These two steps are described briefly in the next paragraphs. Detail is provided in Chapter V.

SUPPLY-SIDE RESOURCE IDENTIFICATION

A comprehensive list of generation technologies and resources was initially created through a review of industry literature, discussions with contractors and developers, and a review of other utility integrated resource plans. The objective was to identify all current and developing technologies which might provide a source of generation. The key attributes of each supply-side option–technological maturity, effect on the environment, performance and reliability–were also identified and evaluated in this step. The power supply options identified are discussed in Appendix A.

SUPPLY-SIDE RESOURCE SCREENING

Assumptions and data regarding capital and O&M costs, generating capacities, heat rates, availability, operating life and construction scheduling were assembled for each technology and resource option identified. The data for the assumptions were developed from discussions with equipment suppliers, other utility IRPs, and research of industry data. A qualitative screen reviewed technologies for their environmental impact, regulatory impact, and commercial availability. The purpose of this screen was to focus additional review and analysis efforts only on those technologies which offered a reliable, low-cost resource with minimal environmental and regulatory risk.

Economic evaluation was performed on the supply-side options that survived the screen. The PROVIEW and PROSCREEN II models, described later, were used to perform the analysis. The PROVIEW model results provided an indication of the year in which the supply-side options would theoretically be added to the resource plan and the present value of incremental revenue requirements (PVRR) associated with that plan. PROSCREEN II provided more detailed evaluative information, including annual cumulative revenue requirements, capacity utilization statistics and system emissions data.

Once the economic evaluation was completed, the most attractive options, as defined by the lowest PVRR, resource reliability and impact on system reliability, were selected for integration with the demand-side options in the IRP optimization step.

E. ENVIRONMENTAL COMPLIANCE PLANNING

Important environmental issues will affect Santee Cooper's future resource plans. One of these issues is the Clean Air Act Amendments of 1990 (CAAA). The Amendments were signed into law on November 15, 1990. Santee Cooper is most affected by Title IV of the Act, which mandates sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emission reductions from fossil-fired steam-generating units. The Act will be implemented in two phases. Phase I will become effective on January 1, 1995, and Phase II on January 1, 2000. None of Santee Cooper's coal-fired generating units are affected under the SO_2 and NO_x reduction requirements in Phase I. All of Santee Cooper's fossil-fired electric generating units are affected under the SO_2 and NO_x reduction requirements in Phase II.

A second environmental issue of potential importance is the taxing of carbon emissions. A carbon tax bill was proposed in the United States House in early 1991, and while it did not become law, there had been mounting discussion from President Clinton's 1992 presidential campaign over the need for such legislation. The examination of the carbon tax issue in the IRP used the carbon tax rates from the 1991 House bill.

F. RESOURCE OPTIMIZATION

In the resource optimization process, the demand- and supply-side options passing the prior screening analyses were integrated to create and evaluate as many alternative resource plans as reasonably possible. The alternative plans provided a mix of demand-side and supply-side resource options to reliably meet customers' needs at the lowest PVRR. An initial Base Case Plan was developed by optimizing the available supply-side only options. This Base Case/Supply Only Plan was based on the required additional resources resulting in the lowest PVRR. This Base Case Plan assumed continuation of Santee Cooper's existing DSM programs. This Base Case Plan would reflect Santee Cooper's resource plan in the event no new DSM programs were implemented.

Included in the integration process was the consideration of Santee Cooper's planning philosophy of accepting minimal rate increases due to DSM while minimizing overall revenue requirements. The integration stage identified plans with: 1) minimum revenue requirements; 2) minimum rate impacts; or 3) a compromise with minimum revenue requirements and marginally increased rates. Each of these plans is presented to illustrate the different impacts on DSM planning depending on the policy followed by Santee Cooper. Each of these integrations and their results is discussed in Chapter VII.

An expansion plan was developed based on the DSM programs that resulted in a favorable benefit to cost ratio in the total resource cost test. The expansion plan, including these DSM programs and the optimal supply plan, was selected as the Reference Case Expansion Plan (the Reference Plan). Alternative Plans were developed on the basis of other realistic scenarios potentially available to Santee Cooper. The Base Plan, Reference Plan, and Alternative Plans were used in the sensitivity analysis step. Since the ALUMAX contract may terminate after March 31, 2000, resource optimization plans were developed for both the continuation and termination of this 300 MW load.

The economic evaluation and resource integration process used the PROVIEW and PROSCREEN II planning models to evaluate all of the alternative plans. PROVIEW and PROSCREEN II are widely used in integrated resource planning analysis. The models have fundamentally different functions and approaches which complement each other when used together for integrated resource planning analysis.

PROVIEW is a dynamic economic optimization model which ranks demand- and supply-side options on the basis of revenue requirements under a prescribed set of assumptions and constraints. The model inputs include a wide variety of supply-side and DSM options, along with fuel costs, reliability limits, environmental compliance options, financial constraints and other costs involved in operating a utility system. PROVIEW analyzes the effects on cost and reliability by adding resources to the system or modifying load through the addition of DSM programs. All possible resource combinations are analyzed to determine a theoretical ranking of integrated plans. The model output displays the order of possible expansion plans from the lowest cost to the highest cost and shows the effects and timing of various resource additions. The results are expressed in present value of revenue requirements. In developing the IRP, the PROVIEW model was used as an up-front screen to determine the appropriate timing and class of resources to add to the Santee Cooper resource portfolio. This directional analysis provided a good indication of the type of resources (load management, conservation, baseload, peaking) to be added and the timing of those additions.

The PROSCREEN II model performs much of the same analysis as PROVIEW but on a more detailed level and without internal resource optimization. PROSCREEN II calculates costs of a specific combination of resource options in a single run of the model. It is different from PROVIEW in that multiple runs of PROSCREEN II would be required to approximate the results of a single PROVIEW optimization. The advantage of PROSCREEN II is that it provides a more detailed analysis, including annual revenue requirements. Because it does not analyze multiple combinations of resources within a model run, its execution time is much less, and so it is a valuable tool for performing sensitivity analysis on assumptions within a specific resource scenario. With PROSCREEN II, the constraints in assumptions and resource plans are easier to control; thus it is possible to apply practical judgment to fixed resource plans while varying other production cost data to derive a more meaningful comparative analysis between real world scenarios.

In the development of the IRP, PROSCREEN II was used to refine the analysis that was done with the PROVIEW model. The resource expansion plans generated from PROVIEW were entered into the PROSCREEN model and run to determine a number of evaluative statistics, including cumulative present value of revenue requirements, plant capacity factors, SO_2 and carbon emission levels and reserve margins. These additional data provided a more complete and practical comparison of the various resource scenarios.

G. SCENARIO AND SENSITIVITY ANALYSES

To test the flexibility and robustness of the IRP alternative plans, a sensitivity analysis was performed. The Base Plan, Reference Plan, and Alternative Plans were tested for their reactions to changes in key assumptions. The results were reviewed to determine whether there were significant impacts on Santee Cooper customers. The assumptions tested included:

- High and low load growth
- Price changes of fuel supplies
- Variation in levels of demand-side management
- Environmental and legislative impacts
- Capital cost of future generating units.

Details on the sensitivity analysis and assumptions applied are discussed in Chapter VIII.

H. SELECTING THE IRP EXPANSION PLAN

The results of the sensitivity analysis are used to determine the optimal expansion plan. The selection of the resource plan depends upon careful consideration of a number of criteria, including revenue requirements, system average rate level impacts, resource reliability, system reliability, economic impacts on South Carolina and flexibility.

While the sophisticated analysis will provide the theoretically optimum mix of resources, no degree of analysis can substitute for management judgment. Theoretical analysis was supplemented with pragmatic experience to ensure that the plan would deliver reliable capacity in a reasonable and least cost manner.

I. NEAR-TERM ACTION PLAN

A Near-term Action Plan which describes the steps that Santee Cooper may take over the next five years to implement the 1994 IRP was developed. The plan addresses the steps necessary to pursue supply-side and demand-side options, implement selected DSM programs and proceed with supply resource options. Chapter IX presents the specifics of the Near-term Action Plan. Included in the Action Plan are alternative steps which depend on the status of ALUMAX after March 31, 2000.

III. DEMAND AND ENERGY FORECAST

III. DEMAND AND ENERGY FORECAST

The demand and energy forecast used in the 1994 IRP was prepared by Santee Cooper's Load Forecasting Department and reviewed and approved in April 1994 by Santee Cooper's Load Forecasting Committee. The forecast is identified within Santee Cooper as Load Forecast 9401.

The 1994 load forecast reflects: 1) Santee Cooper's 1994 rate schedules; 2) the continued operation of MacAlloy, the Charleston Naval Base, through March 1996; and 3) ALUMAX's firm and nonfirm projected consumption. Finally, the forecast includes Central Electric Cooperative's (Santee Cooper's largest single customer) energy and demand forecast to reflect latest economic data for South Carolina.

The 1994 forecast projects a reduction in overall load from military bases while projecting a mild growth in load due to the industrial sector. What has not been factored into this forecast and could have a sizable impact on it is the use of the military facilities by entities other than the military. Talks have been underway for modified usage of these facilities; however, no definite plans have been forthcoming. Santee Cooper chose not to modify the base forecast for this potential, since the high load forecast could be considered a sensitivity which accounts for this increased load.

Included in the 9401 forecast is curtailable load for each monthly peak demand throughout the forecast. In the past, this curtailable load has not been included in the forecasted peak demands. This change in presentation, though, does not reflect a change in Santee Cooper's planning process. The planning process in this IRP assumes the removal of the curtailable load in identifying the date of the year of need for new resources.

A. PEAK DEMAND FORECAST

Santee Cooper provided a total of six load forecasts to be used in the 1994 IRP. The Base Case forecast is based on Santee Cooper's best estimation of the future for its service territory. In addition, low and high band load forecasts were provided. Each forecast contained the underlying assumption that the ALUMAX load would not exist after March 2000. As a sensitivity to this assumption, each of the three forecasts were then modified to include the ALUMAX load throughout the study period. Each demand and energy forecast is presented below along with an indication of Santee Cooper's existing resources. The following charts indicate Santee Cooper's year of need for new resources based on the assumptions for DSM and existing supply-side resources prior to any modifications as a result of this IRP. This year of need occurs at the point in time when Santee Cooper's load growth as reflected in total requirements exceeds existing generation.

BASE FORECAST WITHOUT ALUMAX

The base forecast represents Santee Cooper's projection of the future based on the utility's best estimation of future assumptions. The forecast assumes an overall annual growth rate over the study period of 2.1 percent. This reflects a growth rate of approximately 0.7 percent over the first ten years and 2.2 percent in the second half of the forecast period. The 1994 forecasted demand is 2,954 MW, based on the current expectations for residential, commercial, industrial, and wholesale loads. This forecast also includes an assumption of DSM penetration for programs currently implemented. Exhibit III-1 contains a graph of the peak demands forecasted for 1994 to 2015, the total system requirements, including interruptible load reductions and reserve requirements, and Santee Cooper's total resources.

This load forecast results in Santee Cooper requiring new resources in the year 2003.

BASE FORECAST WITH ALUMAX

This forecast is the base forecast with the assumption that the ALUMAX load will continue on the Santee Cooper System throughout the study period. The ALUMAX demand includes 158 MW of firm load, 142 MW of nonfirm load (112 MW of nonfirm load in 1994), and 11 MW of transmission losses. The inclusion of the ALUMAX load results in an overall annual growth rate of 2.0 percent, consisting of a growth rate of 1.8 percent in the first ten years and 2.1 percent in the second ten years. Exhibit III-2 contains a graph of the peak demands forecasted for 1994 to 2015, the total system requirements, including interruptible load reductions and reserve requirements, and Santee Cooper's total resources.

This load forecast results in Santee Cooper requiring new resources in the year 2000. This represents a three-year acceleration in resource needs due to the continuation of the ALUMAX sales.

HIGH FORECAST WITHOUT ALUMAX

This forecast reflects changes in conditions and assumptions which result in increased power sales. These changes include population growth, economic conditions, manufacturing employment and industrial business outlook. In the high load forecast, it was assumed that growth rates for households and employment were increased by 0.5 percent per year from the base forecast. In addition, heating and cooling degree days were

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

BASE PEAK DEMAND FORECAST WITHOUT ALUMAX

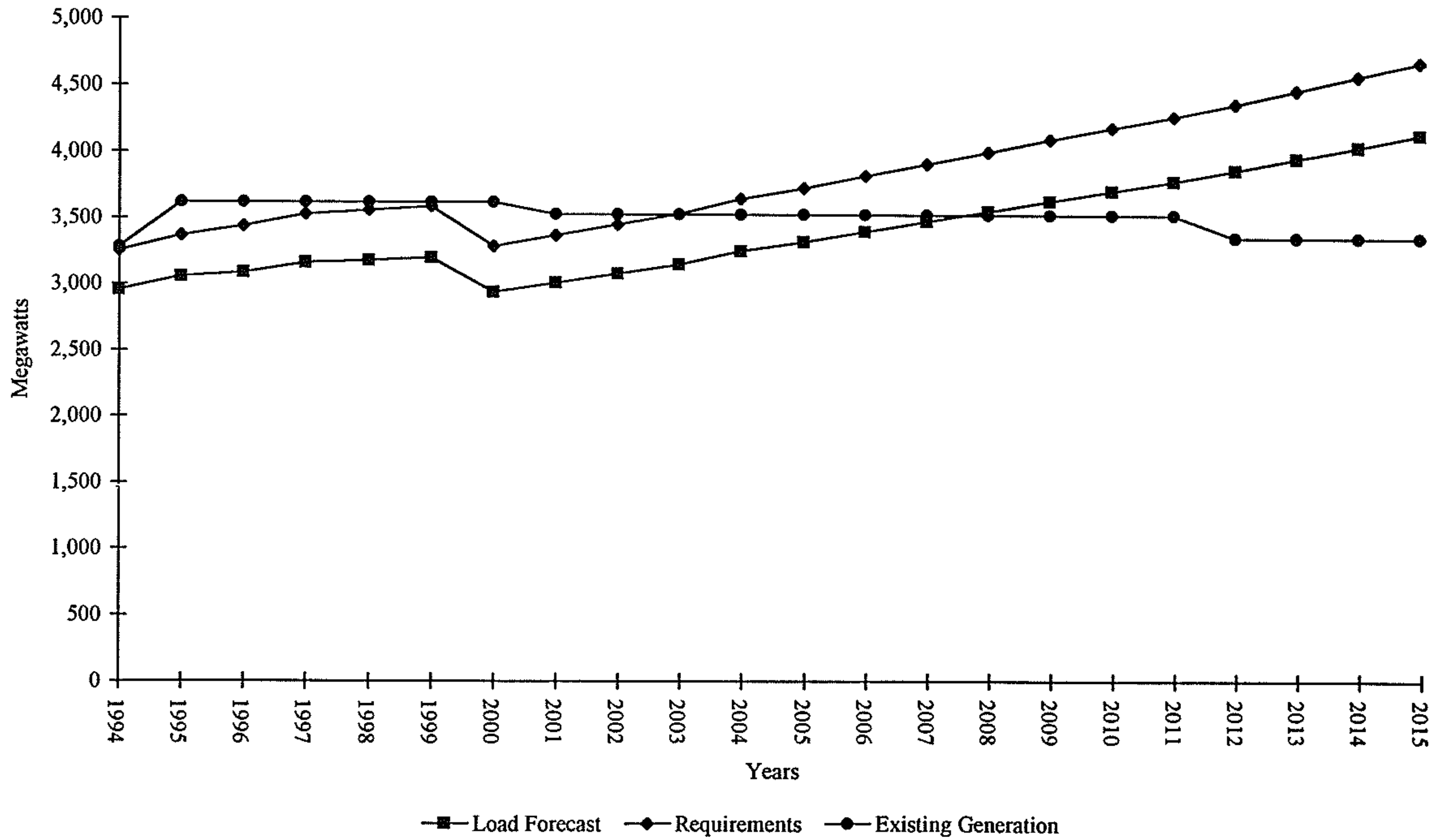


EXHIBIT III-1

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

BASE PEAK DEMAND FORECAST WITH ALUMAX

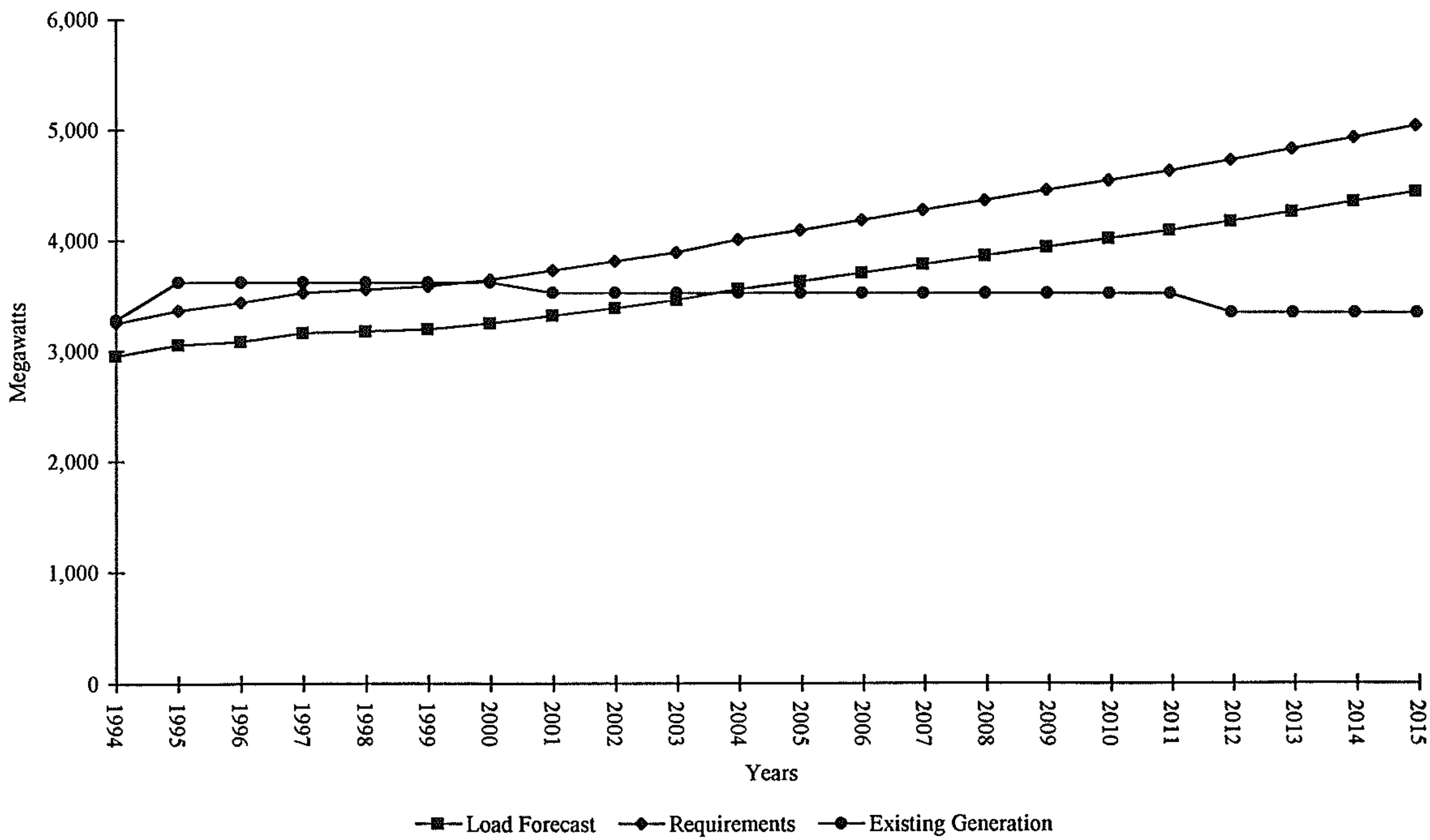


EXHIBIT III-2

increased to levels such that the probability of witnessing heating and cooling days in excess of those levels was only 5.0 percent. An increase to 3.0 percent from the base forecast of 1.5 percent in industrial sector growth rates was also included in the high forecast. The forecast assumes an overall annual growth rate over the study period of 2.0 percent. This reflects a growth rate of approximately 1.1 percent over the first ten years and 2.8 percent in the second half of the forecast period. Table II-3 contains the annual peak demands forecasted for 1994 to 2015. Exhibit III-3 contains a graph of the peak demands forecasted for 1994 to 2015, the total system requirements, including interruptible load reductions and reserve requirements, and Santee Cooper's total resources.

This load forecast results in Santee Cooper not having sufficient resources from the beginning of the study period.

HIGH FORECAST WITH ALUMAX

This forecast is the high forecast with the assumption that the ALUMAX load will continue on the Santee Cooper System throughout the study period. The ALUMAX demand includes 158 MW of firm load, 142 MW of nonfirm load (112 MW of nonfirm load in 1994), and 11 MW of transmission losses. The inclusion of the ALUMAX load results in an overall annual growth rate of 2.3 percent, consisting of a growth rate of 2.0 percent in the first ten years and 2.6 percent in the second ten years. Exhibit III-4 contains a graph of the peak demands forecasted for 1994 to 2015, the total system requirements, including interruptible load reductions and reserve requirements, and Santee Cooper's total resources.

This load forecast results in Santee Cooper not having sufficient resources from the beginning of the study period.

LOW FORECAST WITHOUT ALUMAX

This forecast reflects changes in conditions and assumptions which result in reduced power sales. These changes include population growth, economic conditions, manufacturing employment and industrial business outlook. In the low load forecast, it was assumed that growth rates for households and employment were decreased by 1.0 percent per year from the base forecast. In addition, heating and cooling degree days were decreased to levels such that the probability of heating and cooling days below those levels was only 5.0 percent. A decrease to 0.0 percent from the base forecast of 1.5 percent in industrial sector growth rates was also included in the high forecast. The forecast assumes an overall annual growth rate over the study period of 1.5 percent. This reflects a growth rate of approximately 0.2 percent over the first ten years and 2.5 percent in the second half of the forecast period. Table II-3 contains the annual peak demands forecasted for 1994 to 2015. Exhibit III-5 contains a graph of the peak demands forecasted for 1994 to 2015,

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

HIGH PEAK DEMAND FORECAST WITHOUT ALUMAX

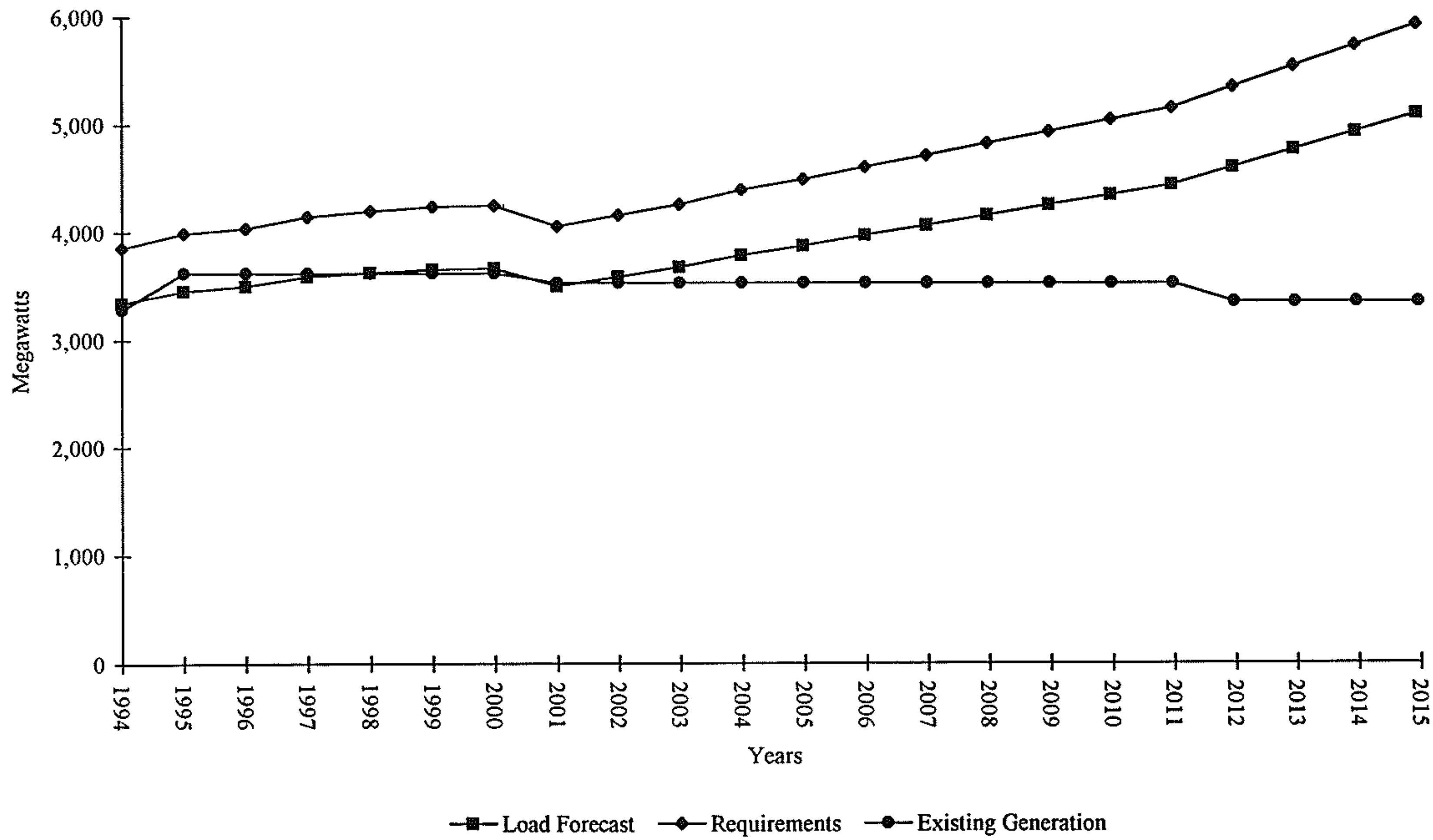


EXHIBIT III-3

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

HIGH PEAK DEMAND FORECAST WITH ALUMAX

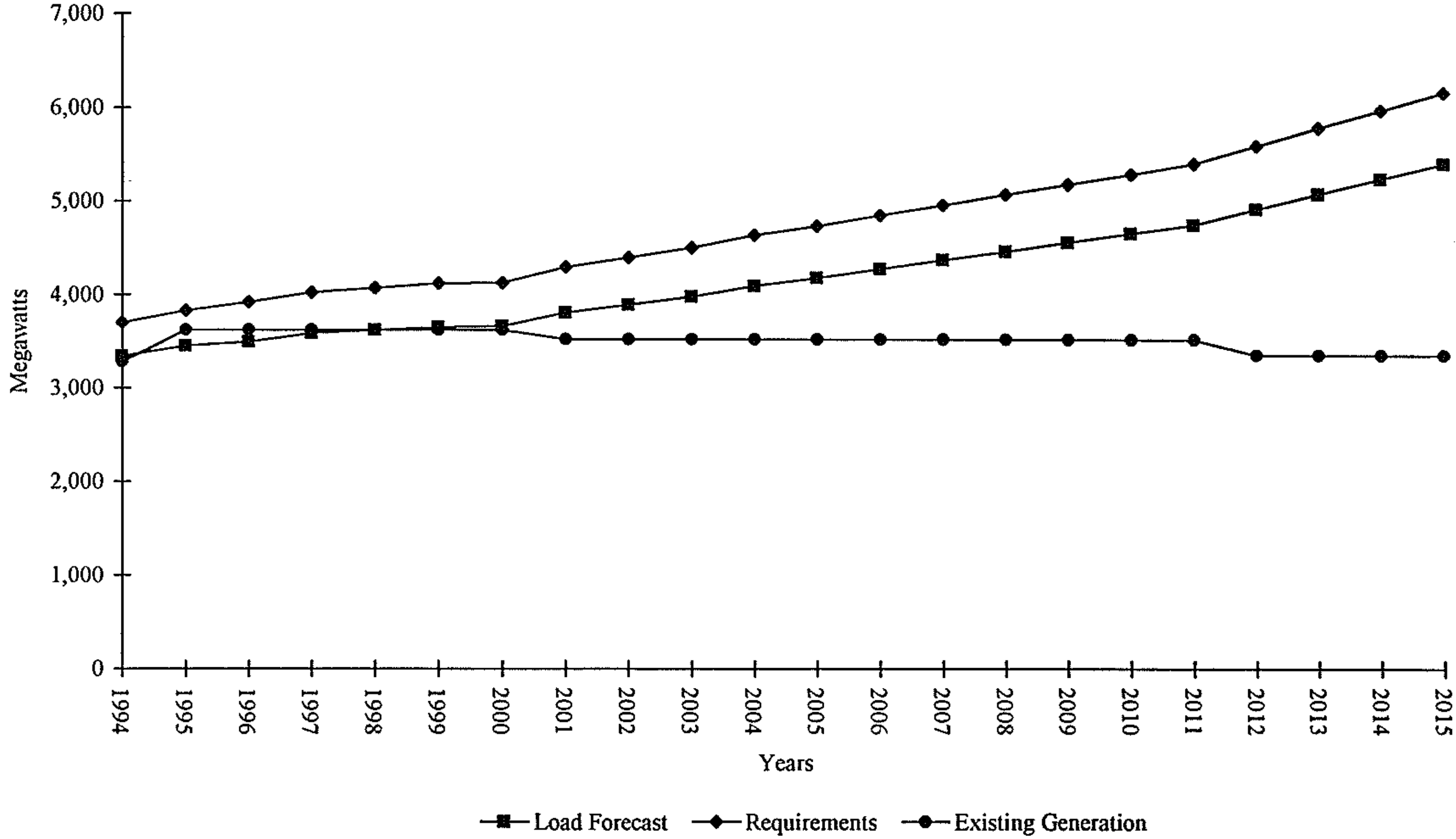


EXHIBIT III-4

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

<u>LOW PEAK DEMAND FORECAST WITHOUT ALUMAX</u>

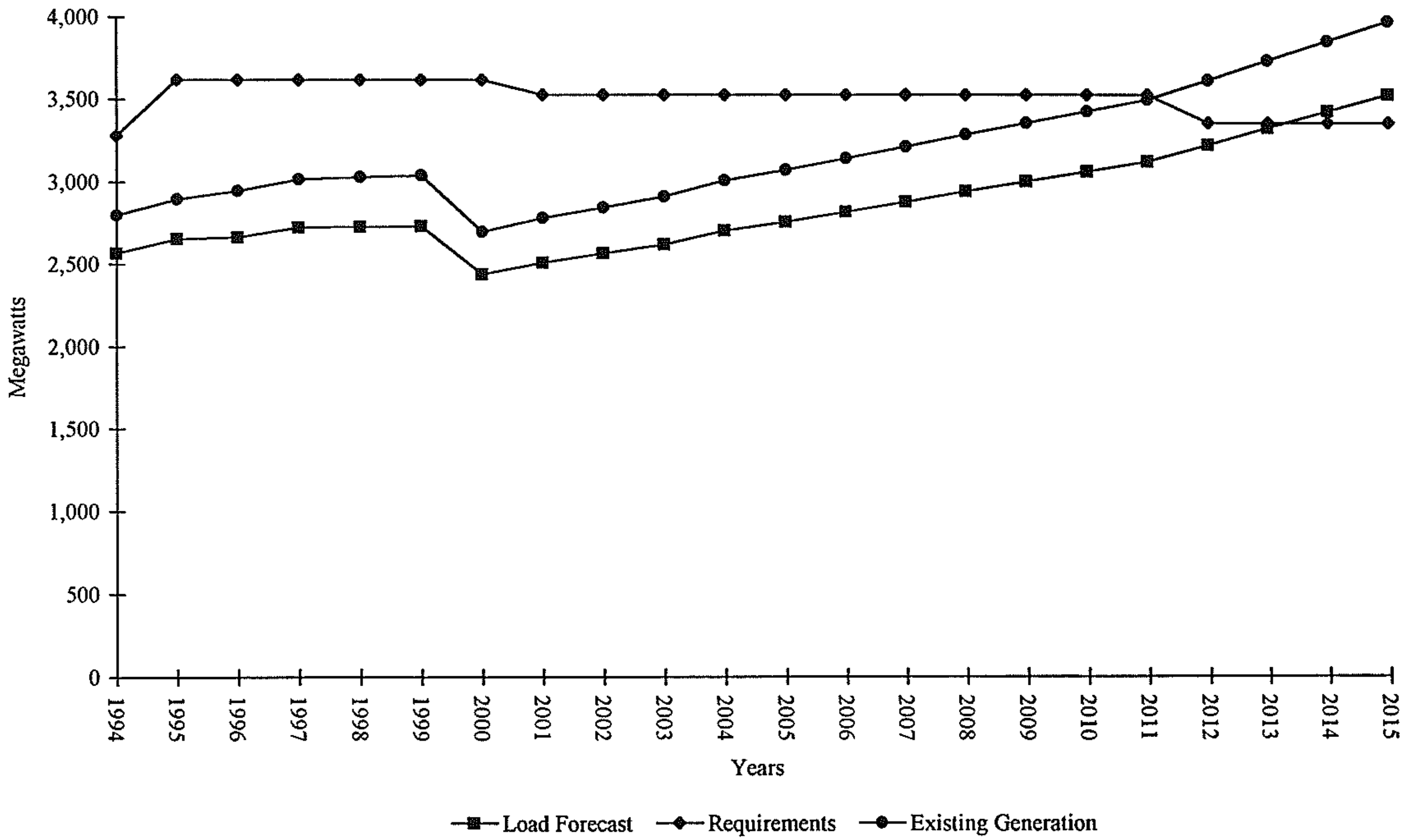


EXHIBIT III-5

the total system requirements, including interruptible load reductions and reserve requirements, and Santee Cooper's total resources.

This load forecast results in Santee Cooper requiring new resources in the year 2011.

LOW FORECAST WITH ALUMAX

This forecast is the low forecast with the assumption that the ALUMAX load will continue on the Santee Cooper System throughout the study period. The ALUMAX demand includes 158 MW of firm load, 142 MW of nonfirm load (112 MW of nonfirm load in 1994), and 11 MW of transmission losses. The inclusion of the ALUMAX load results in an overall annual growth rate of 1.9 percent, consisting of a growth rate of 1.5 percent in the first ten years and 2.2 percent in the second ten years. Exhibit III-6 contains a graph of the peak demands forecasted for 1994 to 2015, the total system requirements, including interruptible load reductions and reserve requirements, and Santee Cooper's total resources.

This load forecast results in Santee Cooper requiring new resources in the year 2006.

B. ENERGY FORECAST

The 1994 forecast is based on the individual forecasts for each of Santee Cooper's customer classes: residential, commercial, industrial (a separate forecast was prepared for ALUMAX), municipals, and Central Electric Cooperative.

As in the case of the demand forecasts, Santee Cooper prepares an energy forecast for each of the high, low, and base assumptions. In addition, Santee Cooper prepared an energy forecast with and without the ALUMAX load. Each of these energy forecasts is provided below.

The energy forecasting model employed by Santee Cooper contains equations to forecast appliance saturations and monthly sales. Average or normal weather was utilized to forecast all quantities in the base case forecast. High and Low energy forecasts were based on optimistic and pessimistic economic scenarios. These cases were constructed in order to define some uncertainty that exists over a long period of time. Exhibit III-7 illustrates the three energy forecasts without the ALUMAX energy sales as of 2000.

The drop in the energy forecast was a result of the 1,980 GWH of ALUMAX energy lost from the system sales. Exhibit III-8 illustrates the load forecasts if the ALUMAX sales remain on the Santee Cooper system.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

LOW PEAK DEMAND FORECAST WITH ALUMAX

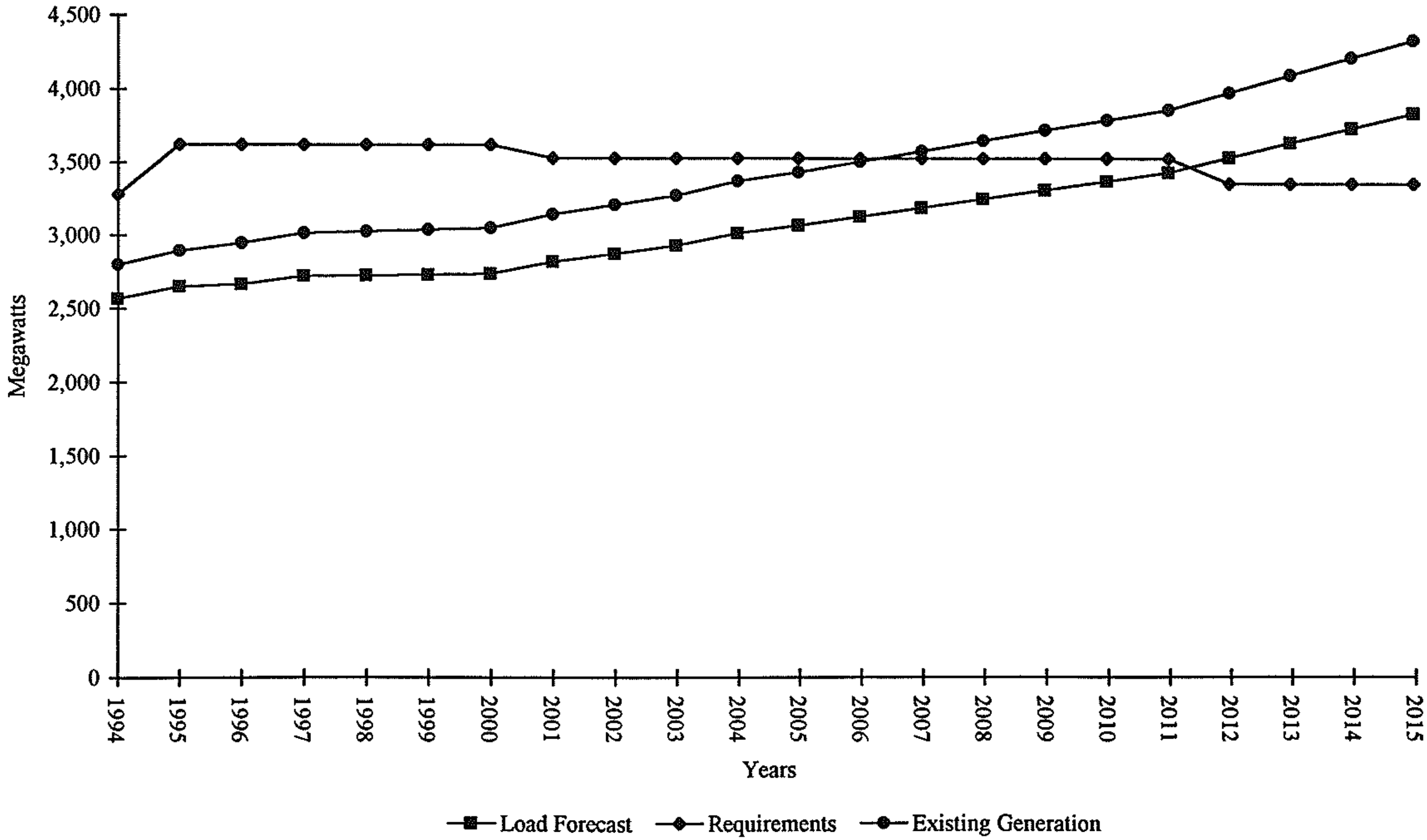


EXHIBIT III-6

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ENERGY FORECAST WITHOUT ALUMAX

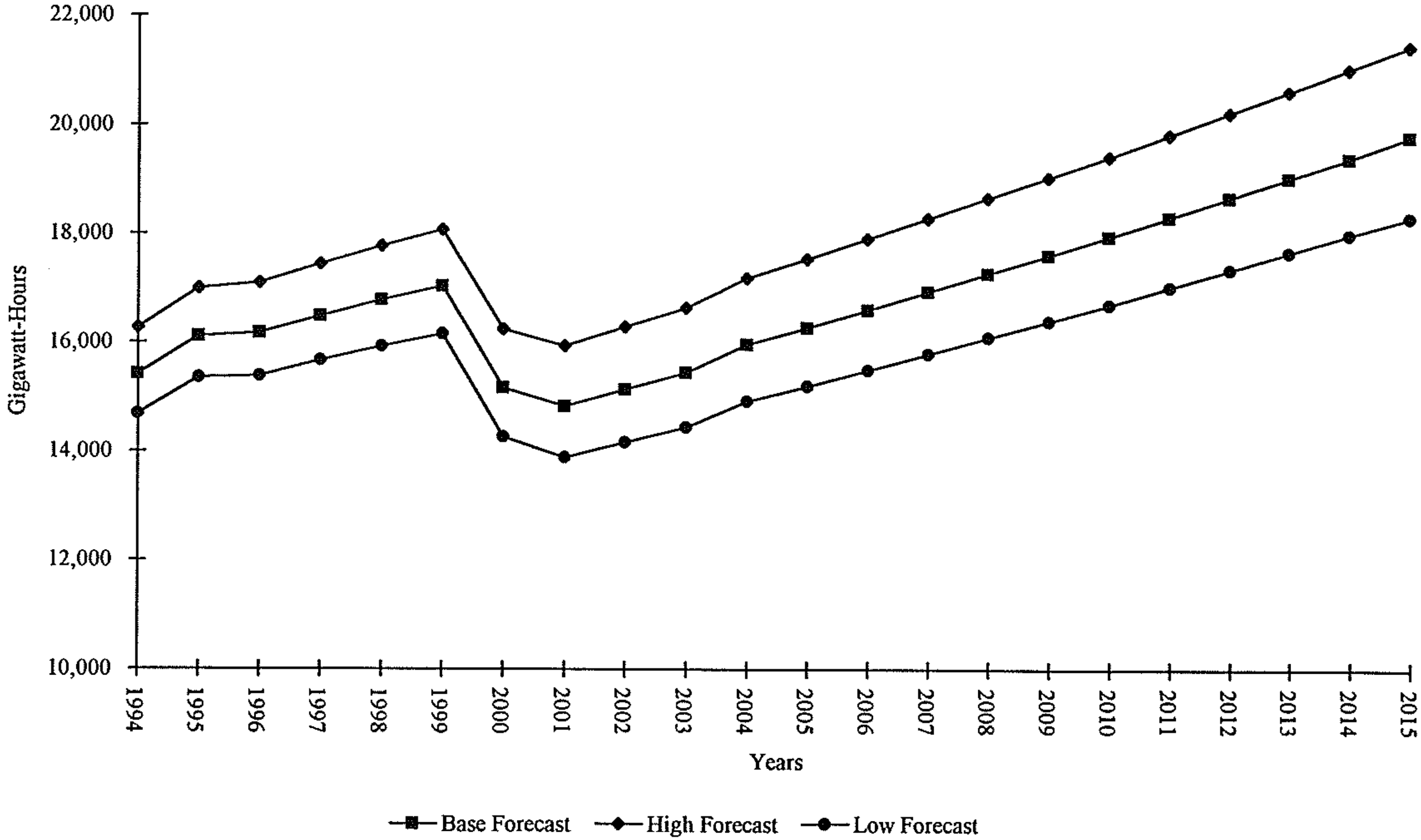


EXHIBIT III-7

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ENERGY FORECAST WITH ALUMAX

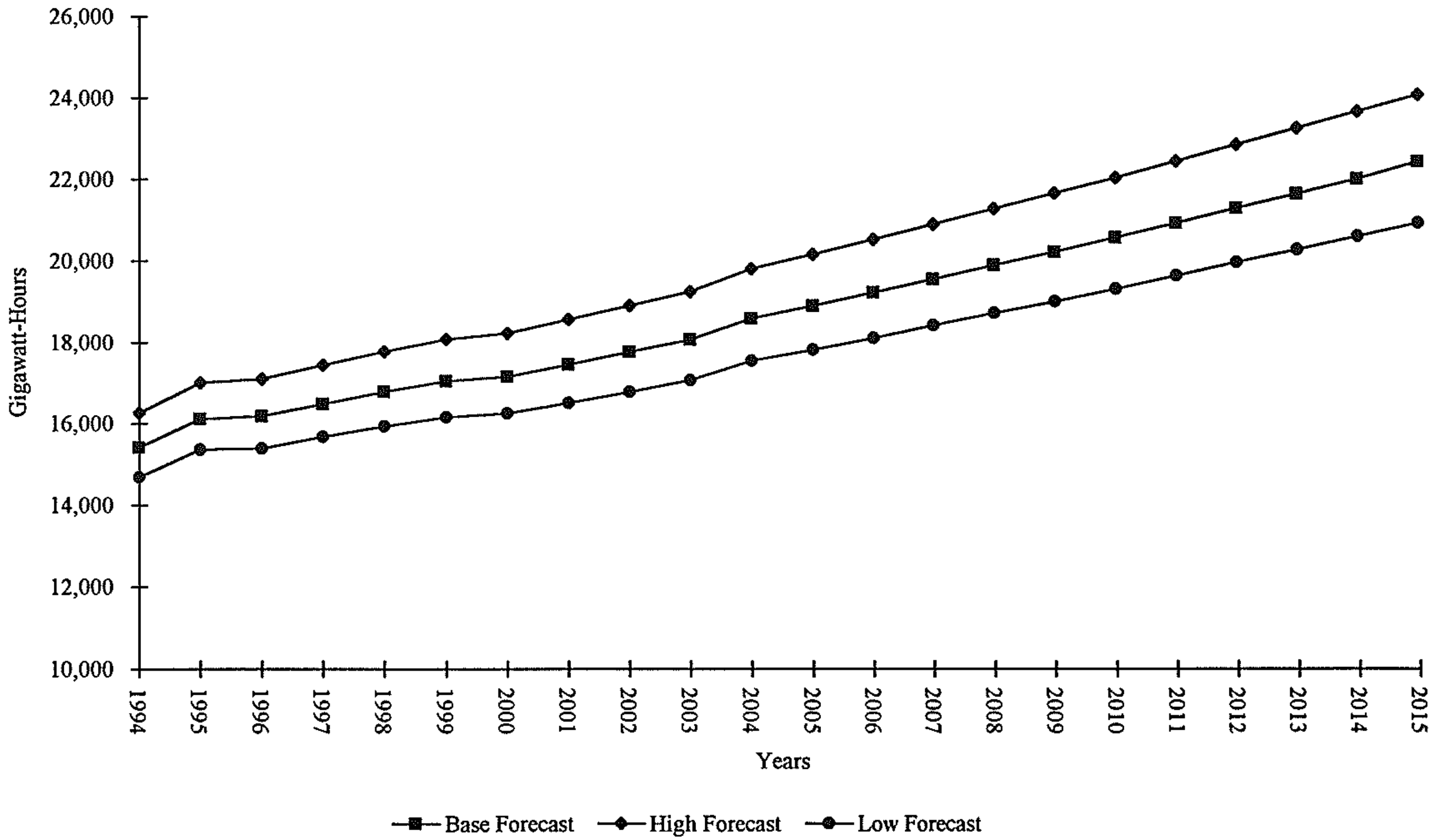


EXHIBIT III-8

The primary determinant of electric sales by Santee Cooper was assumed to be economic growth in the State of South Carolina. This growth depends on prospects for the national economy, which in turn depend significantly on prospects for the world economy and the competitive position of the United States among other countries. This dependency can produce a great deal of uncertainty, especially over a 20-year forecast horizon.

INTERRUPTIBLE LOAD

In April 1994, Santee Cooper implemented a new rate schedule called the Large Light and Power Interruptible Rider (L-94-I). Any industrial customer that agrees to receive power under this rider is subject to Santee Cooper's interrupting or curtailing all or a part of the demand covered by the rider. For planning purposes, this interruptible load is available as a resource to be called upon before a new supply-side resource is added to Santee Cooper's portfolio of resources. The energy associated with these loads is treated to allow Santee Cooper to continue to serve it through off-system purchases if such energy is available.

For planning purposes in this IRP, the energy was not served; however, a sensitivity analysis was performed in which the energy associated with the interruptible loads was included in the analysis to estimate Santee Cooper's marginal cost of energy. The load forecast includes an estimate of the interruptible demand at 152 MW in 1994, 156 MW in 1995, and 119 MW thereafter through the end of the study. The energy associated with the interruptible loads begins at 1,175 GWH in 1994, grows to 1,217 GWH in 1995, and then remains at 926 GWH through the rest of the study period.

IV. DEMAND-SIDE MANAGEMENT

IV. DEMAND-SIDE MANAGEMENT

This chapter describes the demand-side planning process employed in the development of the IRP, the programs Santee Cooper currently plans to pursue, and the energy and demand impacts modeled in the IRP from these programs. The DSM effort at Santee Cooper is divided into two components: 1) the DSM programs for Santee Cooper's retail customers and 2) the DSM efforts for its largest wholesale customer–Central Electric Cooperative. Santee Cooper is able to develop and market programs for its retail customers; however, it can only suggest and support the efforts by Central. As of mid-1994, Santee Cooper had three programs already approved and implemented. This IRP study will identify potential programs for all of Santee Cooper's customers. The programs proposed will establish participation, expenditure, and demand and energy savings estimates for each of them.

A. DEMAND-SIDE MANAGEMENT PLANNING PROCESS

The continuing DSM planning process consists of five steps: the identification of DSM measures, the application of qualitative screening criteria, the combination of technologies into programs, the performance of economic analyses, and the selection of programs. This process is shown in Exhibit IV-1 and described hereafter.

IDENTIFICATION OF DSM MEASURES

The first step in the DSM planning process is the compilation of a detailed list of DSM measures. This list was derived from a review of industry literature, trade publications, and other utility studies. The purpose of this step is to identify technologies which may be packaged into DSM programs. The frequent changes in technology increase the importance of maintaining technology listings which can be periodically updated.

In all, 227 measures were identified, of which 81 were residential, 98 were commercial, and 48 were industrial. Examples of residential measures include many types of heat pumps, passive and active solar heat, and energy-efficient refrigerators and freezers. Examples of commercial and industrial measures include fluorescent lighting, thermal energy storage, and heat recovery from exhaust air.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

APPLICATION OF QUALITATIVE SCREENING CRITERIA

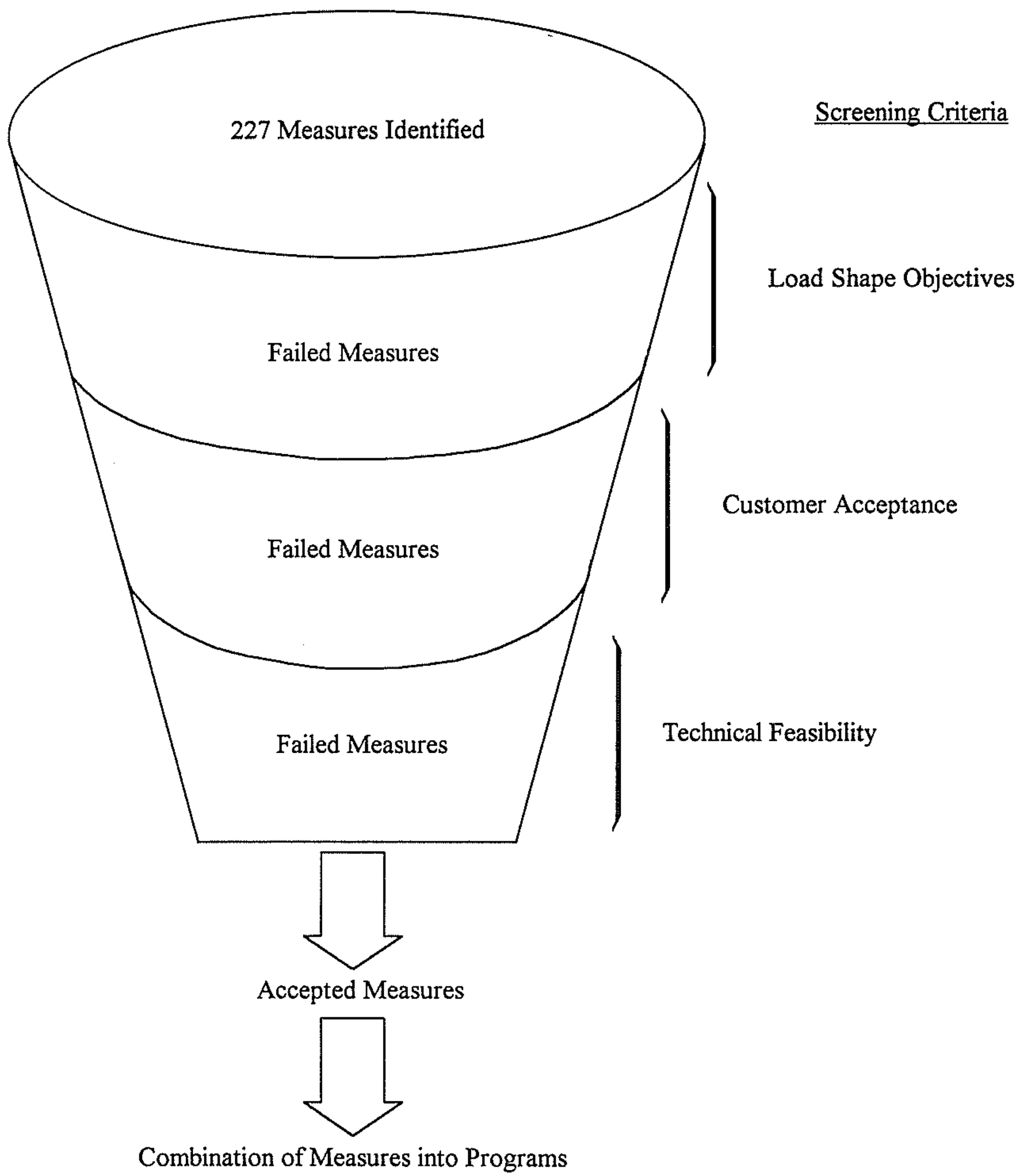
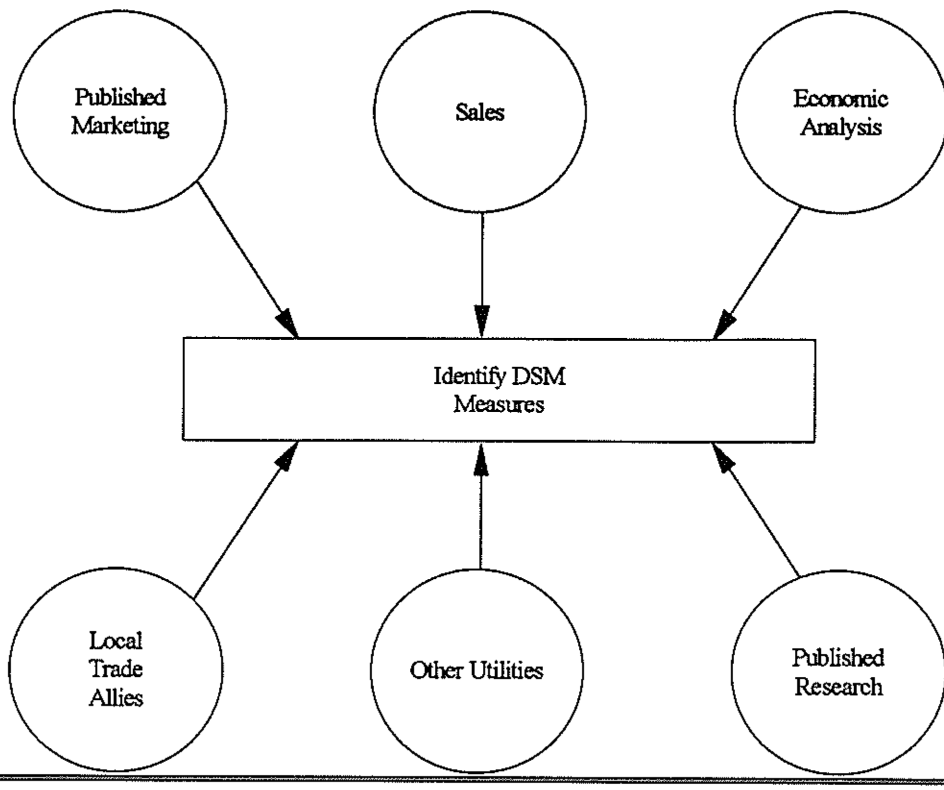


Exhibit IV-2 demonstrates the variety of sources referenced in the identification of DSM measures. Appendix B contains the detailed listing of DSM measures which were identified through these data sources.

Exhibit IV-2

Identification of DSM Measures



APPLICATION OF QUALITATIVE SCREENING CRITERIA

The identification of potential DSM measures discussed in the previous step probably contains many measures which may not be appropriate for Santee Cooper's service area, electrical system, and customer mix. In order to screen out measures that may be appropriate and to concentrate on measures that may be of greater interest, three qualitative criteria were applied. These criteria are:

- *Technical feasibility* - This criterion assesses the availability of the technology in the marketplace.

- *Customer Acceptance* - This criterion assesses the willingness of Santee Cooper customers to accept a particular measure. Measures which result in adverse lifestyle changes or are inappropriate for the South Carolina climate are rejected.

- *Load Shape Objectives* - This criterion assesses the impact of measures on electric energy consumption and peak demand requirements. Acceptable load shape objectives for DSM screening are conservation, peak clipping and load shifting.

In total, 156 of the 227 measures initially identified were screened out in the process. Appendix B lists all of the measures and groups of measures that were screened out and the reasons for rejecting them.

COMBINATION OF TECHNOLOGIES INTO PROGRAMS

The next step is to combine those measures which passed the qualitative screening process into DSM programs. The task was to balance the objectives of packaging as many of the measures into programs as is practical. It was also important that each program be designed to be purposeful, marketable, and manageable.

The remaining measures were addressed by 20 programs. Recognizing Santee Cooper's preference for experience and scarcity of resources, the programs were further screened to produce eleven for economic analysis. The specific reasons the 20 programs were reduced to eleven are identified in Appendix B. These programs represented a combination of some end-use-specific programs and included programs from Santee Cooper's 1993 IRP.

Table IV-1 demonstrates the relationship between the end uses, DSM programs, and measures for the residential market segment. Six of the eleven DSM programs identified were considered for the residential market. Note that the measures indicated for these six programs are only a sample of the measures addressed in the proposed programs.

Table IV-1 Residential Programs Studied		
End-use Category	Representative Measures	Program Studied
Space Cooling and Heating	Direct Load Control	Air Conditioning Direct Load Control Program
	Ground Source Heat Pump	Ground Source Heat Pump Program
	High Efficiency Heat Pump	High Efficiency Heat Pump Program
		Good Cents Manufactured Home Heat Pump Program
Duct Insulation	Duct Testing & Repair	Duct Testing and Repair
Swimming Pools	Control of Swimming Pool Pumps	Swimming Pool Pump Load Control
* These programs also impact other end uses, such as space heating and cooling.		

Similarly, each major end-use category for the commercial and industrial customers is included in the DSM programs for those market sectors. For the commercial and industrial customer classes, a total of 146 measures were identified. These were reduced in number again using the above identified criteria. Particular attention was given to the load impact by end users, with special focus on those with the largest share of energy usage in the commercial sector. After the screening of measures, programs were identified and then screened to produce five significant candidates for economic analysis. Again, the specific reasons for the final elimination of certain programs are identified in Appendix B, and largely relate to the maturity of the technology required to implement the program or the limited resources available at Santee Cooper to implement and administer the programs. These relationships are depicted in Table IV-2.

Table IV-2 Commercial and Industrial Programs Studied		
End-use Category	Representative Measures	Program Studied
Space Cooling	High Efficiency Air Conditioning Thermal Energy Storage	Air Conditioning Program Thermal Energy Storage
Miscellaneous	Standby Generation	Standby Generators Program
Lighting	High Efficiency Lighting	High Efficiency Lighting Program
Motors	High Efficiency Motors	Premium Efficiency Motors Program

In summary, the eleven program concepts developed during this step are:

- *Residential*
  - Load Control for Air Conditioning
  - Ground Source Heat Pump
  - Good Cents Manufactured Home Heat Pump Program
  - High Efficiency Heat Pumps
  - Swimming Pool Load Control
  - Duct Testing and Repair
- *Commercial/Industrial*
  - Thermal Energy Storage
  - Standby Generation
  - High Efficiency Lighting
  - Premium Efficiency Motors
  - Commercial Air Conditioning

The next activity within this step is to develop detailed program data for each of the DSM concepts. The data gathered for each program included:

- *Demand and Energy Impacts* - Load shape data primarily came from industry literature, Santee Cooper, and trade ally studies.

- *Participation Rates* - The main source of information came from industry literature and Santee Cooper.

- *Santee Cooper Program Expenditures, Including Incentives* - The primary source for estimates of incentives was literature from other utilities and checked with Santee Cooper. Costs for administration and marketing were based on labor rates supplied by Santee Cooper.

- *Customer Investment* - Data from trade allies and other utilities were primarily used to derive incremental costs for participants choosing the DSM measure.

- *Eligible Rate Classes* - The choice of rate classes depended on the average type of customer expected to participate in the program. Rate classes are important for calculating the economic perspective of the participant and the revenue lost by Santee Cooper.

DSM PROGRAM SUMMARIES

Exhibits IV-3 and IV-4 present the demand and energy impacts for the DSM programs studied. The pages after the exhibit contain a brief description of each program.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

DEMAND AND ENERGY IMPACTS - RESIDENTIAL

	High Efficiency Heat Pumps		Load Control Air Conditioning		Swimming Pool Load Management		Duct Testing and Repair		Ground Source Heat Pump		Manufactured Home Heat Pump Program	
Years	MW	GWh	MW	GWh	MW	MWh*	MW	GWh	MW	GWh	MW	GWh
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1995	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1996	0.8	2.0	7.2	0.0	0.1	0.0	0.5	1.1	0.1	0.9	0.9	2.6
1997	1.5	3.9	14.4	0.1	0.3	2.0	0.3	2.1	0.2	1.7	1.8	5.1
1998	2.3	5.9	21.6	0.2	0.4	3.9	0.5	3.2	0.3	2.6	2.6	7.7
1999	3.1	7.9	28.8	0.3	0.5	7.8	0.7	4.3	0.4	3.4	3.5	10.3
2000	3.9	9.9	35.9	0.4	0.6	7.8	0.8	5.3	0.5	4.3	4.3	12.8
2001	4.6	11.8	43.1	0.5	0.8	7.8	1.2	6.4	0.7	5.1	5.3	15.4
2002	5.4	13.8	50.3	0.6	0.9	19.5	1.2	7.5	0.8	6.0	6.1	17.8
2003	6.2	15.8	57.5	0.8	1.0	19.5	1.3	8.5	0.9	6.9	6.9	20.5
2004	7.0	17.7	64.7	1.2	1.2	44.9	1.5	9.6	1.0	7.7	7.8	23.1
2005	7.7	19.7	71.9	1.4	1.3	48.8	1.7	10.7	1.1	8.6	8.6	25.7
2006	7.7	19.7	79.1	2.0	1.4	68.4	1.7	10.7	1.1	8.6	8.6	25.7
2007	7.7	19.7	86.3	1.6	1.6	46.9	1.7	10.7	1.1	8.6	8.6	25.7
2008	7.7	19.7	93.5	2.0	1.7	95.7	1.7	10.7	1.1	8.6	8.6	25.7
2009	7.7	19.7	100.6	1.8	1.8	87.9	1.7	10.7	1.1	8.6	8.6	25.7
2010	7.7	19.7	107.8	2.3	1.9	115.2	1.7	10.7	1.1	8.6	8.6	25.7
2011	7.7	19.7	115.0	2.8	2.1	117.2	1.7	10.7	1.1	8.6	8.6	25.7
2012	7.7	19.7	122.2	2.1	2.2	97.7	1.7	10.7	1.1	8.6	8.6	25.7
2013	7.7	19.7	129.4	2.3	2.3	105.5	1.7	10.7	1.1	8.6	8.6	25.7
2014	7.7	19.7	136.6	2.6	2.5	109.4	1.7	10.7	1.1	8.6	8.6	25.7
2015	7.7	19.7	143.8	2.8	2.6	119.1	1.7	10.7	1.1	8.6	8.6	25.7

*Due to the small magnitude of the energy savings, the values are presented in MWh.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

DEMAND AND ENERGY IMPACTS - COMMERCIAL

	Thermal Energy Storage		Stand-by Generation		High Efficiency Lighting		Premium Efficiency Motors		Commercial Air Conditioning	
Years	MW	GWh	MW	MWh*	MW	GWh	MW	GWh	MW	GWh
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1995	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1996	0.0	0.0	1.1	38.6	0.7	2.6	0.1	0.5	0.5	1.2
1997	0.2	0.0	2.1	77.2	1.3	5.2	0.2	0.9	0.9	2.3
1998	0.3	0.0	3.2	116.2	2.0	7.8	0.3	1.4	1.4	3.5
1999	0.5	0.0	4.3	154.3	2.6	10.4	0.5	1.9	1.9	4.6
2000	0.6	0.0	5.4	193.4	3.3	13.0	0.6	2.3	2.3	5.8
2001	0.8	0.0	6.4	231.5	3.9	15.6	0.7	2.8	2.8	7.0
2002	1.0	0.0	7.5	269.6	4.6	18.3	0.8	3.2	3.2	8.1
2003	1.1	0.0	8.6	307.6	5.2	20.9	0.9	3.7	3.7	9.3
2004	1.3	0.0	9.7	347.7	5.9	23.5	1.0	4.2	4.2	10.4
2005	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6
2006	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6
2007	1.4	0.0	10.7	386.8	6.5	26.1	1.2	4.6	4.6	11.6
2008	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6
2009	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6
2010	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6
2011	1.4	0.0	10.7	385.8	6.5	26.1	1.2	4.6	4.6	11.6
2012	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6
2013	1.4	0.0	10.7	385.8	6.5	26.1	1.2	4.6	4.6	11.6
2014	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6
2015	1.4	0.0	10.7	386.7	6.5	26.1	1.2	4.6	4.6	11.6

*Due to the small magnitude of the energy savings, the values are presented in MWh.

EXHIBIT IV-4

SUMMARY OF RESIDENTIAL PROGRAMS

HIGH EFFICIENCY HEAT PUMPS

The objective of this program is to encourage customers who intend to purchase heat pumps to purchase high efficiency systems. Over time, the second goal of the program is to encourage dealers through dealer incentives to stock more energy efficient units and thus influence the entire market towards energy efficiency. The target customers would be all residential customers that are replacing a heat pump. Target customers would include those in single family homes, manufactured homes, and apartments. In the case of rental property, incentive payments would be made to the purchaser of the equipment, whether landlord or tenant.

DIRECT LOAD CONTROL OF AIR CONDITIONERS

The objective of this program is to give Santee Cooper the flexibility to reduce peak demand by direct control of air conditioners. New and existing residential customers would be targeted for the installation of radio-controlled receivers on central air conditioners. Cycling would be conducted up to 18 times during the summer months of June, July, and August. It is assumed that equipment will be cycled six times per month for an average of four hours each occasion. A 43 percent cycling strategy will be employed; that is, 13 minutes off out of each half hour of control.

DIRECT LOAD CONTROL OF SWIMMING POOL PUMPS

The objective of this program is to reduce peak demand during the summer and winter by cycling off customers' swimming pool pumps during peak hours. The target customers would be those with a swimming pool equipped with a pump. Customers will be targeted with opportunities for multiple switch installations to save on installation costs. Thus a customer may simultaneously receive switches for both the swimming pool pump and the water heater or air conditioner. The control period will be as long as necessary during the peak hours from 1:00 P.M. to 10:00 P.M. For purposes of analysis, there will be six days of control for the months of June, July, and August. In addition, control will be exercised four days each month in December, January, and February.

SUMMARY OF RESIDENTIAL PROGRAMS (CONT'D.)

GROUND SOURCE HEAT PUMPS

The objective of this program is to reduce demand and save energy during the summer and winter seasons by stimulating the installation of ground source heat pumps. The target customers would be new residential accounts, although existing customers would also be eligible. Target customers would include those in single family homes, although other types of dwellings would not be excluded from participating. Eligible equipment would include heat pumps exceeding 1.5 tons. Closed loop systems would be encouraged, although open loop systems would also be eligible. Units are rated by EER for ground source systems.

GOOD CENTS MANUFACTURED HOME HEAT PUMPS

The program objective is to reduce demand and save energy during summer and winter seasons by stimulating thermal envelope upgrades and the installation of high efficiency heat pumps in manufactured homes. Target customers would be residential customers purchasing new manufactured housing. This would include individuals that purchase manufactured housing for sale or lease to their residents. Eligible equipment includes split and packaged systems. Split systems are not installed at the factory but are installed at the site by the retailer or a contractor to the retailer. Packaged systems can be installed at the factory as a complete heating and cooling system.

To be eligible, customers must upgrade the insulation of manufactured homes to Good Cents standards. They must also install a heat pump of at least 12 SEER. The importance of this program will increase starting in October 1994, when more stringent HUD Code requirements take effect

DUCT TESTING AND REPAIR

The objective of the program is to reduce peak demand and save energy during summer and winter seasons by testing and repairing space conditioning distribution systems. The target customers would be those with central air conditioning and space heating systems. Customers of particular interest would be those with high energy bills. Site-built homes would be the primary target, but manufactured homes and small apartment buildings would also be eligible. Ducts would be tested with a duct blaster, although flow hoods and blower doors may also be employed. Trained and certified field workers will conduct the tests and repair the equipment. Materials that are of high quality and long durability will be specified in duct repair.

SUMMARY OF COMMERCIAL/INDUSTRIAL PROGRAMS

HIGH EFFICIENCY LIGHTING

The objective of this program is to assist customers in saving energy and reducing peak demand by the installation of more efficient lighting. The program will increase the awareness and expertise of commercial/industrial customers, facility managers, and trade allies in the installation and use of more efficient lighting technologies. The program will encourage a more thorough consideration of efficient lighting options and a more reliable operation once installations are made. The target customers would be commercial and industrial accounts with significant lighting loads. Both large and small accounts would be targeted in new and existing buildings.

THERMAL ENERGY STORAGE

The objective of this program is to shift demand and energy from the on-peak hours to the off-peak hours through the use of thermal energy storage systems. The target customers would be commercial and industrial accounts with on-peak cooling loads that can be supplied with off-peak cool storage. Both new and existing buildings would be eligible, with particular focus on new or expanded facilities, since the incremental costs can be less than retrofit costs. While it is expected that large facilities with experienced building engineers will be the source of major projects, small projects may be developed in other facilities, such as churches. Eligible cool storage systems would include chilled water, ice, and eutectic salts. Full systems would be eligible, and thus complete supply of on-peak cooling with off-peak storage would be allowed. Partial systems would be eligible also, with on-peak cooling to be met by off-peak storage and on-peak chiller operations. Thermal energy storage systems based on packaged units and chillers would be eligible.

STANDBY GENERATION

The objective of this program is to curtail peak demand by encouraging operation by customers of standby generators. The target customers would be commercial and industrial accounts with emergency or standby generators. Customers would be encouraged to operate generators under load conditions during a few days each year at the time of system peak demand. Customers would be contacted by phone and asked to curtail load by operating the standby generators for a fixed amount of time up to eight hours but averaging six hours on each occasion. Commitments would be expected for up to 9 days per year but averaging only 6 days per year.

PREMIUM EFFICIENCY MOTORS

The objective of this program is to save peak demand and energy by encouraging the installation of premium efficiency motors. The target customers would be commercial and industrial accounts with significant motor loads. Both large and small accounts would be targeted in new and existing buildings. Motors from less than five horsepower up to 250 horsepower would be eligible. Sizes larger than 250 horsepower are typically operated a large number of hours per year, which justifies the extra expense of purchasing premium motors already. Various types of motors would be eligible, including totally enclosed fan-cooled and open drip-proof motors. Adjustable speed drives on motors would also be eligible. To qualify, customers would need to certify that motor operation would be greater than 2,000 hours per year.

COMMERCIAL AIR CONDITIONING

The objective of this program is to save peak and demand energy by encouraging the installation of high efficiency air conditioning. The target customers would be commercial and industrial accounts with significant air conditioning loads. Both large and small accounts would be targeted in new and existing buildings. Eligible measures would include packaged air conditioning units. Future program additions could include split systems and central systems. Both air conditioning and heat pump units would qualify. However, for purposes of analysis, packaged air conditioning only units are assumed for now.

PERFORMANCE OF ECONOMIC ANALYSES

The next step in the process is to take the detailed program data gathered in the preceding step and assess the economic benefits and costs of each program. Each program concept is modeled in the DSVIEW economic evaluation module of PROSCREEN. The initial economic evaluation will evaluate the program costs in their entirety. No breakdown between retail and wholesale customers will be identified. After this initial analysis, an estimate of the retail versus wholesale economic comparison will be conducted. Since the costs for the proposed programs will need to be borne by some entity–either Santee Cooper or Central Cooperative–the significant difference for this IRP analysis between retail and wholesale will be the estimate of lost revenues associated with the program.

DSVIEW is a PC-based software package specifically designed to evaluate a wide range of DSM programs. DSVIEW has the capability to handle a comprehensive, detailed set of Santee Cooper system- and DSM-specific information.

DSVIEW accepts specific DSM program inputs such as:

- Increased Participant Costs
- Customer Load Shapes
- DSM Impact Load Shapes
- Applicable Rate Structures
- Utility Program Administrative Costs
- Participant Levels
- Program Lifetime
- Utility Incentives
- DSM Technology Lifetime.

In addition to the specific DSM program costs, DSVIEW utilizes the Santee Cooper system-specific data included in the PROSCREEN II database. The system-specific data of interest in the DSM analysis would be the load shape, fixed and variable generation costs, future supply-side resource costs, and economic data such as escalation rates, cost of capital, and discount rate.

DSVIEW utilizes specific program costs along with Santee Cooper system-specific inputs to assess the benefits of hourly impacts of each program concept. The results are expressed as benefit-cost ratios. These ratios are briefly described below.

- *Participant Test*: A measure of the quantifiable benefits and costs of a DSM program from the point of view of the participating customer. It is designed to indicate whether the program is economically attractive to the customer. The test includes the benefits associated with reduced electric bills and incentive payments weighed against the increased costs due to the purchase of equipment required to participate in the program such as a new heat pump.

- *Total Resource Cost (TRC) Test*: A measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. Resource costs include changes in supply costs, utility costs, and participant costs. Since the utility and its ratepayers are taken as a whole, changes in the dollar amounts that flow between them are ignored.

- *Utility Cost Test*: A measure of the change in total costs to the utility that is caused by a DSM program. Thus, this test evaluates a DSM program from the point of view of a utility's total costs. The test includes the benefits associated with reduced production costs and deferred generation capacity capital costs. These benefits are weighed against increases in the utility's total costs including DSM program costs, utility costs, and incentives.

- *Ratepayer Impact Measurement (RIM) Test*: A measure of the difference between the change in total revenues recovered through rates by a utility and the change in total costs resulting from the DSM program. If the change in revenues is larger or smaller than the change in total costs, then rate levels may need to be changed to obtain proper revenue recovery. Thus, this test in effect evaluates the impact on rates resulting from a particular DSM program. Impacts on individual classes can be analyzed if costs and demand reductions are allocated in the same method used to determine rates. To fully determine rate impacts on a particular rate class resulting from a particular DSM program, a detailed analysis will be required. For the purposes of this study, the RIM test considered revenue changes resulting from the estimated change in energy sales (kWh); revenue changes resulting from changes in demand (kW) were considered minimal, and were not included in the screening.

The results of the DSVIEW economic screening process for the six residential programs and the five commercial/industrial programs appear in Table IV-3. Three key modeling assumptions were included in the screening of the DSM programs. These assumptions and the screening implications were:

- Use of the base load forecast with ALUMAX
  - Assumed a higher marginal cost of avoided power
- No demand rate for commercial DSM programs
  - Minimized the lost revenue from reduced peak demand
- Modeled peak demand reductions at peak hour of the year, and energy reductions over the peak hour plus one hour before and one hour after
  - Maximized the benefits of the DSM program due to deferred capacity and reduced production costs.

If the programs are evaluated with the TRC Test, seven of the eleven programs result in benefit-to-cost ratios of 1.0 or better. These seven programs and the resulting ratios are:

- Stand-by Generation: 13.24
- High Efficiency Lighting (Commercial/Industrial): 2.88
- Premium Efficiency Motors (Commercial/Industrial): 2.62
- Good Cents Manufactured Home Heat Pump (Residential): 1.83
- Air Conditioning Load Control: 1.39
- Commercial Air Conditioning (Commercial/Industrial): 1.37
- Duct Testing and Repair (Residential): 1.00

All of the other programs resulted in ratios of 0.54 or less.

Table IV-3

Results of DSM Economic Screening - New Programs

	Name of Test			
Program	Participant	TRC	Utility	RIM
Standby Generators	Inf.	13.24	0.51	0.50
High Efficiency Lighting	3.28	2.88	4.91	1.07
Premium Efficiency Motors	3.57	2.62	4.20	1.03
Good Cents Manufactured Home Heat Pump	5.74	1.83	0.47	0.35
Air Conditioning Direct Load Control	Inf.	1.39	0.54	0.53
Commercial Air Conditioning	1.36	1.37	3.62	1.07
Duct Testing and Repair	1.70	1.00	1.41	0.67
Thermal Energy Storage	1.02	0.51	1.15	0.50
Swimming Pool Direct Load Control	Inf.	0.54	0.34	0.33
High Efficiency Heat Pump	0.95	0.47	0.73	0.50
Ground Source Heat Pump	0.50	0.34	1.32	0.62

Note: The results of this screening ignore the differences between retail and wholesale costs and benefits.

B. SELECTION OF DSM PROGRAMS

The last step in the DSM screening is the analysis of the economic results of each DSM program and the application of judgment to determine whether the results make intuitive sense for Santee Cooper's system requirements. It may make sense to select programs for further research or implementation even though they fail the economic screening analysis.

A key element guiding Santee Cooper's selection of DSM options is the cost-effectiveness of each DSM program. The Company is committed to maintaining its low rates and is therefore sensitive to DSM programs that will increase rates, especially for those customers not participating in the DSM program.

Santee Cooper may consider several important factors which play a role in management's decision-making process. Among these considerations are:

- Meeting the energy management expectations of customers
- Maintaining a solid and noncompetitive relationship with local trade allies
- Providing reliable electric service and having confidence in the persistence of DSM energy and demand impacts
- Maintaining the financial integrity of the Company.
- Develop a set of programs for resource integration, which makes good sense for Santee Cooper and its customers.

The following paragraphs discuss the economic test results of the eleven DSM programs screened.

HIGH EFFICIENCY LIGHTING PROGRAM

The High Efficiency Lighting Program received a 3.28 on the Participant Test, a 2.88 on the TRC Test, a 4.91 on the Utility Test, and a 1.07 on the RIM test. This indicates that the program is good for the participants in the program and it will result in lower overall revenue requirements for Santee Cooper. Exhibit IV-5 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results. In general, a value of greater than zero on the chart would result in a DSM test score of 1.0 or greater.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE HIGH EFFICIENCY LIGHTING PROGRAM

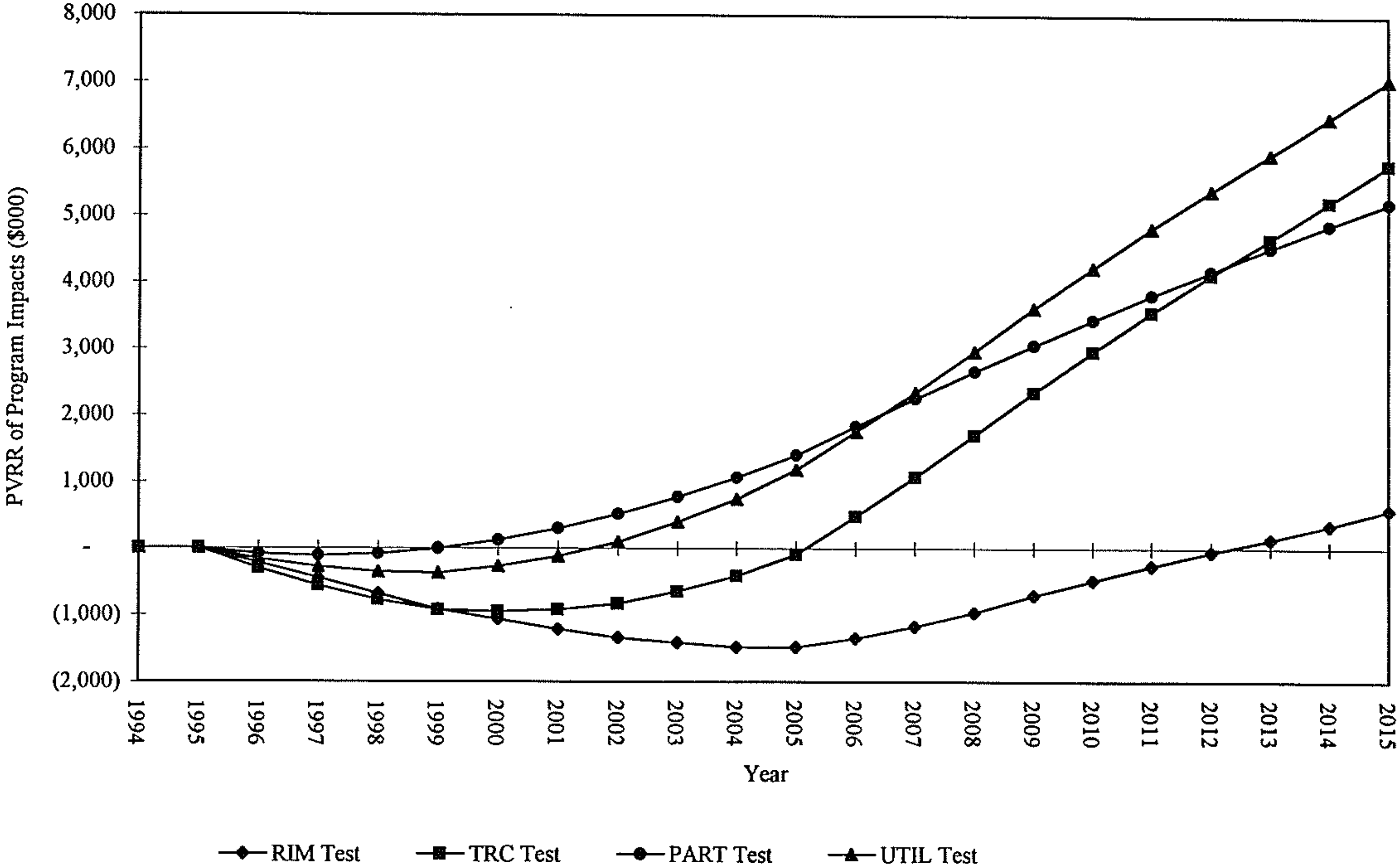


EXHIBIT IV-5

Participant Test

The significant revenue reduction that represents a cost in the RIM test is a benefit in the Participant test. An additional benefit to this program is the magnitude of incentives received by the participants. These benefits are offset only by the costs the participant incurs to become a part of the program, such as installing the new high efficiency lights. The overall benefits of the program were over five to one greater than the costs to participate in it.

TRC Test

The TRC test included the benefits from reduced production costs due to lower energy sales and reduced generation capacity capital costs due to a reduced peak demand. These savings were offset by the costs incurred by participants in the program and the utility's costs to implement the program. For this particular program, the overall costs of the program were offset by a three to one ratio by the savings from implementing the program.

Utility Test

The savings in production costs and deferral of new generation capacity were the two contributing factors to a benefit to cost ratio of 4.81.

RIM Test

The RIM test included the benefits from reduced production costs due to lower energy sales and reduced generation capacity capital costs due to a reduced peak demand. These savings exceeded the costs to implement and evaluate the DSM program, including projected incentive payments.

Summary

Overall, this program could be beneficial to Santee Cooper. As such, the program would provide economic benefits for Santee Cooper to actively pursue it.

STAND-BY GENERATION PROGRAM

The Stand-By Generation Program received a 13.24 on the TRC Test, a 0.51 on the Utility Test, and a 0.50 on the RIM test. The Participant test indicated an unlimited benefit, since it was assumed the participants would already have an emergency generator that would be used in this program. This program is aimed at those that need the generator for other operating reasons and represents an incremental increase in revenues to the customer. The scores of the program indicate that the program is good for the participants in the program but it will result in higher overall revenue requirements for

Santee Cooper. Exhibit IV-6 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

The Participant test was based on the significant incentive payments to be received by those that participate in the program weighed against the assumption that the participants would not incur any incremental increase in costs to participate. In reality, the participants would incur variable costs due to fuel to operate the stand-by generators. However, for study purposes, it was assumed the operation of the stand-by generators for Santee Cooper would displace the required time to operate the units for routine maintenance and testing.

TRC Test

The TRC test resulted in a very favorable score of 13.24. This is illustrated in the exhibit as a positive total present value of annual savings outweighing the increased costs to implement the program.

Utility Test

The utility test indicates that this program would result in increased revenue requirements for Santee Cooper. The largest single component of the costs for this program to Santee Cooper are the incentive payments. The current assumption would be to pay $48,000 in 1994 dollars to the participants in the program. For the Utility Test to result in a break-even present value, the incentives would need to be reduced by 94 percent, or essentially eliminated altogether.

RIM Test

A significant factor in this analysis was the magnitude of incentive payments to the participants in the program. The RIM test resulted in 0.50 because of the magnitude of these payments. If, though, Santee Cooper could interest participants in the program with zero incentive payments, then the RIM Test would be greater than 1.0.

Summary

As the program is formulated now, it would result in increased revenue requirements. However, if the incentive payments could be drastically reduced, or even eliminated altogether, then the program would result in benefits outweighing costs to both the participants and Santee Cooper. The underlying premise of this program is that customers already have stand-by, or emergency, generators that need occasional testing. If Santee Cooper could interest these customers in performing the necessary testing at Santee Cooper's critical load times, this program could be worth pursuing.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE STAND-BY GENERATOR PROGRAM

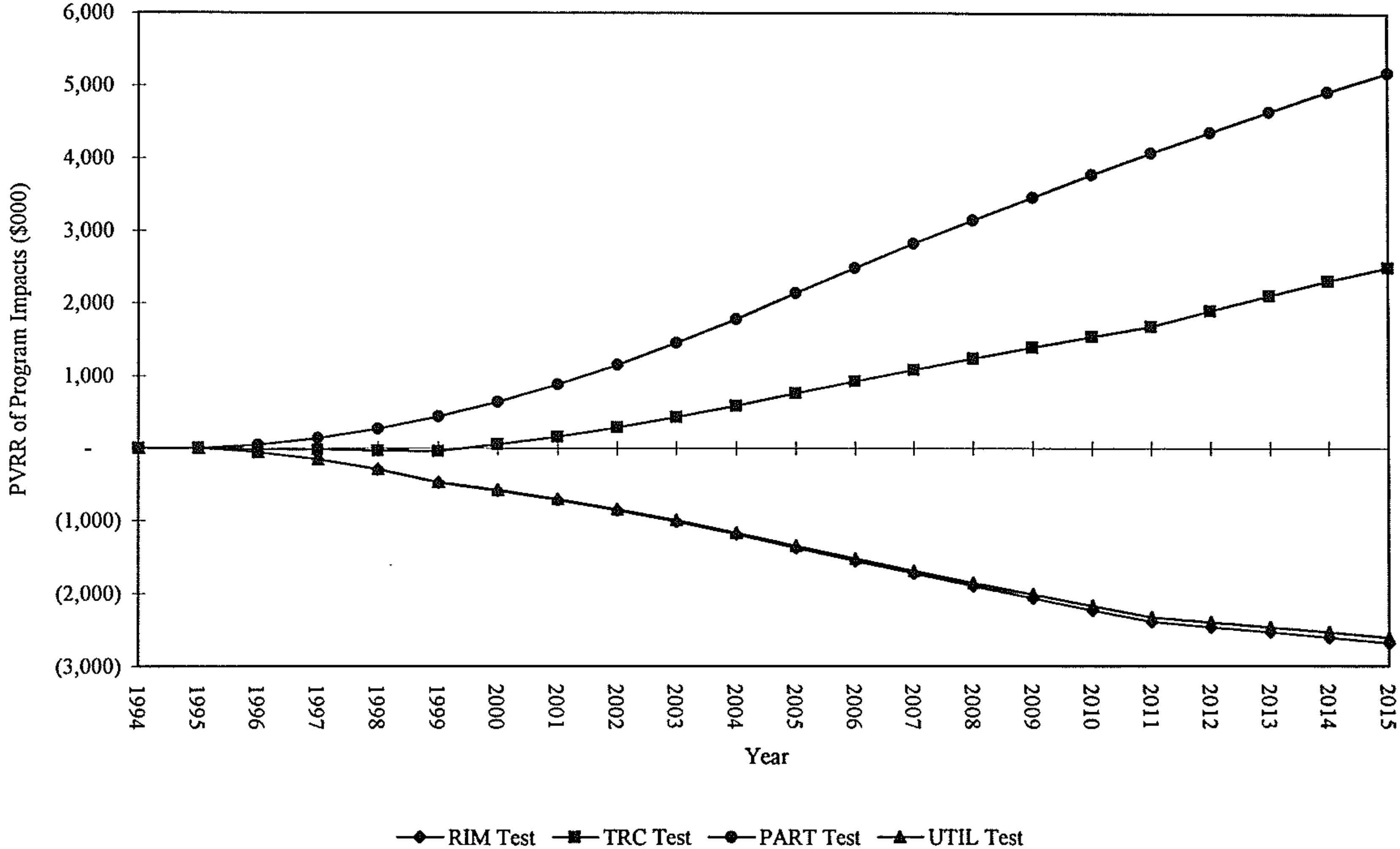


EXHIBIT IV-6

PREMIUM EFFICIENCY MOTOR PROGRAM

The Premium Efficiency Motor Program received a 3.57 on the Participant Test, a 2.62 on the TRC Test, a 4.20 on the Utility Test, and a 1.03 on the RIM test. The scores of the program indicate that the program is good for the participants in the program and it will result in lower overall revenue requirements for Santee Cooper. Exhibit IV-7 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

The Participant test result was based on the significant reduction in customer bills resulting from the reduced sales. This reduction in bills produced a benefit to cost ratio of almost six to one.

TRC Test

The TRC test resulted in a favorable score of 2.62. This is illustrated in the exhibit as a positive total present value resulting from annual savings outweighing the increased costs to implement the program. The positive results of this program were largely due to the production cost savings from the reduced energy sales.

Utility Test

The Utility test indicated the savings from reduced production costs and deferral of generating capacity significantly outweighed the costs to implement this program.

RIM Test

The RIM test resulted in a score of 1.03. This score indicates that the benefits of the program outweigh any increased costs.

Summary

This program would be positive for the participants and would reduce revenue requirements for Santee Cooper. As such, the program would provide economic benefits for Santee Cooper to actively pursue it.

GOOD CENTS MANUFACTURED HOUSING HEAT PUMP PROGRAM

This program received a 5.74 on the Participant Test, a 1.83 on the TRC Test, a 0.47 on the Utility Test, and a 0.35 on the RIM test. The scores of the program indicate that the program is good for the participants in the program but it will result in higher overall revenue requirements for Santee Cooper. Exhibit IV-8 illustrates the cumulative present

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE PREMUM EFFICIENCY MOTOR PROGRAM

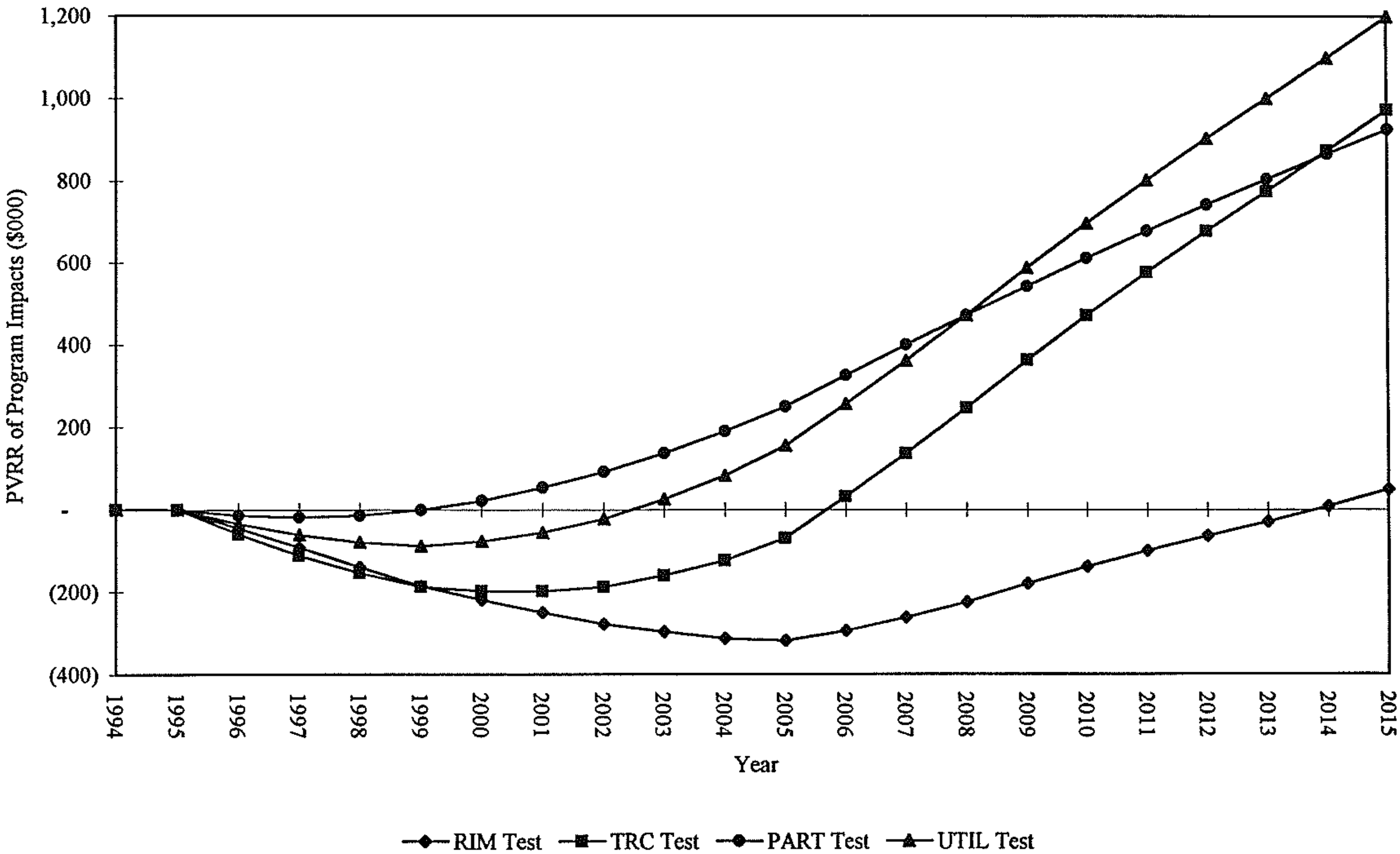


EXHIBIT IV-7

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE MANUFACTURED HOUSING HEAT PUMP PROGRAM

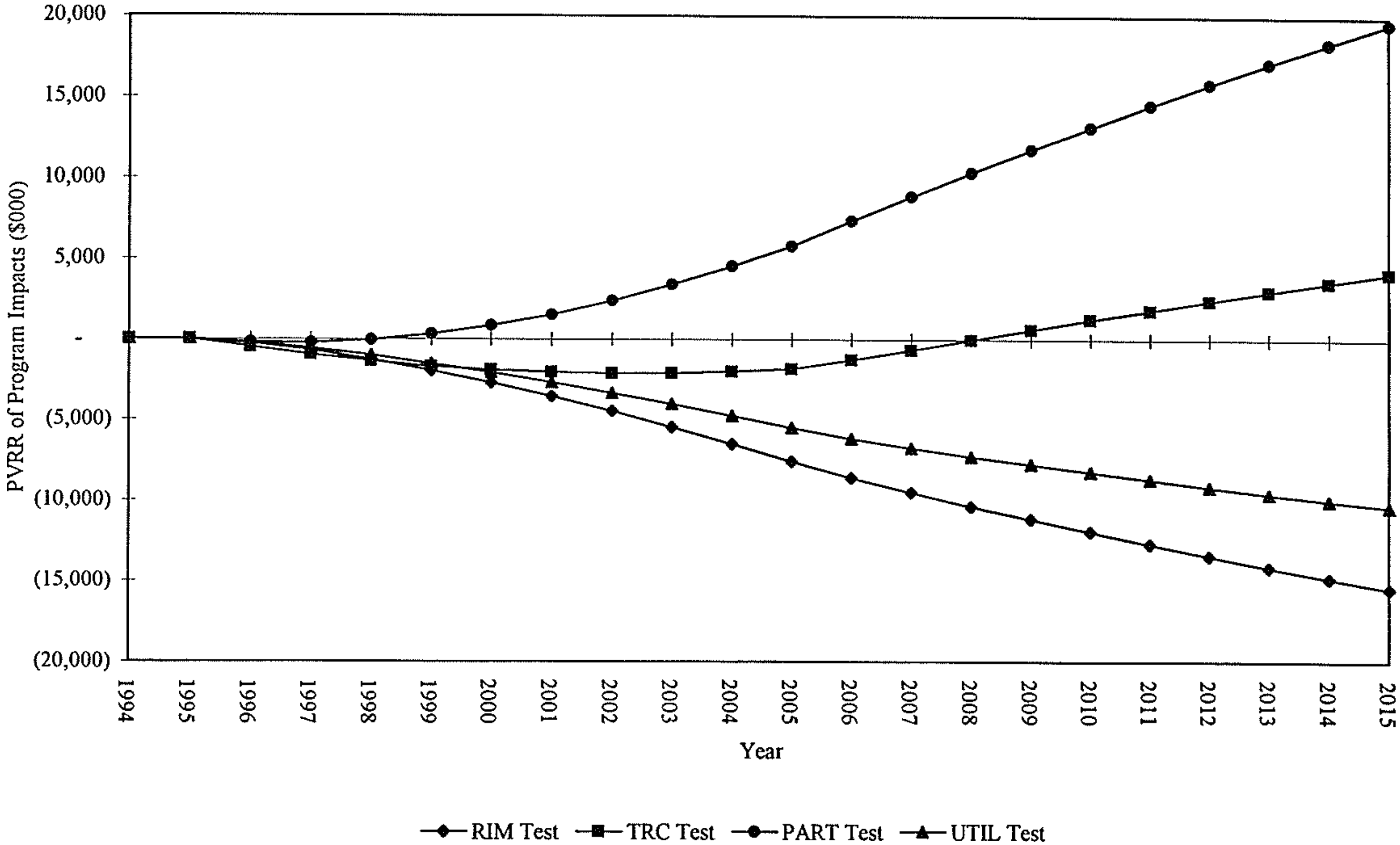


EXHIBIT IV-8

value impacts of the costs and savings used to generate the above described DSM test results. Overall, this program appeared positive for the participants in the program, but it resulted in increased costs to Santee Cooper.

Participant Test

The Participant test was based on the significant reduction in customer bills resulting from the reduced sales and an attractive incentive payment to the participants over the entire study period. The only offsetting cost to the program was the assumed customer cost to participate in it. This reduction in bills and incentive payments resulted in a benefit to cost ratio of almost seven to one.

TRC Test

The TRC test resulted in a favorable score of 1.83. This is illustrated in the exhibit as a positive total present value of combined annual savings outweighing Santee Cooper's increased costs to implement the program. The positive results of this program were largely due to the production cost savings from the reduced energy sales. A significant cost of this program was the assumed direct customer costs to participate in it.

Utility Test

The utility test indicated an increased revenue requirement due to the program as evidenced by the negative present value in the above exhibit. Two reasons stand out as the cause of this negative result: decreased revenues from reduced sales and assumed incentive payments to participate in the program.

RIM Test

The RIM test resulted in a score of 0.35 based largely on the reduction in sales projected on the Santee Cooper system. This reduced sales impact resulted in an overall reduction in revenue greater than the total benefits received as a result of the program.

Summary

As the program is currently designed, it would not be attractive to Santee Cooper and would result in increased revenue requirements. However, if the program were modified to reduce the incentive payments sufficiently to result in a positive net present value, or a Utility test of 1.0 or greater, the payments would need to be dropped by almost 60 percent from the current program design. This change would still result in a RIM test of less than 1.0; however, the other tests indicate a potentially favorable program if Santee Cooper's strategy were to implement a program that was favorable for the participants, resulted in neutral to reduced revenue requirements.

COMMERCIAL AIR CONDITIONING PROGRAM

The Commercial Air Conditioning Program received a 1.36 on the Participant Test, a 1.37 on the TRC Test, a 3.62 on the Utility Test, and a 1.07 on the RIM test. The scores of the program indicate that the program is good for the participants in the program and it will result in lower overall revenue requirements for Santee Cooper. Exhibit IV-9 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

The Participant test indicated a positive benefit to cost ratio largely due to the reduction in customer bills resulting from the lower systemwide energy sales. These savings were somewhat offset, though, by the incremental costs incurred by the participants to purchase the new high efficiency air conditioners.

TRC Test

The TRC test resulted in a favorable score of 1.37. This is illustrated in the exhibit as a positive total present value of annual savings outweighing the increased costs to implement the program. The positive results of this program were largely due to the savings from the reduced production costs resulting from lower energy sales.

Utility Test

The utility test indicated that this program would be positive for Santee Cooper by reducing revenue requirements in the future due to reduced production costs and deferral of new generation.

RIM Test

The RIM test resulted in a score of 1.07. As such, the program would provide economic benefits for Santee Cooper. The RIM test included the benefits from reduced production costs due to lower energy sales and reduced generation capacity capital costs due to a reduced peak demand. These savings were not offset by the costs to implement and evaluate the DSM program, including projected incentive payments. A significant factor in this analysis was the reduction in overall revenues resulting from reduced sales.

Summary

This program would be positive for the participants and would reduce revenue requirements for Santee Cooper. As such, the program would provide economic benefits for Santee Cooper to actively pursue it.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE COMMERCIAL AIR CONDITIONING PROGRAM

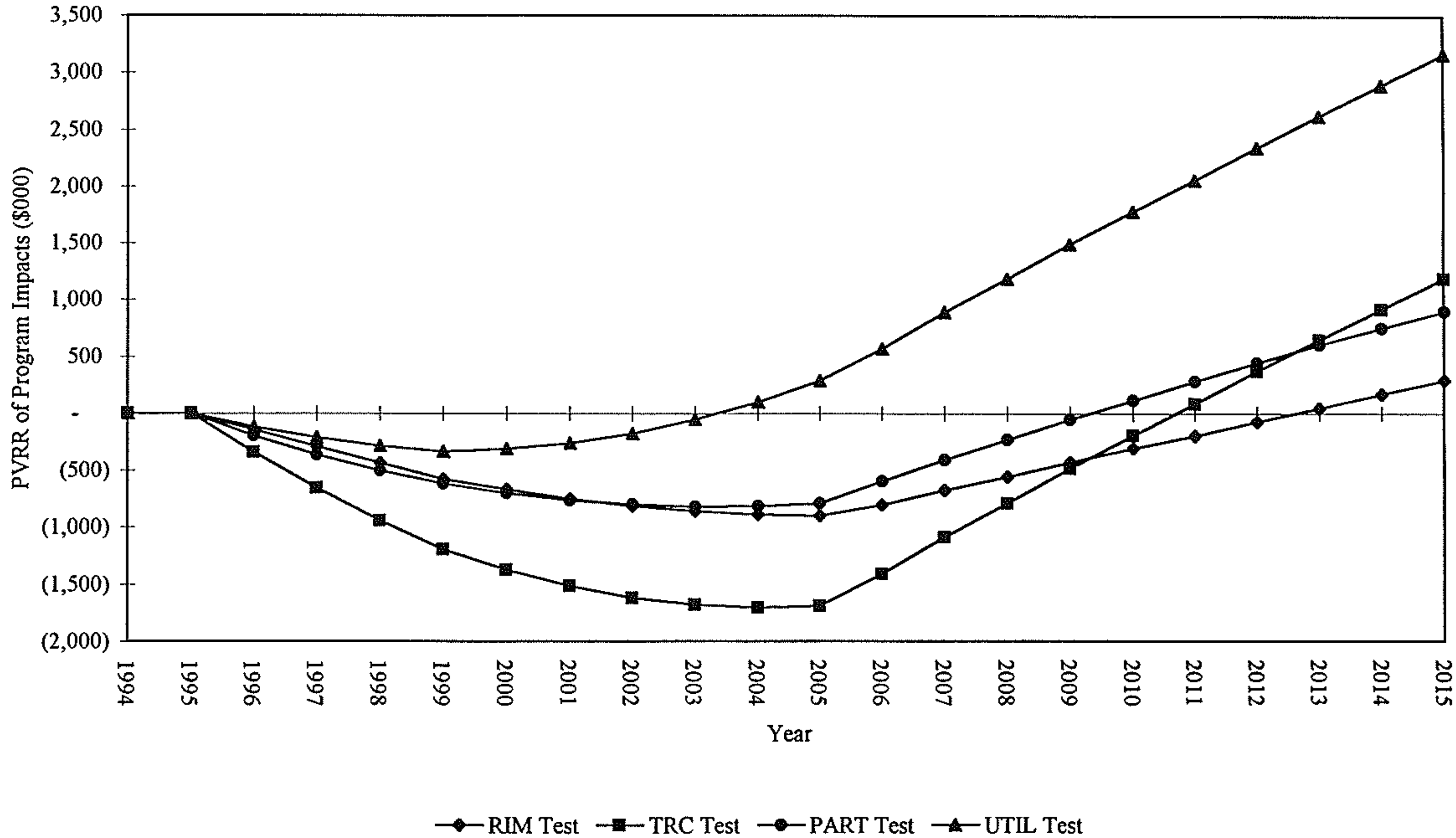


EXHIBIT IV-9

AIR CONDITIONING DIRECT LOAD CONTROL

This program received a 1.39 on the TRC Test, a 0.54 on the Utility Test, and a 0.53 on the RIM Test. The Participation test indicated an unlimited benefit, since it was assumed that the participants would not need to purchase any equipment to participate. All of the direct costs would be borne by the utility. The scores of the program indicate that the program is good for the participants but will result in higher overall revenue requirements for Santee Cooper. Exhibit IV-10 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results. It was the significant incentive payments and program costs that resulted in a negative impact on revenue requirements.

Participant Test

The Participant test assumed no cost to the participant; therefore, any benefits received as a participant would result in an infinite benefit to cost ratio. This program did provide sizable benefits to the participants in the form of incentives.

TRC Test

The TRC test resulted in a favorable score of 1.39. This is illustrated in the exhibit as a positive total present value of annual savings outweighing the increased costs to implement the program. The positive results of this program were largely due to the savings from the deferral of new generation and the incentive payments to the participants. Though these savings were significant, the costs to install the new switches would need to be monitored if this program were implemented, since these costs could easily overcome the deferral savings.

Utility Test

The utility test indicated an increase in revenue requirements due to this program. This result was largely driven by the costs to implement the program due to the costs of the switches and the incentives paid to the participants.

RIM Test

The RIM test resulted in a score of 0.53 based largely on the costs to purchase and install the load control switches and the high annual incentive payments. These costs were somewhat offset by the sizable reduction in costs due to new generation additions; however, these savings were not sufficient to overcome the higher costs.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE DIRECT LOAD CONTROL AIR CONDITIONING PROGRAM

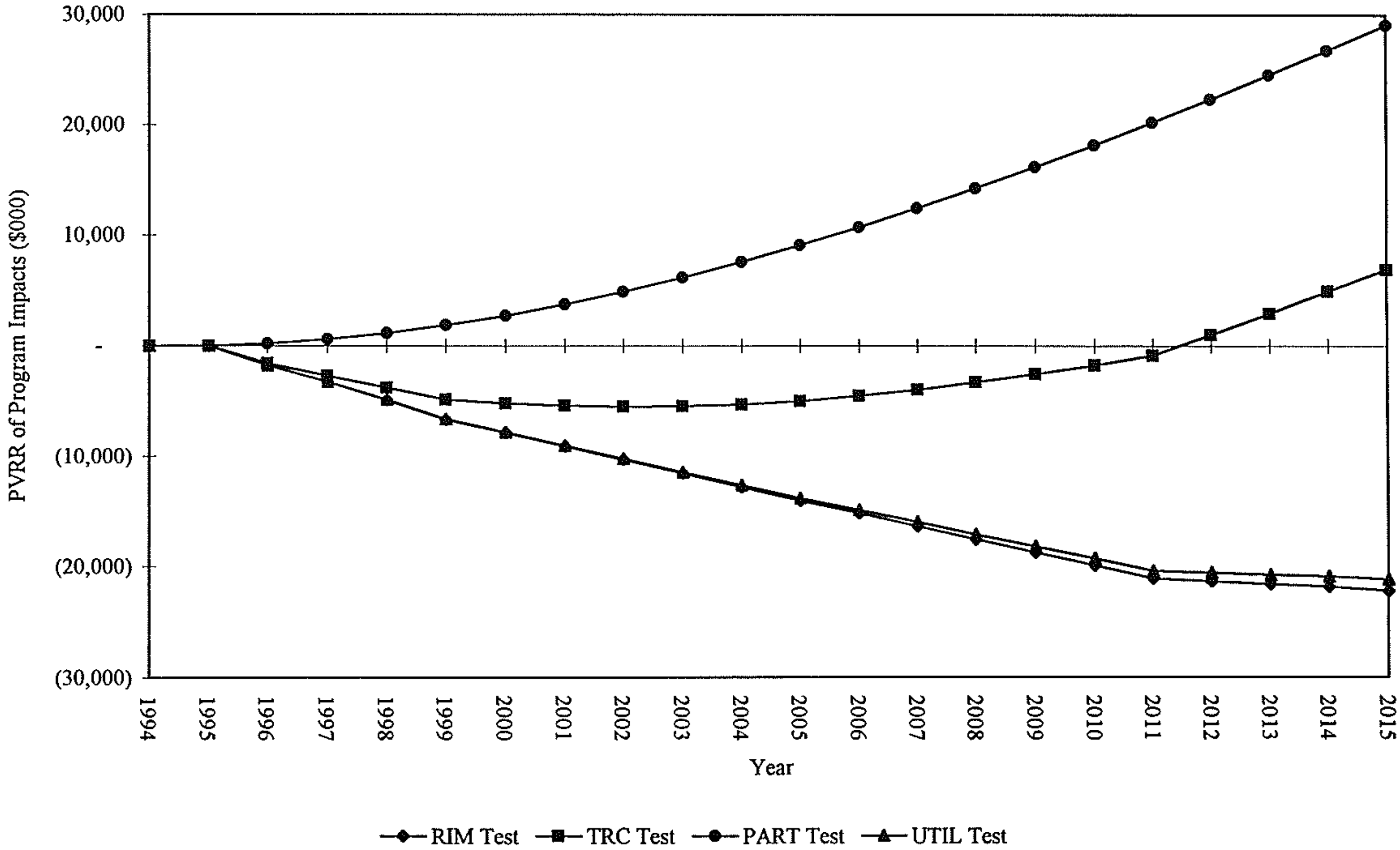


EXHIBIT IV-10

Summary

As the program is currently designed, it would be good for the participants, since they would have no real costs due to the program; however, Santee Cooper would see increased costs from the costs of the switches and the incentive payments. The switch costs are largely out of Santee Cooper's control; the level of incentive payments is not. If Santee Cooper were to implement this program with minimal or no incentive payments, it would result in decreased revenue requirements.

RESIDENTIAL DUCT TESTING AND REPAIR PROGRAM

The Residential Duct Testing and Repair Program received a 1.70 on the Participant Test, a 1.00 on the TRC Test, a 1.41 on the Utility Test, and a 0.67 on the RIM Test. The scores of the program indicate that the program is good for the participants in the program and will result in lower overall revenue requirements for Santee Cooper. Exhibit IV-11 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

The Participant test indicated a positive benefit to cost ratio largely due to the reduction in customer bills resulting from the lower systemwide energy sales plus incentive payments to participants in the program. These savings were somewhat offset, though, by the incremental costs incurred by the participants to purchase the new high efficiency air conditioners.

TRC Test

The TRC test resulted in a favorable score of 1.00. This is illustrated in the exhibit as a positive total present value of annual savings outweighing the increased costs to implement the program. The positive results of this program were largely due to the savings from the reduced production costs resulting from lower energy sales; however, the net savings for this program were marginal because of the costs to the participants to participate in the program. These participant costs included costs to repair the duct problems found in the examination phase of the program.

Utility Test

As currently designed, this program would result in decreased revenue requirements to Santee Cooper due to reduced production costs and deferral of new generation.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE RESIDENTIAL DUCT PROGRAM

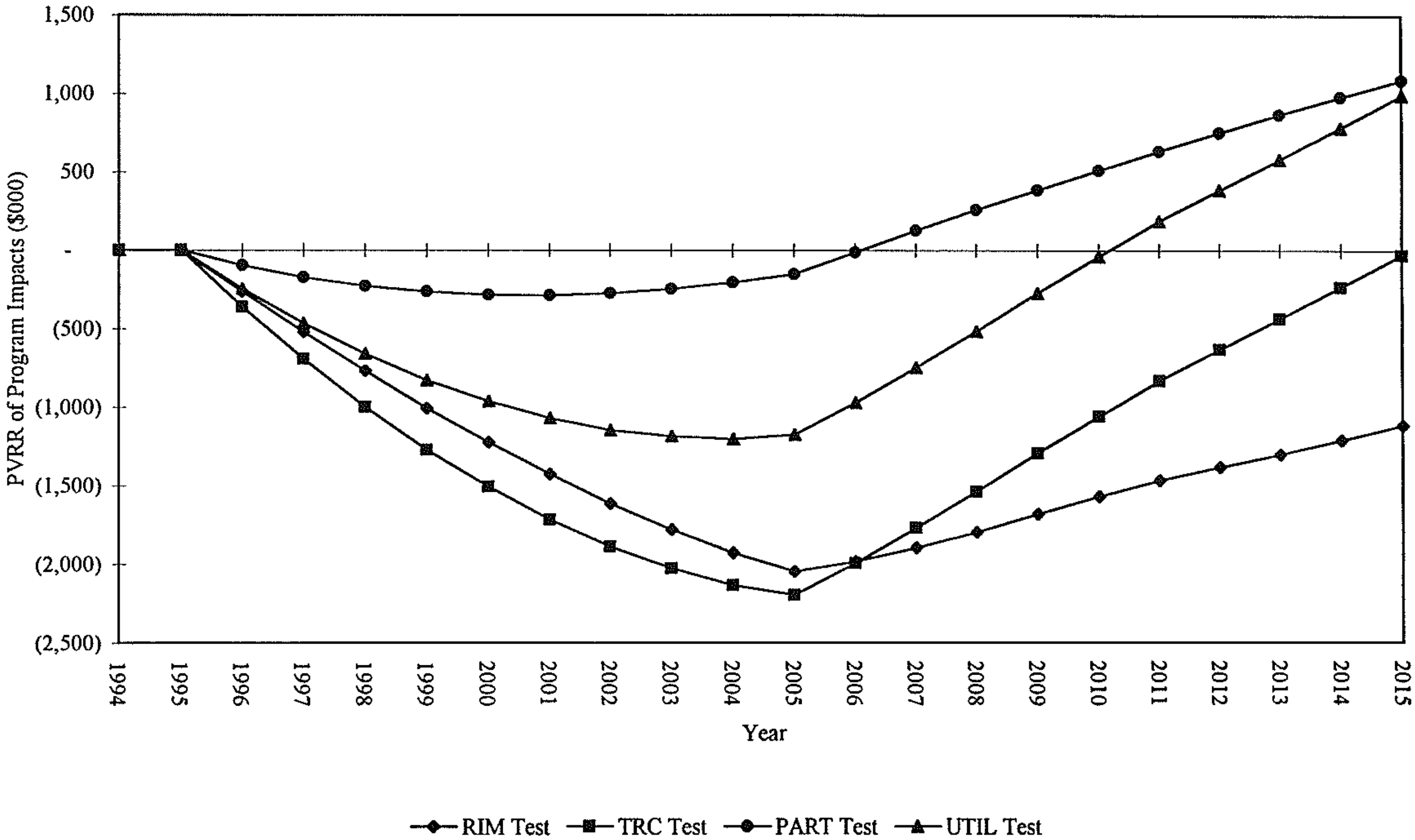


EXHIBIT IV-11

RIM Test

The RIM test resulted in a score of 0.67 largely based on the reduction in revenues associated with the reduced sales as expected from a conservation type program. These costs were somewhat offset by the sizable reduction in costs due to reduced production costs; however, these savings were not sufficient to overcome the lower revenues.

Summary

Overall, this program could fit into Santee Cooper's DSM strategy if programs were chosen that were favorable to participants, reduced revenue requirements to Santee Cooper.

THERMAL ENERGY STORAGE PROGRAM

The Thermal Energy Storage Program received a 1.02 on the Participant Test, a 0.51 on the TRC Test, a 1.15 on the Utility Test, and a 0.50 on the RIM Test. Exhibit IV-12 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

The Participant test results reflect that the cost to install the systems is outweighed by the benefits received through reduced energy bills.

TRC Test

The TRC test resulted in a non-favorable score of 0.51 primarily based on the assumed costs to the participant's to install the thermal energy systems. The costs of the systems outweighed the savings. These projected savings resulted from shifting the energy from on-peak to off-peak and the minimal generation capacity deferral savings.

Utility Test

The revenue requirements are illustrated in Exhibit IV-12. They indicate that this program would reduce revenue requirements for Santee Cooper because of reduced production costs and deferral of new generation, both of which marginally offset the costs to implement the program and the incentive payments to the participants.

RIM Test

The reduction in sales resulting from this program is not offset by benefits received from the program.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE THERMAL ENERGY STORAGE PROGRAM

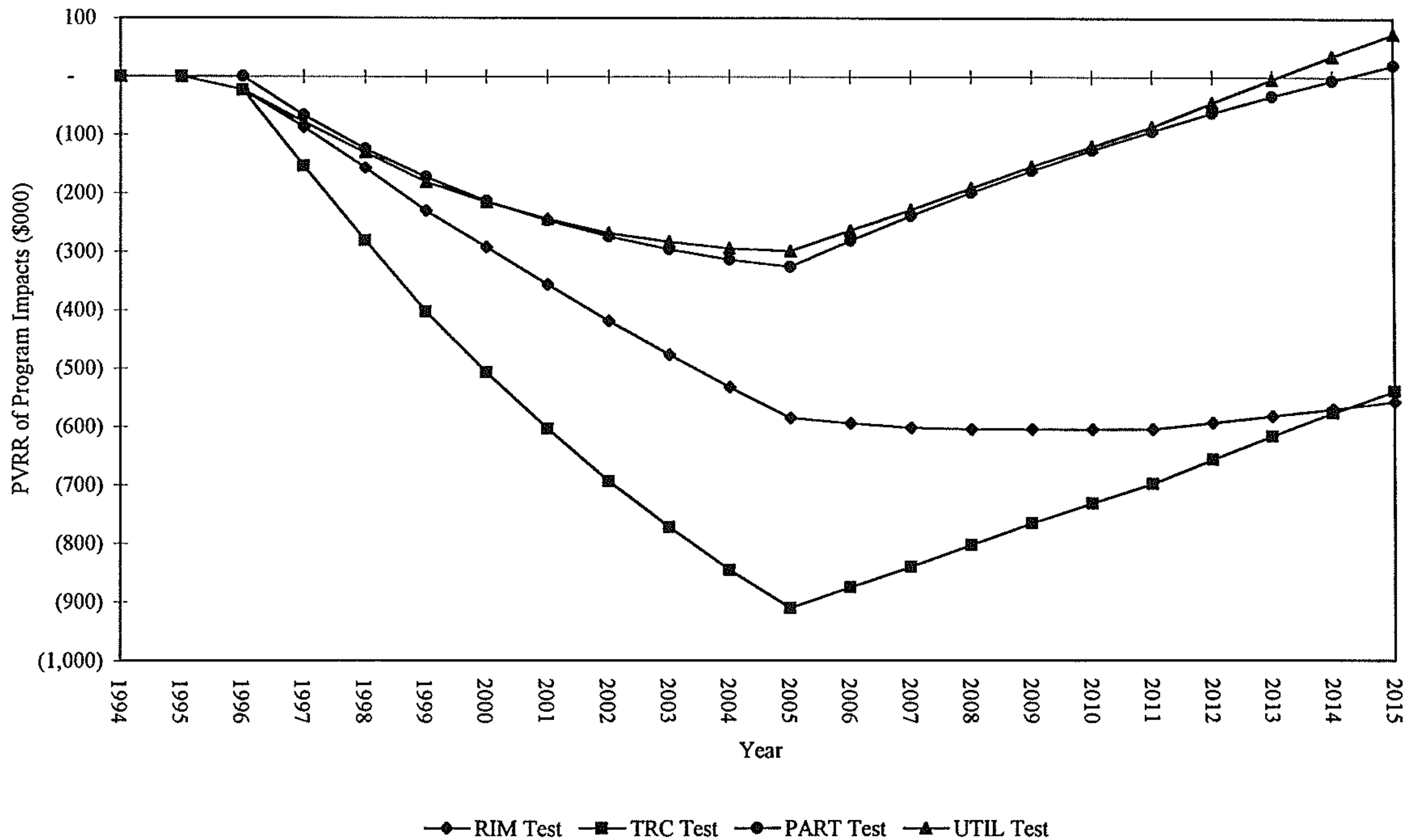


EXHIBIT IV-12

Summary

As the program is currently developed, it would be beneficial to the utility and to the participants. The costs to purchase the equipment are relatively uncertain, as shown by research conducted for the IRP. These costs ranged from $100 to $1000 per kilowatt of demand deferred. This study assumed $700. This program was implemented in June 1994 by Santee Cooper.

HIGH EFFICIENCY HEAT PUMP PROGRAM

The High Efficiency Heat Pump Program received a 0.95 on the Participant Test, 0.47 on the TRC Test, 0.73 on the Utility Test, and a 0.50 on the RIM Test. The scores of the program indicate that the program is good for the participants in the program; however, since it failed the other tests, it would increase Santee Cooper's revenue requirements due to the levels of incentive payments to the participants and the decrease in sales resulting from the program. Exhibit IV-13 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

The Participant test results reflect the cost to install the systems relative to the benefits received in the form of incentive payments. An increase in the incentive payments would probably result in additional participants; however, this increase would further drive the TRC and RIM test lower and make the program even less favorable.

Utility Test

The Utility test score was 0.73, which is indicative of a program that would result in an increase in present value of revenue requirements if it were implemented. This is largely due to the incentive payments to the participants, which were higher than the combination of the reduced production costs and the marginal savings from deferred new generation capacity.

TRC Test

The TRC test resulted in a non-favorable score of 0.47 primarily based on the assumed costs to the participant to install the high efficiency heat pumps. The costs of the systems outweighed the savings resulting from shifting the energy from on-peak to off-peak and the minimal generation capacity deferral savings.

RIM Test

The RIM test for this program resulted in a score of 0.50. Two significant factors in this score were the incentive payments proposed for the participants and the reduced

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE HIGH EFFICIENCY HEAT PUMP PROGRAM

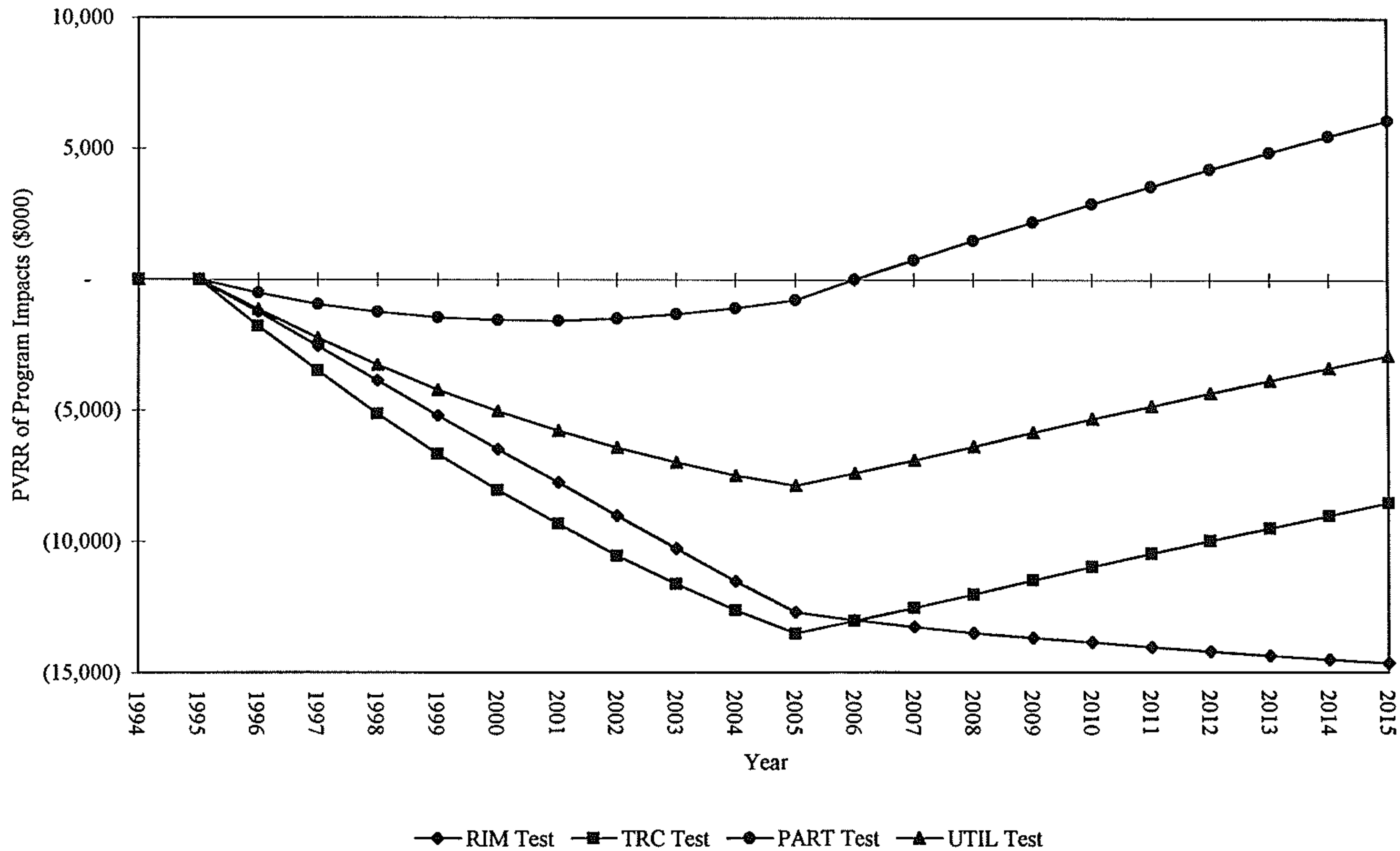


EXHIBIT IV-13

utility revenues from loss of energy sales due to the program. These two factors outweighed the benefits of the program resulting from reduced production costs, also due to the reduced energy sales. The net result was therefore reflected in a negative present value, as illustrated in Exhibit IV-13.

Summary

Overall, this program does not appear favorable to Santee Cooper. Though the Participant test indicated a possible benefit to the participants, there were not sufficient benefits to Santee Cooper. The results would be increased revenue requirements and rates.

DIRECT LOAD CONTROL OF SWIMMING POOL PUMP PROGRAM

The Direct Load Control of Swimming Pool Pump Program received a 0.54 on the TRC Test, a 0.34 on the Utility Test, and a 0.33 on the RIM Test. Since the program assumes the participant already owns a swimming pool eligible for this program, there would be no costs to the participant to participate in it. The scores of the program indicate that the program is good for the participants in the program; however, since it failed the other tests, it would increase Santee Cooper's revenue requirements due to the levels of incentive payments to the participants and the costs to implement the program. Exhibit IV-14 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

Since the participants would incur no costs to participate in the program, only savings, the participants would be better off if this program were implemented by Santee Cooper.

Utility Test

The Utility test score was 0.34, which is indicative of a program that would result in an increase in present value of revenue requirements if it were implemented. This is largely due to the incentive payments to the participants and the implementation costs of the program, which were higher than the combination of the minimal reduction in production costs and the projected savings from deferred new generation capacity.

TRC Test

The TRC test resulted in a non-favorable score of 0.54 primarily based on the assumed costs to Santee Cooper to implement the program. These implementation costs outweighed the savings resulting from the generation capacity deferral savings and the very minimal savings from reduced production costs.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE DIRECT LOAD CONTROL OF SWIMMING POOL PROGRAM

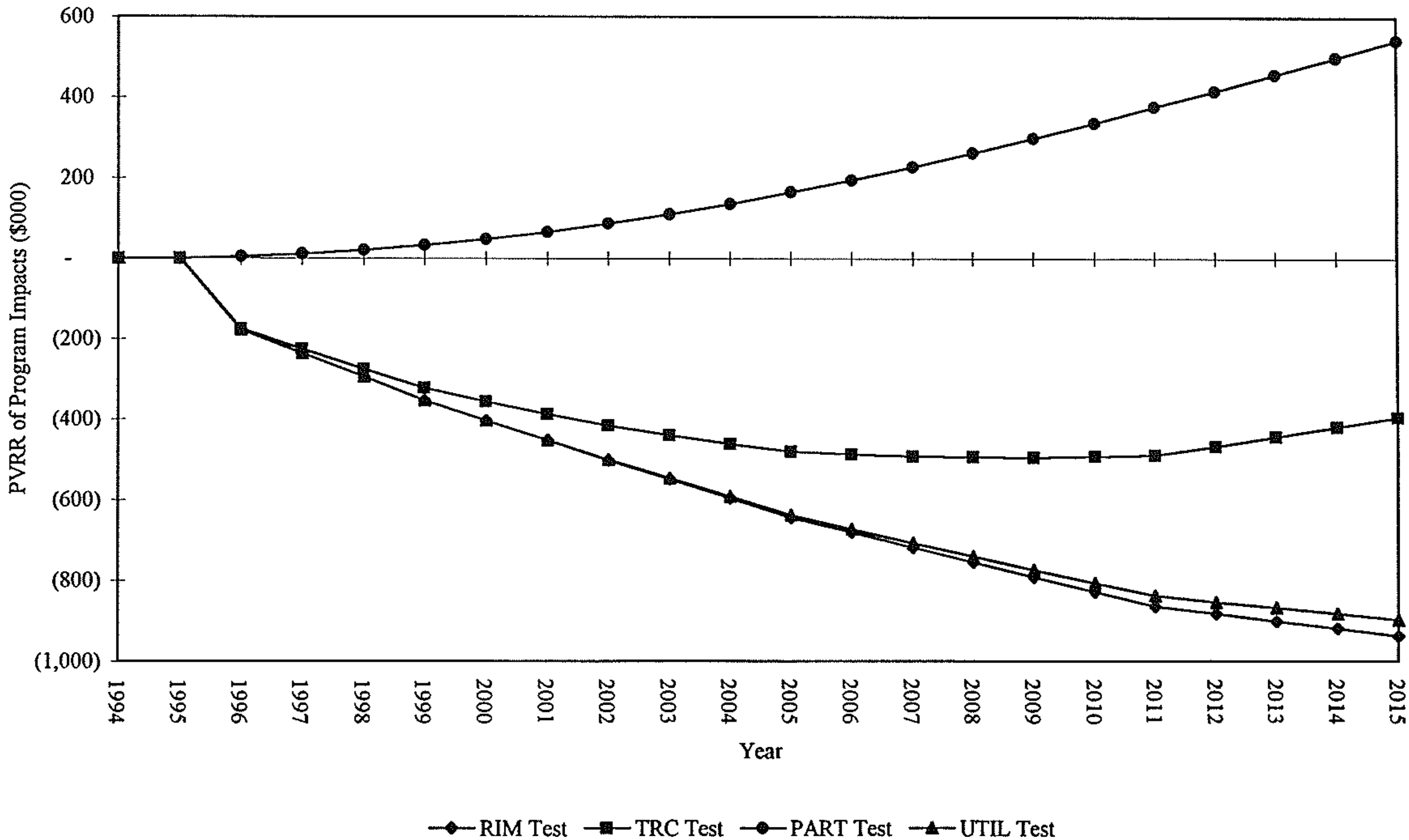


EXHIBIT IV-14

RIM Test

The RIM test for this program resulted in a score of 0.33. Two significant factors in this score were the incentive payments proposed for the participants and the costs to implement the program. These two factors outweighed the benefits of the program resulting from the deferral of new generation capacity.

Summary

Overall, this program does not appear to be favorable for Santee Cooper.

GROUND SOURCE HEAT PUMP PROGRAM

The Ground Source Heat Pump Program received a 0.50 on the Participant Test, a 0.34 on the TRC Test, a 1.32 on the Utility Test, and a 0.62 on the RIM Test. The scores indicate that the program would result in reduced revenue requirements for Santee Cooper due to decreased energy sales from the program. Exhibit IV-15 illustrates the cumulative present value impacts of the costs and savings used to generate the above described DSM test results.

Participant Test

The participants in this program would be required to purchase the new ground source heat pumps, the costs of which did not outweigh the benefits from reduced bills and incentive payments received.

Utility Test

The Utility test score was 1.32, which is indicative of a program that would result in a decrease in revenue requirements if it were implemented. This is largely due to the reduced production costs that were sufficiently low enough to outweigh the program implementation costs and the incentive payments to the participants.

TRC Test

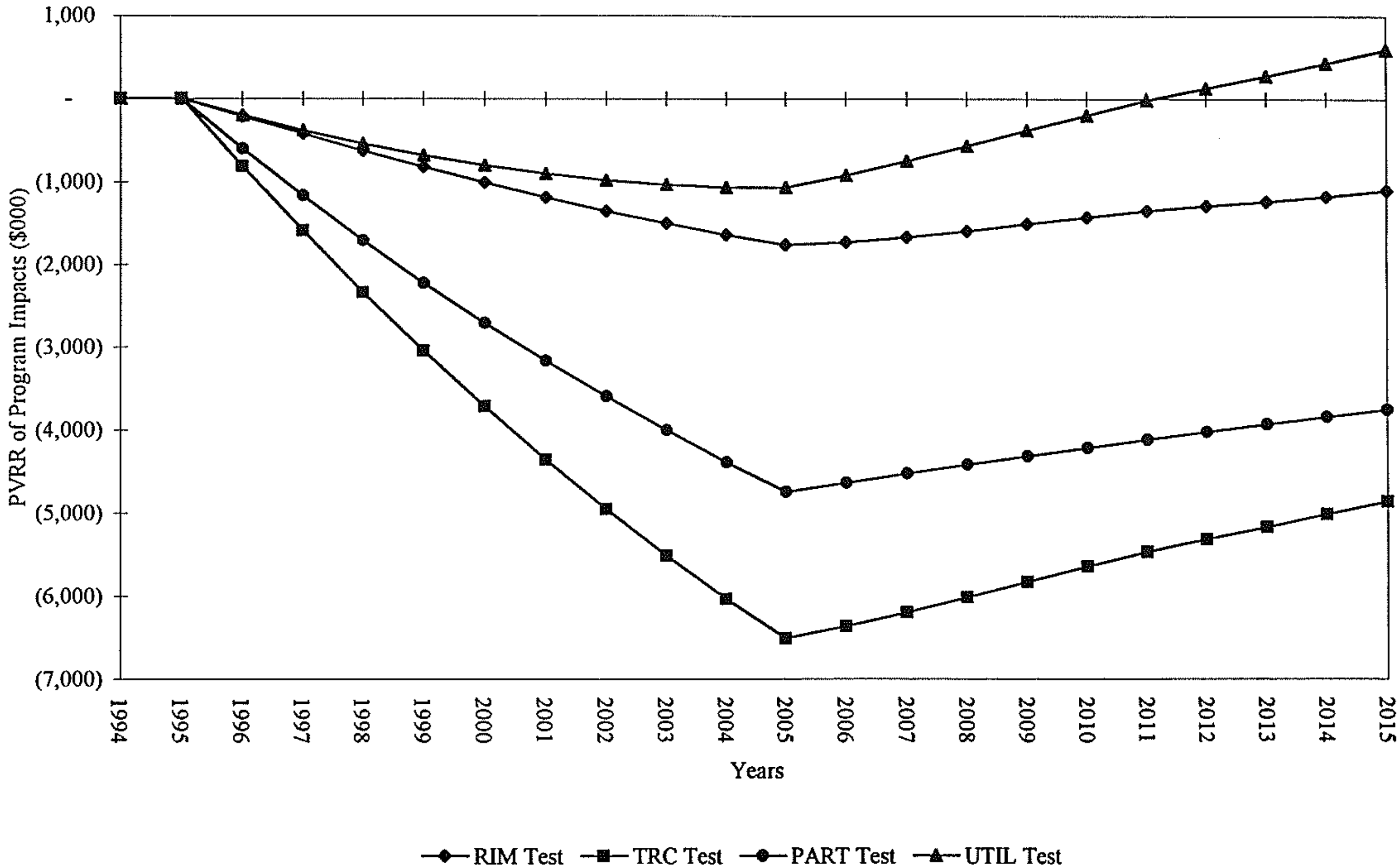
The TRC test resulted in a non-favorable score of 0.34 primarily based on the costs to the participants in the program, which were required to purchase the new heat pumps. The costs of these systems to the participants outweighed the savings resulting from reduced production costs and the marginal savings from the generation capacity deferral.

RIM Test

The RIM test for this program resulted in a score of 0.62. Two significant factors in this score were the incentive payments proposed for the participants and the reduced

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ECONOMIC TESTS OF THE GROUND SOURCE HEAT PUMP PROGRAM



revenues from a decrease in energy sales due to the program. These two factors outweighed the benefits of the program resulting from the reduced production costs and the marginal savings from deferral of new generation capacity. The net result was therefore reflected in a negative present value, as illustrated in Exhibit IV-15.

Summary

Overall, as the program is currently envisioned, it is not favorable to the participants; however, it could be beneficial to Santee Cooper in that it reduced revenue requirements. The factor that made it unattractive to the participants was the cost to purchase and install the equipment. Therefore, before Santee Cooper eliminates this program from consideration, it would be beneficial to conduct further investigations into the costs of the equipment or monitor these costs into the future in the event they decrease as more knowledge is gained in the industry on the equipment.

C. REVIEW OF EXISTING DSM PROGRAMS

Santee Cooper has implemented a total of three DSM programs. These three programs are:

- Residential Good Cents
- Commercial Good Cents
- H_2O Advantage.

Each of these programs will be briefly described in this chapter. In addition, the results of an economic analysis conducted on each program will be provided. This economic analysis evaluates each program from the perspective of the incremental benefits and costs associated with continuing it versus its termination. The evaluation reflects the committed costs and residual benefits of the programs if they were terminated at this point in time. The screening results are summarized in Table IV-4.

Table IV-4
Results of DSM Economic Screening - Existing Programs
(Combined Costs and Benefits)

		Name of Test		
Program	Participant	TRC	Utility	RIM
Residential Good Cents	Inf.	6.69	0.64	0.49
Commercial Good Cents	Inf.	1.02	0.83	0.63
H_20 Advantage	Inf.	0.82	0.19	0.19

RESIDENTIAL GOOD CENTS PROGRAM

The Residential Good Cents Program is designed for both new homes and retrofitted existing homes. The purpose of the program is to guide homeowners into the design and construction of energy efficient dwellings. The program works with owners and contractors to ensure energy efficient installation of the following measures:

- Insulation - ceiling, walls and doors
- Attic ventilation
- Infiltration control

- Windows
- Water heating insulation and efficiency
- Duct work
- HVAC systems.

The homes must be total electric and be inspected by Santee Cooper or the wholesale utility representative upon completion of the work. A participant that has been approved by Santee Cooper will receive a monthly credit to compensate for the increased costs associated with the higher efficiency materials used in the dwelling.

The results of the screening tests are described below:

- Participant Test - The participant test resulted in a score of infinity, since no specific customer costs were included. In reality, the participants will incur slightly increased construction costs for the higher efficiency materials and equipment.

- Total Resource Cost Test (TRC) - 6.69, indicating a strong positive economic benefit to both Santee Cooper and the participants.

- Utility Test (UTIL) - 0.64, indicating the costs of the program are greater than the benefits to Santee Cooper. The results of this test are strongly influenced by the size of the incentive payments when compared to the reduced production costs and deferred generation capacity benefits. A reduction in incentive payments of less than 50 percent would result in a utility test score of greater than 1.0.

- Rate Impact Test (RIM) - 0.49. A reduction in incentive payments mentioned above could improve this benefit to cost ratio but would not make the ratio greater than 1.0.

Overall, this program appears to have definite economic potential for Santee Cooper. Some review of the levels of incentive payments is in order, however, given the results of the Participant test and the Utility cost test.

COMMERCIAL GOOD CENTS PROGRAM

The Commercial Good Cents Program is for new commercial buildings. The purpose of the program is to guide contractors into the design and construction of energy efficient buildings. The program works with owners and contractors to ensure energy efficient installation of the following measures:

- Insulation - ceiling, walls and doors

- Lighting
- Windows
- Attic ventilation
- Infiltration control
- Water heating insulation and efficiency
- Duct work
- HVAC systems.

The buildings must be inspected by Santee Cooper upon completion of the work. A participant that has been approved by Santee Cooper will receive a rebate to compensate for the increased costs associated with the higher efficiency materials used in the building.

The results of the screening tests are identified below:

- Participant Test - Infinity, since no specific customer costs were identified. In reality, the participants will incur slightly increased construction costs for the higher efficiency materials and equipment.

- Total Resource Cost Test (TRC) - 1.02, indicating a slightly positive economic benefit to both Santee Cooper and the participants. If the costs of the program could be reduced even slightly, the ratio of benefits to costs would be greater than 1.0.

- Utility Test (UTIL) - 0.83, indicating the costs of the program are greater than the benefits to Santee Cooper. Again, the costs of the program drive the benefit to cost ratio. A reduction in costs of approximately five percent would result in a UTIL score of greater than 1.0.

- Rate Impact Test (RIM) - 0.63, indicating a reasonable reduction in program costs would not result in a benefit to cost ratio of greater than 1.0.

Overall, this program also appears to have economic potential for Santee Cooper. Some review of the levels of program costs is in order, though, given the results of the economic analyses.

H_2O ADVANTAGE PROGRAM

The objective of the program is to reduce peak demand and new generating transmission requirements by controlling residential storage water heating equipment. At the same time, the program allows electric water heating to be more competitive with alternative fuel sources. The program requires the use of 80 gallon (or larger) water heaters with the installation of a load management device that controls the periods that the water heating elements can be energized resulting in minimal inconvenience to program participants.

The results of the screening tests are identified below:

- Participant Test - Infinity, since no specific customer costs were identified. All of the costs for this program are borne by Santee Cooper

- Total Resource Cost Test (TRC) - 0.82, indicating a slightly negative economic benefit to both Santee Cooper and the participants. The costs of the program as identified by Santee Cooper are sufficiently high to require a reduction of approximately 32 percent for the benefit to cost ratio to reach 1.0 or greater.

- Utility Test (UTIL) - 0.19, indicating the costs of the program are greater than the benefits to Santee Cooper. Again, the costs of the program and the incentives drive the benefit to cost ratio. A reduction in costs and incentives will be necessary to result in a UTIL score of greater than 1.0.

- Rate Impact Test (RIM) - 0.19, indicating the reduction in program costs alone would not result in a benefit to cost ratio of greater than 1.0.

Overall, given the projected costs and benefits provided by Santee Cooper for this program, it would appear an effort should be undertaken to review the program costs and incentive levels or find a way to spread these costs over greater potential savings as the program moves forward.

D. RETAIL VERSUS WHOLESALE PROGRAM ECONOMICS

Santee Cooper's largest single wholesale customer is Central Electric Cooperative. As part of the relationship between Santee Cooper and Central, Santee Cooper will develop DSM programs and offer them to Central. The costs for these programs will be partly paid by Santee Cooper and partly by Central.

In the evaluation of the DSM programs discussed above (Tables IV-3 and IV-4), all of the costs for the new programs were considered, regardless of which utility would incur them. This was done because any program costs incurred as a result of the implementation of the programs would be borne by one of the two utilities. However, an element that would change from Santee Cooper's perspective would be the value of the lost revenue associated with each program. This difference is due to the rates charged to Central as a wholesale customer versus the rates charged to Santee Cooper's retail customers. This difference is especially noticeable in the case of residential customers. The ratio assumed in this study between retail residential rates and wholesale rates to Central is approximately 6 to 2.2 cents per kilowatt-hour. For additional conservatism, and due to the limited economic impact related to the demand reduction, the demand component of the rates was not included in the screening.

The difference between Santee Cooper's retail commercial rates and Central's wholesale rates is not quite so significant (approximately 2.2 versus 2.0 units per kilowatt-hour). Therefore, the difference in lost revenues between retail and wholesale due to commercial DSM programs has little difference in the economic screening of the new programs.

In the case of the three existing programs, Santee Cooper provided detailed information on Central's portion of the programs and Santee Cooper's share of the total costs. Therefore, a more detailed evaluation of the retail and wholesale program economics could be performed for these programs. The following tables (Tables IV-5 and IV-6) contain the results of this evaluation.

Detailed information pertaining to the year-by-year demand and energy savings and annual costs and benefits by program is contained in Appendix C. This data is divided between retail and wholesale analyses.

Table IV-5

Results of DSM Economic Screening - Retail

Program	Participant	TRC	Utility	RIM
		Name of Test		
High Efficiency Lighting	3.15	2.73	4.64	1.05
Standby Generators	Inf.	12.89	0.50	0.49
Premium Efficiency Motors	3.42	2.48	3.95	1.01
Good Cents Manufactured Home Heat Pump	7.41	1.73	0.46	0.26
Air Conditioning Direct Load Control	Inf.	1.33	0.52	0.51
Commercial Air Conditioning	1.31	1.30	3.42	1.05
Duct Testing and Repair	3.16	0.94	1.34	0.38
Thermal Energy Storage	0.99	0.48	1.09	0.49
High Efficiency Heat Pump	1.37	0.45	0.69	0.33
Swimming Pool Direct Load Control	Inf.	0.51	0.32	0.32
Ground Source Heat Pump	0.91	0.32	1.24	0.35
Residential Good Cents	Inf.	1.82	0.98	0.59
Commercial Good Cents	Inf.	0.99	0.79	0.44
H_2O Advantage	Inf.	0.19	0.10	0.10

Table IV-6

Results of DSM Economic Screening - Wholesale

Program	Participant	TRC	Utility	RIM
	Name of Test			
High Efficiency Lighting	2.78	3.00	5.10	1.29
Standby Generators	Inf.	13.49	0.51	0.51
Premium Efficiency Motors	3.01	2.72	4.34	1.24
Good Cents Manufactured Home Heat Pump	5.64	1.90	0.47	0.37
Air Conditioning Direct Load Control	Inf.	1.43	0.54	0.54
Commercial Air Conditioning	1.16	1.43	3.76	1.27
Duct Testing and Repair	1.50	1.03	1.47	0.77
Thermal Energy Storage	0.89	0.53	1.20	0.58
High Efficiency Heat Pump	0.89	0.49	0.75	0.55
Swimming Pool Direct Load Control	Inf.	0.55	0.34	0.34
Ground Source Heat Pump	0.45	0.35	1.37	0.71
Residential Good Cents	Inf.	20.47	0.55	0.43
Commercial Good Cents	Inf.	0.91	0.74	0.56
H_2O Advantage	Inf.	0.76	0.16	0.16

E. DSM PROGRAM SCREENING SUMMARY

Overall, seven of the new and two of the existing programs resulted in TRC scores of near 1.0 or greater, ten new and all three of the existing programs scored greater than 1.0 on the Participant test, six of the new and none of the existing programs scored greater than 1.0 on the Utility test, and three new programs scored greater than 1.0 on the RIM test (Tables IV-3 and IV-4).

Each test reflects a different policy decision by Santee Cooper to either implement a program or dismiss it from future plans. For instance, if reduced revenue requirements is the sole criterion for evaluating a DSM program, then any program receiving a score of 1.0 or greater on the Utility Test would be acceptable. However, if the sole criterion is to avoid increasing rates due to the DSM programs, then the Utility test would be disregarded and the RIM test would be the decision criterion. A third policy would be to implement programs that were good for the participants, reduced revenue requirements, but increased rates only minimally.

The purpose of this IRP study is to identify the potential plans available to Santee Cooper and their resultant economic impacts in light of the decision criteria utilized by the utility. Therefore, to reflect the economic impacts of alternative DSM decision criteria, four DSM scenarios were passed to PROVIEW for integration with available supply-side options. The first scenario included all nine of the programs passing the TRC test. The second scenario included the programs passing the Utility Test. The third plan includes only the three new DSM programs scoring 1.0 or greater on the RIM test. The final scenario is a combination of programs. Table IV-7 summarizes the programs in each scenario.

Table IV-7

Summary of DSM Programs Scoring 1.0 or Greater

Rank	TRC	UTIL	RIM	TRC/UTIL
1	High Efficiency Lighting	High Efficiency Lighting	High Efficiency Lighting	High Efficiency Lighting
2	Stand-by Generation	Premium Efficiency Motors	Commercial Air Conditioning	Premium Efficiency Motors
3	Premium Efficiency Motors	Commercial Air Conditioning	Premium Efficiency Motors	Commercial Air Conditioning
4	Manu. Housing Heat Pumps	Residential Duct Testing and Cleaning		Residential Duct Testing and Cleaning
5	Commercial Air Conditioning	Ground Source Heat Pumps		Residential Good Cents
6	Direct Load Control of Air Conditioning	Thermal Energy Storage		Commercial Good Cents
7	Residential Duct Testing and Cleaning			
8	Residential Good Cents			
9	Commercial Good Cents			

Table IV-8 illustrates that the DSM programs potentially reduce Santee Cooper's system peak demand by up to approximately 150 MW for those programs passing the Total Resource Cost test by 2004. Table IV-9 puts the savings for each scenario on a percentage of the annual peak demand. This exhibit shows the demand reduction to be approximately 3.0 percent in 2004 for those programs passing the TRC test.

Annual Projected DSM Expenditures

The total expenditures for the scenarios is as varied as the range of peak demand reductions. Table IV-10 illustrates this point.

The annual expenditures for the programs include the costs to implement and evaluate the programs each year plus the incentive payments to the participants. As expected, the programs passing the TRC test have the greatest overall annual expenditures because of the number of programs included in each group. As a final review, Table IV-11 illustrates the dollars expended on these programs per MW of demand reduction.

The next step in the development of the IRP relative to DSM will be to integrate the programs identified in Table IV-7. The results of this integration process are described in Chapter VII.

Table IV-8

Megawatt Savings From DSM Programs Passed to PROVIEW for Integration (MW)

Year	TRC Test	Utility Test	RIM Test	TRC/ Utility
1994	0.00	0.00	0.00	0.00
1995	0.00	0.00	0.00	0.00
1996	15.83	2.66	1.23	6.59
1997	32.21	5.47	2.46	13.73
1998	48.97	8.29	3.70	21.25
1999	66.02	11.10	4.93	29.06
2000	83.26	13.92	6.16	37.06
2001	100.78	16.73	7.39	45.34
2002	118.44	19.55	8.62	53.76
2003	136.36	22.37	9.85	62.44
2004	154.40	25.34	11.08	71.24
2005	172.67	27.99	12.31	80.26
2006	187.46	27.99	12.31	87.87
2007	202.37	27.99	12.31	95.59
2008	217.59	27.99	12.31	103.62
2009	232.94	27.99	12.31	111.78
2010	248.60	27.99	12.31	120.25
2011	264.27	27.99	12.31	128.74
2012	280.65	27.99	12.31	137.92
2013	297.05	27.99	12.31	147.13
2014	313.66	27.99	12.31	156.56
2015	330.78	37.99	12.31	166.48

Table IV-9

Percent Savings from Peak Demand from DSM Programs Passed to PROVIEW for Integration

Year	TRC Test	Utility Test	RIM Test	TRC/ Utility
1994	0%	0%	0%	0%
1995	0%	0%	0%	0%
1996	1%	0%	0%	0%
1997	1%	0%	0%	0%
1998	2%	0%	0%	1%
1999	2%	0%	0%	1%
2000	3%	0%	0%	1%
2001	3%	1%	0%	2%
2002	4%	1%	0%	2%
2003	4%	1%	0%	2%
2004	5%	1%	0%	2%
2005	5%	1%	0%	2%
2006	6%	1%	0%	3%
2007	6%	1%	0%	3%
2008	6%	1%	0%	3%
2009	6%	1%	0%	3%
2010	7%	1%	0%	3%
2011	7%	1%	0%	3%
2012	7%	1%	0%	4%
2013	7%	1%	0%	4%
2014	8%	1%	0%	4%
2015	8%	1%	0%	4%

Table IV-10

Projected DSM Expenditures for Programs Passed to PROVIEW for Integration ($000)

Year	TRC Test	Utility Test	RIM Test	TRC/ Utility
1994	--	--	--	--
1995	--	--	--	--
1996	4,311	999	435	1,913
1997	5,159	1,073	451	2,707
1998	6,334	1,110	466	3,313
1999	7,707	1,148	482	4,079
2000	9,116	1,189	499	4,843
2001	13,779	1,229	516	8,820
2002	15,326	1,274	535	9,638
2003	16,902	1,319	554	10,440
2004	18,579	1,365	573	11,295
2005	20,350	1,413	594	12,195
2006	20,437	20	--	12,058
2007	21,935	20	--	12,947
2008	23,527	21	--	13,899
2009	25,137	22	--	14,836
2010	26,841	23	--	15,831
2011	28,561	23	--	16,805
2012	30,211	24	--	17,670
2013	31,985	25	--	18,619
2014	33,895	26	--	19,661
2015	35,943	27	--	20,797

Table IV-11

Dollars Expended on DSM Programs Per Projected kW Saved ($/kW)

Year	TRC Test	Utility Test	RIM Test	TRC/ Utility
1994	--	--	--	--
1995	--	--	--	--
1996	272	376	--	291
1997	160	196	183	197
1998	129	134	126	156
1999	117	103	98	140
2000	109	85	81	131
2001	137	73	70	195
2002	129	65	62	179
2003	124	59	56	167
2004	120	54	52	159
2005	118	50	48	152
2006	109	1	--	137
2007	108	1	--	135
2008	108	1	--	134
2009	108	1	--	133
2010	108	1	--	132
2011	108	1	--	131
2012	108	1	--	128
2013	108	1	--	127
2014	108	1	--	126
2015	109	1	--	125

V. SUPPLY-SIDE RESOURCE OPTIONS

V. SUPPLY-SIDE RESOURCE OPTIONS

The objective of the supply-side resource options analysis is to identify and evaluate all reasonable supply-side resource technologies. The supply-side analysis process is depicted in Exhibit V-1 and consists of supply-side resource identification and supply-side options definition and screening. These steps are detailed in the sections that follow.

A. SUPPLY-SIDE RESOURCE IDENTIFICATION

All generation technologies and resources which represented reasonable supply-side alternatives were identified and reviewed. Generation technologies information is available from a wide range of sources, including trade journals, vendor brochures, industry magazines and research organizations.

When the identification process was completed, the technologies and resources were placed into the categories of conventional technologies, emerging technologies and purchased power. These categories are defined below.

- *Conventional Technologies* - technologies that are proven, mature and widely employed in generating facilities throughout the industry.
- *Emerging Technologies* - technologies that are in the development stage, with a small number of utility-size plants currently operating or under construction. These technologies may be well defined; however, it is likely that further design modifications will be made as more is learned about their operating performance.

An overriding criterion utilized in the screening of the various alternative technologies is Santee Cooper's approach to pursue only proven technologies. This approach minimizes the risks to the ratepayers resulting from the failure of the technology to materialize as rapidly or as effectively as originally anticipated.

The supply-side technology and resource options that were identified are presented in Table V-1. Many of these technologies were further expanded by fuel type, differences in boiler technologies, or unit sizes.

Table V-1

Supply-side Options Identified

Conventional Technologies	Emerging Technologies
Pulverized Coal	Pressurized Fluidized Bed
Advanced Cycle Pulverized Coal	Atmospheric Fluidized Bed
Oil-fired Combined Cycle	Integrated Coal Gasification Combined Cycle
Pumped Storage	Evolutionary Light Water Nuclear Reactor
Oil-fired Combustion Turbine	Passive Light Water Reactor
Diesel Generator	Advanced Liquid Metal Reactor
Lead Acid Battery Storage	Waste-to-Energy
	Fuel Cells
	Compressed Air Energy Storage
	Geothermal
	Biomass
	Solar
	Super Conducting Magnetic Storage

B. SUPPLY-SIDE OPTIONS DEFINITION AND SCREENING

After the identification of technologies and resource options, cost and operating data were assembled. Key assumptions, including capital and O&M costs, generating capacities, heat rates, availability, operating life and construction scheduling, were defined. The data for the assumptions were developed from the following sources:

- *IRPs from Other Utilities.* Santee Cooper maintains regular communication with utilities throughout the United States through representation on several of the coordinating councils' committees, as well as through other industry panels, including the Edison Electric Institute and North American Electric Reliability Council. As a result of these relationships, M&A had access to the IRPs of these utilities for review of the most current costs and operating assumptions for new technologies.

- *Industry Research and Trade Journals.* Santee Cooper monitors and at times participates in the studies performed by industry research organizations. These sources provide valuable information on mature, emerging and newly developed technologies and resources.

- E*ngineering Studies.* Santee Cooper periodically engages outside firms to perform engineering feasibility studies to evaluate supply options. The purposes of these studies are to evaluate options to build new capacity, investigate joint projects with other utilities or assess potential cogeneration options.

GENERATING TECHNOLOGY SCREEN

Each of the technologies from the conventional and emerging technology categories in Table V-1 were screened to eliminate those that did not present viable options. During the screening process the candidates were subjectively evaluated against three criteria: environmental impact, regulatory impact and commercial availability. A description of the criteria and evaluation of the technologies follows, and the results of the screen are presented in Table V-2. The technologies are also described in more detail in Appendix A.

Environmental Impact Analysis

This criterion is used to evaluate the relative environmental impacts of each technology on environmental concerns. The technologies were evaluated for the time requirements for environmental review, emissions considerations, ease of siting, and overall public acceptance. The technologies were then classified as either low, medium, or high (L, M, or H) in degree of environmental sensitivity, with a low score being more favorable.

Table V-2

Results of Candidate Technology Screen

Type	Environmental Impact	Regulatory Impact	Commercial Availability
Pressurized Fluidized Bed			
- Bubbling/Subcritical*	M	L	Demonstration
- Bubbling/Supercritical	M	L	Pilot
- Circulating	M	L	Laboratory
- Combined Cycle	M	L	Pilot
Pulverized Coal *	M	M	Mature
Atmospheric Fluidized Bed			
- Bubbling Bed*	M	L	Commercial
- Circulating*	M	L	Commercial
Coal Gasification Combined Cycle			
- Entrained Flow/Medium Integration*	L	L	Demonstration
- Entrained Flow/Highly Integrated	L	L	Demonstration
- Entrained Flow/Nonintegrated	L	L	Demonstration
- Moving Bed/Medium & High Intg.	L	L	Demonstration
- Humid Air Turbine	L	L	Demonstration
Evo. Light Water Nuclear Reactor	H	H	Commercial
Passive Safety Light Water	H	H	Demonstration
Adv. Liquid Metal Reactor	H	H	Laboratory
Adv. Cycle Pulverized Coal*	M	M	Mature
Gas Turbine Combined Cycle*	L	L	Mature
Combustion Turbine - Steam Inj.	L	L	Mature
Muni. Solid Waste Mass Burn	H	H	Commercial
Refuse Derived Fuel Fired Stoker	H	H	Commercial
Refuse Derived Fuel/Coal Cofired	H	H	Demonstration
Scrap Tires/Coal Cofire	H	H	Demonstration
Scrap Tire Fired Mass Burn	H	H	Demonstration
Fuel Cells	L	L	Mature
- IGMCFC	L	L	Demonstration
- IGFC - Phosphoric Acid	L	L	Demonstration
- Molten Carbonate	L	L	Pilot
Pumped Storage (Conventional)			Mature
Combustion Turbine*	L	L	Mature
Diesel Generator	M	M	Mature
Hydro Pumped Storage	H	L	Mature
Underground Hydro Pumped Storage	H	M	Mature
Compressed Air Energy Storage			
- Rock Cavern	M	L	Demonstration
- Salt Cavern	M	L	Commercial
- Aquifier	M	L	Demonstration
- Humid Air Turbine/Rock Cavern	M	L	Pilot
- Humid Air Turbine/Salt Cavern	M	L	Pilot
- Humid Air Turbine/Acquifier	M	L	Pilot
Geothermal			
- Binary	L	M	Demonstration
- Dual Flash	L	M	Demonstration
Wood Fired Stoker	L	M	Commercial
Wood Fired Circ. FBC	L	M	Commercial
Wood/Coal Cofired	L	M	Commercial
Wood Fired Gasification CC	L	M	Demonstration
Adv. Wood Fired Gasification CC	L	M	Pilot
Whole Tree Energy	L	M	Pilot
Wind	M	M	Demonstration
Solar - Trough/Gas Hybrid	L	L	Pilot
Solar - Fresnel Lens	L	L	Pilot
Lead Acid Battery Storage	L	L	Mature
Adv. Battery Storage	L	L	Pilot
Super Cond. Magnetic Storage	M	M	Pilot
Aeroderivative Combustion Turbine	L	L	Mature

* Selected for economic analysis

Low impact scores were given to technologies with comparatively low emissions and a generally high public acceptance expectation. Medium impact scores were given to the technologies with important emissions considerations, siting and public acceptance expectations which could be reasonably overcome with an appropriate degree of care and consideration of other benefits. High impact scores were given to the technologies for which environmental regulatory approval, siting, and public acceptance would be difficult if not impossible to obtain at this time.

Regulatory Screening Analysis

The regulatory impact was viewed as a composite effect of all the various regulatory agencies which may be involved. These included the South Carolina Public Service Commission, the Federal EPA and other environmental agencies, the FERC, and the NRC. The purpose of this criterion was to recognize the significant impact that these regulatory agencies have on a project's viability. This impact can delay siting and permitting, cause the expenditure of valuable time and resources in contesting litigation or public hearings, or compel the implementation of design or operating changes in response to new or pending legislation.

The regulatory screening criterion assessed the technology's perceived ability to be licensed quickly and operate without excessive or performance-impairing regulatory hurdles. The technologies were categorized as either high, medium, or low in terms of the potential for impact from regulatory reviews, with a low score again being favorable.

Low classification scores were assigned to the technologies assumed to have few problems meeting regulatory limits under existing design configurations. As such, little or no regulatory delay or cost impact would be expected to get the technology licensed, or only minimal design changes would be needed. Medium classification scores were given to technologies with existing design configurations providing the ability to meet expected regulatory requirements without the costly addition of modifications. However, it could reasonably be expected that negotiation over these requirements could impact the project schedule and require additional design changes. High classification scores were given to technologies with considerable time-consuming licensing and review processes, as with nuclear generating plants, and those with concerns primarily related to air emissions that would make licensing and environmental compliance difficult.

Commercial Availability Screening Analysis

This criterion addressed the development of the technology. Since the IRP encompasses a twenty-year horizon, it is likely that one or more of the identified technologies which may not be available at this particular time may become so in the future. For this reason the technology should be monitored for potential future application.

The maturity of a technology is defined as its position in the technological development cycle. A technology may still be in the laboratory stages, which would mean a unit of its kind has never been built at any size and the scientists are still researching the theory related to the technology. The Advanced Liquid Metal Reactor nuclear technology would fall in this category. At the other end of the curve would be a mature technology, such as a pulverized coal unit. A mature technology would be one in which multiple units have been built over the years and which provides the industry with significant data for construction and operating statistics.

Between these two degrees of technology development are two intermediate development stages. A commercial technology is defined as having some limited experience in the industry with this type of unit. The existing units may be small-scale units, or larger units may have only recently entered the operational phase of commercial life. Limited knowledge of large, commercial-scale operation is currently available. Though units in this category do not have significant operating experience in utility settings, it is likely that there will be more extensive experience by the time Santee Cooper is expected to need new baseload capacity.

A demonstration technology is defined as one in which the new technologies have been integrated into a very limited number of utility-grade facilities. These few facilities are operated with the intent of learning more about how the new designs function as part of an overall power plant. The outcome of the observations of these units usually results in additional design modifications in future units.

Associated with the degree of technology development are the current construction and operating cost estimates and the desired in-service date for the generation resource. The costs for the mature technologies are well established as a result of many years of full-scale utility operations. However, the cost estimates for some of the newer technologies are based on laboratory projections, scaled estimates for pilot projects and sources other than actual operation. As these technologies gain more experience in operation, especially in utility-grade conditions, the cost estimates will become more reliable. Therefore, in the case of resource requirements into the next century, the utility planners will be prudent to monitor the newer technologies and include the maturing ones in future IRP efforts.

The mature technologies were categorized as conventional. The emerging technologies were defined for the purposes of this IRP as those in the commercial, demonstration, and laboratory stages of development.

Supply-side Technologies Selected

Table V-3 presents a summary of the technologies that passed the generating technology screen. These technologies were selected for the economic evaluation process, described later in this chapter. With the importance to Santee Cooper of providing reliable and efficient service, most of the technologies selected were in the mature category. However, because some of the technologies are quite far along in the development stage, they were included in the screening effort.

Table V-3

Supply-side Technologies Selected for Economic Analysis

Conventional Technologies	Emerging Technologies
1. Oil-Fired Combustion Turbine (80 MW)	5. Atmospheric Fluidized Bed Combustion - Bubbling Bed Boiler (200 MW)
2. Oil-fired Combined Cycle (240 MW, 80-MW Increments)	6. Atmospheric Fluidized Bed Combustion - Circulating Bed Boiler (200 MW)
3. Pulverized Coal (560, 400, and 240 MW sizes)	7. Pressurized Fluid Bed Combustion - Bubbling Bed Boiler/Subcritical (320 MW)
4. Advanced Cycle Pulverized Coal (300 MW supercritical)	8. Integrated Coal Gasification Combined Cycle - Entrained Flow/Med. Integration (500 MW)

C. RESULTS OF SUPPLY-SIDE OPTIONS DEFINITION AND SCREENING

The supply-side options chosen as a result of the analyses described in Sections A and B are presented below. They are categorized under Conventional Technologies and Emerging Technologies.

CONVENTIONAL TECHNOLOGIES

Four of the resources from the conventional technologies category were chosen as viable options. These options include:

- *Pulverized Coal.* The pulverized coal option consisted of three differently sized units: 560 MW, 400 MW, and 240 MW.

  The plants use conventional pulverized coal boilers and turbine generators and apply pollution control measures consisting of scrubbers, cooling towers, ash and scrubber sludge handling and disposal equipment. For purposes of this study, these units were assumed to be located at a yet to be determined "greenfield" site.

- *Oil-fired Combustion Turbines.* The combustion turbines were modeled after General Electric's Frame 7 units. Though these types of units can be operated on both gas and oil, for the purposes of this study, they were assumed to operate on oil only and have a simple-cycle design with a summer generating capacity of 80 MW.

- *Combined Cycle.* A single 240-MW combined-cycle unit consisting of two simple-cycle combustion turbines was considered. The heat output of each turbine would feed individual heat recovery steam generators (HRSG). The steam output from each of these HRSGs drives a steam turbine/generator capable of producing 80-MW of electricity. For an additional alternative, this combined-cycle technology was assumed capable of a construction approach in which the two combustion turbine units could be constructed one or more years earlier than the HRSG and steam turbine/generator.

- *Advanced Cycle Pulverized Coal.* A single 300-MW supercritical pulverized coal unit was also considered. This type of unit is similar to the standard pulverized coal units described above; however, it operates at higher temperatures and pressures. These changes in operation provide greater operating efficiencies.

EMERGING TECHNOLOGIES

Four of the resources from the emerging technologies category were selected for economic analysis. These options included:

- *Integrated Coal Gasification Combined Cycle.* IGCC technology utilizes a flow gasifier to convert pulverized coal to a gas that can be burned in a steam boiler or piped directly into a gas turbine. The resulting sulfur compounds are reduced to elemental sulfur in the facility. The analysis assumed a 500-MW facility located on a new Santee Cooper generating site.

- *Atmospheric Fluidized Bed Combustion.* Two different AFBC technologies were selected for screening. The first was a 200-MW bubbling bed boiler and the second was a 200-MW circulating bed boiler. In general, the AFBC technology burns crushed coal with limestone in an atmospheric pressure fluid bed suspended by air blown from below. The limestone removes the majority of the SO_2, and the particulates are captured in a series of cyclones followed by an electrostatic precipitator. The heat transfer surface is located in the bed and in the convection pass above the bed. The steam is used to drive a conventional steam turbine generator. The facility Santee Cooper analyzed is based on a 300-MW facility of circulating bed design.

- *Pressurized Fluid Bed Combustion.* A 320-MW PFBC bubbling bed boiler was assumed for this study. A pressurized environment allows for combustion to occur in a deeper bed, which results in a smaller amount of total system pressure drop and allows for up to 50 percent of the total combustion residence time to be in the bed, where heat transfer rates are higher. The pressure of the PFBC design allows for a smaller bed area and a smaller required physical plant area.

SCREENING RESULTS

The economic screening was performed by projecting the total busbar costs of each technology while varying the assumed capacity factor of the unit from zero to 100 percent. The results of this screening are illustrated in Exhibits V-1 , V-2, and V-3. The screening curves in Exhibit V-1 indicate that the 240-MW pulverized coal unit was significantly more costly to operate than the two larger units; therefore, the smaller unit was rejected. In addition, Exhibit V-2 indicates that the cost to operate the 200-MW AFBC bubbling bed unit was high enough compared to the other technologies to reject it.

Finally, Exhibit V-3 evaluated the combustion turbine and the combined cycle units fueled by either gas or oil. The curves indicate that gas is a more economical fuel for these units. However, gas is not available at the assumed sites for these units. Discussions with the local gas supplier pointed to the possibility of constructing a gas

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SCREENING CURVES CONVENTIONAL TECH BASELOAD

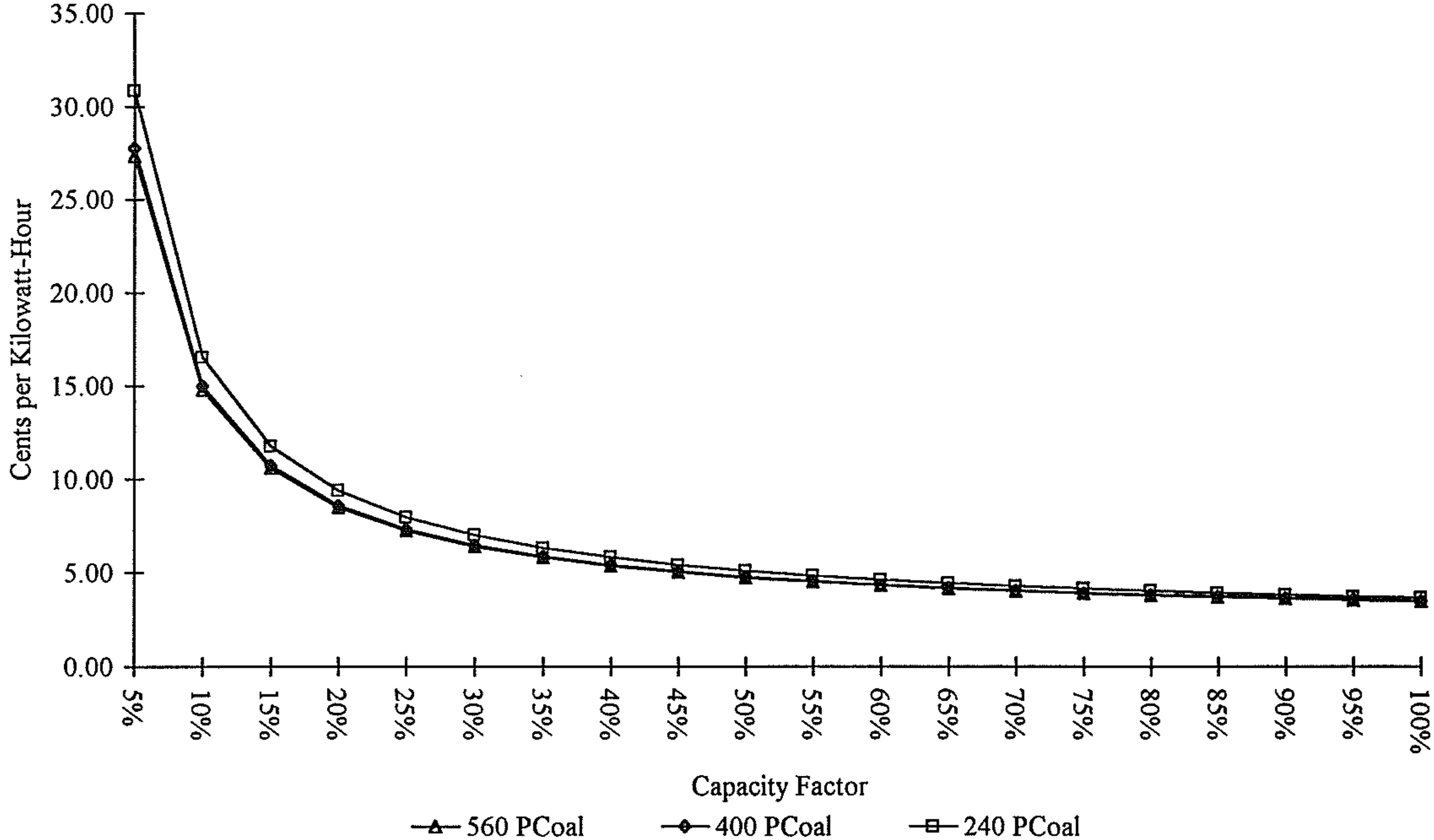


EXHIBIT V-1

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SCREENING CURVES, ADV TECH BASELOAD

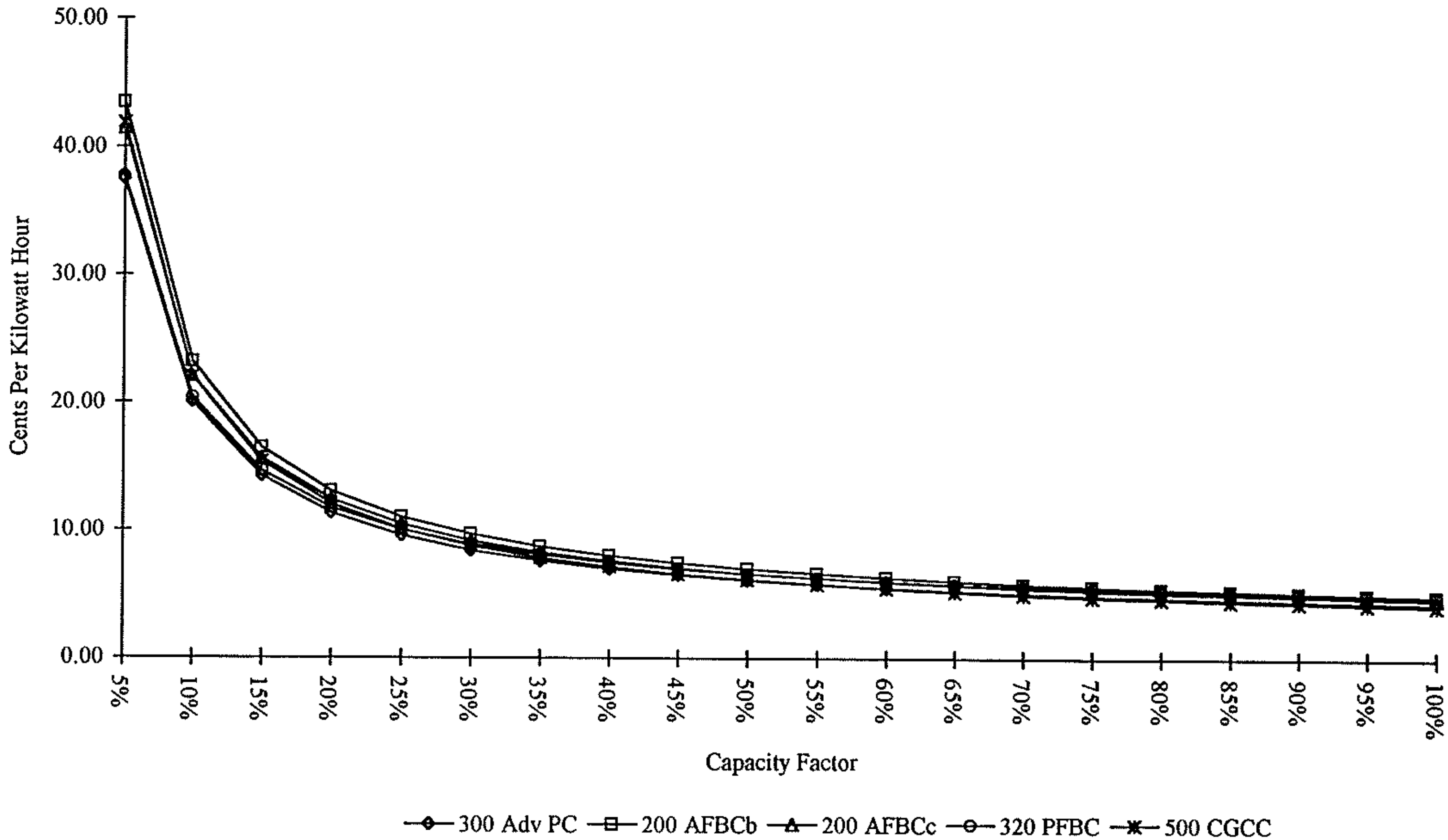


EXHIBIT V-2

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SCREENING CURVES, PEAKING - INTERMEDIATE

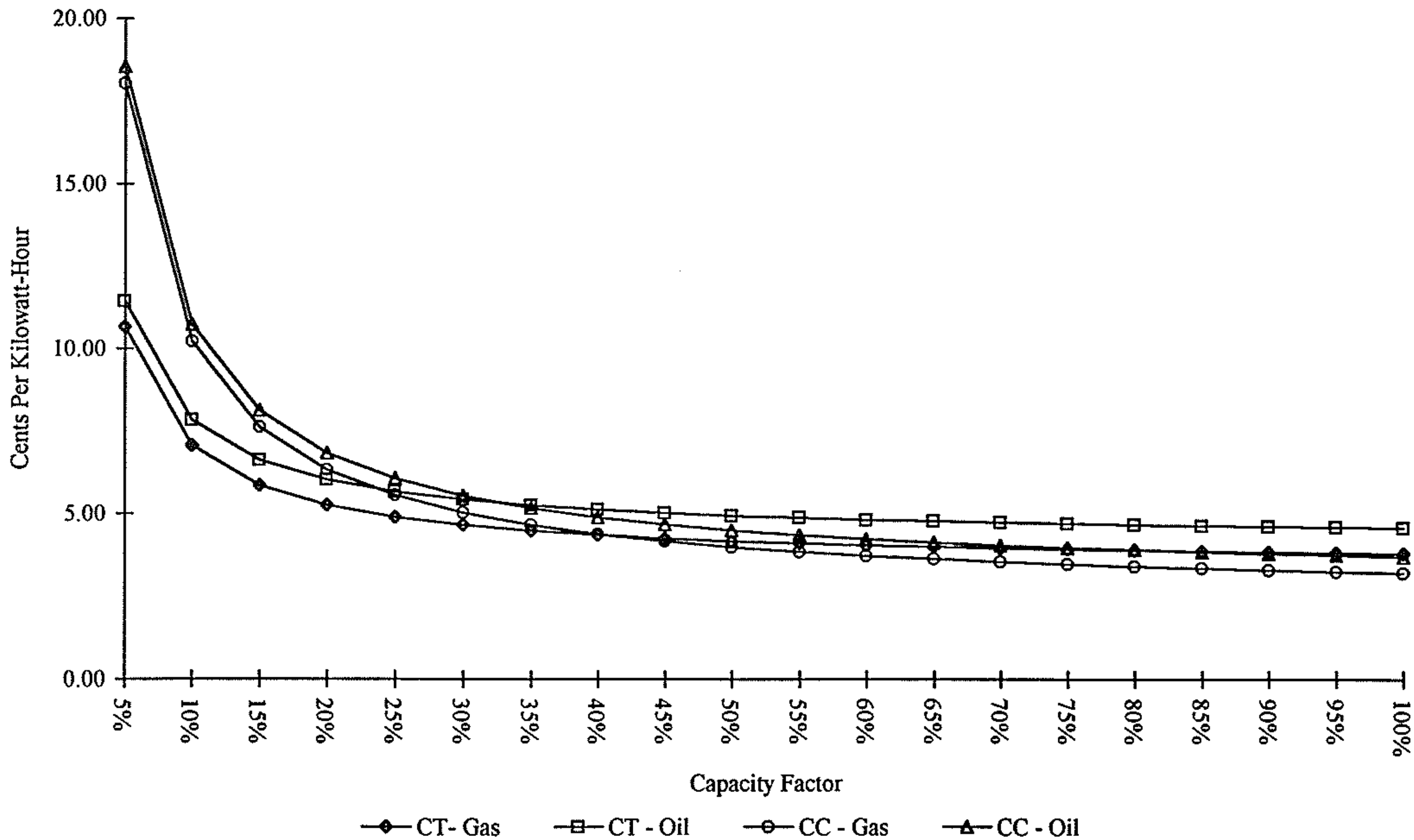


EXHIBIT V-3

pipeline if the gas demand warranted it. Therefore, though oil was selected as the fuel for further screening analyses, the gas option was considered in later analyses to determine the possible volume of gas such a unit would use and to determine whether it would be significant enough to pursue a gas-fired unit.

All of the remaining technologies had operating costs close enough to pass them on to the PROVIEW model and allow the model to dynamically screen and rank the alternatives against Santee Cooper's projected loads and requirements.

PROVIEW OPTIMIZATION - SUPPLY OPTIONS

PROVIEW will optimize the supply-side alternatives by recognizing the need for one or more new resources during the planning period (1994 to 2015) and will create numerous alternative cases, each consisting of a different supply-side alternative meeting these requirements. In Santee Cooper's case and assuming the baseload forecast without ALUMAX, PROVIEW recognized a need for a new resource in 2003. From that point in time forward, PROVIEW would insert each of the available technologies into Santee Cooper's resource mix. This process would continue throughout the period until 2015.

The model would then calculate the present value of incremental revenue requirements (PVRR) for each of the new supply plans. Since the planning period was only 20 years, and since any new resource considered had an economic life in excess of the 20-year period, PROVIEW would calculate the PVRR for the period beyond the 20 years to capture the economic end effects of the new resources. The model would then provide a ranking of these plans from lowest to highest PVRR based on the entire study period - planning period economics plus economic end effects. The results of this supply-side analysis indicated the 2003 resource requirement was best met by installing a new 80 MW combustion turbine.

The dynamic feature of PROVIEW will result in numerous alternative plans being tested. In many cases, the various plans are minor variations of another plan. For instance, the difference between the first plan and the second ranked plan was only the installation of the second phase of a combined cycle unit in 2015 instead of a combustion turbine. This would not be a significant change in the plan. However, the third ranked plan resulted in a pulverized coal unit in the year 2012 instead of the combined cycle unit. This was considered a significant change in the plans and would be considered further in the sensitivity and scenario analysis that would follow.

The combined cycle and pulverized coal plans are shown in Table V-4.

Table V-4

Comparison of Screening Analysis

Year	Combined Cycle Plan	Pulverized Coal Plan
1994		
1995		
1996		
1997		
1998		
1999		
2000		
2001		
2002		
2003	One 80-MW CT	One 80-MW CT
2004	One 80-MW CT	One 80-MW CT
2005	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT
2007	Two 80-MW CTs	Two 80-MW CTs
2008	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT
2012	Two 80-MW CTs and One 80-MW Phased CC	One 400-MW PC
2013	Two 80-MW CTs	
2014	One 80-MW CT	One 80-MW CT
2015	One 80-MW CT	One 80-MW CT
1994-2015 PVRR	$5,974,906,500	$5,986,542,500

A review of the top 40 ranked plans indicated that the only technologies that were economically viable for Santee Cooper to consider would be combustion turbines, combined cycle units, and pulverized coal units. The operating costs of the other technologies were uneconomical compared to these three.

D. IMPACT OF ALUMAX ON RESOURCE REQUIREMENTS

The above screening analysis was conducted on the Base Case forecast with the assumption that ALUMAX would not be a customer after March 31, 2000. However, there is a possibility that it would remain on Santee Cooper's system indefinitely. Therefore, it was necessary to evaluate this change in load condition also, and determine whether this increased load had any effect on the supply-side analysis. Table V-5 contains the results of this analysis as an indication of how the timing and technology of the selected resource might change.

Table V-5

Comparison of ALUMAX Impact

Year	Combined Cycle Plan without ALUMAX	Combined Cycle Plan with ALUMAX
1994		
1995		
1996		
1997		
1998		
1999		
2000		One 80-MW CT
2001		Two 80-MW CT
2002		One 80-MW CT
2003	One 80-MW CT	One 80-MW CT
2004	One 80-MW CT	Two 80-MW CTs
2005	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT
2007	Two 80-MW CTs	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW Phased CC
2012	Two 80-MW CTs and One 80-MW Phased CC	One 400-MW PC
2013	Two 80-MW CTs	
2014	One 80-MW CT	One 80-MW CT
2015	One 80-MW CT	Two 80-MW CTs
1994-2015 PVRR	$5,974,906,500	$6,654,110,000
Total New Capacity	1,360 MW	1,760 MW

The differential in the two loading conditions results in a more rapid need for new capacity, which accelerated the need date from 2003 to 2000. The economic impact of this load is $1,808,000,000 due to increased capacity requirements and production costs over the study period.

E. IMPACT OF HIGH AND LOW LOAD FORECASTS

The above screening analysis was conducted on the Base Case forecast; however, Santee Cooper's load forecast has been bounded by high and low forecasts, each of which will have significant impacts on the resource requirements. Therefore, it was necessary to evaluate this change in load condition also and determine whether this higher or lower load had any effect on the supply-side analysis. Table V-6 contains the results of this analysis as an indication of how the timing and technology of the selected resource might change.

Table V-6

Comparison of Combined Cycle Plan

Year	High Load Forecast	Base Forecast	Low Load Forecast
1994			
1995			
1996			
1997	Three 80-MW CTs		
1998	One 80-MW CT		
1999			
2000			
2001			
2002			
2003		One 80-MW CT	
2004	One 80-MW CT	One 80-MW CT	
2005	One 80-MW CT	One 80-MW CT	
2006	One 80-MW CT	One 80-MW CT	
2007		Two 80-MW CTs	
2008	One 80-MW CT	One 80-MW CT	
2009	One 80-MW CT	One 80-MW CT	
2010		One 80-MW CT	
2011	One 80-MW CT	One 80-MW CT	
2012	One 400-MW PC	Two 80-MW CTs and One 80-MW Phased CC	Four 80-MW CTs
2013	One 80-MW CT	Two 80-MW CTs	One 80-MW CT
2014	One 80-MW CT	One 80-MW CT	Two 80-MW CTs
2015	One 80-MW CT and One 80-MW Phased CC	One 80-MW CT	One 80-MW CT
1994-2015 PVRR	$6,683,958,000	$5,974,906,500	$5,514,844,000
Total New Capacity	1,520 MW	1,360 MW	640 MW

The low load case results in Santee Cooper having very little planning to do for the next 15 to 20 years. The concern for the utility has to be to plan for the Base Case or higher load level and then actually experience the low load condition. However, since the Base Case load forecast indicates the need for combustion turbines for the next 18 years, Santee Cooper will have sufficient time to monitor the loads and plan for the lower loads if they were to develop.

The high load forecast, however, presents Santee Cooper with a more difficult situation. The load is high enough in the early years that it would need capacity immediately. The problem with this condition is the time necessary to plan, license, and construct new capacity of any technology, even a combustion turbine, which can take up to four or more years.

These load conditions will be reviewed in more detail in later chapters to identify the economic risks to Santee Cooper to plan and implement a particular resource plan based on a load forecast and then experience something significantly different. In addition to the timing, number, and technologies in question in the resource plan, there is also the issue of compliance with the Clean Air Act Amendments discussed above. This issue will be addressed in later chapters as the supply-side and DSM alternatives are integrated and alternative plans developed.

F. SUMMARY OF OPTIMIZED SUPPLY-SIDE PLANS

In summary, the results of the supply-side alternative optimization were dependent on the load forecast assumed and the future status of the ALUMAX load. The critical difference between the various load conditions was the timing associated with the start of adding new generating units to Santee Cooper's system.

As expected, the higher the load, the earlier the next unit would be required. In the event of the high load forecast with ALUMAX present, Santee Cooper was capacity deficient as early as 1994. Since a new resource could not be constructed immediately, Santee Cooper would be required under this condition to explore the wholesale market for purchase opportunities.

In the low load case without ALUMAX, the new resource would not be required until 2012, or well beyond any near-term need to identify type or location of the next unit. Under this condition, Santee Cooper would want to explore the wholesale market to identify any opportunities to increase the utilization of existing resources.

Table V-7 contains a summary of each of the six load conditions, and identifies the size, type, and timing for each new supply-side resource. The next chapter uses these six cases and presents an environmental compliance plan for each to meet the requirements of the Clean Air Act Amendments of 1990.

Table V-8 contains the incremental annual revenue requirements associated with these six cases.

Table V-7

Summary of Supply-side Plans by Load Forecast

YEAR	BASE W/O ALUMAX	BASE WITH ALUMAX	HIGH W/O ALUMAX	HIGH WITH ALUMAX	LOW W/O ALUMAX	LOW WITH ALUMAX
1994						
1995						
1996						
1997			3-80-MW CTs	3-80-MW CTs		
1998			1-80-MW CT	1-80-MW CT		
1999						
2000		1-80-MW CT				
2001		2-80-MW CTs		1-80-MW CT		
2002		1-80-MW CT		1-80-MW CT		
2003	1-80-MW CT	1-80-MW CT		1-80-MW CT		
2004	1-80-MW CT	2-80-MW CTs	1-80-MW CT			
2005	1-80-MW CT	1-80-MW CT	1-80-MW CT	1-80-MW CT		
2006	1-80-MW CT	1-80-MW CT	1-80-MW CT	1-80-MW CT Phased CC		
2007	2-80-MW CTs	1-80-MW CT		1-80-MW CT		1-80-MW CT
2008	1-80-MW CT	1-80-MW CT	1-80-MW CT	1-80-MW CT		1-80-MW CT
2009	1-80-MW CT	1-80-MW CT	1-80-MW CT			1-80-MW CT
2010	1-80-MW CT	1-80-MW CT		1-80-MW CT		1-80-MW CT
2011	1-80-MW CT	1-80-MW Phased CC	1-80-MW CT	1-80-MW Phased CC		1-80-MW CT
2012	2-80-MW CTs & 1-80-MW Phased CC	1 400-MW PC	1 400-MW PC	1 400-MW PC	4-80-MW CTs	3-80-MW CTs
2013	2-80-MW CTs		1-80-MW CT	1-80-MW CT	1-80-MW CT	2-80-MW CTs
2014	1-80-MW CT	1-80-MW CT	1-80-MW CT	1 400-MW PC	2-80-MW CTs	1-80-MW Phased CC
2015	1-80-MW CT	2-80-MW CTs	1-80-MW CT		1-80-MW CT	2-80-MW CTs
1994-2015 Year PVRR	$5,974,906,500	$6,654,110,000	$6,683,958,000	$7,414,695,500	$5,514,844,000	$6,090,114,000
Total New Capacity	1,360	1,760	1,520	1,920	640	1,040

Table V-8

Summary of Revenue Requirements for Supply-side Plans by Load Forecast ($000)

YEAR	BASE W/O ALUMAX	BASE WITH ALUMAX	HIGH W/O ALUMAX	HIGH WITH ALUMAX	LOW W/O ALUMAX	LOW WITH ALUMAX
1994	306,964	306,964	329,475	329,475	293,521	293,521
1995	318,284	318,284	334,717	334,717	305,102	305,102
1996	328,186	328,186	346,325	346,325	314,134	314,134
1997	346,790	346,790	379,162	379,162	331,584	331,584
1998	368,739	368,739	407,801	407,801	352,513	352,513
1999	399,545	399,545	444,191	444,191	381,325	381,325
2000	378,758	425,188	422,736	471,468	359,940	402,420
2001	382,957	451,541	429,510	500,671	361,776	422,392
2002	412,244	485,872	462,040	543,027	389,624	450,990
2003	443,964	522,242	495,513	588,251	417,003	480,138
2004	476,394	561,610	534,576	626,553	444,193	511,304
2005	514,048	604,027	580,094	679,353	476,975	544,980
2006	551,979	643,375	628,603	732,117	509,463	580,863
2007	590,519	688,516	664,586	777,363	537,926	615,596
2008	636,188	741,362	720,975	841,134	576,001	659,835
2009	684,946	799,662	781,248	903,426	614,474	705,907
2010	727,532	845,686	825,887	957,764	650,080	748,246
2011	783,775	910,049	895,927	1,030,364	695,115	802,575
2012	856,992	994,878	986,076	1,115,714	752,408	873,136
2013	913,054	1,049,432	1,050,236	1,183,854	800,315	926,314
2014	981,811	1,120,072	1,129,964	1,277,729	861,924	995,125
2015	1,059,282	1,203,282	1,214,196	1,354,712	923,276	1,069,642
1994-2015 PVRR	5,974,906.5	6,654,110	6,683,958	7,414,695.5	5,514,844	6,090,114

VI. COMPLIANCE WITH THE CLEAN AIR ACT AMENDMENTS OF 1990

VI. COMPLIANCE WITH THE CLEAN AIR ACT AMENDMENTS OF 1990

The objective of this chapter is to review the requirements of the Clean Air Act Amendments of 1990 (CAAA), and to develop a proposed compliance plan for the supply-side resource plan presented in Chapter V. This chapter is divided into the following sections:

A. Provisions of the CAAA

B. SO_2 emission estimates for the supply-side plan

C. Identification and evaluation of SO_2 emission compliance plan alternatives

D. NO_x emissions estimates for the supply-side plans

E. Carbon tax impacts.

A. PROVISIONS OF THE CAAA

HISTORY OF AIR REGULATIONS IN THE UNITED STATES

The Federal government identified air pollution as a concern in the first half of this century. Since 1955, the government has enacted a total of nine major Acts controlling substances emitted into the atmosphere. These nine laws are:

- The Air Pollution Act of 1955
- The Air Pollution Control Act Amendments of 1960
- The Air Pollution Control Act Amendments of 1962
- The Clean Air Act of 1963
- The Motor Vehicle Air Pollution Control Act of 1965
- The Air Quality Act of 1967
- The Clean Air Act Amendments of 1970
- The Clean Air Act Amendments of 1977
- The Clean Air Act Amendments of 1990 (CAAA).

Each of these laws had far-reaching implications on the electric utility industry, as they set standards which required the industry to add new pollution control equipment on new, and in some cases, existing generating units.

The Air Quality Act of 1967 was probably the first far-reaching piece of legislation impacting the operation of electric power plants. Among other provisions, the 1967 Act designated air quality control regions, set air quality criteria, set forth the development and issuance of information on air pollution control techniques, and required states to establish air quality standards.

The Clean Air Act of 1970 also set a new proliferation of restrictions on the utility industry. This Act created the Environmental Protection Agency, set national ambient air quality standards, gave the states the primary responsibility for policing the compliance with the laws, set standards of performance for all new stationary pollution sources, required utilities to monitor emissions and maintain emission records, and set forth enforcement procedures.

The Clean Air Act Amendments of 1977 set standards of performance specifically for fossil fuel-fired stationary pollution sources, provided emission standards for hazardous pollutants such as benzene and radionuclides, revised asbestos standards, and provided for stack heights at plants based on "good engineering practice." A key aspect of this Act was the development of the nonattainment program in which existing sources were required to utilize reasonably available control technology to control emissions, and new sources were required to meet a standard of lowest achievable emission rates and offset emissions.

The CAAA had numerous provisions included in the legislation with the intent of providing the EPA more insight into Congress' intent to reduce air pollution. The Act has eleven separate Titles or major sections. Title IV - Acid Disposition Control was the part of the Act that received most of the publicity and is the driving factor in developing sulfur dioxide and nitrogen oxide reduction programs. Key objectives of this Title are:

- Reduce SO_2 emissions by 10 million tons per year from a 1980 baseline
- Set a national SO_2 emissions cap in the year 2000
- Reduce NO_x emissions by 2 million tons per year
- Establish baseline emissions
- Establish a market-based system for trading allowances (one ton of SO_2 equals one allowance and is an authorization to emit during or after a specified year one ton of sulfur dioxide)

- Set a two-step time frame for implementation of the requirements
  - Phase I implementation January 1, 1995
  - Phase II implementation January 1, 2000.

CAAA TITLE IV REQUIREMENTS

Phase I of the CAAA identifies 251 individual existing generating units that are affected and require a reduction in sulfur dioxide emissions. Santee Cooper does not have a Phase I affected unit. All units above 75 MW of electrical output are considered affected units under Phase II. Each affected unit would be provided annual allowances as determined by the EPA on the basis of a procedure established in the CAAA.

A utility is allowed to pool the allowances from each generating unit as a total allowed annual SO_2 emissions limit. Any allowances not used during a calendar year can either be saved, or banked, for future use or offered for sale to another entity. The number of allowances for each unit is based on the unit's historical operations, and is adjusted for all units to achieve an annual total of 10 million tons of SO_2 emitted from utility power plants. Table VI-1 is a summary of allowances for Santee Cooper's units based on the calculations of the EPA.

The values in this table are provided by the Code of Federal Regulations Volume 40, Chapter 1 Section 73.10 (40 CFR CH. 1 Sect 73.10 Table 2). These totals take into account all adjustments for bonuses or reductions as of July 1, 1993.

Table VI-1
Phase II Allowance Allocations

Unit	2000 to 2009 Allowances	2010 and Beyond Allowances
Cross 1	5,555	5,591
Cross 2	8,864	8,923
Grainger 1	3,087	3,106
Grainger 2	274	276
Jefferies 1	0	0
Jefferies 2	0	1
Jefferies 3	3,857	3,367
Jefferies 4	3,716	3,143
Winyah 1	7,510	7,560
Winyah 2	6,190	5,109
Winyah 3	3,590	2,500
Winyah 4	3,396	3,420
Total	**46,039**	**42,996**

As of this most recent publication of the CFR, Santee Cooper can expect to receive 46,039 allowances for the first ten years beginning in 2000 and 42,996 allowances each year thereafter beginning in 2010.

B. PROJECTED SO_2 EMISSIONS

Actual emissions are a direct result of generating electricity from fossil-fueled power plants necessary to meet loads. Therefore, as the loads served vary, so too will the emissions. A total of six individual supply plans that are dependent on the load forecast and the status of the ALUMAX load have been identified for Santee Cooper. Exhibit VI-1 illustrates the estimated SO_2 emissions for each of these six supply plans.

BASE CASE FORECAST WITHOUT ALUMAX (BASEWOAL)

Exhibit VI-1 illustrates the cumulative allowance bank for Santee Cooper's base case planning load forecast and the optimized supply-side resource plan described in the last chapter. As the chart indicates, in 2000, Santee Cooper will have excess allowances until 2006, at which time the allowance requirements will exceed the annual allocation. Since the base case assumes Santee Cooper will bank any excess allowances during the early years, the annual shortfall of allowances will not require Santee Cooper to take any action until 2011, when the bank of allowances is depleted.

BASE CASE FORECAST WITH ALUMAX (BASEALUM)

As illustrated in Exhibit VI-1, the presence of the 300 MW ALUMAX load places Santee Cooper in a shortfall position of allowances in the year 2000, which is the beginning of Phase II. Therefore, actions will be needed by January 1, 2000 to reduce SO_2 emissions in order to comply if ALUMAX notifies Santee Cooper that it intends to continue operations at the current levels of energy requirements.

HIGH LOAD FORECAST WITHOUT ALUMAX (HIGHWOAL)

The high load forecast and the supply-side resource plan required to serve this load result in SO_2 emissions sufficiently low enough to avoid significant actions until the year 2005. The emissions are in excess of allowances in the first year by less than 500 tons; however, the emissions over the next two years are below the available number of allowances. Therefore, Santee Cooper could take certain operating measures to be discussed later to overcome the shortfall in the first year and delay any capital additions until 2005 to maintain compliance.

HIGH LOAD FORECAST WITH ALUMAX (HIGHALUM)

As in the case with the base load forecast with the ALUMAX load, this high load forecast scenario requires Santee Cooper to take remedial steps to comply with the CAAA at the outset of Phase II. The emissions exceed 46,000 tons per year by over 14 percent in year 2000 and continue to climb over the remainder of the evaluation period.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SO_2 ALLOWANCE BANKING

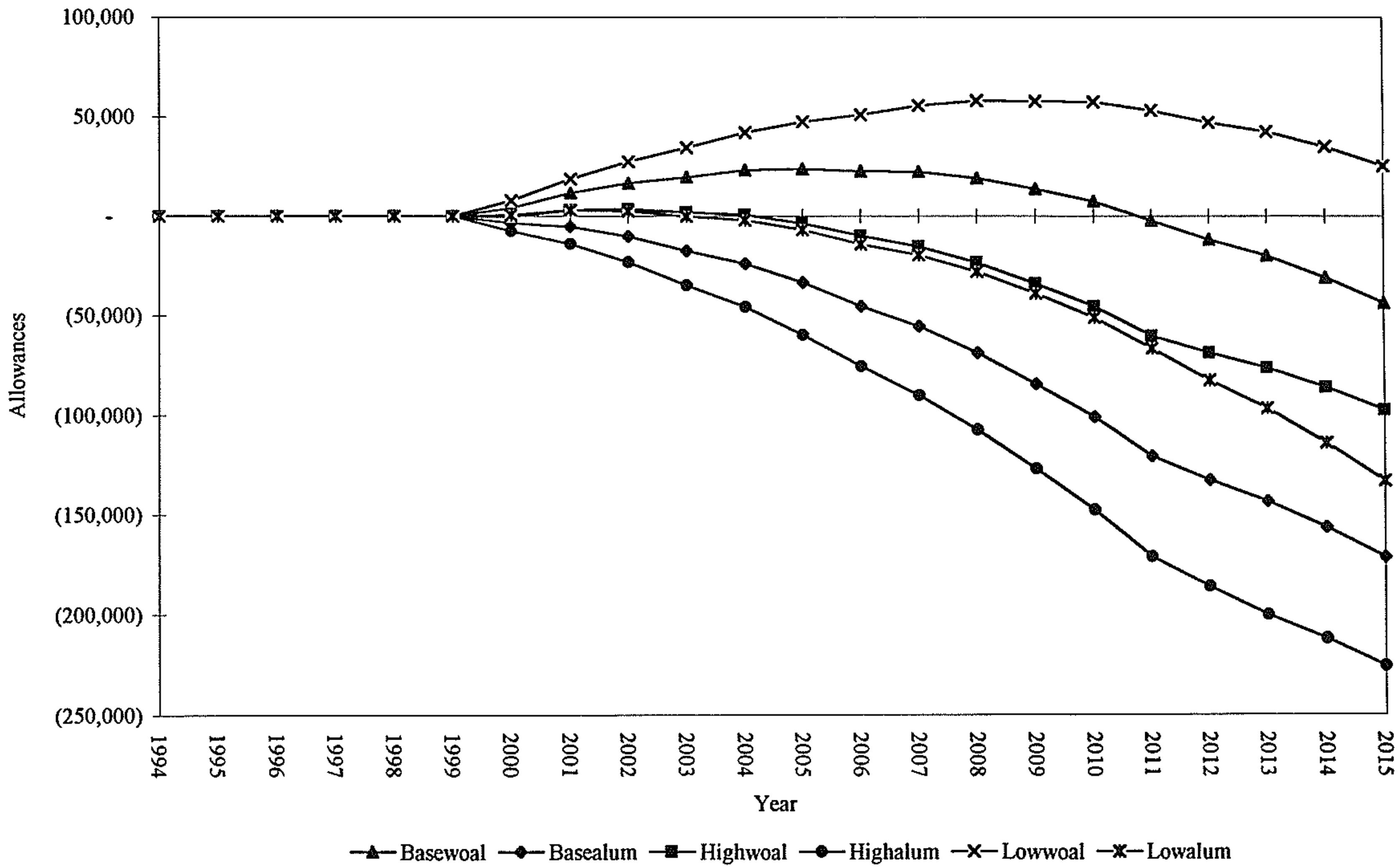


EXHIBIT VI-1

LOW LOAD FORECAST WITHOUT ALUMAX (LOWWOAL)

The low load forecast without ALUMAX and its supply-side resource plan is in compliance with the CAAA throughout the evaluation period. This assumes Santee Cooper is banking its excess allowances, since the annual allowance requirements exceed its allocation beginning in 2010. However, the banked allowances are sufficient to meet requirements well past 2015. This indicates that if the load does not continue to grow as Santee Cooper is projecting in the base case forecast, the issue of compliance will not require significant remedial efforts. In fact, the one positive that would come from a slowing of the load growth in Santee Cooper's service territory would be the availability of a large supply of allowances for Santee Cooper to provide to the market as a source of additional revenue.

LOW LOAD FORECAST WITH ALUMAX (LOWALUM)

The low load forecast with ALUMAX will result in a shortage of allowances by year 2003; however, since the first two years resulted in excess allowances, there are sufficient allowances to allow Santee Cooper to delay remedial efforts requiring capital additions until 2004.

SUMMARY

Table VI-2 contains the annual SO_2 emission projections illustrated in Exhibit VI-1.

In five of the six load forecast conditions, Santee Cooper will be faced with the issue of taking remedial actions to comply with the CAAA. The question becomes one of what steps can and should be taken and the timing of these steps. In two of the cases, steps will need to be taken immediately to achieve compliance by the start of Phase II in 2000. The size of the shortfall between projected emissions and allocated allowances is sizable enough to indicate significant actions requiring capital expenditures.

Two of the load conditions are low enough to allow Santee Cooper additional time by a couple of years past the start of Phase II to monitor the actual conditions and to assess the allowance trading market before steps need to be taken. Both of these load conditions are the high and low extremes, with ALUMAX being the uncertainty between them.

The most probable load forecast, as exemplified in the base case forecast without ALUMAX, provides Santee Cooper with a reasonable amount of time, almost ten years from the start of Phase II, to take a "wait-and-see" approach to compliance. This additional time will allow Santee Cooper to monitor its own unit operation with respect to emissions and will provide the opportunity to evaluate the allowance trading market to determine whether it holds any advantages in Santee Cooper's compliance strategies.

Table VI-2

SO_2 Allowance Bank Summary
Before Compliance Plans

Year	Base Case Without ALUMAX	Base Case With ALUMAX	High Load Without ALUMAX	High Load With ALUMAX	Low Load Without ALUMAX	Low Load With ALUMAX
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	4,050	(3,640)	(313)	(7,763)	7,738	629
2001	11,621	(5,502)	2,985	(14,085)	18,721	3,074
2002	16,571	(10,456)	3,496	(23,467)	27,409	2,404
2003	19,457	(17,674)	1,741	(35,043	34,340	(423)
2004	22,964	(24,066)	513	(45,874)	42,050	(2,206)
2005	23,570	(33,603)	(3,706)	(59,822)	47,408	(7,150)
2006	22,477	(45,463)	(10,196)	(75,764)	50,845	(14,440)
2007	22,194	(55,702)	(15,463)	(90,340)	55,662	(19,943)
2008	19,051	(68,983)	(23,740)	(107,728)	57,850	(28,306)
2009	13,650	(84,493)	(34,150)	(127,108)	57,838	(39,169)
2010	7,317	(101,125)	(45,689)	(147,759)	57,303	(51,227)
2011	(2,377)	(120,923)	(60,459)	(171,323)	53,151	(66,768)
2012	(12,037)	(132,834)	(69,028)	(186,380)	47,010	(82,683)
2013	(20,189)	(143,573)	(76,607)	(200,282)	42,620	(96,924)
2014	(31,155)	(156,582)	(86,304)	(212,338)	34,981	(114,138)
2015	(43,880)	(171,298)	(97,549)	(225,805)	25,128	(133,127)

C. IDENTIFICATION AND EVALUATION OF SO_2 EMISSION COMPLIANCE PLAN ALTERNATIVES

Based on a review of the sulfur dioxide emissions projected in the base case, Santee Cooper will become deficient in the year 2011. At that time, the options available to it will be:

- Purchasing additional allowances on the open market
- Fuel switching
  - Lower sulfur coal
  - Converting to natural gas from coal
- Environmentally affected dispatching of the emitting units
- Installing a scrubber on an existing coal fired unit.

PURCHASING ADDITIONAL ALLOWANCES ON THE OPEN MARKET

The assumption in the development of the Base Case was to not utilize the market option for any additional allowances needed by Santee Cooper. Therefore, the initial evaluation did not consider the option to purchase allowances when the need was identified, or to sell excess allowances when they were available. However, as a sensitivity analysis to be discussed later in this chapter, the issue of a market value was considered to identify the value of allowance trading to Santee Cooper.

FUEL SWITCHING

Two fuel switching alternatives were considered in this analysis. The first alternative considered switching from Santee Cooper's current coal to one with a lower sulfur content. The second analysis considered switching Winyah 1 to natural gas from coal. The results of these two analyses are described below.

Switch to Lower Sulfur Coal

The option to fuel-switch to a lower sulfur coal was considered. Santee Cooper already burns coal that ranges from 0.9 to 1.5 percent sulfur; it was necessary to consider coal with a sulfur content as low as 0.7 percent. The fuel switching option was compared to the option to install a scrubber at Santee Cooper's Winyah unit. For fuel switching to the lower sulfur coal to be cost-effective, the coal cost increase could not exceed approximately seven percent of Santee Cooper's existing coal contracts over the evaluation period. A review of available coal price forecasts indicates the difference between the two coals is expected to be in the range of 10 to 15 percent. The result of this analysis indicated that even though the option to fuel switch to lower sulfur coal would be sufficient to comply in the base case, the cost differential between the two fuels is expected to be greater than the alternatives available to Santee Cooper. This review did not consider the additional costs to convert the boiler and precipitator to handle the lower sulfur fuel. Had these costs been included, the option to switch to the lower sulfur coal would have poorer economic results than found in the study.

Switch to Natural Gas

This analysis considered switching Winyah 1 to natural gas instead of burning coal. This alternative would result in Santee Cooper complying with the CAAA. However, the cost to pursue this alternative would increase Santee Cooper's revenue requirements over the period 1994 to 2015 by $180,220,500. Therefore, this alternative was not considered a viable route for Santee Cooper to pursue. Since this option did not have favorable economics, consideration to the availability of the gas supply was not evaluated.

ENVIRONMENTALLY AFFECTED DISPATCHING

The option to environmentally dispatch the units did provide some benefit to Santee Cooper. However, this benefit resulted only in delaying the installation of a scrubber by one year and only in those cases when compliance efforts were required beyond the start of Phase II. The production cost penalty for this change in dispatch was projected to be no more than approximately $180,000 in 1994 PVRR and was dependent on the amount of emissions offset required.

INSTALLATION OF A SCRUBBER AT AN EXISTING UNIT

The approach to complying with the CAAA taken by many utilities is to install a scrubber at an existing coal-fired generating unit. The questions then becomes, when is the retrofit scrubber required and which unit or units will provide the utility with the greatest reduction in emissions for the cost of the scrubber.

In the case of Santee Cooper, three generating units were identified as potential sites based on discussions with Santee Cooper staff and a review of their 1993 IRP. These three units are: Winyah 1, Winyah 2, and Jefferies 3. The reason for selecting these three units was primarily capacity of the units resulting in greater emission reductions from these units than from the Grainger units, which are smaller. It was recognized that Winyah 2 is already 46 percent scrubber; therefore, the evaluation concentrated on Winyah 1 as the preferred candidate unit. In each case, 90 percent of the unit's SO_2 emissions was assumed to be removed by the retrofit scrubber. The study assumed conventional scrubber technology at a cost of approximately $200 per kilowatt of unit capacity.

The criterion used to develop the compliance plan was minimum revenue requirements. With this criterion, the Winyah 1 unit was identified as the optimum site for a scrubber retrofit, because of the space available for the equipment and the size of the unit. The other unit that also provided a possibility was a Jefferies unit; however, the benefits of installing a scrubber at Jefferies were not as great over the long-term period as the Winyah unit provided.

The increased capital and operating cost to install a scrubber at the Winyah unit over the 2000 to 2015 period was $8,241,000 in 1994 PVRR over the economic life of the scrubber. This is in addition to the minimal increase in cost for the environmentally affected dispatch.

The compliance plans for each of the other five load conditions were developed from the same criteria of minimizing revenue requirements and utilizing a retrofit scrubber at Winyah Unit 1. Table VI-3 identifies the resulting plans and their costs over the period 1994 to 2015 to meet the requirements of the CAAA. Table VI-4 indicates the allowance bank after implementing this Compliance Plan

Table VI-3

CAAA Compliance Plans Costs

Case	CAAA Compliance Plans	1994 to 2015 PVRR ($000)
Base Case without ALUMAX	EAD in 2011 Winyah 1 Scrubber in 2012	5,983,332
Base Case with ALUMAX	Winyah 1 Scrubber in 2000	6,694,842
High Load without ALUMAX	EAD in 2000 Winyah 1 Scrubber in 2005	6,709,570
High Load with ALUMAX	Winyah 1 Scrubber in 2000 Jefferies 3 Scrubber in 2010	7,462,964
Low Load without ALUMAX	Plan in compliance	5,514,844
Low Load with ALUMAX	EAD in 2003 Winyah 1 Scrubber in 2004	6,118,559

Table VI-4

SO_2 Allowance Bank Summary
After Compliance Plans

Year	Base Case Without ALUMAX	Base Case With ALUMAX	High Load Without ALUMAX	High Load With ALUMAX	Low Load Without ALUMAX	Low Load With ALUMAX
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	4,050	9,042	(612)	4,172	7,738	629
2001	11,621	19,609	2,585	10,412	18,721	3,074
2002	16,571	27,516	2,951	13,810	27,409	2,404
2003	19,457	33,259	1,050	15,027	34,343	(412)
2004	22,964	39,769	(321)	16,929	42,059	(2,139)
2005	23,570	43,323	(4,655)	16,050	47,405	6,312
2006	22,477	45,132	1,421	13,068	50,857	12,658
2007	22,194	47,962	8,662	11,489	55,692	20,576
2008	19,051	48,065	13,342	7,333	57,893	25,779
2009	13,650	45,929	15,735	1,244	57,951	28,658
2010	7,317	42,537	16,856	3,087	57,350	30,270
2011	(2,377)	36,146	15,073	2,415	53,139	28,495
2012	964	32,418	15,361	6,475	47,063	26,415
2013	5,613	29,968	16,783	11,526	42,636	25,911
2014	7,784	25,549	16,032	15,040	34,955	22,473
2015	8,266	19,940	14,155	17,720	25,130	17,250

ALLOWANCE MARKET OPPORTUNITIES

The base assumption in the evaluation has been that the value of allowances on the open market would have no impact on Santee Cooper's compliance plan. Therefore, in the years actual emissions were below the number of allocated allowances, the utility would bank the excess. When the emissions exceeded the annual allocation, they would utilize whatever allowances had been banked from previous years or would comply through the plans identified in Table VI-3.

However, the allowances will in all likelihood have a market value, which would mean a potential revenue source for a utility with excess allowances. The allowance market would also provide alternatives to installing a scrubber in the event of a projected shortfall of allowances. In Santee Cooper's case, a scrubber will be needed under the base case load assumptions by the year 2012. However, if the value of the allowances is low enough, delaying the timing of the scrubber could be worthwhile. Likewise, if the value of the allowances is high enough, it could be of value to Santee Cooper to install the scrubber early and sell the excess allowances on the open market.

The future value of the allowances is uncertain; therefore, four different values representing potential market values were considered: $80 per ton, $200 per ton, $250 per ton and $800 per ton. The impacts of these differing values were compared to the base case assumption of not buying for shortfalls or selling any excesses.

Base Case

The base case indicates sufficient allowances to meet requirements until 2012. This assumes Santee Cooper banks its excess allowances each year. In the years when shortfalls occur, the bank is drawn down until it is depleted. No sales or purchases of allowances are assumed, and a scrubber is installed at Winyah in 2012.

$80 per Allowance

In this case and the subsequent cases, it is assumed that Santee Cooper will utilize the allowance market for the sale of excess allowances and purchase to cover shortfalls unless it is lower cost to install a scrubber to cover the shortfalls rather than purchase.

In the $80 case, a scrubber is not installed; the need for allowances is met each year through purchases. The 1994 PVRR is $5,976,851,000 over the period 1994 to 2015. This represents a decrease in overall costs of $6,481,000 compared to the no-purchase/no-buy base case. Exhibit VI-2 illustrates how savings can be achieved in the early years when utilizing this approach.

$200 per allowance

If the allowance values are $200, then allowances are sold in the early years when excesses are available. Since the excesses are sold, no bank of allowances is created; therefore, the need for the scrubber is accelerated from 2012 to 2006. After the scrubber is installed, the excess allowances continue to be sold on the open market.

The 1994 PVRR for this plan is $5,978,461,000 for the period 1994 to 2015, representing an increase in cost of $4,871,000. However, as Exhibit VI-2 illustrates, a savings exists for this plan until 2013.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ANNUAL REV. REQ. DIFFERENCES FOR CHANGES IN ALLOWANCE VALUES

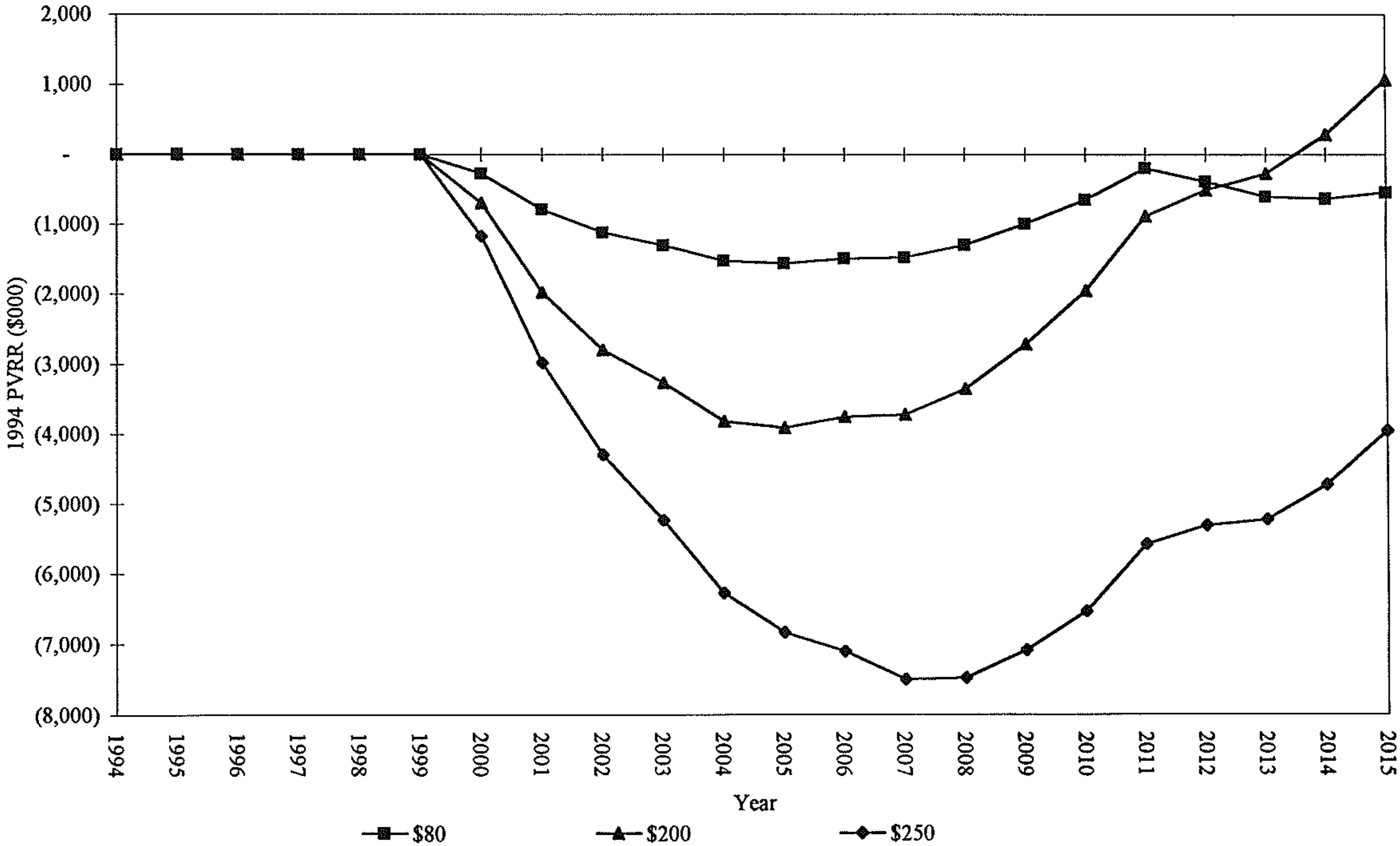


EXHIBIT VI-2

$250 per allowance

If the allowance values are $250, then a scrubber would be recommended at the start of Phase II in 2000 to be able to sell as many allowances as Santee Cooper does not need to meet its own requirements. The 1994 PVRR for this plan is $5,973,433,000 for the period 1994 to 2015, representing a savings of $9,889,000. As Exhibit VI-2 illustrates, this total savings over the planning period is not indicative of the potential savings accrued over the early years.

$800 per allowance

As in the $250 case, if the allowance values are increased to $800, then a scrubber would be recommended at the start of Phase II in 2000 to be able to sell as many allowances as Santee Cooper does not need to meet its own requirements. The 1994 PVRR for this plan is $5,907,806,500 for the period 1994 to 2015, representing a savings of $75,526,000.

Summary

As would be expected, as the value of the allowances increase, the decision to utilize the allowance market to minimize revenues becomes a critical question in compliance planning. In Santee Cooper's case, an allowance value of $200 to $250 should be considered a signal to consider the timing of a scrubber in light of a potential revenue source. Though modeling was not performed at allowance values between $200 and $250, an analysis of the results at these two levels indicates a potential value of $205 to $215 per allowance would be the point in which adding a scrubber in 2000 to sell excess allowances would provide an economic benefit to Santee Cooper.

D. NO_X EMISSIONS ESTIMATES FOR THE SUPPLY-SIDE PLANS

Section 407 of Title IV of the CAAA states that any generating unit classified as an affected unit for SO_2 emission limitations will also be considered an affected unit for NO_x emission limitation purposes. The Act directs the EPA to set emission limits on each individual affected unit based on its type of boiler. In addition, the language of the legislation states that standards of performance for emissions will be based on the best available control technology (BACT) to meet those limits. The technology expected to be utilized by utilities to meet these regulations is low NO_x burners.

On March 22, 1994, the EPA met a portion of its responsibility under CAAA by finalizing rules for NO_x emissions. However, on November 29, 1994, the U.S. Court of Appeals for the District of Columbia Circuit vacated the NO_x rule. According to the Court's decision, the EPA overextended its authority by including Overfire Air (OFA) in the definition of low NO_x technology. A new rule is not expected until late 1995. The issues indicated below are made based on the vacated rule.

The scope of this IRP was only to identify the NO_x emissions for Santee Cooper's units and not to determine if they are in compliance, or to identify a compliance plan if they are not. Exhibit VI-3 illustrates the projected annual NO_x for the base case load forecast without the ALUMAX load. Table VI-5 contains the annual year-by-year NO_x emissions by unit.

The following issues are noted here as affecting Santee Cooper in its NO_x compliance planning.

1) EPA has only established NO_x limits for Phase I units.
2) EPA has until 01/01/97 to establish Phase II limits.
3) The presumptive Phase II limits are 0.43 lb/MBtu for the Winyah, Jefferies, and Grainger units, and 0.38 lb/MBtu for the Cross units.
4) Any Santee Cooper units average to achieve NO_x compliance must be done so at the Phase II limits, and can not exceed the respective limits of the units averaged collectively.
5) NO_x emissions are averaged over the year.
6) Early election options may be taken on Winyah 1, Cross 2, and Cross 1 (meet Phase I limits from 01/01/97 through 01/01/08, then the lower Phase II limits apply).
7) Alternate Emission Limits may be requested for Winyah 2, Winyah 3, and Winyah 4 since LNB/OFA technology was installed on these units and optimized.
8) Jefferies and Grainer units will have LNB technology installed before 01/01/00 to comply with limits established by EPA for Phase II units.

Table VI-5

Summary of NOx Emissions by Unit

Year	Jefferies 3 (Lbs/MMBtu)	Jefferies 4 (Lbs/MMBtu)	Grainger 1 (Lbs/MMBtu)	Grainger 2 (Lbs/MMBtu)	Winyah 1 (Lbs/MMBtu)	Winyah 2 (Lbs/MMBtu)	Winyah 3 (Lbs/MMBtu)	Winyah 4 (Lbs/MMBtu)	Cross 2 (Lbs/MMBtu)	Average (Lbs/MMBtu)
1994	1.01	1.10	0.82	0.90	1.03	0.53	0.66	0.61	0.37	0.57
1995	1.03	1.10	0.82	0.90	1.03	0.49	0.56	0.49	0.37	0.38
1996	1.02	1.10	0.82	0.90	1.03	0.50	0.58	0.50	0.37	0.41
1997	1.02	1.10	0.82	0.90	1.03	0.50	0.57	0.50	0.37	0.39
1998	1.02	1.10	0.82	0.90	1.03	0.50	0.58	0.51	0.37	0.39
1999	1.02	1.10	0.82	0.90	1.03	0.51	0.62	0.54	0.37	0.42
2000	1.03	1.10	0.82	0.90	1.03	0.50	0.58	0.51	0.37	0.41
2001	1.03	1.10	0.82	0.90	1.03	0.50	0.56	0.50	0.37	0.38
2002	1.03	1.10	0.82	0.90	1.03	0.50	0.57	0.51	0.37	0.40
2003	1.02	1.10	0.82	0.90	1.03	0.50	0.59	0.52	0.37	0.42
2004	1.03	1.10	0.81	0.90	1.03	0.51	0.59	0.52	0.37	0.39
2005	1.02	1.10	0.81	0.90	1.03	0.51	0.60	0.53	0.37	0.42
2006	1.02	1.10	0.82	0.90	1.03	0.51	0.61	0.53	0.37	0.43
2007	1.02	1.10	0.81	0.90	1.03	0.52	0.61	0.54	0.37	0.41
2008	1.02	1.10	0.81	0.90	1.03	0.52	0.60	0.56	0.37	0.42
2009	1.02	1.10	0.81	0.90	1.03	0.53	0.61	0.57	0.37	0.44
2010	1.02	1.10	0.81	0.91	1.03	0.54	0.61	0.57	0.37	0.41
2011	1.02	1.10	0.81	0.91	1.03	0.54	0.62	0.58	0.37	0.43
2012	1.01	1.10	0.00	0.00	1.03	0.55	0.63	0.60	0.37	0.43
2013	1.02	1.10	0.00	0.00	1.03	0.55	0.62	0.59	0.37	0.41
2014	1.01	1.10	0.00	0.00	1.03	0.56	0.64	0.61	0.37	0.42
2015	1.01	1.10	0.00	0.00	1.03	0.56	0.64	0.62	0.37	0.43

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ANNUAL AVERAGE NO_x EMISSIONS

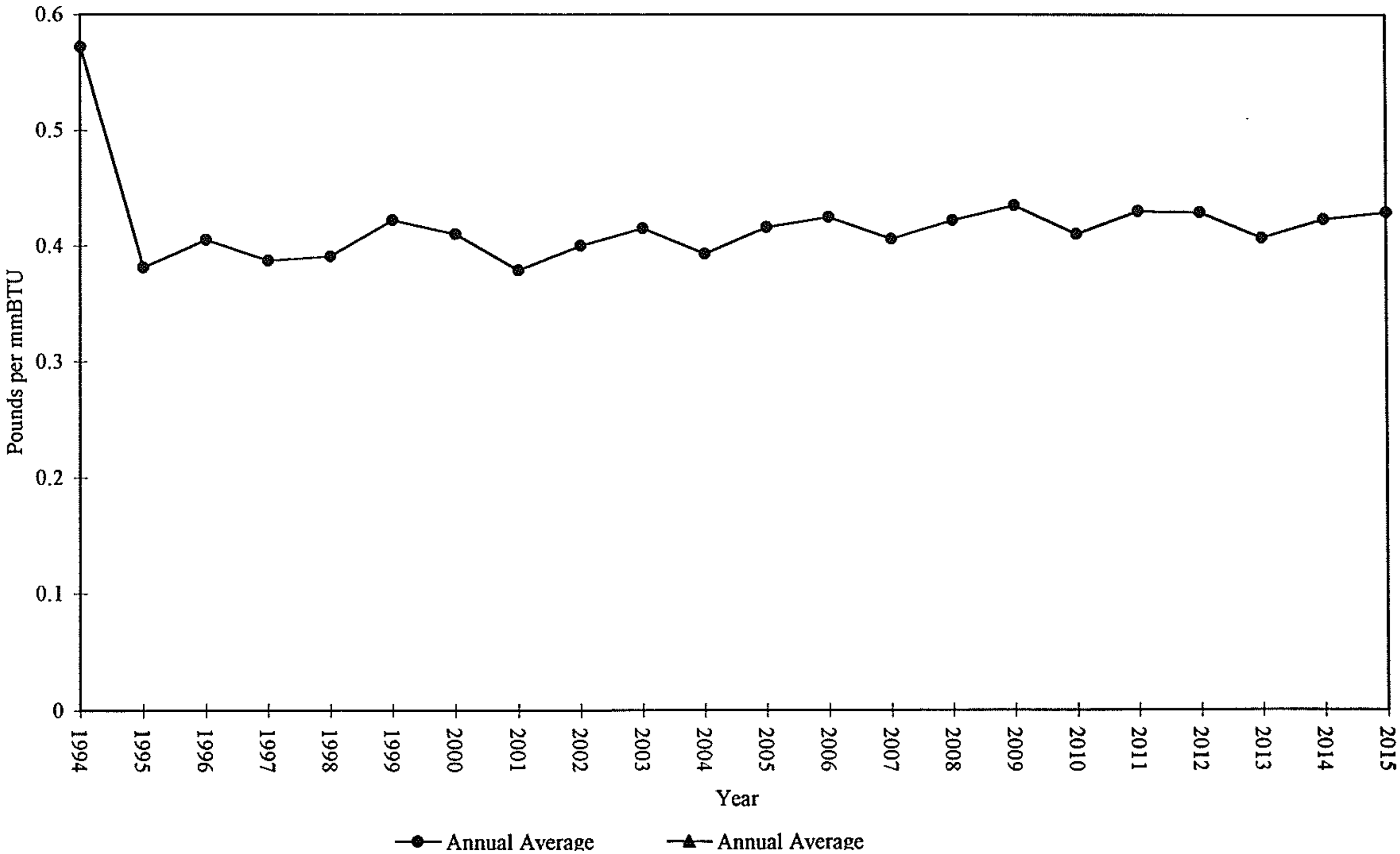


EXHIBIT VI-3

E. CARBON TAX IMPACTS

Another environmental issue of potential importance is the taxing of carbon emissions. A carbon tax bill was proposed in the United States House in early 1991, and while it did not become law, President Clinton in his 1992 presidential campaign discussed the need for such legislation. The examination of the carbon tax issue in the IRP used the carbon tax rates from the 1991 House bill.

The rates, which are presented below, reflect the fuel-specific tax that equates to the House bill's proposal of $30 per ton (in 1992 dollars) of carbon emissions:

- $18 per ton of coal
- $3.90 per barrel of oil
- $0.48 per thousand cubic feet of gas.

The carbon tax issue has been overshadowed by the more broad-based energy tax. On February 17, 1993, President Clinton presented his deficit reduction plan, which, among other things, called for certain sources of energy to be taxed according to their BTU content. The IRP examined the broad-based energy tax case using the following assumptions from the President's plan:

- $0.257 per million BTU from coal and natural gas
- $0.599 per million BTU from oil.

The results of this evaluation indicate an increase in revenue requirements over the 1994 to 2015 time period of $672,208,000 if such a tax were to become law.

F. CONSERVATION AND RENEWABLE ENERGY RESERVE

The Energy Conservation and Renewable Energy Reserve (CRER) program provides an opportunity for utilities to earn allowances for implementing efficiency measures and renewable energy generation. These allowances can make it easier for utilities to comply with the CAAA.

Santee Cooper can apply to the CRER for energy savings in effect since January 1, 1992 and until the beginning of Phase II. The allowances earned are equal to the energy saved time 0.004 and divided by 2,000. All of the programs proposed for Santee Cooper would qualify for the CRER if they result in energy savings and this savings can be verified, the only exception may be the Thermal Energy Storage program since it is designed as a peak shifting program and is not intended to reduce energy consumption.

VII. IRP OPTIMIZATION AND DEFINITION OF EXPANSION PLANS

VII. IRP OPTIMIZATION AND DEFINITION OF EXPANSION PLANS

This chapter of the IRP describes the existing Santee Cooper power generation system, the future need for additional resources and the results of the integration analysis that identify the expansion plans to best fulfill that need. The purpose of identifying a base case expansion plan is to provide a yardstick with which to measure all other expansion plans and identify near-term action items. The Base Case Plan selected represents the lowest cost expansion plan as derived from the optimization analysis before new DSM programs are considered. From the Base Case Plan, a Reference Plan is developed. In the latter, all DSM programs that have passed the Total Resource Cost test (both new and existing programs) are integrated with the possible supply-side options to determine an optimum mix of resources to meet the future resource requirements with minimum PVRR.

A. SANTEE COOPER'S POWER GENERATION SYSTEM AND NEED FOR ADDITIONAL RESOURCES

Santee Cooper generates nearly all of its power internally from the generating units listed in Table I-3. Santee Cooper's diversity of fuels is indicated in Table VII-1. Table VII-2 provides a summary of Santee Cooper's existing generating resources..

Table VII-1
Generating Capacity By Fuel Type

Fuel Type	Percentage of Total Capacity
Coal *	77
Nuclear	9
Oil (Steam & CTs)	8
Hydro (Non-SEPA)	6

*Assumes Cross 1 commercial in 1995

In addition to installed capacity, Santee Cooper has a purchased power contract with Virginia Power Company for 200 MW until the end of 1994 and an open-ended contract with the Southeastern Power Administration (SEPA) for 215 MW.

NEED FOR ADDITIONAL RESOURCES

Exhibits III-1 and III-2 illustrate the need for additional resources beginning in 2003 without ALUMAX and in 2000 with

ALUMAX. At these two points in time, Santee Cooper's forecasted requirements (including reserves less interruptible loads) will exceed existing resources.

Table VII-2

Summary of Existing Generating Resources

Unit Name	Type	Capacity (MW)	Retirement Date
Jefferies 1	Coal	46	2000
Jefferies 2	Coal	46	2000
Jefferies 3	Coal	153	2015
Jefferies 4	Coal	153	2015
Grainger 1	Coal	85	2011
Grainger 2	Coal	85	2011
Winyah 1	Coal	270	N/A
Winyah 2	Coal	270	N/A
Winyah 3	Coal	270	N/A
Winyah 4	Coal	270	N/A
Cross 1	Coal	540	N/A
Cross 2	Coal	520	N/A
Myrtle Beach 1-5	Oil	90	N/A
Hilton Head 1-3	Oil	97	N/A
Sumner Nuclear	Nuclear	295	N/A
Spillway Hydro	Hydro	2	N/A
Jefferies Hydro	Hydro	128	N/A
St. Stephen Hydro	Hydro	64	N/A

B. RESOURCE INTEGRATION

Chapters IV and V of this report discussed the method and results of the demand and supply-side resource screening process. With these steps completed, the task of resource integration was begun.

The integration process, as conceptually depicted in Exhibit II-1, focused on combining the recommended demand-side and supply-side resource candidates to determine the optimal base case expansion plan with regard to lowest PVRR.

During development of the Base Plan and Reference Plan, numerous combinations of resource scenarios were analyzed in the PROVIEW model to determine the mix of options to best fulfill the future capacity and energy needs of Santee Cooper's customers. The development of the Reference Plan was run with the package of DSM programs that was selected in the analysis of DSM options. The results provided Santee Cooper with a series of theoretical expansion plans for various supply-side and demand-side combinations.

When the PROVIEW runs were completed, the theoretical expansion plans were then input to the PROSCREEN II model, which generated a greater amount of evaluative data, including annual revenue requirements, projected reserve margins, and plant capacity factors. With this information, practical judgment was added to the analysis of the theoretical plans to select a Base Plan without new DSM programs and a Reference Plan with an optimum mix of new DSM programs, existing DSM programs, and supply-side alternatives.

The integration process was run initially for the base load forecast without ALUMAX after March 31, 2000. However, realizing the significance of this particular load to Santee Cooper's future, the final results will reflect resource plans based on the base load forecast plus ALUMAX both continuing to be served and assuming its termination.

SUPPLY RESOURCE OPTIONS ANALYZED

Options that survived the supply-side evaluation process were included in the integration process. The options analyzed are presented in Table VII-3.

Table VII-3

Supply-side Options Analyzed

Resource Option	Fuel Source
400-MW Pulverized Coal	Coal
560-MW Pulverized Coal	Coal
80 -MW Combustion Turbine	#6 Oil
240-MW Combined Cycle (Phased Unit)	#6 Oil
300-MW Advanced Cycle Pulverized Coal	Coal
200-MW Atmospheric Fluidized Bed - Circulating	Coal
320-MW Pressurized Fluidized Bed - Bubbling	Coal
500-MW Integrated Coal Gasification Combined Cycle	Coal

Each of these technologies was evaluated in the integration step and given a rank based on a minimum PVRR criterion.

DEMAND-SIDE RESOURCE ADDITIONS

As discussed in Chapter IV, seven of the proposed and two of the existing DSM programs scored 1.0 or greater on the TRC test. Six of the new and none of existing programs scored greater than 1.0 on the Utility test, and three of the new programs scored greater than 1.0 on the RIM test. The programs passing each of these tests are listed in Table VII-4.

Table VII-4

Summary of DSM Program Alternatives

Base Plan	Ref. Plan	UTIL Plan	RIM Plan	TRC/UTIL Plan
Res. Good Cents	High Eff. Lighting	High Eff. Lighting	High Eff. Lighting	High Eff. Lighting
Comm. Good Cents	Stand-By Generators	Prem. Eff. Motors	Prem. Eff. Motors	Prem. Eff. Motors
H_2O Advantage	Prem. Eff. Motors	Comm. Air Conditioning	Comm. Air Conditioning	Comm. Air Conditioning
	Good Cents Man. Housing Heat Pumps	Duct Test. & Repair		Duct Test. & Repair
	Commercial Air Conditioning	Ground Source Heat Pump		Res. Good Cents
	Direct Load Control of Air Conditioners	Thermal Energy Storage		Comm. Good Cents
	Duct Test. & Repairs			
	Res. Good Cents			
	Comm. Good Cents			

INTEGRATION RESULTS

The integration was run up to five different ways to develop the plan that would best meet Santee Cooper's future resource requirements. The basis for each integration effort was the possible approaches Santee Cooper could take in moving forward with a DSM program. The five integration efforts can be described as follows:

- *Base Expansion Plan* - This plan resulted in the optimum mix of supply-side only options and assumed the continuation of only existing DSM programs.
- *Reference Expansion Plan* - This plan resulted in a mix of new and existing DSM programs that passed the Total Resource Cost and Participant tests, and supply-side options that passed the economic screening effort.

- *Minimum Utility Cost Expansion Plan* - This plan resulted in the mix of new and existing DSM programs that passed the Utility and Participant tests, and supply-side options that passed the economic screening effort.

- *Minimum Rate Impact Expansion Plan* - This plan resulted in the mix of new and existing DSM programs that passed only the Rate Impact and Participant tests, and supply-side options that passed the economic screening effort.

- *TRC/UTILITY Expansion Plan* - This plan resulted in the mix of new and existing DSM programs that passed the TRC, the Utility, and the Participant tests with a score of 1.0 or better, plus the supply-side options that passed the economic screening effort. The two existing programs were the only exceptions, and these were passed for optimization even though they did not pass both the TRC and Utility tests. However, they were marginally close to passing, and they showed possibility in the breakdown between retail and wholesale programs.

These integration efforts allowed a variety of DSM programs and supply-side alternatives to compete to determine which combination would produce the lowest PVRR given alternative DSM policies available to Santee Cooper. The efforts produced five different plans that included a number of different DSM programs. The five integrations contained the following DSM program alternatives:

The results of these integration efforts are included in Table VII-5.

Table VII-5

Integration Results ($000)

Plan Description	1994 to 2015 PVRR	Study Period PVRR
Base Plan w/o ALUMAX	5,974,907	14,281,761
Base Plan w/ALUMAX	6,654,110	16,090,209
Reference Expansion Plan w/o ALUMAX	5,916,238	13,967,228
Reference Expansion Plan w/ALUMAX	6,576,565	15,735,020
UTIL Plan	5,971,324	14,245,541
RIM Plan	5,967,681	14,252,763
TRC/Utility Plan w/o ALUMAX	5,922,727	14,038,649
TRC/Utility Plan w/ALUMAX	6,596,640	15,818,343

The results of these integration efforts indicate that over the study period the DSM programs result in lower PVRR for Santee Cooper when compared to the supply-side only plan. The integrated plans did result in a deferral of combustion turbines, as shown in Tables VII-6a and VII-6b. Tables VII-7a and VII-7b provide the annual incremental revenue requirements associated with each of these plans.

Table VII-6a

Comparison of Integrated Plans (w/o ALUMAX)

Year	Base Plan	Reference Plan	Utility Plan	RIM Plan	TRC/Utility Plan
1994					
1995					
1996		HP, LIT, MOT, AC, DLCA, STBY, DUC, RESG, COMG	TES, DUC, LIT, MOT, AC, GSHP	LIT, MOT, AC	DUC, LIT, MOT, AC, RESG, COMG
1997					
1998					
1999					
2000					
2001					
2002					
2003	One 80-MW CT		One 80-MW CT	One 80-MW CT	
2004	One 80-MW CT		One 80-MW CT	One 80-MW CT	One 80-MW CT
2005	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2007	Two 80-MW CTs	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT	Two 80-MW CTs	Two 80-MW CTs	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2012	One 80-MW CT & One 80-MW Phased CC	Three 80-MW CT	Two 80-MW CT & One 80-MW Phased CC	Two 80-MW CTs & One 80-MW Phased CC	Three 80-MW CTs
2013	Two 80-MW CTs	One 80-MW CT	One 80-MW CT	Two 80-MW CTs	Two 80-MW CT
2014	One 80-MW CTs	One 80-MW Phased CC	Two 80-MW CTs	One 80-MW CT	One 80-MW Phased CC
2015	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
20-Year PVRR ($000)	$5,974,907	$5,916,238	$5,971,324	$5,967,681	$5,922,727
Total New Capacity	1,360 MW	1,040 MW	1,360 MW	1,360 MW	1,200 MW

Table VII-6b

Comparison of Integrated Plans (with ALUMAX)

Year	Base Plan	Reference Plan	TRC/Utility Plan
1994			
1995			
1996		HP, LIT, MOT, AC, DLCA, STBY, DUC, RESG, COMG	DUC, LIT, MOT, AC, RESG, COMG
1997			
1998			
1999			
2000	One 80-MW CT		
2001	Two 80-MW CTs	Two 80-MW CTs	Two 80-MW CTs
2002	One 80-MW CT		One 80-MW CT
2003	One 80-MW CT	One 80-MW CT	One 80-MW CT
2004	Two 80-MW CTs	One 80-MW CT	Two 80-MW CTs
2005	One 80-MW CT	One 80-MW CT	
2006	One 80-MW CT	One 80-MW CT	Two 80-MW CTs
2007	One 80-MW CT	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW Phased CC	One 80-MW CT	One 80-MW CT
2012	One 400-MW PC	One 400-MW PC	One 400-MW PC
2013			
2014	One 80-MW CT		
2015	Two 80-MW CTs	One 80-MW Phased CC	One 80-MW Phased CC
20-Year PVRR ($000)	$6,654,110	$6,576,565	$6,596,640
Total New Capacity	1,760 MW	1,360 MW	1,520 MW

CORRECTED COPY

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

COMBINED CYCLE UNITS

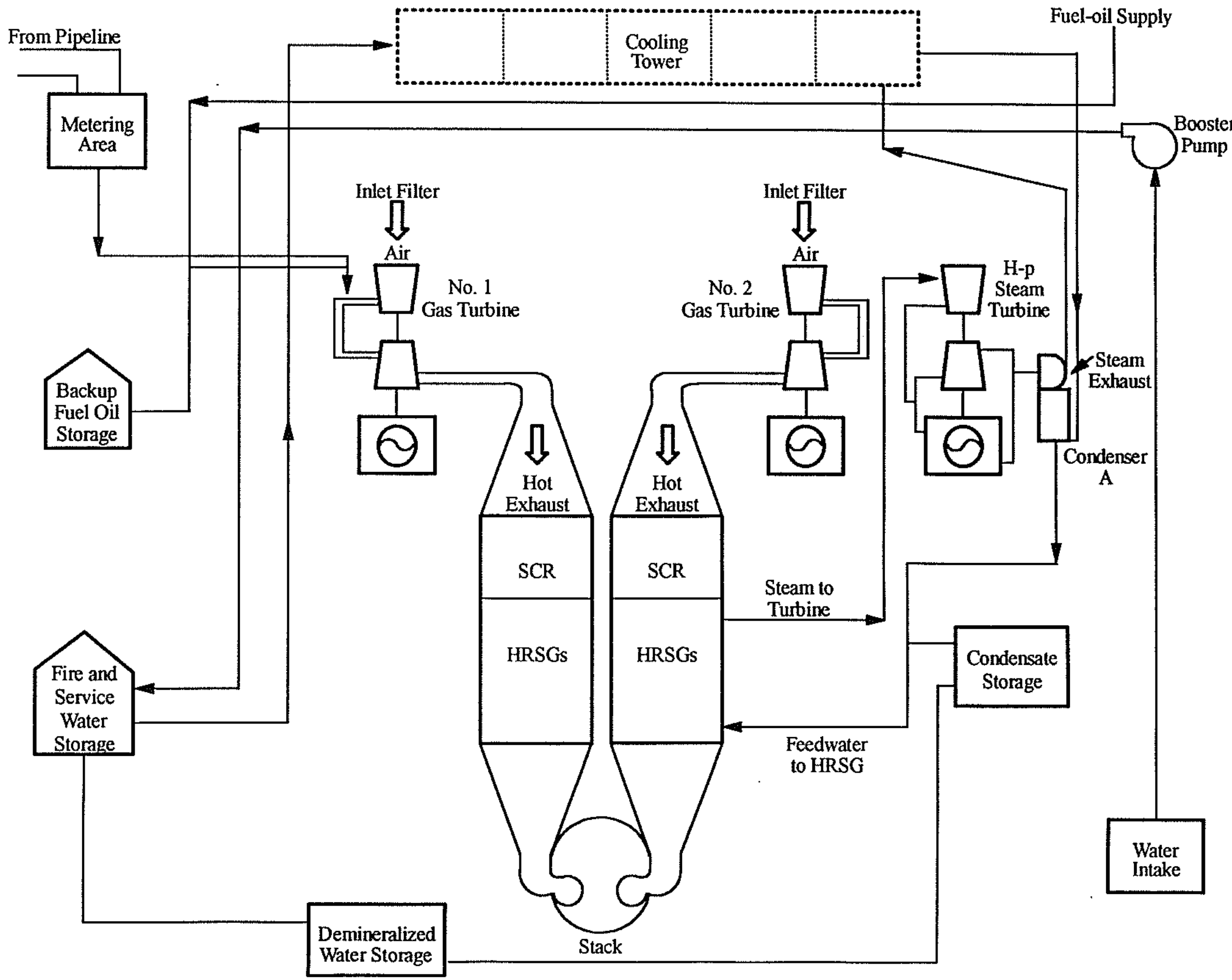


EXHIBIT A-2

Annual Fixed O&M: (1994$) $15.63/kW-yr

Annual Variable O&M: (1994$) $1.77/MWh

Equivalent Availability: 90.5%

50-MW Combustion Turbine - Steam Injected (appropriate for industrial use)

A steam-injected gas turbine (STIG) is a simple cycle combustion turbine in which combustion gases are passed through a heat recovery steam generator (HRSG), which heats pressurized water to generate superheated steam. This process provides greater overall operating efficiency when compared to a stand-alone simple cycle combustion turbine. Historically, this technology has been used in cogeneration applications in which steam is produced and used in a manufacturing process. At the times when the steam is not required by the steam host, it is re-routed back to the generator.

Units of this technology have been widely used in industrial settings and range in capacity from 1 to 50 MW. The larger units are closer to the utility-desired applications. Most STIG units are aeroderivatives. The General Electric units LM 5000-120 STIG have the best overall heat rate of the STIGs.

Because of the units' efficiency, they have been used in some applications as intermediate load units. However, when the economics of a STIG are compared to those of a combined cycle unit, the STIG falls short for a conventional utility operation such as Santee Cooper.

Unit Statistics

Capacity: 50 MW

Fuel Type: Natural Gas (Primary), #6 Oil (Secondary)

Technology Status: Mature

Duty Cycle: Intermediate

Total Plant Cost: (1994$) $950/kW (w/o IDC)

Full Load Heat Rate: 9,133 Btu/kWh

Annual Fixed O&M: (1994$) $16.24/kW-yr

Annual Variable O&M: (1994$) $6.28/MWh

Equivalent Availability: 90.6%

Table VII-7a

Summary of Revenue Requirements for Integrated Resource Plans ($000) Without ALUMAX

Year	Base Case Without ALUMAX	Reference Plan Without ALUMAX	Utility Plan Without ALUMAX	RIM Plan Without ALUMAX	TRC/Utility Plan Without ALUMAX
1994	306,964	306,964	306,964	306,964	306,964
1995	318,284	318,284	318,284	318,284	318,284
1996	328,186	331,432	330,202	328,933	329,193
1997	346,790	349,271	348,799	347,450	347,535
1998	368,739	371,611	370,615	369,307	369,932
1999	399,545	401,956	401,229	399,982	400,364
2000	378,758	380,951	380,328	379,117	379,400
2001	382,957	384,736	384,342	383,187	383,269
2002	412,244	413,584	413,447	412,348	412,198
2003	443,964	442,233	444,928	443,903	440,950
2004	476,394	471,347	477,098	476,153	472,756
2005	514,048	508,098	514,466	513,613	509,689
2006	551,979	543,592	550,162	550,714	546,024
2007	590,519	578,072	585,556	586,213	580,674
2008	636,188	622,528	630,964	631,681	625,260
2009	684,946	669,570	682,351	683,176	672,531
2010	727,532	711,168	724,833	725,711	714,307
2011	783,775	765,416	780,784	781,802	768,750
2012	856,992	835,607	853,658	854,740	839,301
2013	913,054	886,895	906,246	910,746	894,113
2014	981,811	953,698	978,026	979,277	961,094
2015	1,059,282	1,028,174	1,055,128	1,056,505	1,035,917

Table VII-7b
Summary of Revenue Requirements for Integrated Resource Plans ($000)
With ALUMAX

Year	Base Case With ALUMAX	Reference Plan With ALUMAX	TRC/Utility Plan With ALUMAX
1994	306,964	306,964	306,964
1995	318,284	318,284	318,284
1996	328,186	331,430	329,193
1997	346,790	349,268	347,535
1998	368,739	371,607	369,932
1999	399,545	401,948	400,364
2000	425,188	424,851	423,356
2001	451,541	450,657	449,249
2002	485,872	481,794	482,915
2003	522,242	517,126	518,460
2004	561,610	552,974	557,143
2005	604,027	593,760	595,621
2006	643,375	630,512	635,960
2007	688,516	674,082	679,806
2008	741,362	725,067	731.014
2009	799,662	781,181	787.516
2010	845,686	826,288	832,877
2011	910,049	890,290	897,224
2012	994,878	973,478	980,423
2013	1,049,432	1,026,789	1,033,926
2014	1,120,072	1,093,370	1,100,744
2015	1,203,282	1,169,397	1,176,925

Exhibit VII-1a illustrates the cumulative revenue requirement differences between the Base Plan and the four expansion plans without ALUMAX. Exhibit VII-1b illustrates the cumulative revenue requirement differences between the Base Plan, Reference Plan and Combined Plan with ALUMAX.

The exhibit illustrates that even though the DSM programs give Santee Cooper lower overall revenue requirements over the period 1994 to 2015, this improved economic picture does not occur until 2002 to 2011 depending on the plan. This means the higher up-front costs of the programs do not result in lower revenue requirements for at least the first eight to ten years.

A further look at the economics associated with the programs can be seen in Exhibits VII-2a and VII-2b, in which the annual production cost impact among the three plans are illustrated.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

CUMULATIVE PVRR DIFFERENCE DUE TO DSM PROGRAMS
(without ALUMAX)

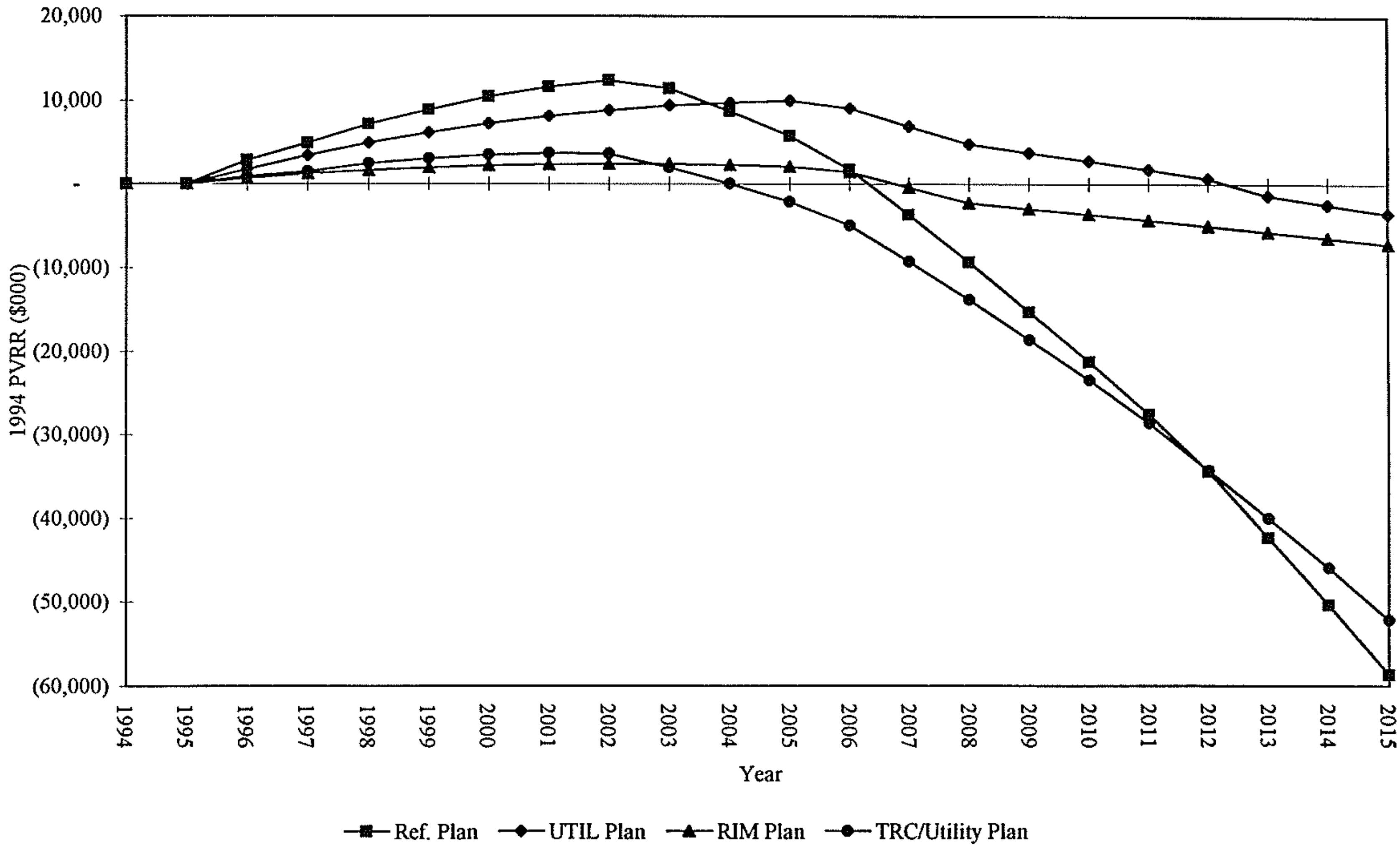


EXHIBIT VII-1a

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

CUMULATIVE PVRR DIFFERENCE DUE TO DSM PROGRAMS
(with ALUMAX)

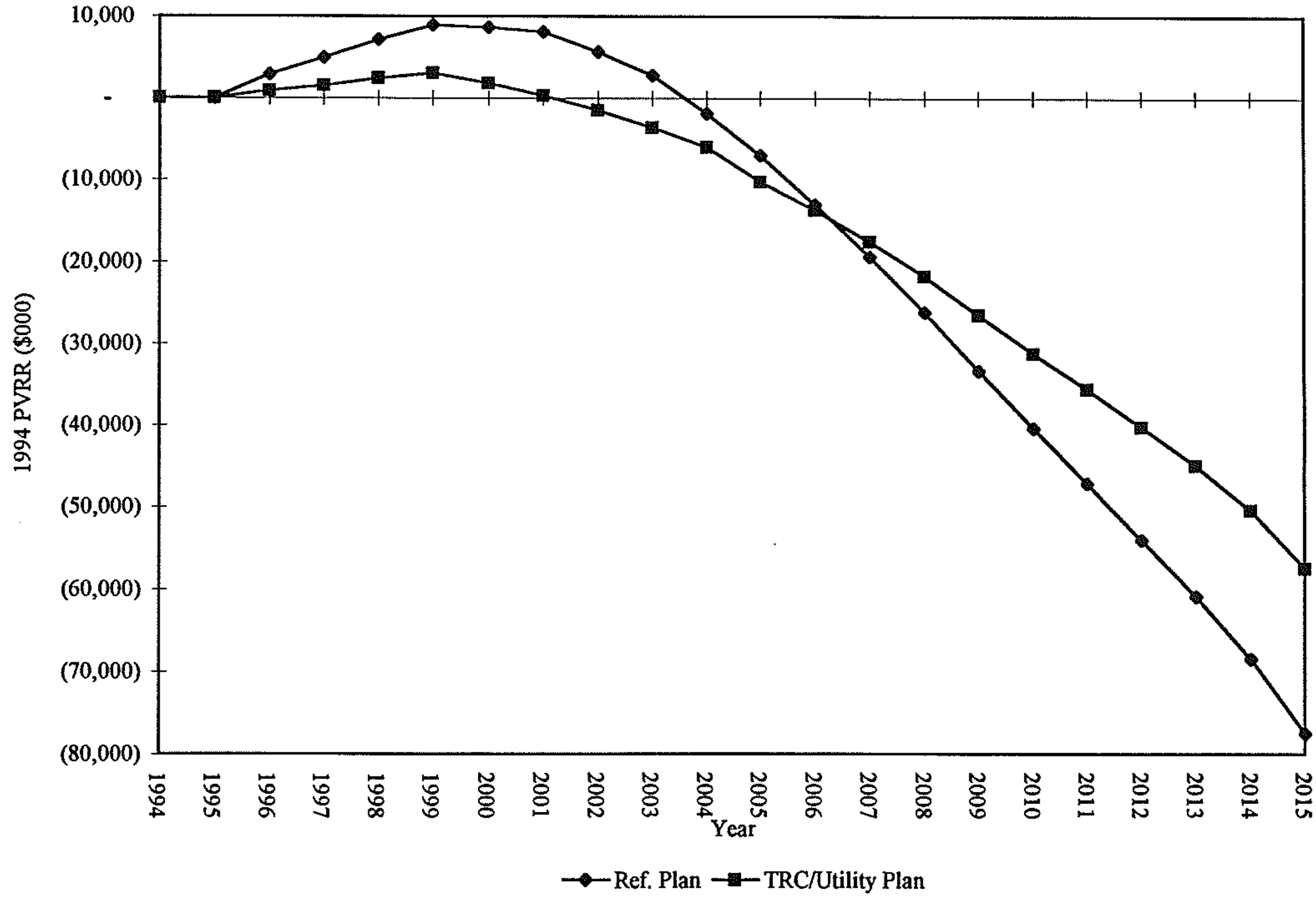


EXHIBIT VII-1b

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

PRODUCTION COST IMPACTS FROM DSM PROGRAMS
(without ALUMAX)

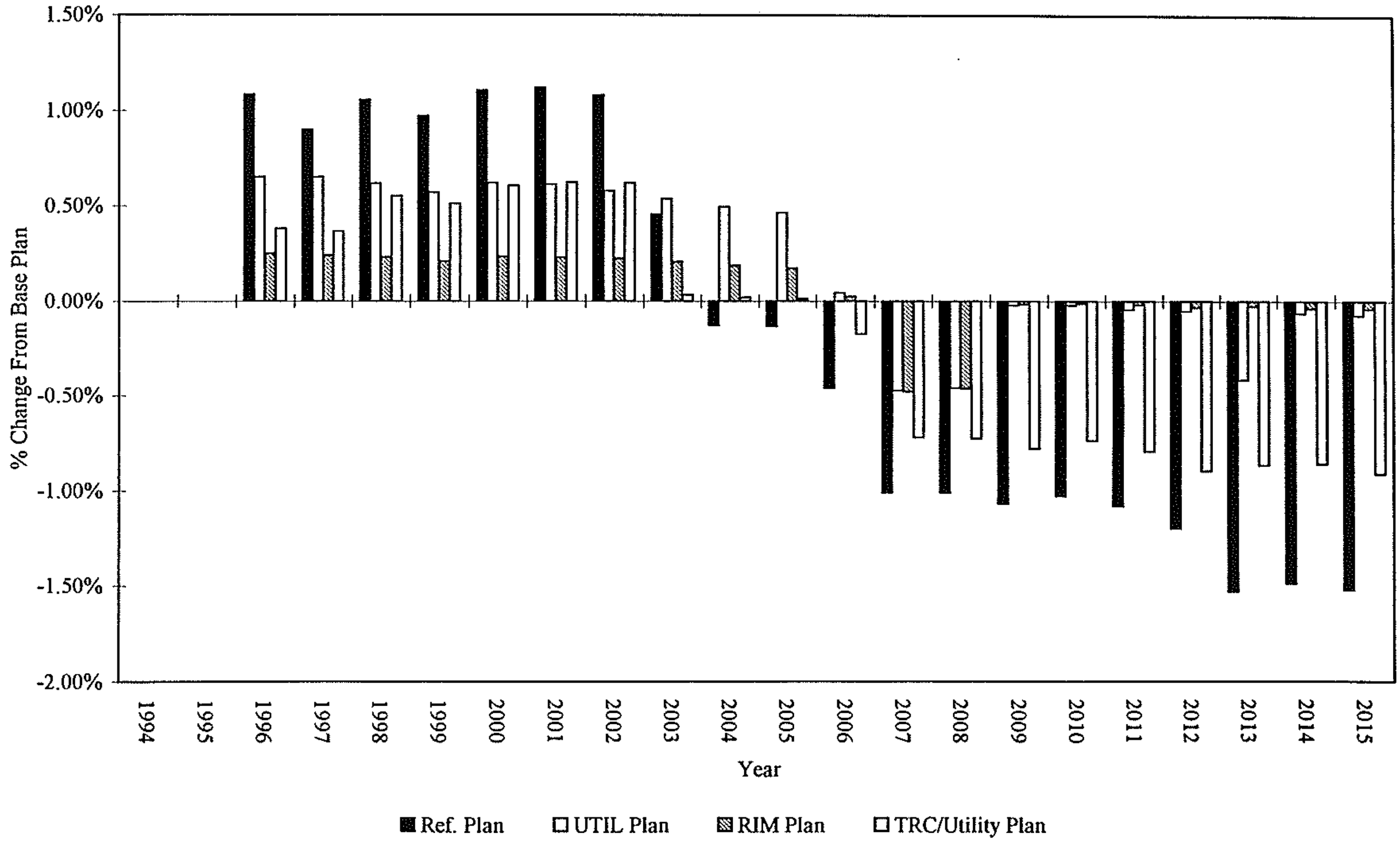


EXHIBIT VII-2a

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

PRODUCTION COST IMPACTS FROM DSM PROGRAMS
(with ALUMAX)

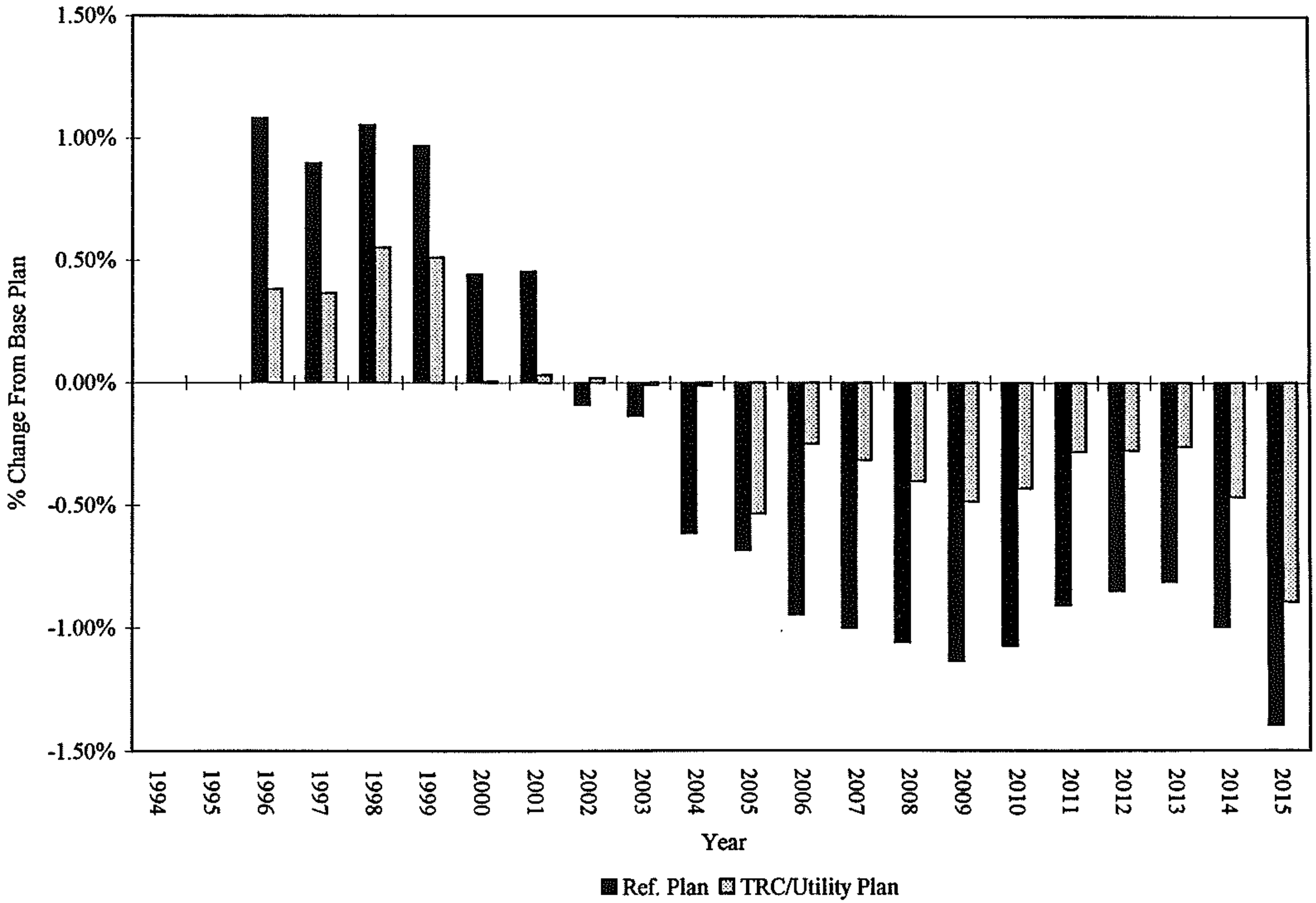


EXHIBIT VII-2b

As the exhibits indicate, the integrated plans that include the DSM programs result in production cost increases for Santee Cooper beginning in 1996 and continuing through 2002 to 2006, again depending on the plan and the disposition of ALUMAX. Cost decreases then occur each year thereafter.

DSM PROGRAM INTEGRATION SUMMARY

The analysis of the four DSM strategies, and their economic impacts compared to the Base Plan indicate that over the period 1994 to 2015, Santee Cooper's revenue requirements will be reduced by a continued implementation of DSM programs. The results of these analyses indicate that the two strategies providing the largest economic benefit would be either the:

- Implementation of the seven new and two existing DSM programs that passed the TRC test (Reference Plan); or the

- Implementation of the four new and two existing DSM programs in the TRC/Utility Plan.

Both of these plans result in significant savings from the Base Plan through deferral of new generation and SO_2 compliance efforts. The greatest difference between these two strategies is the cost of the DSM programs. Table VII-8 summarizes this difference in annual expenditures for the two strategies. These annual expenditures are expected to be the same regardless of the status of ALUMAX.

Table VII-8

Annual DSM Expenditures for the Two Lowest PVRR DSM Expansion Plans

Year	Reference Plan ($000)	TRC/Utility Plan ($000)	Difference ($000)
1996	4,311	1,913	2,398
1997	5,159	2,707	2,452
1998	6,334	3,313	3,021
1999	7,707	4,079	3,628
2000	9,116	4,843	4,273
2001	13,779	8,820	4,959
2002	15,326	9,638	5,688
2003	16,902	10,440	6,642
2004	18,579	11,295	7,284
2005	20,350	12,195	8,155
2006	20,437	12,058	8,379
2007	21,935	12,947	8,988
2008	23,527	13,899	9,628
2009	25,137	14,836	10,301
2010	26,841	15,831	11,010
2011	28,561	16,805	11,756
2012	30,211	17,670	12,541
2013	31,985	18,619	13,366
2014	33,895	19,661	14,234
2015	35,943	20,797	15,146
PVRR	$5,916,238	$5,922,727	$6,489

As indicated on the above table, the expenditures for the two strategies are significantly different, with a small incremental economic benefit between the two as indicated in Table VII-5.

C. ENVIRONMENTAL IMPACT OF EXPANSION PLANS

Each of the five integrated resource plans identified above will affect the sulfur dioxide emission identified in Chapter VI. Table VII-9 contains the annual emissions bank before compliance as a result of the five expansion plans.

Table VII-9

Allowance Bank Before Compliance (without ALUMAX)

Years	Base Plan	Ref. Plan	UTIL Plan	RIM Plan	TRC/Utility Plan
2000	4,050	4,379	4,177	4,136	4,325
2001	11,621	12,312	11,887	11,802	12,201
2002	16,571	17,714	17,008	16,868	17,530
2003	19,457	21,116	20,095	19,890	20,848
2004	22,964	25,193	23,822	23,547	24,846
2005	23,570	26,466	24,682	24,324	26,025
2006	22,477	26,120	23,850	23,410	25,575
2007	22,194	26,561	23,804	23,284	25,923
2008	19,051	24,252	20,900	20,300	23,465
2009	13,650	19,631	15,742	15,063	18,767
2010	7,317	14,155	9,653	8,927	13,193
2011	-2,377	5,316	193	-596	4,260
2012	-12,037	-3,826	-9,314	-10,147	-4,941
2013	-20,189	-11,413	-17,321	-18,189	-12,577
2014	-31,155	-21,890	-28,156	-29,059	-23,094
2015	-43,880	-34,195	-40,768	-41,700	-35,429

As shown above, the four alternative DSM plans sufficiently reduce SO_2 emissions to allow for a delay of a scrubber installation by one year. In Chapter VI, the plan was to utilize environmentally affected dispatching of Santee Cooper's units in 2011 and install a new scrubber at the Winyah Unit 1 by 2012. The Reference Plan would allow this scrubber to be delayed by one year to 2013. This delay results in a PVRR savings of $2,164,000 to Santee Cooper. A similar delay in the need for the scrubber would not occur in the case with ALUMAX. In that case, the scrubber would still be required in 2000, though the energy savings from the DSM programs prior to 2000 would provide Santee Cooper with additional SO_2 allowances equal to 0.004 times the amount of energy saved.

D. ALTERNATIVE SUPPLY-SIDE PLANS

As the resource options were analyzed, a number of different expansion plans were created and evaluated around alternative supply-side options. Each of the plans represented different combinations of resource options, some having a PVRR close to that of the Base and Reference Plans, others that were much higher. A total of three Alternative Resource Plans were created: 1) the addition of a 400-MW pulverized coal plant in 2012 instead of the Base Case of a phased combined cycle unit (PC Plan); 2) an all combustion turbine plan (CT Plan); and 3) a combined cycle unit in 2003 operating on gas and at a minimum capacity factor of 60 percent (CC-2003). In each of these three Alternative Plans, the balance of the resource requirements were met through combustion turbines. The three plans were selected because they represent fundamentally different resource strategies and provided valuable insight into the effect on PVRR under varying assumptions. A comparison of the theoretical resource expansion plans for the Base Plan, the Reference Plan, the PC Plan, the CT Plan, and the CC-2003 Plan is shown in Table VII-10.

Table VII-10

Comparison of Alternative Plans

Year	Base Plan	Ref. Plan	PC Plan	CT Plan	CC-2003 Plan
1994	0		0	0	0
1995	0		0	0	0
1996	0	DSM Prog.	0	0	0
1997	0		0	0	0
1998	0		0	0	0
1999	0		0	0	0
2000	0		0	0	0
2001	0		0	0	0
2002	0		0	0	0
2003	1CT		1CT	1CT	1CC
2004	1CT		1CT	1CT	0
2005	1CT	1CT	1CT	1CT	0
2006	1CT	1CT	1CT	1CT	1CT
2007	2CT	1CT	2CT	2CT	2CT
2008	1CT	1CT	1CT	1CT	1CT
2009	1CT	1CT	1CT	1CT	1CT
2010	1CT	1CT	1CT	1CT	1CT
2011	1CT	1CT	1CT	1CT	1CT
2012	2CT, 1CC	3CT	1PC	3CTs	3CTs
2013	2CT	1CT	0	2CT	2CT
2014	1CT	1CC	1CT	1CT	1CT
2015	1CT	1CT	1CT	1CT	1CT
PVRR ($000)	$5,974,907	$5,916,238	$5,986,543	$5,977,671	$6,231,940
Total New Capacity	1,360 MW	1,040 MW	1,360 MW	1,360 MW	1,360 MW

A comparison of the plans provided information on the expected cumulative present value of revenue requirements over near-term and long-term periods. Table VII-11 shows the PVRR differences for 10-year, 20-year, and the entire study periods.

Table VII-11

Cumulative Present value of Revenue Requirements
(millions of 1994 dollars)

Scenario	1994-2003	1994-2015	Study Period
Base Plan	$2,767	$5,975	$14,282
Ref. Plan	$2,779	$5,916	$13,967
PC Plan	$2,767	$5,987	$14,299
CT Plan.	$2,767	$5,978	$14,332
CC-2003	$2,788	$6,232	$15,167

The Base Plan, PC Plan, and CT Plan are very similar plans until 2012, as shown in Table VII-10, when the key to the evaluation is the technology chosen. These three plans result in PVRRs over the 1994 to 2015 time period that have less than one percent difference among them. The CC-2003 plan is a look at the same technology as the Base Case Plan, however, it evaluates a change in the timing, operation, and fuel type. The results of this evaluation indicated a significant cost increase with this plan over the Base Case Plan.

The following chapter investigates the key assumption variables that might indicate a preference for one of the plans over another. The effort is to determine the robustness of the plans under changes in conditions that are very possible given the amount of time between now and the decision period.

VIII. SENSITIVITY ANALYSIS

VIII. SENSITIVITY ANALYSIS

In order to test the flexibility and robustness of the all Supply-side/Base Plan and the Reference Plan, a series of sensitivity analyses was conducted. Cases were run by changing key assumptions and evaluating the resulting impact on the Base, Reference, and Alternative Plans.

Sensitivity testing of plans indicates how they can be expected to perform under varying conditions. A resource plan that is extremely robust under sensitivity analysis may in fact be the most desirable plan even if the economics are not least cost under the base set of assumptions. To test their robustness, each of the three plans was examined against changes in a number of assumptions which could potentially impact their economics. The assumptions were:

- High and low load growth - Without ALUMAX
- Price changes of fuel
  - Assumed increases in oil prices
  - Assumed decreases in coal prices
- Capital cost of future units
  - General increase in construction costs
  - General decrease in construction costs
  - Increases in combined cycle construction costs
  - Decreases in pulverized coal construction prices.

In addition to these sensitivity cases, Santee Cooper requested specific special studies to address key issues it faces in the near future. These special studies include:

- The economics associated with a potential 35 MW cogenerator.
- The savings due to extending the operating lives of certain Santee Cooper generating units.
- The development of projected marginal costs associated with the interruptible loads of certain industrial customers on Santee Cooper's system.

These sensitivity cases were performed using the base load forecast without ALUMAX after March 31, 2000 since the purpose of performing these studies is to test the difference between the combined cycle, pulverized coal, and on each combined cycle given changes in base assumptions. The results of these sensitivities would not change if ALUMAX was assumed in service.

The following sections describe each of the sensitivity analyses performed and the results on each of the selected resource plans. The PROSCREEN results are expressed in PVRR differences from the Base and Reference Plan values in 1994 dollars.

A. HIGH AND LOW LOAD GROWTH SENSITIVITY

This analysis considers the risks associated with the Base, Reference, and Alternative Supply Plans in the event Santee Cooper were to pursue one of the plans and the loads that actually materialize were significantly above or below the forecasted loads. This analysis used the high and low load forecasts without the ALUMAX load past 2000. Table VIII-1 illustrates the results of this analysis.

Table VIII-1

Cumulative Present Value of Revenue Requirements
Differences From Base Case Forecast
Without ALUMAX
(millions of 1994 dollars)

Scenario	Base Load	High Load	Low Load
Base Plan	$5,975	$6,469	$5,620
Reference Plan	$5,916	--	$5,495
PC Plan	$5,987	$6,464	$5,562
CT Plan	$5,978	$6,481	$5,612
CC-2003 Plan	$6,232	--	--

The results of this sensitivity to load analysis indicates that the difference between the 1994 PVRR of the Base, Reference, PC, and CT Plans is minimal. The fourth plan, considering accelerating the in-service date of the combined cycle unit to 2003, resulted in a significant increase in PVRR when compared to the Base and Reference Plans.

B. FUEL PRICE SENSITIVITIES

The issue in an IRP study is to determine the risk to the utility in the event a specific plan is implemented and the future conditions vary significantly from the study projections. Therefore, this sensitivity analysis considered the risk potential for one of the most critical assumptions–fuel. The two predominant fuels used by Santee Cooper are oil and coal. Therefore, each of the plans under consideration will be very dependent on the future prices of these fuels.

HIGH/LOW OIL PRICES

The Base, Reference, and all of the Alternative Plans include numerous additions of combustion turbines throughout the study period. In addition, the Base, Reference, and CT Plans are heavily dependent on the price of oil. Therefore, a sensitivity analysis was performed on the impact to the plans when the oil prices increase or decrease. For this analysis, we considered both an increase and a decrease in oil prices of 10 and 30 percent. Table VIII-2 contains the results of this sensitivity analysis.

Table VIII-2

Cumulative Present Value of Revenue Requirements
Changes in Oil Price Forecast
(millions of 1994 dollars)

Plan	+30 %	+10 %	No Change	-10 %	-30 %
Base Plan	$6,010	$5,987	$5,975	$5,963	$5,940
Reference Plan	$5,951	$5,926	$5,916	--	--
PC Plan	$6,009	$5,994	$5,987	$5,979	$5,964
CC-2003	$6,252	$6,239	$6,232	$6,225	$6,208

The analysis did not evaluate the sensitivity of oil prices on the CT-Plan, since it was very similar in performance to the Base and Reference Plans. This analysis indicates that even though the results are very close, they still illustrate that the Base and Reference Plans result in lower overall PVRR over the 1994 to 2015 planning period. It is only under the condition of an increase of close to 30 percent in oil prices before the PC - Plan begins to show better results.

HIGH/LOW COAL PRICES

The PC Plan includes the construction of a 400 MW pulverized coal unit instead of a combined cycle unit in 2012. Therefore, the risk of changes in coal prices to which Santee Cooper is exposed depends on which of the plans it pursues. A sensitivity analysis was performed on the coal price forecast to determine how sensitive the economics of the coal plan is relative to the other plans. Table VIII-3 contains the results of this analysis.

Table VIII-3

Cumulative Present Value of Revenue Requirements
Changes in Coal Price Forecast
(millions of 1994 dollars)

Plan	+30 %	+10 %	No Change	-10 %	-30 %
Base Case	$6,625	$6,192	$5,975	$5,755	$5,314
PC Plan	$6,641	$6,205	$5,987	$5,765	$5,322

This analysis indicates that if oil prices are near the forecast in this study and coal prices change by up to 30 percent more or less than the forecast prices, the Base Plan will continue to show better overall economic results.

SUMMARY OF FUEL PRICE SENSITIVITY

The results of these two sensitivity analyses indicate that the Base Reference Plans are economically preferred given the base study assumptions, and expose Santee Cooper to relatively minor risks for coal or oil price fluctuations of up to 30 percent either above or below the current projections. Since oil prices are relatively low today, compared to the recent past, this finding is of significant value to Santee Cooper as it evaluates its future expansion plans.

C. HIGH/LOW CAPITAL COSTS

Each of the plans under consideration includes the construction of numerous new generating units. These plans are based on the best estimates available at this time; however, the actual costs for these new units will vary in the future for many unforeseen reasons. Therefore, the plans were evaluated for changes in these future costs. Two approaches were taken to this analysis. The first approach considered an increase or decrease in all construction costs. The second analysis assumed the cost estimates for the combustion turbines were accurate, but the costs for the combined cycle and the pulverized coal units would vary. These results are shown in Tables VIII-4 and VIII-5.

Table VIII-4

Cumulative Present Value of Revenue Requirements
Changes in All Construction Costs
(millions of 1994 dollars)

Plan	+15 %	No Change	-15 %
Base Plan	$5,993	$5,975	$5,957
Ref. Plan	$5,928	$5,916	$5,914
PC Plan	$6,011	$5,987	$5,962
CT Plan	$5,995	$5,978	$5,960

The analysis of a change in all construction costs results in the Base and Reference Plans being economically preferred for an increase in the costs, although all four of the plans are very similar in this analysis.

Table VIII-5

Cumulative Present Value of Revenue Requirements
Changes in Only Combined Cycle and Pulverized Coal Construction Costs
(millions of 1994 dollars)

	Combined	Cycle		Pulverized	Coal
Plan	+15 %	-15 %	No Change	+15 %	-15 %
Base Plan	$5,977	$5,973	$5,975	$5,975	$5,975
PC Plan	$5,987	$5,987	$5,987	$5,997	$5,976

This analysis indicates that the Base Plan is economically preferred under any change in the combined cycle costs. Decreases in the costs to construct a pulverized coal plant will make the PC Plan the better plan and economically equal to the Base Plan.

SUMMARY OF CONSTRUCTION PRICE SENSITIVITIES

Overall, any reasonable variation in general construction costs, or in specific costs impacting just combined cycle or pulverized coal construction, will result in the Base and Reference Plans either economically preferred to the PC-Plan, or at the very least, the plans will be equivalent. The consideration at this point is most likely the situation where prices in reality are actually higher than those projected in this IRP. A review of just the increasing cost cases illustrates that the Base and Reference Plans will be preferred in all cases over the PC-Plan although by a very small margin.

D. SUMMARY

Overall, the cases considered for Santee Cooper to meet future load growth conditions reflect a considerable time between now and the point when new generating resources are required. Under the base load forecast, the next generating resource is not required until 2003, when Santee Cooper requires additional peaking capacity. It is not until 2012 that an intermediate or base load unit will be necessary. The technology that today best reflects the economical solution to meeting peaking requirements is a combustion turbine.

Therefore, these sensitivity cases concentrated on evaluating the risks associated with the 2012 resource requirement. In each of the cases evaluated, the difference between the Base and Reference Plans and the other plans, given changes in the base assumptions, will result only in a change in the revenue requirements in 2012 and beyond. The PVRR for the cases identified will show minimal differences between each condition evaluated.

The alternative plan to accelerate the in-service date of the combined cycle unit to 2003 resulted in poor economics, indicating this plan would not be in Santee Cooper's best economic interests.

To summarize this evaluation, the economics of these plans are essentially equivalent today, and since the technologies considered all have construction lead times of no more than 12 years, Santee Cooper has the luxury to continue monitoring the operating environment to best determine the timing and type of the next unit well into the next century. During that time, other technologies may become acceptable candidates and would be of value to consider.

As part of this IRP, Santee Cooper requested the evaluation of three specific issues concerning outstanding decisions facing it in the near future. These special studies include:

- The economics associated with a potential 35 MW cogenerator
- The savings due to extending the operating lives of certain Santee Cooper generating units
- The development of projected marginal costs associated with the interruptible loads of certain industrial customers on Santee Cooper's system.

The results of these special studies are discussed below.

COGENERATION

Santee Cooper has signed an agreement providing for the potential of 35 MW of cogeneration available to it from an industrial customer. The question regarding this issue is the projected avoided costs applicable to this cogenerator. To answer the question, the analysis consisted of comparing the annual average revenue requirements from the Base Case Plan without the cogenerator to those with

Table VIII-6

Comparison of Integrated Plans with and without Cogeneration

Year	Base Case Plan	Base Case Plan with Cogeneration
1994		
1995		35 MW Cogenerator
1996		
1997		
1998		
1999		
2000		
2001		
2002		
2003	One 80-MW CT	One 80-MW CT
2004	One 80-MW CT	One 80-MW CT
2005	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT
2007	Two 80-MW CTs	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT
2012	One 80-MW CT & One 80-MW Phased CC	Three 80-MW CT
2013	Two 80-MW CTs	One 80-MW CT
2014	One 80-MW CT	One 80-MW CT & One 80-MW Phased CC
2015	One 80-MW CT	One 80-MW CT
1994-2015 PVRR ($000)	$5,974,907	$5,903.142
Total New Capacity	1,360 MW	1,360 MW

the cogenerator.

To provide the maximum benefit to the cogenerator, the Base Plan was allowed to re-optimize with the cogenerator available to capture any generation deferral savings associated with the unit. Table VIII-6 contains the modified supply-side expansion plan given this cogenerator.

The plan still includes the same additional new capacity as the Base Plan; however, it shifts the timing of two combustion turbines and delays the need for the combined cycle unit from 2012 to 2014. Table VIII-7 illustrates the resulting incremental avoided costs for this cogenerator. These avoided costs reflect the change in the average system costs for Santee Cooper and assume a 70 percent capacity factor for the cogenerator.

The irregular pattern in the avoided costs after 2007 are a result of the shifting in timing of the new combustion turbines and combined cycle units between the two cases. Based on this analysis, Santee Cooper would be economically indifferent to a 35MW cogeneration facility at rates equivalent to those in Table VIII-7. Santee Cooper would be interested if the rates were below those shown in the table.

Table VIII-7
Cogeneration Avoided Costs

Year	Avoided Cost (¢/kWh)
1995	1.77
1996	1.78
1997	1.90
1998	1.98
1999	2.13
2000	2.16
2001	2.32
2002	2.39
2003	2.52
2004	2.68
2005	2.80
2006	2.85
2007	4.52
2008	4.77
2009	5.17
2010	3.92
2011	4.28
2012	4.87
2013	6.60
2014	5.36
2015	5.89

LIFE EXTENSION

An issue for consideration at Santee Cooper is the benefits associated with life extension of certain older generating units. As directed by Santee Cooper, this evaluation only addresses the differences in revenue requirements resulting from deferring the retirement dates of the units for ten years. The units in question are:

- Jefferies Unit 1 in 2000
- Jefferies Unit 2 in 2000
- Jefferies Unit 3 in 2015
- Jefferies Unit 4 in 2015
- Grainger Unit 1 in 2011
- Grainger Unit 2 in 2011.

CORRECTED COPY

Delaying the retirement of these units will change Santee Cooper's expansion plan in the Base Plan, since less generating capacity will be required. The new resource expansion plan is shown in Tables VIII-8a and VIII-8b.

Table VIII-8a

Comparison of Life Extension Analysis - Without ALUMAX

Year	Base Case Plan	Jeff 1&2 Ret. 2010 Jeff 3&4 Ret. 2015 Grain. 1&2 Ret. 2011	Jeff 1&2 Ret. 2010 Jeff 3&4 Ret. 2025 Grain. 1&2 Ret. 2021
1994	---	---	---
1995	---	---	---
1996	---	---	---
1997	---	---	---
1998	---	---	---
1999	---	---	---
2000	---	---	---
2001	---	---	---
2002	---	---	---
2003	One 80-MW CT	---	---
2004	One 80-MW CT	One 80-MW CT	One 80-MW CT
2005	One 80-MW CT	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT	One 80-MW CT
2007	Two 80-MW CTs	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	Two 80-MW CTs	Two 80-MW CTs
2009	One 80-MW CT	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	Two 80-MW CTs	Two 80-MW CTs
2012	Two 80-MW CTs & One 80-MW Phase CC	Two 80-MW CTs & One 80-MW Phased CC	One 80-MW CT
2013	Two 80-MW CTs	Two 80-MW CTs	Two 80-MW CTs
2014	One 80-MW CT	One 80-MW CT	One 80-MW CT
2015	One 80-MW CT	One 80-MW CT	One 80-MW Phase CC
1994-2015 PVRR ($000)	5,974,907	5,971,442	5,956,757
Total New Capacity	1,360	1,360	1,200

Table VIII-8b

Comparison of Life Extension Analysis - With ALUMAX

Year	Base Case Plan	Jeff 1&2 Ret. 2010 Jeff 3&4 Ret. 2015 Grain. 1&2 Ret. 2011	Jeff 1&2 Ret. 2010 Jeff 3&4 Ret. 2025 Grain. 1&2 Ret. 2021
1994	---	---	---
1995	---	---	---
1996	---	---	---
1997	---	---	---
1998	---	---	---
1999	---	---	---
2000	One 80-MW CT	One 80-MW CT	One 80-MW CT
2001	Two 80-MW CTs	One 80-MW CT	One 80-MW CT
2002	One 80-MW CT	One 80-MW CT	One 80-MW CT
2003	One 80-MW CT	One 80-MW CT	One 80-MW CT
2004	Two 80-MW CTs	Two 80-MW CTs	Two 80-MW CTs
2005	One 80-MW CT	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT	One 80-MW CT
2007	One 80-MW CT	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT & One 80-MW Phased CC	One 400-MW PC
2012	One 400-MW PC	One 400-MW PC	---
2013	---	---	---
2014	One 80-MW CT	One 80-MW CT	One 80-MW CT
2015	Two 80-MW CTs	Two 80-MW CTs	One 80-MW CT & One 80-MW Phased CC
1994-2015 PVRR ($000)	6,654,110	6,648,856	6,638,776
Total New Capacity	1,760	1,760	1,600

INTERRUPTIBLE LOADS

Santee Cooper currently has contracts that allow it to request that many of its industrial customers decrease their demand on Santee Cooper's system during peak periods. Santee Cooper will serve these loads through economy purchases, if the energy is available. The intent of this arrangement is to avoid constructing new supply-side resources for this demand. The demand forecasted for this load was 152 MW in 1994, 156 MW in 1995, and 199 MW each year thereafter.

As part of this IRP, Santee Cooper requested an analysis of the economics associated with these arrangements. Therefore, Table VIII-9 contains the results of this analysis.

Table VIII-9

Cumulative Present Value of Revenue Requirements
Interruptible Loads
(Thousands of 1994 dollars)

Case	Difference in PVRR
Santee Cooper does not serve demand or energy	Base Plan
Santee Cooper serves energy only	$1,946
Santee Cooper serves both the demand and energy	$46,125

The annual demand and energy rate projections are presented in Table VIII-10. Overall, the demand and energy rates in Table VIII-10 reflect Santee Cooper's avoided costs resulting from implementing the interruptible rates. The demand rates are based on the difference in fixed costs associated with the additional generation capacity required if the peak demand is not interrupted. Likewise, the energy rate projection reflects the difference in average annual energy costs to serve the interruptible loads from Santee Cooper's system. If Santee Cooper were to meet the demand instead of treating it as non-firm, an addition of two new 80 MW combustion turbines would be required as soon as possible, regardless of the future disposition of ALUMAX.

Table VIII-10

Projected Interruptible Demand and Energy Rates

Year	Demand Rate ($/kW yr.)	Energy Rate (¢/kWh)
1994	--	6.11
1995	--	3.05
1996	--	3.41
1997	16.77	3.67
1998	34.55	4.64
1999	35.59	7.69
2000	36.66	4.25
2001	37.76	6.10
2002	38.88	7.28
2003	40.05	7.30
2004	41.25	7.66
2005	42.49	7.93
2006	43.76	8.11
2007	22.54	6.90
2008	23.21	7.26
2009	47.82	7.21
2010	49.26	7.48
2011	50.74	7.85
2012	52.26	8.73
2013	26.92	8.10
2014	55.44	8.58
2015	57.10	8.84

ALUMAX INTERRUPTIBLE LOADS

The contract with ALUMAX includes a clause in which 142 MW of the 300 MW can be considered non-firm load. A sensitivity analysis was performed on the base load case with ALUMAX in service, and Santee Cooper treating the 142 MW as non-firm.

The analysis of the ALUMAX non-firm load considered the PVRR difference to Santee Cooper between the Base Supply Plan with ALUMAX and a new plan that relied on the non-firm load instead of adding new capacity. The results of this analysis indicate the elimination of the equivalent of two 80 MW units. Table VIII-11 contains the results of this analysis.

Table VIII-11

Impact of Non-Firm ALUMAX Load on Expansion Plans

Year	Base Plan with ALUMAX ($000)	Base Plan with ALUMAX and 142 MW of Non-Firm Load ($000)
2000	One 80-MW CT	
2001	Two 80-MW CTs	One 80-MW CT
2002	One 80-MW CT	One 80-MW CT
2003	One 80-MW CT	One 80-MW CT
2004	Two 80-MW CTs	Two 80-MW CTs
2005	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT
2007	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW Phased CC
2010	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT
2012	One 400-MW PC	One 400-MW PC
2013		
2014	One 80-MW CT	One 80-MW CT
2015	Two 80-MW CTs	Two 80-MW CTs
1994-2015 ($000)	$6,654,110	$6,613,962.5
Total New Capacity	1,760 MW	1,600 MW

By utilizing the non-firm load, Santee Cooper's expansion plan over the study period is reduced 160 MW of new capacity and reduces the PVRR by $40,147,500. This reduced PVRR of $40,147,500 will need to be compared to any offsetting revenue changes occurring by a change in the operation of the ALUMAX facility due to Santee Cooper exercising the non-firm clause in the contract.

IX. NEAR-TERM ACTION PLAN

IX. NEAR-TERM ACTION PLAN

The action plan resulting from this IRP for Santee Cooper will identify issues and critical dates over a five-year decision horizon–1994 to 1999. During that time period, Santee Cooper will face decisions related to three major areas of operation:

- Timing and type of new generation resources
- Compliance with the Clean Air Act Amendments of 1990 (CAAA)
- Further expansion of potential demand-side management programs.

Each of these three issues will be discussed in detail in the following sections of this chapter. The final section of this Chapter summarizes the decisions and their critical timing over the next five years.

A. TIMING AND TYPE OF NEW GENERATION RESOURCES

This IRP identified and screened each and every reasonably conceivable supply-side technology currently discussed throughout the electric utility industry. Of all of the technologies considered, the three that passed the screening and resulted in the lowest overall revenue requirements for Santee Cooper were: pulverized coal, combined cycle, and combustion turbine.

The study assumed three sizes for possible pulverized coal units–240 MW, 400 MW, and 560 MW. These three sizes were based on a review of the typical size units currently under construction or planned throughout the United States. In reality, a utility could plan and construct virtually any size unit, since such a unit is typically designed specifically to meet the utility's needs.

The size of the combustion turbine was assumed to be 80 MW, based on a standard design offered by one of the major suppliers of these units within the United States. The size of the combined cycle was assumed to be 240 MW and was based on the 80 MW size of the combustion turbine included in the study. The study assumed the combined cycle would consist of two of the 80 MW combustion turbines, each serving a Heat Recovery Steam Generator (HRSG). The two HRSGs would then serve a single 80 MW steam generator.

The timing of the new supply-side resource will be based on two key factors:

- Santee Cooper's future load growth
- The continuation of sales to ALUMAX.

Santee Cooper provided three different load forecasts to be considered in this study. They were based on a most likely load growth and high and low economic assumptions for the State of South Carolina. These three load forecasts then had the sales to ALUMAX superimposed on them, for a total of six different load conditions to consider in the IRP. Each of these six load conditions resulted in a different requirement for new generation resources. These six plans were summarized in Table V-7 of this report. Exhibit IX-1 illustrates the timing of the new generation to meet the various load assumptions.

As Table V-7 shows, Santee Cooper's future generation requirements should be met in the early years by new combustion turbines to meet the need for new peaking capacity.

The base load forecast without the ALUMAX load will need new generation in the year 2003. Since the recommended unit would be a combustion turbine with a three- to five-year construction lead time, a decision for this unit will not be required until 1998 to 2000. However, if ALUMAX informs Santee Cooper of its intent to continue operation at the current 300 MW level, the need for new generation will be accelerated to 2000. Therefore, under this higher load condition, a decision for the new capacity will be required during the 1995 to 1997 time period.

The contract with ALUMAX commits ALUMAX to informing Santee Cooper of its intent no later than three years from the expiration of the current agreement. Therefore, ALUMAX should inform the utility by March 1997, of its future plans. This will make 1997 the critical year for Santee Cooper to determine whether a new combustion turbine will be required to meet the loads in 2000.

From Santee Cooper's perspective, its actions necessary to meet the future load uncertainty should be to continue to maintain contact with the ALUMAX plant staff to monitor activities. This will aide in projecting the future course ALUMAX will be taking in order for Santee Cooper to best plan for ALUMAX's final decision.

Exhibit IX-2 provides a flowchart indicating the decision points Santee Cooper should focus on over the next five years to meet the utility's supply requirements. The path recommended for Santee Cooper to follow is dependent upon ALUMAX's decision to continue operations. If ALUMAX decides to terminate service, then Santee Cooper has time to monitor the sales market (including impacts from DSM programs). If, however, ALUMAX continues service, then it is recommended that Santee Cooper have completed the preliminary efforts necessary for a new combustion turbine in 2000. A detailed schedule of activities is identified at the end of this chapter.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

PROJECTED NEW GENERATION REQUIREMENTS

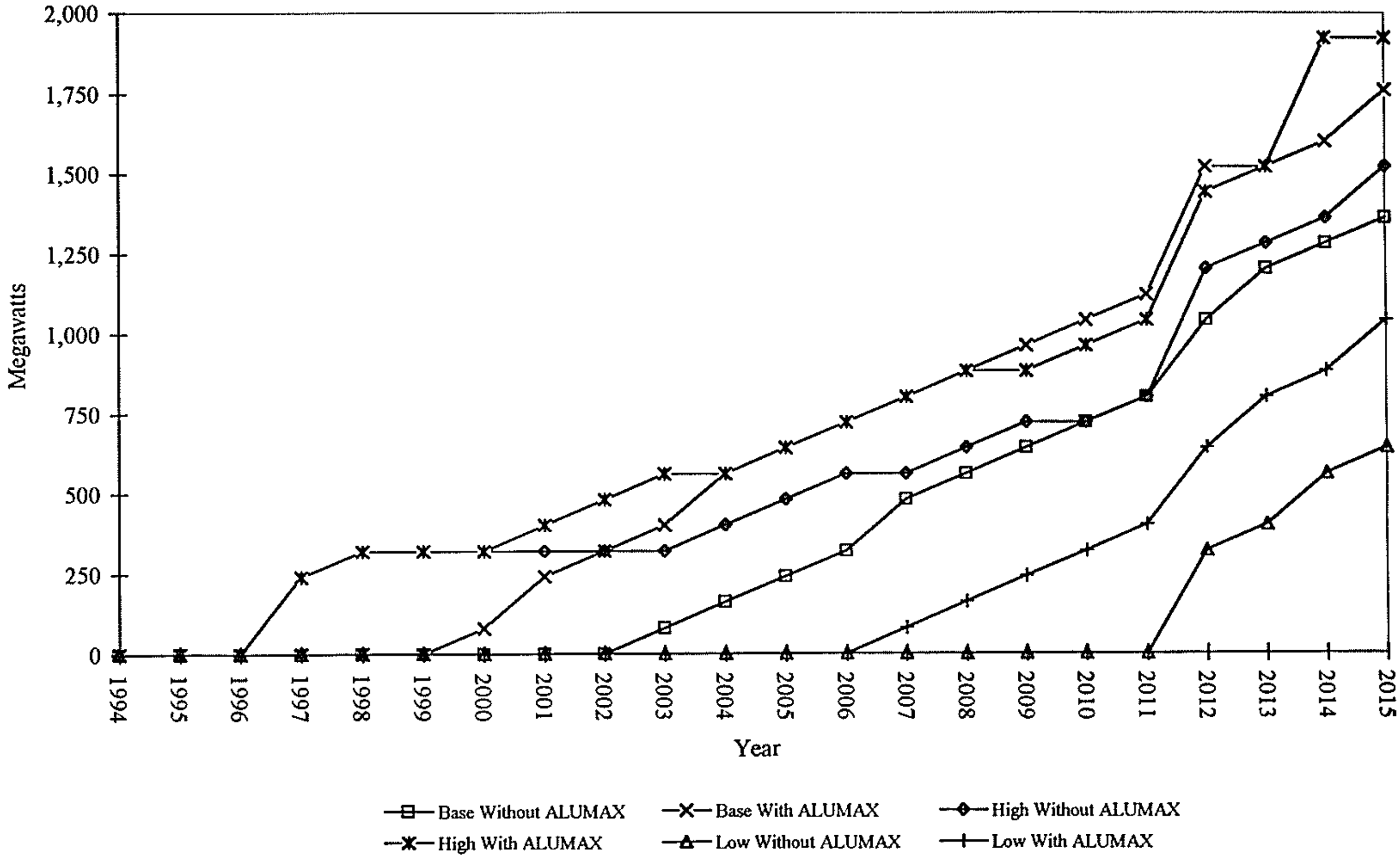


EXHIBIT IX-1

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUPPLY-SIDE ACTION PLAN STEPS

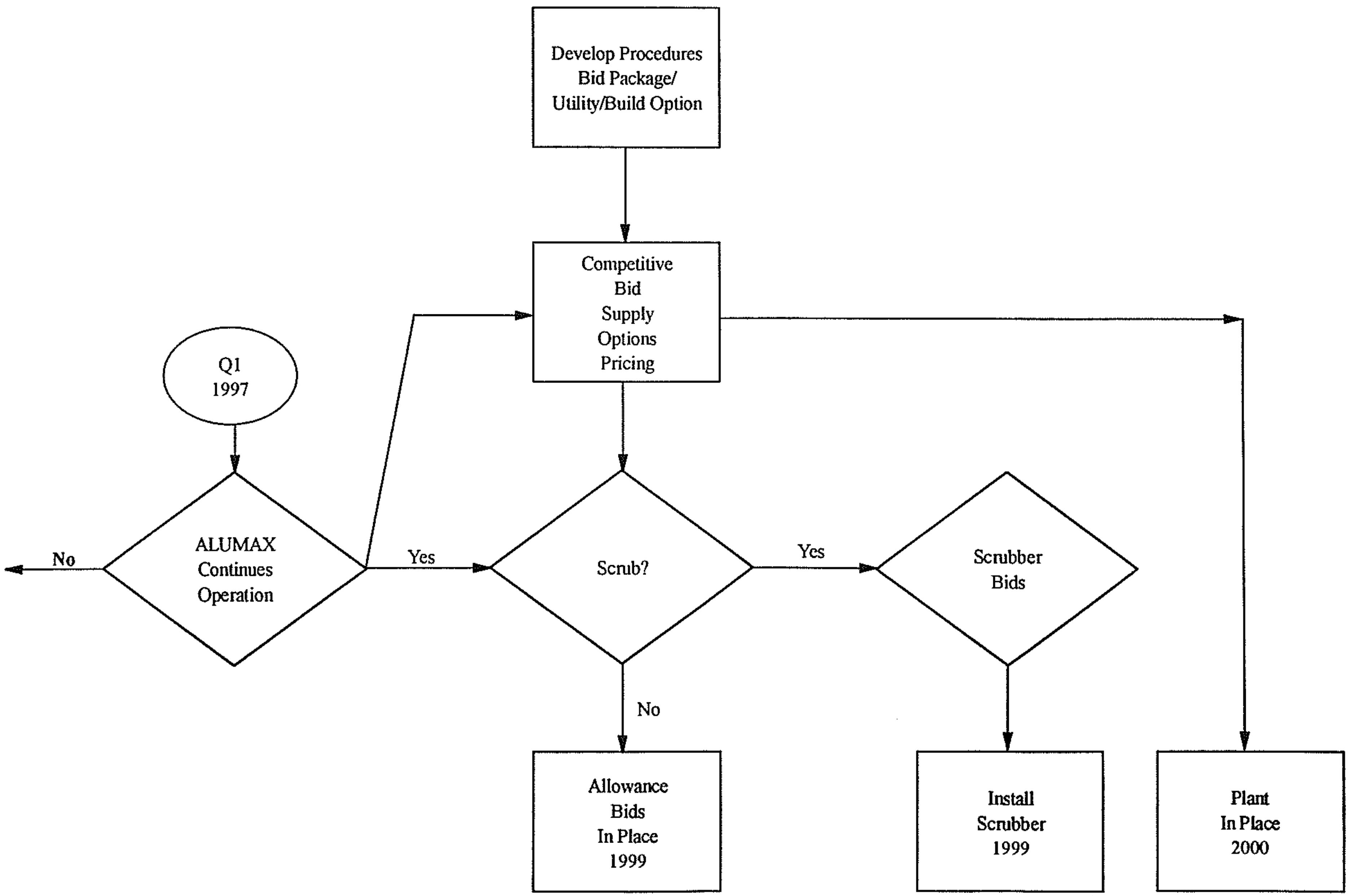


EXHIBIT IX-2
Page 1 of 2

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUPPLY-SIDE ACTION PLAN STEPS (continued)

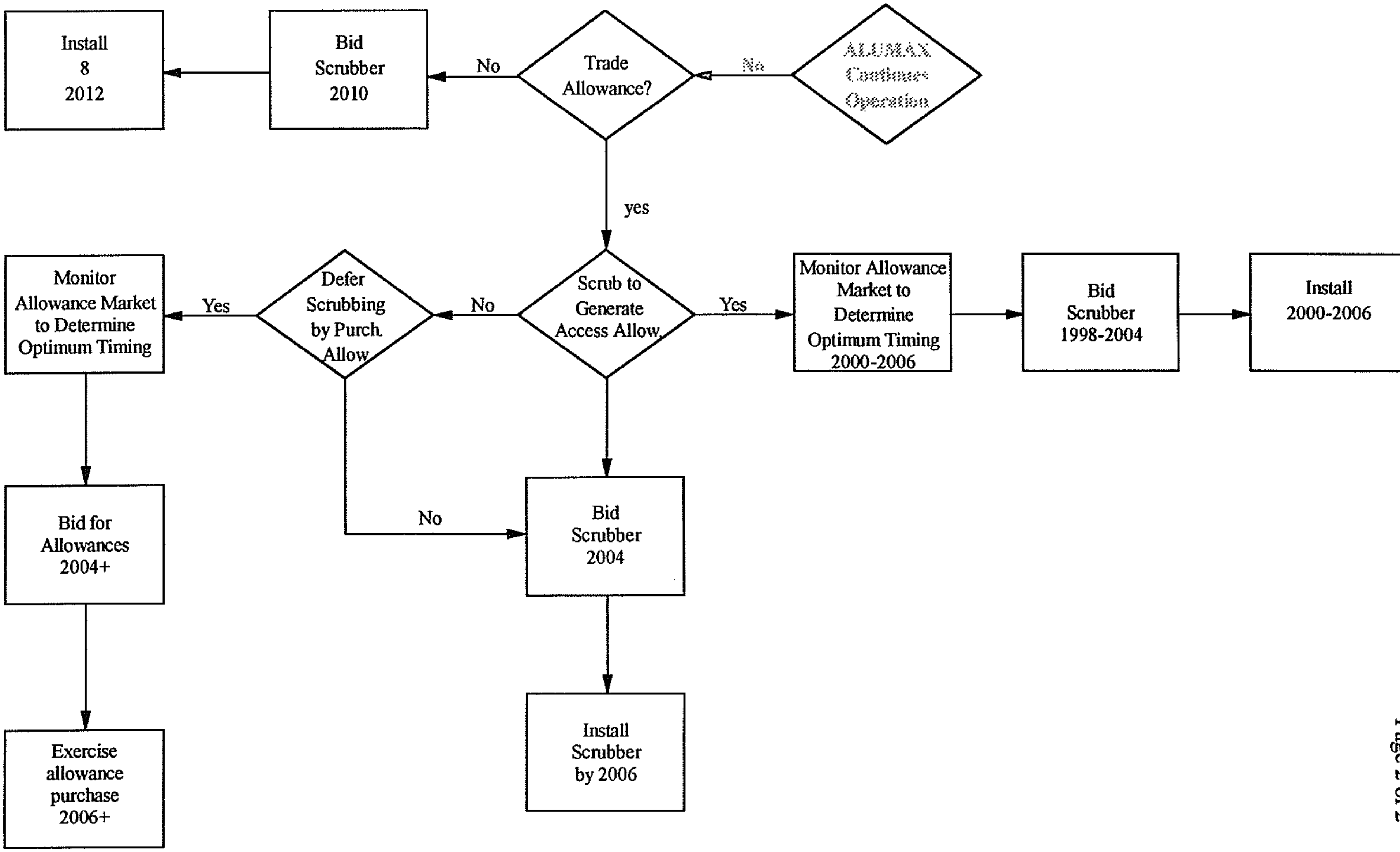


EXHIBIT IX-2
Page 2 of 2

B. COMPLIANCE WITH THE CLEAN AIR ACT AMENDMENTS OF 1990 (CAAA)

The CAAA identify two time periods relative to compliance requirements for sulfur dioxide. Phase I specifically identifies existing fossil-fueled generating units that will be limited in SO_2 emissions beginning in 1995. Phase II more generally identifies SO_2 emission limits for all fossil-fueled generating units beginning in 2000. Santee Cooper does not have any of the Phase I affected units; however, the utility is impacted by the Phase II limits.

The CAAA identifies a new "asset" called an allowance which is equivalent to one ton of SO_2 emitted in a single year. Each utility will be allocated a specific number of allowances each year on the basis of past operations of the units and tied to a maximum annual emissions allowed across all fossil-fueled units in the United States. Table VI-1 identifies Santee Cooper's allowance allocation by unit on a yearly basis.

A utility has three options available to it for the use of the allowances allocated annually:

- Use the allowance to emit sulfur dioxide - up to one ton per allowance
- Sell any allowances not needed to meet actual sulfur dioxide emissions
- Save any unused allowances for use at a later time–allowances can be saved for an indefinite period of time.

In addition, a utility may choose to purchase allowances from the market to meet its requirement if the utility does not have sufficient allowances allocated to it. This decision would balance the economics of internally reducing emissions through measures such as scrubbing versus the cost of the allowances in the marketplace.

In the case of Santee Cooper, the planning philosophy for this study has been to save, or bank, any unused allowances on a year-to-year basis. In addition, the study philosophy has assumed the utility will not purchase allowances from the market as a compliance plan to meet the requirements of the CAAA. Therefore, this IRP assumed all unused allowances would be banked, and the need for additional allowances would be met through utilization of the bank until it was depleted, at which time internal measures would be taken to comply. These internal measures will either be environmentally affected dispatching of the units or the installation of a new scrubber at an existing generating unit.

As with the need for a new unit discussed in the previous section of this chapter, the timing of actions required by Santee Cooper is dependent upon the load growth and the future of ALUMAX. Exhibit IX-3 illustrates the allowance bank balance for each load

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SO$_2$ ALLOWANCE BANKING

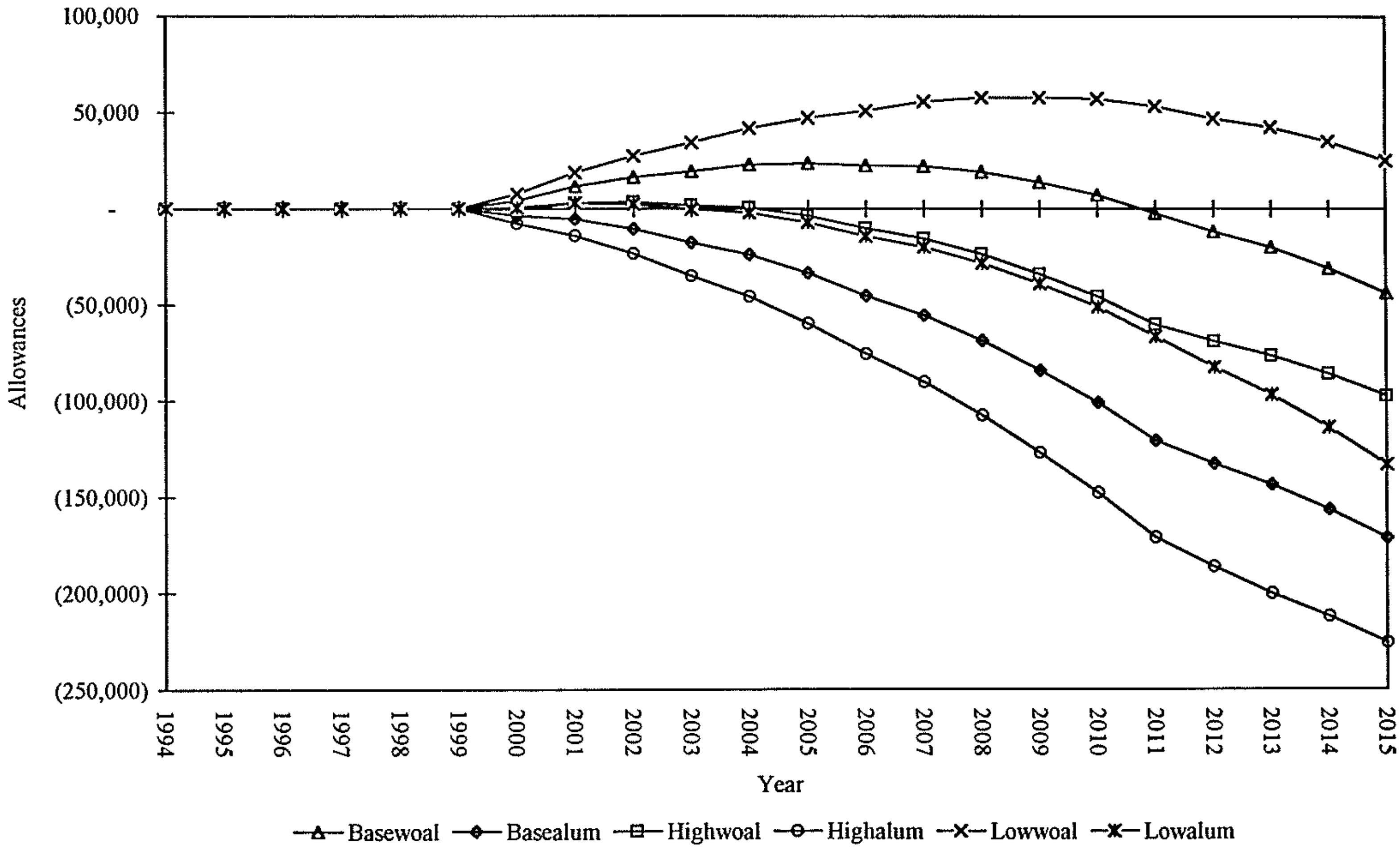


EXHIBIT IX-3

assumption and corresponding supply-side plan. Santee Cooper will need to have a compliance plan implemented at the point in time when the bank is fully depleted.

As illustrated in the exhibit, under the base case conditions, Santee Cooper will have sufficient allowances until 2011. However, if ALUMAX continues operation, a bank of allowances never occurs and a plan for compliance will be required at the onset of Phase II of the CAAA.

Since Santee Cooper may have excess allowances, depending on the disposition of ALUMAX and the system load growth, the timing of a retrofit scrubber and utilization of the allowance market may provide a source of additional revenue. A low market price for allowances could provide Santee Cooper with a lower cost alternative than constructing a scrubber. On the other hand, a high price for allowances could make it beneficial for Santee Cooper to construct a scrubber earlier, generate additional allowances, and sell the excess allowances.

As shown in Chapter VI of this document, a critical market value for this issue is in a range from $200 to $250 per allowance. As the market value of the allowances increase from $200, the economics indicate a potential benefit exists to accelerate the timing of the scrubber. At a market value of $250, it appears to be beneficial to install the scrubber earlier and sell any excess allowances. Issues revolving around ALUMAX and load growth restrict Santee Cooper from setting a final compliance strategy at this time; however, this issue should be reviewed between now and the time ALUMAX notifies Santee Cooper of its business intentions.

Therefore, as with supply planning, the compliance plan is dependent on ALUMAX. Again, since the lead time for implementing a compliance plan is roughly two to three years, the agreement with ALUMAX to notify Santee Cooper of the intent within three years of the end of the agreement, or March 1997, is critical to Santee Cooper's planning.

Prior to the notification by ALUMAX, Santee Cooper should prepare for the continued operation of ALUMAX to be ready for the installation of the necessary scrubber by 2000. This means that prior to the first quarter of 1997, Santee Cooper will need to have reviewed the issue of complying with the CAAA internally and consider relying on the allowance market to meet requirements. If the decision is to comply internally, then Santee Cooper should have prepared construction bid packages to be ready for issuing by the time ALUMAX notifies the utility of its final decision. By having these bid packages prepared in advance, Santee Cooper will be better able to construct and test the new scrubber in time to be operational by the beginning of 2000.

The critical actions for Santee Cooper for the environmental compliance issue are:

- Continued contact with the plant staff at ALUMAX in an effort to project the future disposition of this customer.
- An internal review of Santee Cooper's allowance trading strategy.

C. FURTHER EXPANSION OF POTENTIAL DEMAND-SIDE MANAGEMENT PROGRAMS

Santee Cooper currently maintains three DSM programs. These programs are:

- Residential Good Cents Program
- Commercial Good Cents Program
- H_2O Advantage Program.

As part of this IRP, a total of 227 DSM measures were identified and screened with the resulting identification of eleven new programs. Each of these eleven new and three existing programs were economically screened with four standard DSM screening tests.

- *Participant Test*: A measure of the quantifiable benefits and costs of a DSM program from the point of view of the participating customer. It is designed to indicate whether the program is economically attractive to the customer. The test includes the benefits associated with reduced electric bills and incentive payments weighed against the increased costs due to the purchase of equipment required to participate in the program (e.g., a new heat pump).

- *Total Resource Cost (TRC) Test*: A measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. Resource costs include changes in supply costs, utility costs, and participant costs. Since the utility and its ratepayers are taken as a whole, changes in the dollar amounts that flow between them are ignored.

- *Utility Cost Test*: A measure of the change in total costs to the utility that is caused by a DSM program. Thus, this test evaluates a DSM program from the point of view of a utility's total costs. The test includes the benefits associated with reduced production costs and deferred generation capacity capital costs. These benefits are weighed against increases in the utility's total costs, including DSM program costs, utility costs, and incentives.

- *Ratepayer Impact Measurement (RIM) Test*: A measure of the difference between the change in total revenues recovered through rates by a utility and the change in total costs resulting from the DSM program. If the change in revenues is larger or smaller than the change in total costs, then rate levels may need to be changed to obtain proper revenue recovery. Thus, this test in effect evaluates the impact on rates resulting from a particular DSM program. Impacts on individual classes can be analyzed if costs and demand reductions are allocated in the same method used to determine rates. To fully determine rate impacts on a particular rate class resulting from a particular DSM program, a detailed analysis will be required. For the purposes of this study, the RIM test considered revenue changes resulting from the estimated change in energy sales (kWh); revenue changes resulting from changes in demand (kW) were considered minimal, and were not included in the screening.

The screening for the DSM programs were initially performed disregarding whether Santee Cooper would implement the programs at a retail or wholesale level. Follow-up screening identified the minor variations in costs and benefits due to this wholesale-retail split. The results of the combined screening are presented in Table IX-1.

Table IX-1

Results of DSM Economic Screening - Combined

	Name of Test			
Program	Participant	TRC	Utility	RIM
Standby Generators	Inf.	13.24	0.51	0.50
High Efficiency Lighting	3.28	2.88	4.91	1.07
Premium Efficiency Motors	3.57	2.62	4.20	1.03
Good Cents Manufactured Home Heat Pump	5.74	1.83	0.47	0.35
Air Conditioning Direct Load Control	Inf.	1.39	0.54	0.53
Commercial Air Conditioning	1.36	1.37	3.62	1.07
Duct Testing and Repair	1.70	1.00	1.41	0.67
Thermal Energy Storage	1.02	0.51	1.15	0.50
High Efficiency Heat Pump	0.95	0.47	0.73	0.50
Swimming Pool Direct Load Control	Inf.	0.54	0.34	0.33
Ground Source Heat Pump	0.50	0.34	1.32	0.62
Residential Good Cents	Inf.	6.69	0.64	0.49
Commercial Good Cents	Inf.	1.02	0.83	0.63
H_2O Advantage	Inf.	0.82	0.19	0.19

Note: The results of this screening ignore the differences between retail and wholesale costs and benefits.

In pursuing a DSM program, it is recommended that Santee Cooper review its criteria for DSM. Each of the tests described above screens the benefit to cost ratio from a different perspective. Each of these perspectives should be understood and the preferred approach selected. For instance, the Participant test considers only the benefits and costs of the program from the point of view of the participant and ignores the benefits and costs to the utility. A program that has a benefit to cost ratio of greater than 1.0 on this test is good for the participant; however, the program may result in higher revenue requirements to the utility.

A program scoring 1.0 or greater on the Total Resource Cost test indicates a program that will lower the combined costs for both the participant and the utility. However, since both parties are taken together, the benefits to the participant may outweigh the costs to the utility, again resulting in higher revenue requirements to the utility due to the program.

The Utility test considers the program solely from the perspective of the utility. A program scoring 1.0 or greater on this test will result in lower revenue requirements. Finally, the Rate Impact test considers the benefits and costs of the program along with the lost revenues to the utility due to lost sales from reduced energy requirements. A benefit to cost ratio of less than 1.0 on this test indicates a program requiring a rate increase to cover the program's costs and lost revenues.

The DSM programs a utility pursues depend on which test it focuses on. For the purposes of this IRP, programs that would be pursued under a policy focusing on each test were identified. In addition, a fourth policy towards DSM that combined both a minimum revenue requirement and minimal rate increase policy was considered. Programs resulting from this combined policy were also developed. Table IX-2 identifies the DSM programs that would be pursued by Santee Cooper according to the policy decision.

Table IX-2

Summary of DSM Programs Scoring 1.0 or Greater

Rank	TRC	UTIL	RIM	TRC/Utility
1	High Efficiency Lighting	High Efficiency Lighting	High Efficiency Lighting	High Efficiency Lighting
2	Stand-by Generation	Premium Efficiency Motors	Commercial Air Conditioning	Premium Efficiency Motors
3	Premium Efficiency Motors	Commercial Air Conditioning	Premium Efficiency Motors	Commercial Air Conditioning
4	Manu. Housing Heat Pumps	Residential Duct Testing and Cleaning		Residential Duct Testing and Cleaning
5	Commercial Air Conditioning	Ground Source Heat Pumps		Residential Good Cents
6	Direct Load Control of Air Conditioning	Thermal Energy Storage		Commercial Good Cents
7	Residential Duct Testing and Cleaning			
8	Residential Good Cents			
9	Commercial Good Cents			

These policy decisions and the resulting portfolio of DSM programs are illustrated in Tables IX-3a and IX-3b. As a result of the IRP analysis, it is recommended that Santee Cooper pursue the six programs identified in the combined TRC/Utility package. Of these six programs, four are new programs. This recommendation is based on the magnitude of the difference in PVRR over the 1994-2015 period compared to the projected expenditure for the programs as shown in Table IX-4. Table IX-5 contains a recommended budget for piloting the four new programs, and Santee Cooper's budget for the existing programs. This proposed budget for the new programs assumes Santee Cooper will initially perform a pilot on the new programs at a reduced expenditure level than what was used in the IRP. The recommended budget assumes 20 percent of the full cost in the first year. Each subsequent year was increased by 20 percentage points until the total would equal the full expenditure level assumed in the IRP. This escalation in expenditure assumes a successful pilot.

Table IX-3a

Comparison of Integrated Plans (w/o ALUMAX)

Year	Base Plan	Reference Plan	UTIL Plan	RIM Plan	TRC/UTILITY Plan
1994					
1995					
1996		HP, LIT, MOT, AC, DLCA, STBY, DUC, RESG, COMG	TES, DUC, LIT, MOT, AC, GSHP	LIT, MOT, AC	DUC, LIT, MOT, AC, RESG, COMG
1997					
1998					
1999					
2000					
2001					
2002					
2003	One 80-MW CT		One 80-MW CT	One 80-MW CT	
2	One 80-MW CT		One 80-MW CT	One 80-MW CT	One 80-MW CT
2005	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2006	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2007	Two 80-MW CTs	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT	Two 80-MW CTs	Two 80-MW CTs	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
2012	One 80-MW CT & One 80-MW Phased CC	Three 80-MW CT	Two 80-MW CT & One 80-MW Phased CC	Two 80-MW CTs & One 80-MW Phased CC	Three 80-MW CTs
2013	Two 80-MW CTs	One 80-MW CT	One 80-MW CT	Two 80-MW CTs	Two 80-MW CT
2014	One 80-MW CTs	One 80-MW Phased CC	Two 80-MW CTs	One 80-MW CT	One 80-MW Phased CC
2015	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT	One 80-MW CT
20-Year PVRR ($000)	$5,974,907	$5,916,238	$5,971,324	$5,967,681	$5,922,727
Total New Capacity	1,360 MW	1,040 MW	1,360 MW	1,360 MW	1,200 MW

Table IX-3b

Comparison of Integrated Plans (with ALUMAX)

Year	Base Plan	Reference Plan	TRC/Utility Plan
1994			
1995			
1996		HP, LIT, MOT, AC, DLCA, STBY, DUC, RESG, COMG	DUC, LIT, MOT, AC, RESG, COMG
1997			
1998			
1999			
2000	One 80-MW CT		
2001	Two 80-MW CTs	Two 80-MW CTs	Two 80-MW CTs
2002	One 80-MW CT		One 80-MW CT
2003	One 80-MW CT	One 80-MW CT	One 80-MW CT
2004	Two 80-MW CTs	One 80-MW CT	Two 80-MW CTs
2005	One 80-MW CT	One 80-MW CT	
2006	One 80-MW CT	One 80-MW CT	Two 80-MW CTs
2007	One 80-MW CT	One 80-MW CT	One 80-MW CT
2008	One 80-MW CT	One 80-MW CT	One 80-MW CT
2009	One 80-MW CT	One 80-MW CT	One 80-MW CT
2010	One 80-MW CT	One 80-MW CT	One 80-MW CT
2011	One 80-MW Phased CC	One 80-MW CT	One 80-MW CT
2012	One 400-MW PC	One 400-MW PC	One 400-MW PC
2013			
2014	One 80-MW CT		
2015	Two 80-MW CTs	One 80-MW Phased CC	One 80-MW Phased CC
20-Year PVRR ($000)	$6,654,110	$6,576,565	$6,596,640
Total New Capacity	1,760 MW	1,360 MW	1,520 MW

CORRECTED COPY

Table IX-4

Annual DSM Expenditures for the Two Lowest PVRR DSM Expansion Plans

Year	Reference Plan ($000)	TRC/Utility Plan ($000)	Difference ($000)
1996	4,311	1,913	2,398
1997	5,159	2,707	2,452
1998	6,334	3,313	3,021
1999	7,707	4,079	3,628
2000	9,116	4,843	4,273
2001	13,779	8,820	4,959
2002	15,326	9,638	5,688
2003	16,902	10,440	6,642
2004	18,579	11,295	7,284
2005	20,350	12,195	8,155
2006	20,437	12,058	8,379
2007	21,935	12,947	8,988
2008	23,527	13,899	9,628
2009	25,137	14,836	10,301
2010	26,841	15,831	11,010
2011	28,561	16,805	11,756
2012	30,211	17,670	12,541
2013	31,985	18,619	13,366
2014	33,895	19,661	14,234
2015	35,943	20,797	15,146
20 Year PVRR	$5,916,238	$5,922,727	$6,489

Table IX-5

DSM Pilot Program Budget

Year	Proposed New Program Budget	Proposed Existing Budget
1995	$141,400	$10,132,000
1996	$292,800	$10,825,000
1997	$454,800	$11,834,000
1998	$627,200	$12,659,000
1999	$811,000	$13,635,000

This proposed budget assumes the piloting of four new programs. If, during the pilot phase, these programs prove to be as successful as anticipated, then it is recommended to accelerate the program development into the full program and resulting costs identified in Appendix B.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

FLOWCHART II

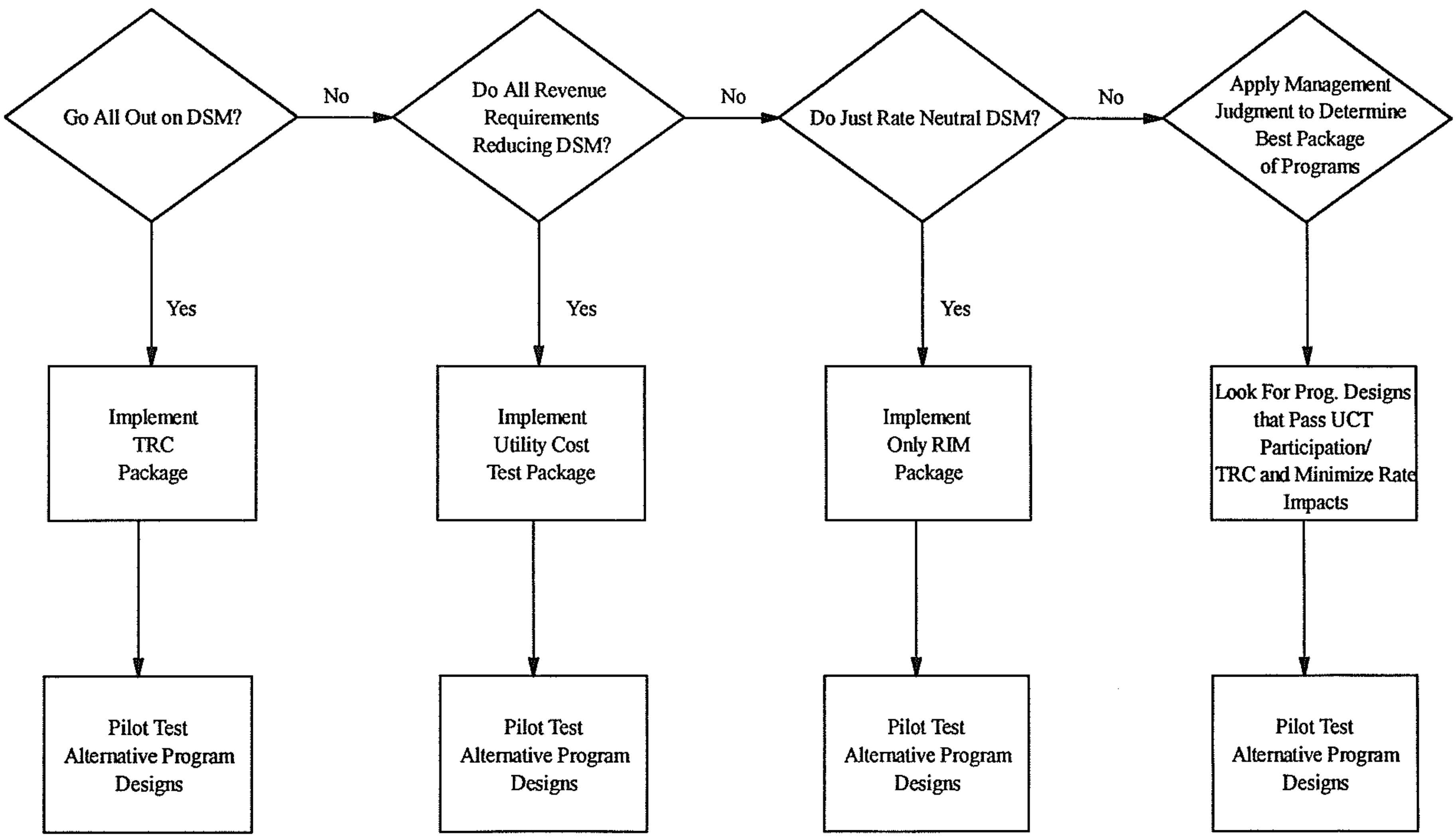


EXHIBIT IX-4

D. SUMMARY

Based on the above discussion, near-term issues critical to Santee Cooper are related to the continued operation of ALUMAX and level of DSM program implementation. The action taken by ALUMAX will drive two actions by Santee Cooper:

1. Timing of next generating unit
2. Timing of retrofit scrubber for environmental compliance.

If ALUMAX continues operation, then Santee Cooper will need new resources and a compliance plan completed by 2000. If ALUMAX terminates their operation in South Carolina, Santee Cooper can defer a new resource for three to four years depending on the development of DSM programs.

Regardless of the actions taken by ALUMAX, it is recommended that Santee Cooper review its policy related to trading in the SO_2 allowance market. Monitoring of the value of the allowances by the market is recommended. Depending on the market value, there may be an economic benefit to utilize the market to determine the timing of a retrofit scrubber.

Finally, it is recommended that Santee Cooper implement the four new DSM programs listed below:

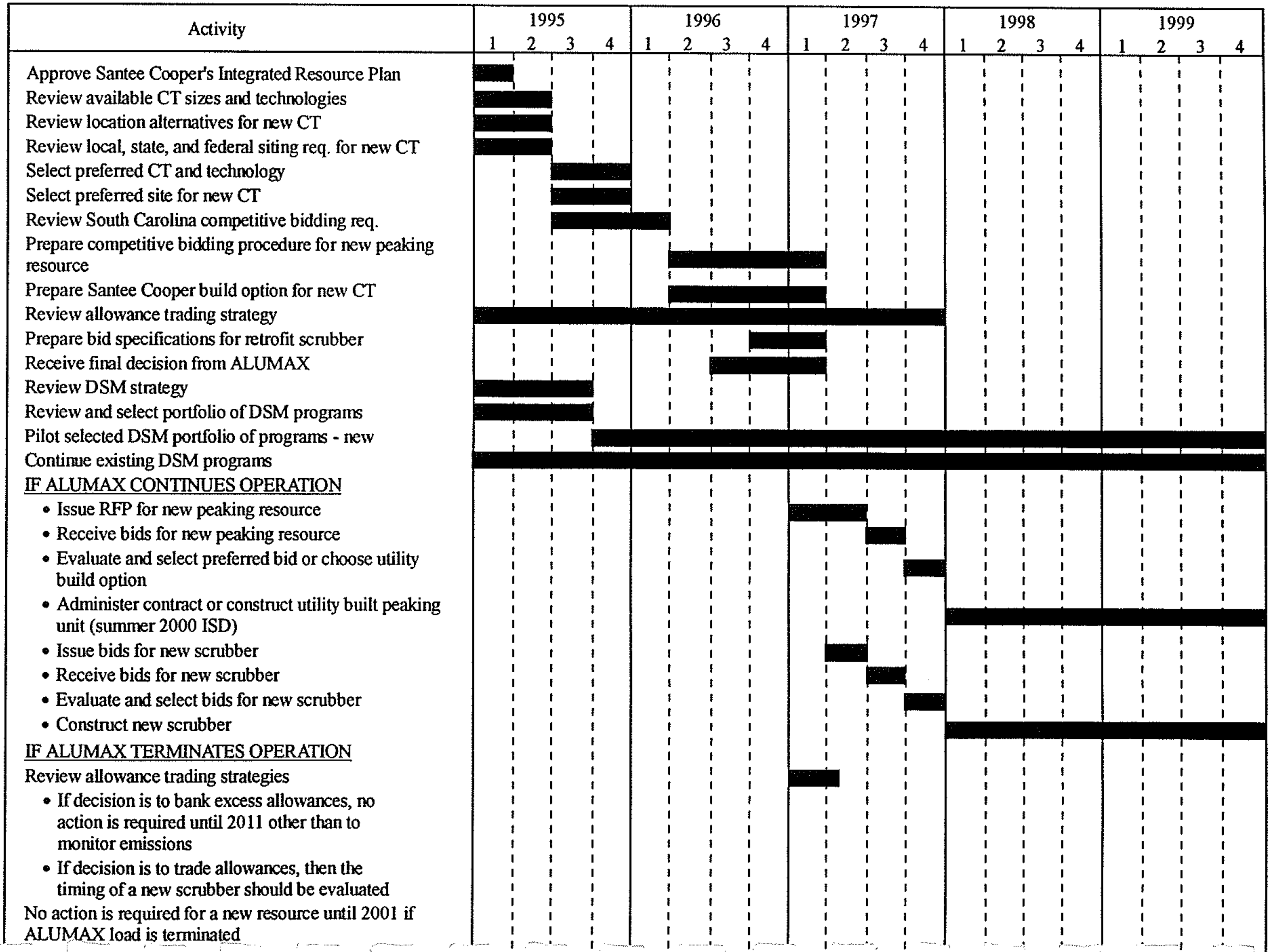
1. High Efficiency Lighting
2. Premium Efficiency Motors
3. Commercial Air Conditioning
4. Residential Duct Testing and Cleaning.

The existing Residential and Commercial Good Cents programs appear to have economic benefits to Santee Cooper and its customers and should therefore be continued.

Exhibit IX-5 contains a time line for actions required over the next five years. Steps taken prior to the first quarter of 1997 reflect uncertainty surrounding ALUMAX. Activities after this time are shown with and without ALUMAX.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

NEAR-TERM ACTION PLAN



APPENDIX A

APPENDIX A
1994 INTEGRATED RESOURCE PLAN
DESCRIPTION OF GENERATION TECHNOLOGIES

INTRODUCTION

This appendix represents the identification of numerous supply-side options to be screened for the Santee Cooper 1994 Integrated Resource Plan. The document contains:

- An overview describing the approach to identifying the options to be screened
- A description of each and every option including:
  - A brief highlight of the technology
  - The capacity of the option
  - Fuel Type
  - Technology development status
  - Duty cycle of the technology
  - Total plant costs in 1994 dollars
  - Unit heat rate
  - 1994 fixed O&M estimate
  - 1994 variable O&M estimate
  - Availability
- A discussion of what the electric utility industry is doing today with respect to new generation construction.

The screening of the technologies identified in this appendix is discussed in Chapter V of the IRP Report.

OVERVIEW

The 1994 supply-side option analysis identified and screened a total of 58 generation resource alternatives as part of the 1994 Integrated Resource Plan (IRP) for Santee Cooper. This appendix will provide Santee Cooper with a description of each resource alternative. Each description will include a brief review of the technology, plus a listing of the estimates for construction costs, annual operating expenses, annual availability factors, and annual average heat rates.

The purpose of an IRP is to provide a thorough review of the possible supply-side technologies available to a utility. Therefore, this document will identify all of the options considered for the Santee Cooper IRP. As in any thorough IRP, many options were considered initially, regardless of the maturity of the technology. Many of these technologies were screened out before the final integration analysis because of unfavorable aspects: maturity of the technology, the reliability of the technology, the utility's ability to finance in regard to perceived risks associated with the technology, environmental and/or regulatory impacts, or commercial availability of the technology.

The maturity of a technology is defined as its position in the technological development cycle. A technology may still be in the laboratory stage, which would mean a unit of its kind has never been built at any size and the scientists are still researching the theory related to the technology. The Advanced Liquid Metal Reactor nuclear technology falls in this category. At the other end of the curve would be a mature technology, in which multiple units have been built over the years and which provides the industry with significant data for construction and operating statistics. An example is a pulverized coal unit.

Between these two degrees of technology development are two intermediate development stages. A commercial technology is defined as one with which the industry has some limited experience. The existing units may be small-scale units or larger units only recently entering the operational phase of their commercial lives. Limited knowledge of large-scale commercial operation is currently available. Though units in this category do not have significant operating experience in utility settings, it is likely that there will be more extensive experience by the time Santee Cooper is expected to need new baseload capacity.

The other degree of technology is demonstration technology, defined as one or more new technologies integrated into a very limited number of utility-grade facilities. These few facilities are operated with the intent of learning more about how the new designs function as part of an overall power plant. The outcome of the observations of these units usually results in additional design modifications in future units.

Associated with the degree of technology development are the current construction and operating cost estimates and the desired in-service date for the generation resource. The costs for the mature technologies are well established as a result of many years of full-scale utility operations. However, the cost estimates for some of the newer technologies are based on laboratory projections, scaled estimates for pilot projects and sources other than actual operation. As these technologies gain more experience in operation, especially in utility-grade conditions, the cost estimates will become more reliable. Therefore, in the case of resource requirements into the next century, the utility planners would be prudent to monitor the newer technologies and include the maturing ones in future IRP efforts.

In addition to identifying the technologies by their positions on the technology development curve, this document will also divide the resource alternatives by peaking, intermediate and baseload technologies. Typically, a generating resource will be designed for the duty cycle it will encounter during the life of the facility. For example, a simple cycle combustion turbine is often considered a peaking unit that will only operate a limited number of hours during the year. On the other hand, a baseload unit will operate a majority of hours during a year. A general rule of thumb in planning assumes a peaking unit will have a capacity factor of up to 20 percent, an intermediate unit of from 20 to 50 percent, and a baseload unit of from 50 to 85 percent.

The following section of this document will identify and discuss the resource options, starting with the mature technologies and working through the technology curve to the resources in the early stages of development. Exhibit A-1 summarizes each of the technologies and their pertinent characteristics.

COMBUSTION TURBINE UNITS

80-MW Simple Cycle Combustion Turbine

Developments in the area of utility application of combustion turbine (CT) technology have in many ways followed developments in the aircraft industry. Because of the light weight and drag requirements of turbojet aircraft engines, early designs were based on lightweight construction and materials, and design configurations were intended to minimize space needs. Further design developments improving efficiency and output also originated in the aircraft industry and were carried over to utility applications.

The principal components of a gas turbine are the compressor, the combustor, and the turbine. Compressors draw in air from the outside environment and use mechanical energy to compress the air to the desired pressure. In the compressor, the air leaving has had its temperature raised to the desired level by the burning of fuel in a combustor. This heated air and gases are then directed to the turbine, where they expand to produce work. A large portion of the mechanical work produced here is then directed to drive the air compressor. In a simple cycle configuration, as much as two-thirds of the work produced drives the compressor, leaving approximately one-third for useful power output.

Combustion turbines are a well-developed, mature technology widely used for peaking applications in which low capital cost and high availability have a greater impact than performance. They are marked by low capital costs, low O&M, modular design, and short lead time to construct. The disadvantage is that they are relatively less efficient to operate at higher capacity factors, and thus become an expensive source of power.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF SUPPLY SIDE OPTIONS

Combustion Turbine	Capacity	Fuel Type	Technology Status	Duty Cycle	Total Plant Cost	Heat Rate	Fixed O&M	Variable O&M	Availability	Additional Notes
Simple Cycle	80	#2 oil	Mature	Peaking	$ 362	12,158	$ 2.39	$ 0.57	90.0%	
Aeroderivative	45	#2 oil	Mature	Peaking	$ 648	10,000	$ 13.40	$ 0.18	83.5%	
Diesel	5	#2 oil	Mature	Peaking	$ 1,568	12,000	$ 3.31	$ 10.28	83.4%	
Battery Energy Storage										
Lead Acid - Light Duty	20	None	Mature	Peaking	$ 589	1.35	$ 0.62	$ 1.44	95.6%	Heat Rate =>Annual Energy Requirements
Lead Acid - Heavy Duty	20	None	Mature	Peaking	$ 776	1.31	$ 1.44	$ 6.73	95.6%	Heat Rate =>Annual Energy Requirements
Advanced Battery Storage - 3 Hr	20	None	Pilot	Peaking	$ 429	1.14	$ 0.42	$ 5.95	91.1%	Heat Rate =>Annual Energy Requirements
Advanced Battery Storage - 5 Hr	20	None	Pilot	Peaking	$ 589	1.04	$ 0.91	$ 4.28	91.1%	Heat Rate =>Annual Energy Requirements
Combined Cycle										
Combined Cycle	240	#2 oil	Mature	Intermediate	$ 596	7,900	$ 15.63	$ 1.77	90.5%	
Steam Injected	50	#2 oil	Mature	Intermediate	$ 950	9,133	$ 16.24	$ 6.28	90.6%	
Hydro Pumped Storage										
Conventional	1,050	None	Mature	Intermediate	$ 875	1.15	$ 3.83	$ 3.83	90.0%	Heat Rate =>Annual Energy Requirements
Underground	2,001	None	Mature	Intermediate	$ 1,152	1.36	$ 5.12	$ 5.12	90.0%	Heat Rate =>Annual Energy Requirements
Pulverized Coal										
Subcritical	560	Coal	Mature	Base	$ 1,209	9,932	$ 11.00	$ 1.30	84.4%	
Subcritical	400	Coal	Mature	Base	$ 1,233	10,002	$ 11.00	$ 1.30	85.1%	
Subcritical	240	Coal	Mature	Base	$ 1,404	10,091	$ 11.00	$ 1.30	85.9%	
Advanced Cycle - Supercritical	300	Coal	Mature	Base	$ 1,376	9,316	$ 32.49	$ 4.98	84.9%	
Solar										
Trough/Gas Hybrid	5	Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Sole Manufacturer is out of business
Fixed Flat Plate	5	Solar	Pilot	Peaking	$ 2,495	N/A	$ 7.06	$ 1.03	93.3%	
Fresnel Lens High	5	Solar	Pilot	Peaking	$ 2,766	N/A	$ 14.79	$ 3.69	92.2%	
Atmospheric Fluidized Bed										
Bubbling	200	Coal	Commercial	Base	$ 1,553	9,998	$ 40.40	$ 6.31	88.3%	
Circulating	200	Coal	Commercial	Base	$ 1,506	10,141	$ 37.13	$ 4.73	89.0%	
Pressurized Fluidized Bed										
Bubbling/Subcritical	320	Coal	Demonstration	Base	$ 1,272	9,664	$ 37.33	$ 8.24	83.4%	
Bubbling/Supercritical	340	Coal	Pilot	Base	$ 1,122	8,424	$ 35.68	$ 5.52	81.2%	
Circulating	200	Coal	Laboratory	Base	$ 1,556	9,465	$ 42.75	$ 7.44	89.1%	
Combined Cycle	340	Coal	Pilot	Base	$ 1,356	8,980	$ 39.86	$ 6.48	73.5%	
BIOMASS										
Wood-fired Stoker	50	Wood	Commercial	Base	$ 1,725	14,310	$ 87.98	$ 10.23	85.0%	
Wood-fired CFBC	50	Wood	Commercial	Base	$ 2,023	14,280	$ 93.40	$ 10.94	85.0%	
Wood/Coal Cofired	200	Wood Waste/Coal	Commercial	Base	$ 78	10,593	$ 35.92	$ 4.41	N/A	Capital Cost represents retrofit costs
Conv. Wood-fire OCC	100	Wood	Demonstration	Base	$ 2,330	12,740	$ 115.27	$ 14.55	N/A	
Adv. Wood-fired OCC	100	Wood	Pilot	Base	$ 2,016	10,090	$ 102.63	$ 10.84	N/A	
Whole Tree Energy	100	Whole Trees	Pilot	Base	$ 1,294	10,974	$ 58.69	$ 8.73	N/A	
Waste-to-Energy										
Municipal Solid Waste	40	Muni. Solid Waste	Commercial	Base	$ 4,145	16,906	$ 120.96	$ 17.25	86.0%	
Refuse-derived Fuel-fired Stoker	40	RDF	Commercial	Base	$ 4,411	15,753	$ 207.22	$ 23.14	86.0%	
Refuse-derived Fuel/Coal Cofired	200	RDF & Coal	Demonstration	Base	$ 115	10,600	$ 37.52	$ 4.72	N/A	Capital Cost represents retrofit costs
Scrap Tires/Coal Cofired	200	Scrap Tires & Coal	Demonstration	Base	$ 24	10,590	$ 37.52	$ 7.32	N/A	Capital Cost represents retrofit costs
Scrap Tire-fired Mass Burn	30	Scrap Tires	Demonstration	Base	$ 3,013	12,737	$ 98.52	$ 12.74	83.0%	
Nuclear										
Evolutionary Adv. Light Water	1,350	Uranium	Commercial	Base	$ 1,266	10,520	$ 59.13	$ 0.98	82.8%	
Passive Safety Light Water	600	Uranium	Demonstration	Base	$ 1,479	10,620	$ 72.04	$ 0.98	85.6%	
Adv. Liquid Metal	1,488	Uranium	Laboratory	Base	$ 1,541	9,515	$ 68.82	$ 1.03	85.6%	
Integrated Coal Gasification CC										
Entrained Flow/Medium Integration	500	Coal	Demonstration	Base	$ 1,493	9,190	$ 41.26	$ 1.82	87.6%	
Entrained Flow/Highly Integrated	500	Coal	Demonstration	Base	$ 1,369	8,710	$ 48.05	$ -	85.7%	
Entrained Flow/Nonintegration	500	Coal	Demonstration	Base	$ 1,789	8,950	$ 62.70	$ 0.64	84.3%	
Moving Bed/Medium Integration	500	Coal	Demonstration	Base	$ 1,545	8,670	$ 53.26	$ 2.65	85.7%	
Moving Bed/High Integration	500	Coal	Demonstration	Base	$ 1,540	8,420	$ 53.15	$ 2.44	85.7%	
Humid Air Turbine	500	Coal	Demonstration	Base	$ 1,319	8,570	$ 42.86	$ 2.23	N/A	
Fuel Cells										
Integrated Coal Gas. Molten Carbonate F	400	Coal	Demonstration	Base	$ 1,984	6,660	$ 62.85	$ 1.54	N/A	
Integrated Coal Gasification FC	23	Gas	Demonstration	Intermediate	$ 1,092	6,450	$ 21.52	$ 2.63	91.6%	
Molten Carbonate	3	Gas	Pilot	Intermediate	$ 1,194	8,300	$ 10.83	$ 6.11	97.0%	
Compressed Air Energy Storage										
CAES - Rock Cavern	350	N/A	Demonstration	Intermediate	$ 538	.74+3913	$ 6.09	$ 1.75	97.3%	Heat Rate =>Annual Energy Requirements
CAES - Salt Cavern	350	N/A	Commercial	Intermediate	$ 418	.74+3913	$ 4.89	$ 0.83	97.3%	Heat Rate =>Annual Energy Requirements
CAES - Aquifer	350	N/A	Demonstration	Intermediate	$ 421	.74+3913	$ 4.89	$ 1.75	97.3%	Heat Rate =>Annual Energy Requirements
CAES w/Humid Air Turbine - Rock Cavr	350	N/A	Pilot	Intermediate	$ 434	.46+6035	$ 4.98	$ 1.75	97.3%	Heat Rate =>Annual Energy Requirements
CAES w/Humid Air Turbine - Salt Cavern	350	N/A	Pilot	Intermediate	$ 369	.46+6035	$ 4.34	$ 0.83	97.3%	Heat Rate =>Annual Energy Requirements
CAES w/Humid Air Turbine - Aquifer	350	N/A	Pilot	Intermediate	$ 368	.46+6035	$ 4.34	$ 0.83	97.3%	Heat Rate =>Annual Energy Requirements
Geothermal										
Binary	26	Brine	Demonstration	Renewable	$ 1,805	31,770	$ 55.15	$ 3.01	92.1%	
Dual Flash	48	Brine	Demonstration	Renewable	$ 1,021	24,154	$ 27.53	$ 1.80	97.0%	
Wind										
Wind Turbine	50	N/A	Demonstration	Intermediate	$ 859	N/A	$ 17.38	$ 3.51	95.0%	
Superconducting Magnetic Storage										
Superconducting Magnetic Storage	500	N/A	Pilot	Peak	$ 693	1.08	$ 4.76	$ 3.81	90.4%	Heat Rate =>Annual Energy Requirements

Combustion turbines also offer some flexibility, however, in that they can be installed as simple cycle and in later years have a Heat Recovery Steam Generator (HRSG) added to incorporate the CT into a combined cycle and meet intermediate load requirements.

The primary emission concern in a combustion turbine is nitrogen oxides, or NO_x. The control for this emission is the injection of water or steam into the combustor. The industry is successfully working towards a dry, low NO_x combustor in which the emission can be controlled without the injection of water or steam.

An issue to monitor in the near future is the manufacturers' production capacity to keep up with projected utility orders. Approximately 28 GW of new combustion turbine or combined cycle generation capacity is planned between 1994 and 2002. This significant volume of new orders could result in premium pricing if the manufacturers are unable to keep pace with the demand. Discussions with some utilities have indicated efforts are being considered to order the units early to reserve a position in the manufacturers' production cycles.

Unit Statistics

Capacity: 80 MW

Fuel Type: Natural Gas (primary), #6 Oil (secondary)
Technology Status: Mature
Duty Cycle: Peaking
Total Plant Cost: (1994$) $362/kW (w/o IDC - interest during construction)
Full Load Heat Rate: 12,158 Btu/kWh
Annual Fixed O&M: (1994$) $2.39/kW-yr
Annual Variable O&M: (1994$) $0.57/MWh
Equivalent Availability: 90.0%

45-MW Combustion Turbine - Aeroderivative

In addition to the simple-cycle combustion turbine described above, the utility industry has also utilized the aeroderivative combustion turbine technology. A unit of this type is essentially a jet engine with a design modification for stationary operation. In general, its operation is similar to the simple-cycle combustion turbine; however, the unit size is smaller than the simple-cycle combustion turbine applications being planned and constructed by utilities today.

The significant differences between the simple-cycles and the aeroderivatives are the economic parameters. The aeroderivatives have higher capital costs by a factor of 2 to 1. The annual fixed O&M costs are also slightly higher. However, the aeroderivatives are more efficient to operate, which results in a lower heat rate, approximately 10 percent lower, which in turn will translate into a lower fuel cost. Overall, the costs to operate an aeroderivative versus a simple-cycle combustion turbine will be higher. Unless there is a specific location or operating requirement for the aeroderivative, a utility will prefer the simple-cycle combustion turbine unit.

Unit Statistics

Capacity: 45 MW

Fuel Type: Natural Gas (primary), #6 Oil (secondary)
Technology Status: Mature
Duty Cycle: Peaking
Total Plant Cost: (1994$) $648/kW (w/o IDC)
Full Load Heat Rate: 10,000 Btu/kWh
Annual Fixed O&M: (1994$) $13.4/kW-yr
Annual Variable O&M: (1994$) $0.18/MWh
Equivalent Availability: 83.5%

5-MW Diesel Generator

Diesel generators offer advantages for certain operating requirements that are also important to consider. Some utilities do rely on diesel generators as a backup or peaking supply, but this is generally only to remote, inaccessible areas. In this role they offer some advantages, namely, their ability to go quickly from cold condition to full load, high degree of reliability, and remote-start capability.

Some of the major disadvantages offered by diesel generators are their small size, unsuitability for significant expansion, noise emissions, potential for damaging fuel oil spills, NO_x emissions levels that can limit operation to as little as 1,000 hours annually, and smoking, which residents view as unsightly, during operation. Particulate emissions also place a constraint on the number of units that can be co-located and limit overall usefulness.

Diesel generators have generally not proven as popular as combustion turbines for smaller, peaking unit duty. Combustion turbines offer a number of advantages, primarily in the areas of cost and environmental performance, where utilities have demonstrated a preference. This is especially true with regard to fuel flexibility. CTs utilize natural gas, which is advantageous during summer periods, whereas the premium cost of oil puts diesels at an extreme disadvantage.

In summary, diesels are not a desired option except in the most remote locations. The difficulties involved, from transmission system modifications, O&M logistical concerns, and emissions characteristics, limit operational usefulness. Finally, fuel considerations, including the higher cost of oil, the absence of fuel switching capability and the CT's ability to use natural gas during summer peaking periods, make this option economically unattractive.

Unit Statistics

Capacity: 5 MW

Fuel Type: #6 Oil
Technology Status: Mature
Duty Cycle: Peaking
Total Plant Cost: (1994$) $1,568/kW (w/o IDC)
Average Annual Heat Rate: 12,000 Btu/kWh
Annual Fixed O&M: (1994$) $3.31/kW-yr
Annual Variable O&M: (1994$) $10.28/MWh
Equivalent Availability: 83.4%

BATTERY ENERGY STORAGE UNITS

20-MW Lead Acid Battery Energy Storage Systems
20-MW Advanced Battery Energy Storage

The use of battery systems offers great potential for small power requirements. A 10-MW load-leveling facility is in operation in the Chino (California) substation. This facility is rated to deliver 10 MW and 40 MWh for four hours. The Puerto Rico Electric Power Authority installation at Sabana Llana substation is rated for 21 MW and 14 MWh and was scheduled to go on line in 1993.

Battery energy storage systems (BEES) are a flexible means to deal with peak storage concerns as well as providing spinning reserve and frequency regulation capability. Since they are small and of modular design, they are easy to install, with little lead time required. Since they produce zero emissions and zero noise, they are generally easy to site and encounter little public opposition.

Two designs for the lead acid batteries are available–light and heavy duty. The light duty battery is typically used for spinning reserve, peak shaving, or combustion turbine deferral because of its quick response time–typically full load is achieved in five milliseconds. The heavy duty battery is typically used for load-leveling and frequency regulation. Both designs are based on a 20-MW capacity and a one-hour storage. The lives of these batteries are uncertain and depend largely on the number of cycles during a year. The light duty design has a lower overall life for the battery modules (compared to the balance of plant) than the heavy duty design. Both designs, though, are expected to require frequent replacements during a typical 30-year planning horizon.

Whereas the older-design batteries use lead acid, a new advanced design is based on either a sodium-sulfur or a zinc-bromide system. The emission levels of the advanced design are virtually zero. The greatest advantage of the new design is the three- or five-hour storage capabilities compared to the one-hour storage of the lead acid design.

Unit Statistics

Capacity: 20 MW

Technology: Lead Acid Battery Energy Storage System
Fuel Type: None
Technology Status: Mature
Duty Cycle: Peaking

Total Plant Cost: (1994$)	$589/kW - Light Duty (w/o IDC)
	$776/kW - Heavy Duty (w/o IDC)

Average Annual Energy Requirements (kWh Input/kWh Output)	
	1.35 - Light Duty
	1.31 - Heavy Duty
Annual Fixed O&M: (1994$)	$0.62/kW-yr - Light Duty
	$1.44/kW-yr - Heavy Duty
Annual Variable O&M: (1994$)	$8.92/MWh - Light Duty
	$6.73/MWh - Heavy Duty
Equivalent Availability: 95.6%	

Technology: Advanced Battery Energy Storage System
Fuel Type: None
Technology Status: Pilot
Duty Cycle: Peaking

Total Plant Cost: (1994$)	$429/kW - 3 hour (w/o IDC)
	$589/kW - 5 hour (w/o IDC)
Average Annual Energy Requirements (kWh Input/kWh Output)	
	1.14 - 3 hour
	1.04 - 5 hour
Annual Fixed O&M: (1994$)	$0.42/kW-yr - 3 hour
	$0.91/kW-yr - 5 hour
Annual Variable O&M: (1994$)	$5.95/MWh - 3 hour
	$4.28/MWh - 5 hour
Equivalent Availability: 91.1%	

COMBINED CYCLE UNITS

240-MW Combined Cycle - Natural Gas- or Oil-fired

The typical combined cycle installation consists of a gas turbine which discharges waste heat into a heat recovery steam generator (HRSG). The HRSG supplies steam that is expanded through a steam turbine cycle driving an electric generator. A combined cycle design is shown in Exhibit A-2.

Configurations considered in most recent studies have been for plants in which two-thirds of the electrical output was from the combustion turbines, with the remaining one-third from the steam generator powered by the HRSG. This is accomplished with two matched combustion turbines in parallel and the HRSG in series after the combustion turbines. The combustion turbines can be operated alone to meet peaking requirements or in conjunction with the HRSG to meet the intermediate load requirements. Installation of the facility is often planned in a phased approach, with the combustion turbines installed first and the HRSG installed some years later as the system load grows.

Another popular usage of the combined cycle configuration is in the repowering of older existing steam units. An example is at Lakeland, Florida, where a mid-1950s vintage 25-MW coal-fired steam unit was repowered with the existing steam turbine and generator and a new 80-MW combustion turbine and HRSG. The combined output of the repowered plant is approximately 113 MW. The installed cost was around $400/kW for a 1993 commercial in-service date, which is significantly lower than the installed cost of a new combined cycle facility. However, it is utilizing certain major pieces of equipment that are already over 40 years old and will require many years of monitoring before it can be proven to be a valid alternative over time.

The largest drawback to the combined cycle plant is the uncertainty related to the future price of natural gas. A number of gas-fired plants under construction on the eastern seaboard may affect the available supply of gas. The industry feeling today is to take advantage of the benefits of gas but to remain vigilant about fuel procurement issues.

Unit Statistics

Capacity: 240 MW

Fuel Type: Natural Gas (primary), #6 Oil (secondary)
Technology Status: Mature
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $596/kW (w/o IDC)
Full Load Heat Rate: 7,900 Btu/kWh

HYDRO PUMPED STORAGE UNITS

Hydro Pumped Storage - Conventional and Underground

Hydro pumped storage is based on using power during off-peak periods to pump water to a higher elevation. Then the water is returned to the lower elevation when peak power is needed and so reduce the generation required during these periods. Recent innovations to this idea have involved locating generation in underground caverns or geological formations and pumping the water to a ground-level reservoir during off-peak periods.

Storage capability depends on the amount of water, the hydraulic head, and the generating capacity. It is generally on the order of 10 hours, which is sufficient to meet most utilities' daily peak requirements.

Hydro pumped storage is a technology that can sometimes ideally meet a given utility's energy storage requirements. The facilities are marked, however, by high capital costs, long construction lead times, and the uncertainty of equipment being able to achieve desired levels of operation.

Unit Statistics

Capacity: 3 units @ 350 MW Conventional

Fuel Type: None
Technology Status: Mature
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $875/kW (w/o IDC)
Average Annual Energy Requirements: 1.15 (kWh Input/kWh Output)
Annual Fixed O&M: (1994$) $3.83/kW-yr
Annual Variable O&M: (1994$) $3.83/MWh
Equivalent Availability: 90.0%

Capacity: 3 units @ 667 MW Conventional

Fuel Type: None
Technology Status: Mature
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $1,152/kW (w/o IDC)
Average Annual Energy Requirements: 1.36 (kWh Input/kWh Output)

Annual Fixed O&M: (1994$) $5.12/kW-yr

Annual Variable O&M: (1994$) $5.12/MWh

Equivalent Availability: 90.0%

PULVERIZED COAL UNITS

560-MW Pulverized Coal-fired Unit - Subcritical
400-MW Pulverized Coal-fired Unit - Subcritical
240-MW Pulverized Coal-fired Unit - Subcritical

Pulverized coal (PC) units represent a proven, mature technology which has been the primary coal-based alternative for use as a baseload generating station for decades. The basic design for these units has not changed significantly since the last wave of baseload construction in the early 1970s; however, constant evolution of design has occurred primarily in response to environmental and efficiency requirements.

Three distinct unit sizes have been identified for the Santee Cooper study. In general, the sizes were selected as multiples of 80 MW to correspond to the assumed size of the combustion turbine alternative. A review of the utility industry's plans indicates a total of 70 new coal-fired units planned and representing 25 gigawatts of capacity. This equates to an average new unit size of 357 MW. The largest unit planned is 832 MW; from there they decrease in size to as small as 100 MW. The majority of the units are in the 300- to 400-MW size. Therefore, for study purposes, three sizes were screened for economics.

General Design. In a PC design, almost any type of coal can be used as the fuel source. The coal is pulverized to the consistency of a fine power, similar to facial powder, and then burned as a gas, so the combustion process can be easily ignited and controlled. PC firing has come to dominate the market to such an extent that power generation by stoker firing is no longer a valid consideration.

In a standard PC design configuration, coal is first crushed to a uniform consistency. The coal is then fed to a pulverizer or mill. It is here the particle size is further reduced to the consistency required for combustion in the boiler.

Many refinements to the basic PC design have occurred in recent years. These developments increase the efficiency of the combustion process, reduce required maintenance, or increase the operating flexibility of the units. A number of other design developments would probably be incorporated in any newly designed PC unit. These include:

- Spiral-wound, once-through boilers have proven more popular to date in Europe than in the United States but offer a number of advantages. They increase the operating flexibility of the unit by operating in a full variable pressure mode at either sub- or supercritical steam pressures.

- Full-arc admission turbines reduce part-load heat rates.
- A high-capacity steam bypass system can improve cycling capability.
- Heat pipe air heaters reduce gas-to-gas side leakage and minimize corrosion and horsepower consumption.
- Header feedwater heaters replace massive tubesheets with header; the result is thinner sections and reduced stresses for better cycling.

Pollution Control Technology. Table 1 establishes a cost baseline for pulverized coal units for service beyond 2000. Although no additional NO_x controls are assumed, to meet the NO_x limits as set forth in March, 1994, additional NO_x controls may be necessary as future regulations are issued. These controls may be low NO_x burners necessary to achieve 0.5 lbs/MMBtu or SCRs for lower emissions. These are general limits and may change for a specific unit at a specified site on the basis of local regulations. For most new units that are planned for commercial operation in the late-1990s and into the 2000s, the EPA has developed a procedure for a review of the emissions from the plant and is requiring the utility to follow "strict technology based limits," which means it expects the utility to meet BACT, or the Best Available Control Technology available. This requirement is especially common in a nonattainment area or in an area with strong environmental sentiment.

Table 1

Future Pulverized Coal Unit

Pollutant	Type of Control	Annual Average Permit Limit
Sulfur Dioxide	Wet Limestone FGD	90% Removal
		1.20 lbs/MMBtu
Particulate - PM	Electrostatic Precipitator	0.01 lbs/MMBtu
- PM_{10}		0.008 lbs/MMBtu
Nitrogen Oxides	Low NO_x Burners	0.5 lbs/MMBtu

Pollution Control Equipment. Ash formed in the furnace is removed from the walls and radiant superheater by soot blowers. The heavier bottom ash is removed directly from the furnace via a submerged drag chain conveyor; the lighter fly ash is to be removed from the flue gas by an ESP. The electrostatic precipitator is designed to remove 99.97 percent of the fly ash.

The most frequently used type of SO_2 removal process employed by utilities today is a wet limestone spray tower system as illustrated in Exhibit A-3. Limestone ball mills produce a slurry which is sprayed at multiple levels into the flue gas as it passes through an absorber vessel. The chemical reaction produces calcium sulfate and calcium sulfite sludge. Directly below the absorber are equally sized reaction tanks which allow adequate retention time for the chemical reactions to occur. Pumps then recycle the slurry on each tank. Flue gas leaving the scrubber passes through mist eliminators and enters a titanium alloy-lined chimney.

The precipitated sludge from the reaction tank is further reduced to a concentration of 20 percent solids in a thickener. Vacuum filters further dewater the sludge and it is then mixed with the fly ash for transport to an environmentally sound waste landfill.

Unit Statistics

Capacity: 560 MW

Fuel Type: Eastern Kentucky Coal
Technology Status: Mature
Duty Cycle: Base
Total Plant Cost: (1994$) $1,209/kW (w/o IDC)
Average Annual Heat Rate: 9,932 Btu/kWh
Annual Fixed O&M: (1994$) $11.00/kW-yr
Annual Variable O&M: (1994$) $1.30/MWh
Equivalent Availability: 84.4%

Capacity: 400 MW

Fuel Type: Eastern Kentucky Coal
Technology Status: Mature
Duty Cycle: Base
Total Plant Cost: (1994$) $1,233/kW (w/o IDC)
Average Annual Heat Rate: 10,002 Btu/kWh
Annual Fixed O&M: (1994$) $11.00/kW-yr
Annual Variable O&M: (1994$) $1.30/MWh
Equivalent Availability: 85.1%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

CONVENTIONAL LIMESTONE PROCESS

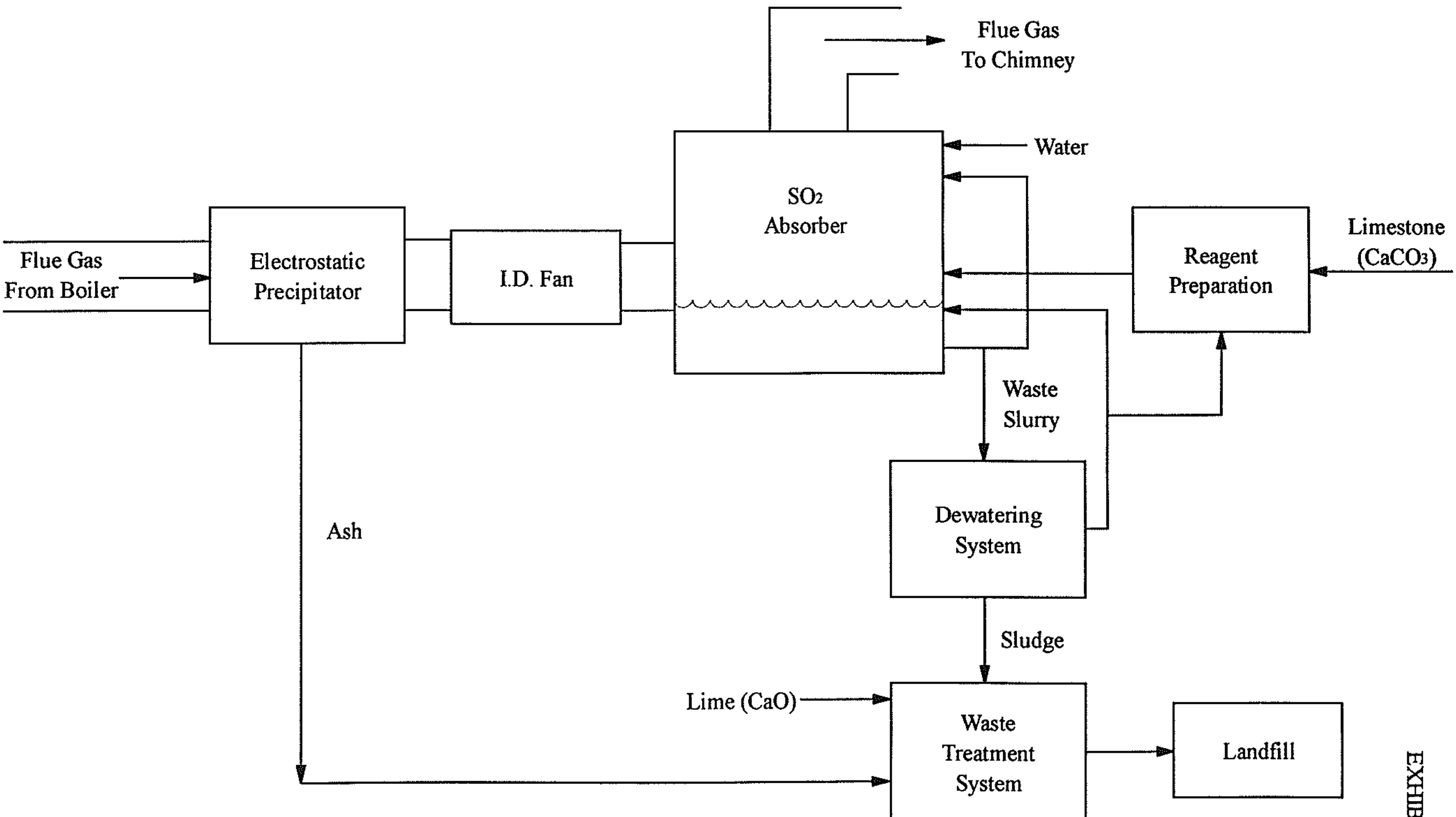


EXHIBIT A-3

Capacity: 240 MW

Fuel Type: Eastern Kentucky Coal
Technology Status: Mature
Duty Cycle: Base
Total Plant Cost: (1994$) $1,404/kW (w/o IDC)
Average Annual Heat Rate: 10,091 Btu/kWh
Annual Fixed O&M: (1994$) $11.00/kW-yr
Annual Variable O&M: (1994$) $1.30/MWh
Equivalent Availability: 85.9%

300-MW Advanced Cycle PC - Supercritical

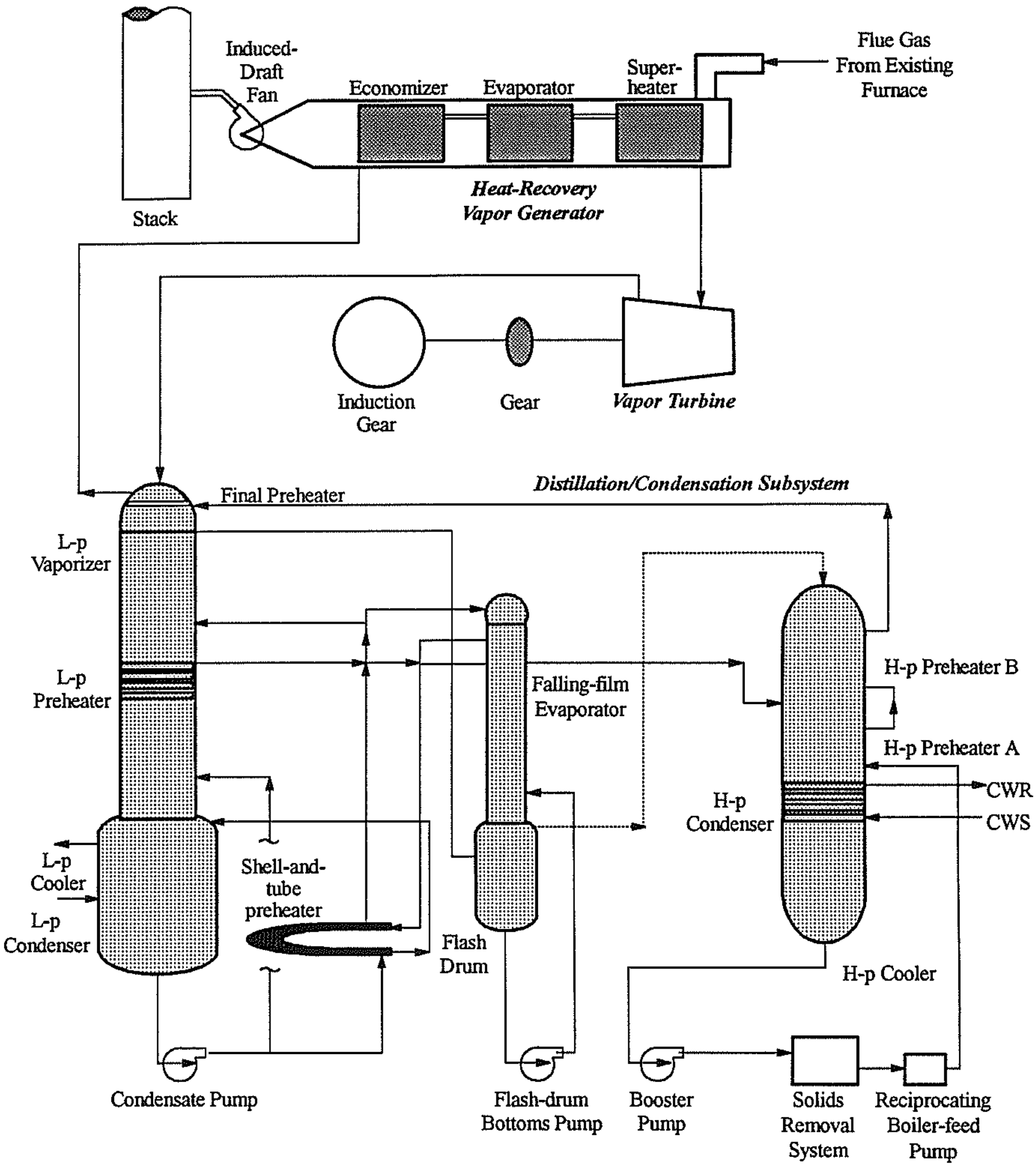
Progress in the development of advanced cycle boiler designs has been steady over the years. Advanced cycle designs include current Rankine cycle versions of supercritical (3,500 psig/1,000°F/1,000°F steam conditions) and ultrasupercritical (4,500 psig/ 1,100°F/1,100°F steam conditions) designs, as well as developments in the Kalina-based steam cycle. These developments would offer potential for any fuel source, although coal's abundant supply gives it obvious advantages. Exhibit A-4 is a schematic representation of an advanced cycle boiler design.

Most developments in supercritical and ultracritical designs have thus far occurred overseas. Japan is proceeding with development of supercritical units on the basis of the success it has enjoyed with its Kawagoe station. This plant has a thermal efficiency of 42 percent, making it the most efficient steam electric plant to enter service in the past 20 years. Although the Kawagoe station burns LNG, research is underway to apply the same ultrasupercritical technology to PC-fired units to achieve a correspondingly high efficiency output. Philadelphia Electric Company's Eddystone Station is the one ultrasupercritical plant operating in the United States today. Built in 1960, it is also the oldest ultrasupercritical plant in the world.

Other utilizations of advanced cycle designs include development of a Kalina-cycle demonstration plant that offers the opportunity to replace the Rankine cycle-based plants, which are the standard today. This technology is characterized by an ammonia/water working fluid which can achieve much higher efficiencies than current state-of-the-art steam power plants. The DOE has a small (3.2 MW) demonstration plant using this process and operating at its Energy Technology Engineering Center near Canoga Park, California.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

ADVANCED CYCLE DESIGNS



The Kalina cycle comprises a heat recovery vapor generator, a vapor turbine generator, and a distillation/condensation subsystem (DCSS). It is the DCSS that enables the enhanced performance of the cycle. It is possible to maintain a lower turbine exhaust pressure by altering the ammonia concentration at different points in the DCSS.

Commercialization of the Kalina cycle is foreseen for coal-fired generation (PC unit, fluidized bed, or gasification), gas, or even geothermal, since the technology can be applied to low temperature sources as well.

A final benefit potentially offered by the Kalina cycle process is the potential to retrofit older, low-performance coal plants without dismantling them. Additional boiler, heat exchange, and turbine equipment can be installed to work in concert with the existing plant. When completed, the new plant's heat rate could be an expected 10 to 20 percent lower than the original plant.

The current status of these advanced cycle design developments still classifies them as in the developmental stage. Successful development of these technologies could potentially benefit Santee Cooper. With Santee Cooper's risk-averse assumption regarding untested technologies, this technology is not valid for consideration at this point, although developments in this area should be closely monitored.

Unit Statistics

Capacity: 300 MW

Fuel Type: Eastern Kentucky Coal
Total Plant Cost: (1994$) $1,376/kW (w/o IDC)
Technology Status: Mature
Duty Cycle: Base
Average Annual Heat Rate: 9,316 Btu/kWh
Annual Fixed O&M: (1994$) $32.49/kW-yr
Annual Variable O&M: (1994$) $4.98/MWh
Equivalent Availability: 84.9%

SOLAR UNITS

80-MW Solar - Trough/Gas Hybrid
5-MW Solar - Fixed Flat Plate
5-MW Solar - Fresnel Lens High

A review of EPRI literature indicates a number of different solar technologies in the early development stage. The solar parabolic trough/gas hybrid power plant is the only version of the solar technologies that has been classified as mature. This is largely due to the experience of the Luz LS-3 solar energy generating system, which was constructed by the former Luz Development Company from 1985 to 1991 in the Mojave Desert of California. This facility has a capacity of approximately 350 MW.

In the California facility, the parabolic trough solar collectors are oriented in the north-south direction and track the sun to focus sunlight onto vacuum-insulated steel pipes. The solar collector field heats the heat transfer fluid from about 560° to 735°F, and the heat is transferred in a series of heat exchangers to generate superheated steam at 1,450 psi and 700°F, with a single reheat to 700°F. The solar collector field and gas-fired boiler can operate independently or in parallel.

The Luz Company faced significant financial and regulatory uncertainty which caused the company to discontinue operations in 1992. This resulted in the discontinuance of further development of this technology through the present time. The company has been purchased by Belgo International, a Belgian firm, which is currently researching a different solar technology.

In the early stages of development are the **Fixed Flat Plate** and the **Fresnel Lens High Concentration** solar cells. In the solar facility described above, the solar energy is used to heat a fluid to generate steam. The fixed flat plate and the Fresnel lens cells directly convert the sunlight into direct-current electric power. The output of the cells is then converted into alternating current via a dc-to-ac converter.

The largest drawback to the use of solar cells is the efficiency of the cells today and the resulting large number of cells required and their large land mass requirements. Current cells are approximately 12 percent efficient, or produce about 120 watts per square meter of surface area at solar noon when the sun's energy is at its peak of 1 kilowatt per square meter. Therefore, a 100-MW power plant would require up to one square mile for the cells alone.

In addition to the land requirements, the highest output occurs when the sun's energy is at its greatest. This means that if the utility's peak needs are in the late afternoon or evening, the solar cells would not be at their peak capabilities.

The fixed plate design consists of a large number of fixed-flat plate photovoltaics with a solar-to-dc electric conversion capability of 15 percent at 25°C cell temperature. The Fresnel Lens design is based on a two-axis tracking array of cells. The assumed solar-to-dc conversion capability is 27.4°C cell temperature.

Unit Statistics

Technology: Solar - Trough/Gas Hybrid
Since the sole manufacturer of this technology is no longer manufacturing it, no unit statistics were developed for it.

Capacity: 5 MW

Technology: Fixed Flat Plate
Fuel Type: Solar
Technology Status: Pilot
Duty Cycle: Peaking
Total Plant Cost: (1994$) $2,495/kW (w/o IDC)
Annual Fixed O&M: (1994$) $7.06/kW-yr
Annual Variable O&M: (1994$) $1.03/MWh
Equivalent Availability: 93.3%

Technology: Fresnel Lens High Concentration
Fuel Type: Solar
Technology Status: Pilot
Duty Cycle: Peaking
Total Plant Cost: (1994$) $2,766/kW (w/o IDC)
Annual Fixed O&M: (1994$) $14.79/kW-yr
Annual Variable O&M: (1994$) $3.69/MWh
Equivalent Availability: 92.2%

ATMOSPHERIC FLUIDIZED BED COMBUSTION (AFBC) UNITS

200-MW Atmospheric Fluidized Bed Combustion - Bubbling
200 MW Atmospheric Fluidized Bed Combustion - Circulating

Atmospheric fluidized bed technology can be initially classified as either bubbling or circulating bed design. Design evaluations have somewhat expanded the choices to four basic types: bubbling bed with solids recirculation, bubbling bed with internal circulation, hybrid designs combining one or more fluidization approaches, and full-fledged circulating fluidized bed (CFB). A schematic representation of an atmospheric circulating fluidized bed design is shown in Exhibit A-5.

In a fluidized bed boiler, coal or another fuel source is mixed with limestone in the combustion chamber in order to reduce emissions. Because the sulfur is captured in the combustion process, there is no need for flue gas scrubbers. Fluidized bed technology also offers a range of options as to type of fuel. Fuels can include all grades of coal, peat bark, tires, woodwaste, sludge (even de-inking sludge from paper recycling), natural gas and oil.

Several early utility retrofit projects provided the earliest feedback on bubbling bed technology, including the TVA's Shawnee Station and Northern States Power's Black Dog Station. Initial operations at these locations did suffer from a number of difficulties, but it is important to note that these units were conceived of as demonstration facilities and, as such, required significant test and evaluation programs. Operating performance for both these units has improved dramatically since installation.

Given the emergence of circulating bed technology, it appears likely that no more bubbling bed units will be built by electric utilities and that the trend is towards larger circulating bed units. A 250-MW CFB unit is to be built under DOE's Clean Coal Technology Program, and the Japanese are planning to build a 350-MW unit. Operations and maintenance requirements have been steadily improving over recent years. In addition, reliability has also improved and is now comparable to similar sized PC units.

The majority of available sizes constructed to date have been under 200 MW; however, there is the option of configuring two boilers to operate in tandem. There are currently approximately 114 such boilers operating today. Of these, seven are in electric utilities, 101 are operated by IPPs, and six are industrial process units.

The industry is still debating as to whether fluidized bed boilers retain their advantage for larger-sized boilers. Fluidized bed boilers have successfully demonstrated their ability to burn a wide range of quality of fuels; yet they require the addition of more limestone than a typical PC unit. In addition, if the price of gas increases, then the comparative costs of solid fuels comes down and fluidized bed units become more attractive.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

CIRCULATING FLUIDIZED BED BOILER

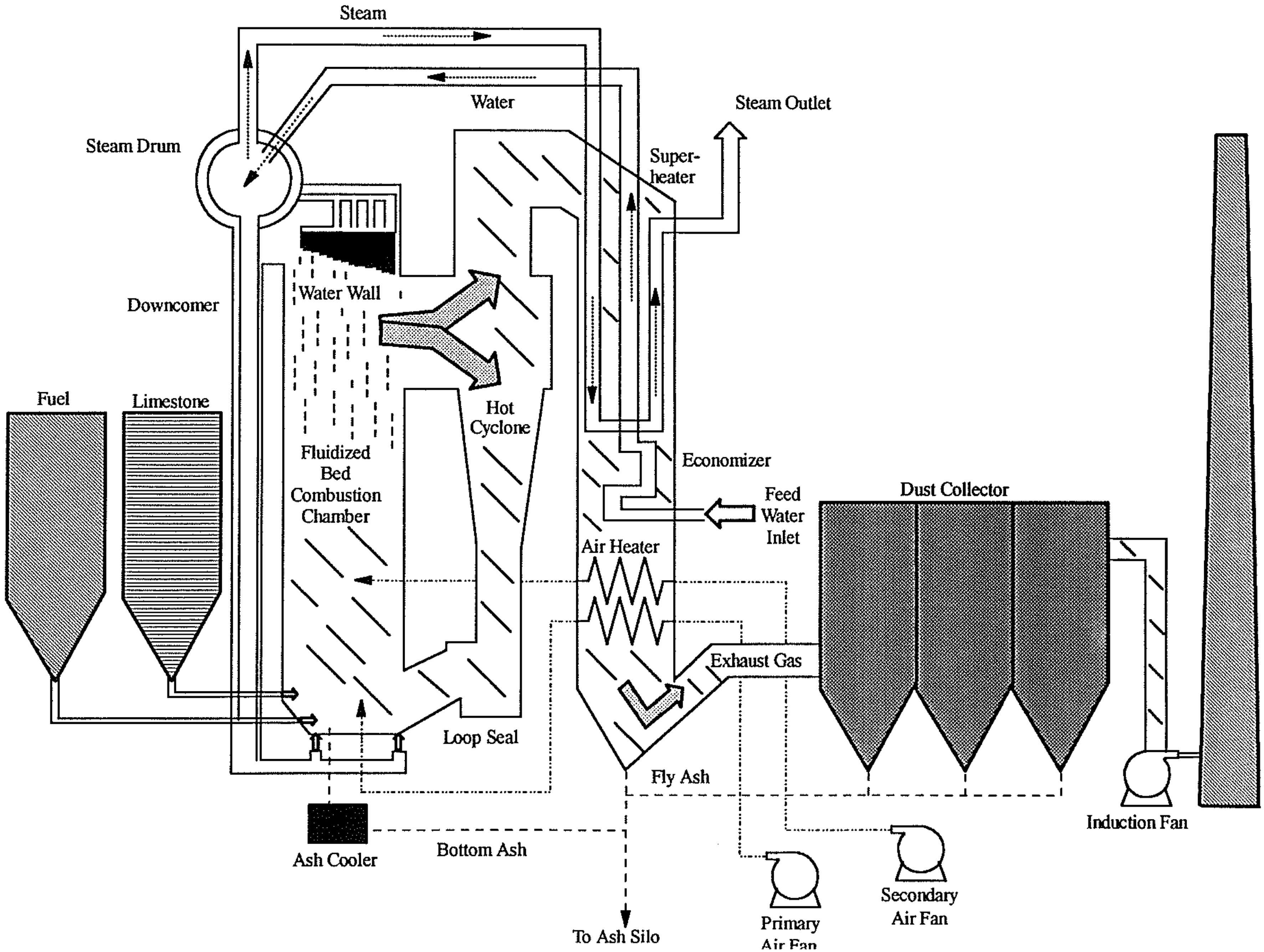


EXHIBIT A-5

On the other hand, emission restrictions, particularly for NO_x, are expected to become more stringent in future years. Under standard operating conditions, NO_x emissions are in the range of 1.5 lbs/MMBtu. Because of the fluidized bed design, NO_x emissions are controlled. A fairly constant and low combustion temperature can be maintained, and the residence time in the boiler itself can be up to six full seconds, allowing more complete combustion. Under this situation, ammonia injection can itself work very well and lower emissions to the area of 0.07 lbs/MMBtu.

Eventually, PC units will be required to add NO_x reduction technologies, which will require capital investment and thus would make PC units less attractive. So a tightening in emissions standard favors the fluidized bed technology.

Unit Statistics

Capacity: 200 MW (Bubbling)

Fuel Type: Eastern Kentucky Coal
Technology Status: Commercial
Duty Cycle: Base
Total Plant Cost: (1994$) $1,553/kW (w/o IDC)
Average Annual Heat Rate: 9,998 Btu/kWh
Annual Fixed O&M: (1994$) $40.40/kW-yr
Annual Variable O&M: (1994$) $6.31/MWh
Equivalent Availability: 88.3%

Capacity: 200 MW (Circulating)

Fuel Type: Eastern Kentucky Coal
Technology Status: Commercial
Duty Cycle: Base
Total Plant Cost: (1994$) $1,506/kW (w/o IDC)
Average Annual Heat Rate: 10,141 Btu/kWh
Annual Fixed O&M: (1994$) $37.13/kW-yr
Annual Variable O&M: (1994$) $4.73/MWh
Equivalent Availability: 89.0%

PRESSURIZED FLUID BED COMBUSTION

320-MW Pressurized Fluidized Bed Combustion - Bubbling/Subcritical
340-MW Pressurized Fluidized Bed Combustion - Bubbling/Supercritical
200-MW Pressurized Fluidized Bed Combustion - Circulating
340-MW Pressurized Fluidized Bed Combustion - Combined Cycle

Pressurized fluidized bed combustion (PFBC) involves burning crushed coal mixed with a limestone or dolomite sorbent in a pressurized environment. The success of the Tidd PFBC/CC plant located in Brilliant, Ohio and operated by American Electric Power is generating significant interest in the potential of this technology. A schematic representation of the pressurized fluidized bed design is shown in Exhibit A-6.

A pressurized environment allows for combustion to occur in a deeper bed, which results in a smaller amount of total system pressure drop and allows for up to 50 percent of the total combustion residence time to be in the bed, where heat transfer rates are higher. The higher pressure of the PFBC design allows for a smaller bed area and a smaller required physical plant area.

Emissions of NO_x are reduced because of the low combustion temperature (1,580° - 1,600° Fahrenheit) of the PFB design. SO_x emissions are also lower than required by the Clean Air Act. One of the principal attractions of this design, however, is the range of fuels that can be used to fire such a plant. PFBC units can efficiently burn coal with high ash, sulfur, and moisture contents.

PFBC can also incorporate a gas turbine and a steam turbine; the result is a combined cycle plant configuration. This is the case at the Tidd plant. Inside the combustor vessel, coal and sorbent are first mixed and combusted to generate steam which is used to drive a steam turbine. A gas turbine compressor simultaneously provides high pressure combustion air to the combustor vessel. This air is fed through the lower bed of the boiler to mix with the crushed coal and sorbent. The exhaust gas continues through the cyclones, which remove most of the particles from the gas. The resulting high-energy cleansed gas is then used to drive the gas turbine.

At this time, it is still unclear whether circulating bed PFBC design will replace the bubbling bed PFBC as the preferred technology, as was the case with AFBC.

Although early development of PFBC units has concentrated on small units, the trend is to scale up these designs to larger units. There are four 80-MW PFBC plants now operating worldwide. Only the Tidd plant is located in the United States. All four plants are of the bubbling bed design. Design work is underway on a 340-MW PFBC unit near Mountaineer with startup scheduled in 1998. Although manufacturers had at one time

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

PRESSURIZED FLUIDIZED BED COMBUSTION

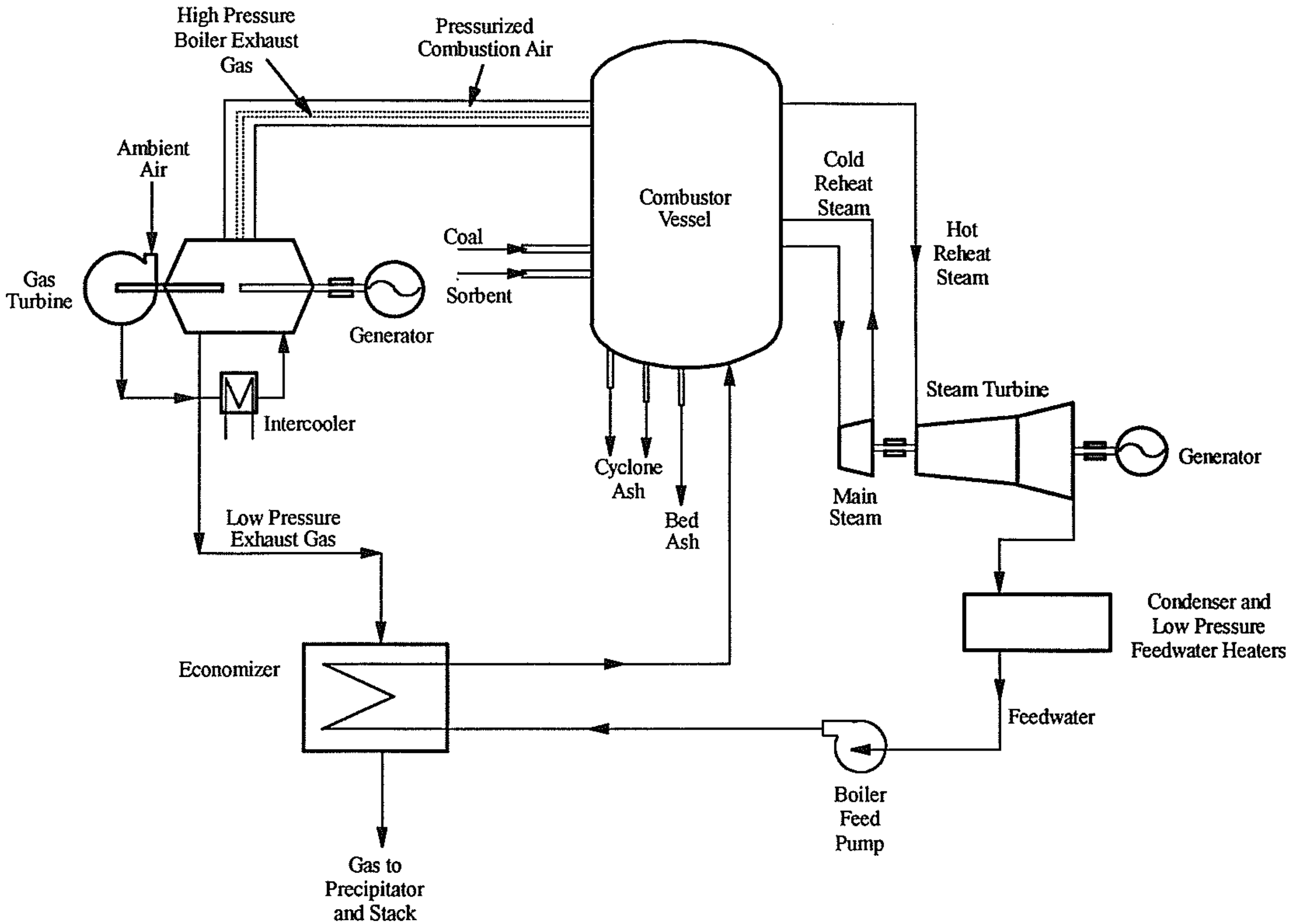


EXHIBIT A-6

thought that units could be sized at 500-MW or more, a general consensus that approximately 300-MW is the practical limit for a single boiler seems to be emerging.

Unit Statistics

Capacity: 320 MW

Technology: PFBC - Bubbling/Subcritical
Fuel Type: Eastern Kentucky Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $1,272/kW (w/o IDC)
Average Annual Heat Rate: 9,664 Btu/kWh
Annual Fixed O&M: (1994$) $37.33/kW-yr
Annual Variable O&M: (1994$) $8.24/MWh
Equivalent Availability: 83.4%

Capacity: 340 MW

Technology: PFBC - Bubbling/Supercritical
Fuel Type: Eastern Kentucky Coal
Technology Status: Pilot
Duty Cycle: Base
Total Plant Cost: (1994$) $1,122/kW (w/o IDC)
Average Annual Heat Rate: 8,424 Btu/kWh
Annual Fixed O&M: (1994$) $35.68/kW-yr
Annual Variable O&M: (1994$) $5.52/MWh
Equivalent Availability: 81.2%

Capacity: 200 MW

Technology: PFBC - Circulating
Fuel Type: Eastern Kentucky Coal
Technology Status: Laboratory
Duty Cycle: Base
Total Plant Cost: (1994$) $1,556/kW (w/o IDC)
Average Annual Heat Rate: 9,465 Btu/kWh

Annual Fixed O&M: (1994$) $42.75/kW-yr
Annual Variable O&M: (1994$) $7.44/MWh
Equivalent Availability: 89.1%

Capacity: 340 MW

Technology: PFBC - Combined Cycle
Fuel Type: Eastern Kentucky Coal
Technology Status: Pilot
Duty Cycle: Base
Total Plant Cost: (1994$) $1,356/kW (w/o IDC)
Average Annual Heat Rate: 8,980 Btu/kWh
Annual Fixed O&M: (1994$) $39.86/kW-yr
Annual Variable O&M: (1994$) $6.48/MWh
Equivalent Availability: 73.5%

BIOMASS UNITS

50-MW Wood-fired Stoker
50-MW Wood-fired Circulating Fluidized Bed Combustion
200-MW Wood/Coal Cofired Boiler
100-MW Conventional Wood-fired Gasification/Combined Cycle
100-MW Advanced Wood-fired Gasification/Combined Cycle
100-MW Whole Tree Energy

The use of agricultural byproducts such as straw, grass, or decayed woodwaste as a fuel source for boilers has been used in many other utility-related applications. The wood residue fuels include residues from wood-producing processes such as logging, forest management, paper production, disposal of utility poles and railroad ties, production and disposal of wood pallets and packing crates, and the demolition of property.

In the past, most wood-fired power plants used the stoker technology. However, modern biomass facilities utilizing a recalculating fluidized bed design are particularly attractive. The efficiency of this process is somewhat limited by the relatively low energy density by weight and volume of the fuel source.

These installations are typically located near a steady source of byproduct to supply a steady fuel source. The fuel requirements for these plants can be quite significant. It is estimated that a 50-MW plant would require on the order of 400,000 tons of wood waste per year. The transportation costs associated with delivering fuel from farther than the immediate area somewhat limit the potential of these units to meet utility requirements. Near-term applications will probably be confined to cogeneration units fueled by waste products for which disposal would otherwise be a burden on the host facility.

The **wood-fired stoker** plant is rated at 50 MW and consumes approximately 1,501 tons per day of blended wood residues. Gross capacity of the unit is 55.9 MW with an auxiliary load of approximately 5.9 MW for a net output of the plant of 50 MW. The net plant heat rate at full load is estimated at 13,893 Btu/kWh.

The 50-MW **wood-fired circulating fluidized bed combustion** unit consumes approximately 1,498 ton per day of the wood residue fuel. The gross output of the unit is estimated at 56.6 MW with an auxiliary load of 6.6 MW. The projected net plant heat rate is 13,864 Btu/kWh. The economics slightly favor the fluidized bed design over the stoker unit.

The 200-MW **wood/coal cofired boiler** unit is designed to burn on a mixture of both wood and coal. The two fuels are copulverized together. This technology operates when a limited amount of wood waste is available. The typical unit operates on five percent or less heat input from the wood waste. If the heat input from the wood increases above five percent, then it is necessary to install dedicated wood pulverizers and facilities to allow separate injection into the boiler for the wood product. The unit statistics identified below assume a retrofit to an existing unit to allow the wood fuel to burn.

The wood cofiring is estimated to consume approximately 453 tons of wood per day with an assumed a heating value of 5,495 Btu/lb. By utilizing this technology, the 200-MW unit reduces its coal consumption by approximately 327 tons per day. However, the efficiency of the unit decreases, and so a net heat rate reduction estimated at 166 Btu/kWh occurs.

The three wood-fueled technologies discussed above are in the commercial technology category. They are therefore still in the development stage and it is considered risky for a utility to proceed with the planning of such units until more operating experience occurs.

When wood firing is considered, two additional technologies have been discussed and considered by the researchers in the electric utility industry. The first is a 100-MW **conventional wood-fired gasification/combined cycle** unit that is considered a demonstration technology. Within this technology are two designs, one using currently available technology (on a smaller scale) in which the wood is first dried and then injected into the fluidized-bed gasifier with air, steam, and dolomite and gasified. The product gas is then cooled, scrubbed with water to remove tars, alkalis, ammonia, and other condensable materials, rehumidified, and fired in an industrial combustion turbine.

The second technology using the gasification approach is considered an **advanced wood-fired gasification/combined cycle** design in which the product gas is passed over a nickel catalyst to reduce ammonia content, combined with pressurized water vapor, cleaned in the ceramic filter, and fired in an aeroderivative combustion turbine.

In both cases, the exhausts from the combustion turbines are passed through a heat recovery steam generator. The steam produced in the HRSG is then injected into a steam turbine for the production of additional electricity.

The first design consumes approximately 2,635 tons of wood per day and generates 73.8 MW from the combustion turbine and 37.3 MW from the steam generator. The unit has an auxiliary load of approximately 11.1 MW. This compares to the second design, which consumes 2,117 tons of wood per day. The same output from the combustion turbine and the steam generator are expected. No units of the 100-MW size currently exist or are planned in the foreseeable future. Sweden has plans to construct and operate a small (6 MW) unit in the near future.

Another wood-fired technology is called the **whole tree energy boiler,** which is currently being developed with the support of EPRI and other organizations. In this technology, the plan is to harvest a large number of close growing trees and burn them in a specially designed boiler. This technology is only in the pilot stage of development and no operating unit of any size is under consideration at this time. When, and if, such a unit is developed, it is projected to consume approximately 1,887 tons per day of whole dried trees. The gross output of the facility is projected at 107.5 MW with 7.5 MW of auxiliary load. The heat rate is projected at 10,654 Btu/kWh. A significant issue for this technology will be the environmental concern over the number of trees that will need to be harvested to operate this facility.

Unit Statistics

Capacity: 50 MW

Technology: Wood-fired Stoker
Fuel Type: Wood
Technology Status: Commercial
Duty Cycle: Base
Total Plant Cost: (1994$) $1,725/kW (w/o IDC)
Average Annual Heat Rate: 14,310 Btu/kWh
Annual Fixed O&M: (1994$) $87.98/kW-yr
Annual Variable O&M: (1994$) $10.23/MWh
Equivalent Availability: 85%

Capacity: 50 MW

Technology: Wood-fired Circulating Fluidized Bed Combustion
Fuel Type: Wood
Technology Status: Commercial
Duty Cycle: Base
Total Plant Cost: (1994$) $2,023/kW (w/o IDC)
Average Annual Heat Rate: 14,280 Btu/kWh
Annual Fixed O&M: (1994$) $93.40/kW-yr
Annual Variable O&M: (1994$) $10.94/MWh
Equivalent Availability: 85%

Capacity: 200 MW (wood-firing equipment only to retrofit existing unit)

Technology: Wood/coal Cofired Boiler

Fuel Type: Wood Waste and Coal
Technology Status: Commercial
Duty Cycle: Base
Total Plant Cost: (1994$) $78.25/kW (w/o IDC)
Average Annual Heat Rate: 10,593 Btu/kWh
Annual Fixed O&M: (1994$) $35.92/kW-yr
Annual Variable O&M: (1994$) $4.41/MWh
Equivalent Availability: N/A

Capacity: 100 MW

Technology: Conventional Wood-fired Gasification/Combined Cycle
Fuel Type: Wood
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $2,330/kW (w/o IDC)
Average Annual Heat Rate: 12,740 Btu/kWh
Annual Fixed O&M: (1994$) $115.27/kW-yr
Annual Variable O&M: (1994$) $14.55/MWh
Equivalent Availability: Unknown

Capacity: 100 MW

Technology: Advanced Wood-fired Gasification/Combined Cycle
Fuel Type: Wood
Technology Status: Pilot
Duty Cycle: Base
Total Plant Cost: (1994$) $2,016/kW (w/o IDC)
Average Annual Heat Rate: 10,090 Btu/kWh
Annual Fixed O&M: (1994$) $102.63/kW-yr
Annual Variable O&M: (1994$) $10.84/MWh
Equivalent Availability: Unknown

Capacity: 100 MW

Technology: Whole Tree Energy Boiler

Fuel Type: Whole Trees
Technology Status: Pilot
Duty Cycle: Base
Total Plant Cost: (1994$) $1,294/kW (w/o IDC)
Average Annual Heat Rate: 10,974 Btu/kWh
Annual Fixed O&M: (1994$) $58.69/kW-yr
Annual Variable O&M: (1994$) $8.73/MWh
Equivalent Availability: Unknown

WASTE-TO-ENERGY UNITS

40-MW Municipal Solid Waste Mass Burning
40-MW Refuse-derived Fuel-fired Stoker
200-MW Refuse-derived Fuel/Coal Cofired
200-MW Scrap Tires/Coal Cofire
30-MW Scrap Tire-fired Mass Burn Boiler

Historically, the main attractiveness of waste-to-energy plants has been the ability to dramatically reduce the volumes of wastes which would otherwise have to be disposed of. For this reason, plants were developed largely for municipal need, and the production of steam was a positive byproduct. These plants can burn a variety of waste products.

- The Camden (New Jersey) resource recovery facility burns 1,050 tons per day of municipal solid waste. The plant accepts more than 200 refuse-filled trucks per day, requires little or no presorting and generates just over 21 MW.

- The Exeter (Connecticut) Energy Project has a net output of 26 MW and disposes of 10 million tires per year. The plant utilizes extensive downstream controls, including urea injection for NO_x control, a wet lime scrubber for SO_x removal, and a 10-compartment fabric filter for fly ash removal. About 25 percent by weight of the input tires results in solid waste.

- The Grayling (Michigan) Generating Station helps dispose of lumber refuse, eases municipal wastewater treatment requirements, and generates 34 MW of electricity.

- The Alexandria/Arlington Station incinerates refuse and generates 22 MW of capacity it sells to Virginia Power. The station became operational in 1988.

- The Norton project in Fairfax County, Virginia, became operational in 1990, burns refuse and sells 75 MW to Virginia Power.

The fuel source of most waste-to-energy plants is municipal solid waste (MSW). The composition of MSW varies greatly from town to town and from season to season. There are two methods to consume this fuel: mass burning and processing the MSW to produce refuse-derived fuel (RDF).

In mass burning, refuse is incinerated in the as-received condition, with larger objects removed for alternate disposal. The MSW is fed directly into a large storage pit from a tipping floor. Some mixing of the MSW constituents may occur in the refuse pit itself. The refuse is then burned as fuel and the residue disposed of in an ash pit for reclamation or disposal.

In RDF applications, incoming material is processed via a number of possible systems to result in a high-quality shredded fuel and other salable by-products. This shredded fuel can be very abrasive, and the ash formed from the fuel can be even more abrasive. Hazardous, explosive and other larger materials are removed from the process at this time. The RDF can then be burned on a traveling grate stoker, fluidized bed, or rotary combustor. There are other considerations which must address ash removal systems, resource recovery markets, and health and safety considerations, primarily the danger of explosive materials present in the MSW.

One specific form of waste-to-energy plants that is receiving considerable attention is that using rubber tires as an additive to gas or coal firing. The Niles plant operated by Ohio Edison is conducting tests under the Clean Coal Technology Program. This plant has recently applied for a modification of its operating permit to burn up to 20 percent of total boiler Btu input from tires. This would equate to disposing of over three million tires per year at this facility alone. Tests performed to date have shown that this would result in no violations of existing permits and in fact could lower emission of SO_x and NO_x. The Niles plant uses cyclone-fired boilers for its process, while plants such as the UDG-Niagara Falls plant in upstate New York use a fluidized bed design to accomplish the same purpose.

Unit Statistics

Capacity: 40 MW

Technology: Municipal Solid Waste Mass Burn
Fuel Type: Municipal Solid Waste
Technology Status: Commercial
Duty Cycle: Base
Total Plant Cost: (1994$) $4,145/kW (w/o IDC)
Average Annual Heat Rate: 16,906 Btu/kWh
Annual Fixed O&M: (1994$) $120.96/kW-yr
Annual Variable O&M: (1994$) $17.25/MWh
Equivalent Availability: 86%

Capacity: 40 MW

Technology: Refuse-derived Fuel-fired Stoker
Fuel Type: Refuse-derived Fuel
Technology Status: Commercial
Duty Cycle: Base

Total Plant Cost: (1994$) $4,411/kW (w/o IDC)
Average Annual Heat Rate: 15,753 Btu/kWh
Annual Fixed O&M: (1994$) $207.22/kW-yr
Annual Variable O&M: (1994$) $23.14/MWh
Equivalent Availability: 86%

Capacity: 200 MW (RDF firing equipment only to retrofit existing unit)

Technology: Refuse-derived Fuel/Coal Cofired
Fuel Type: RDF and Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $115/kW (w/o IDC)
Average Annual Heat Rate: 10600 Btu/kWh
Annual Fixed O&M: (1994$) $37.52/kW-yr
Annual Variable O&M: (1994$) $4.72/MWh
Equivalent Availability: N/A

Capacity: 200 MW

Technology: Scrap Tires/Coal Cofired (Scrap tire firing equipment only to retrofit existing unit)
Fuel Type: Scrap Tires and Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $24/kW (w/o IDC)
Average Annual Heat Rate: 10,590 Btu/kWh
Annual Fixed O&M: (1994$) $37.52/kW-yr
Annual Variable O&M: (1994$) $7.32/MWh
Equivalent Availability: Unknown

Capacity: 30 MW

Technology: Scrap Tire-fired Mass Burn Boiler
Fuel Type: Scrap Tires
Technology Status: Demonstration

Duty Cycle: Base
Total Plant Cost: (1994$) $3,012/kW (w/o IDC)
Average Annual Heat Rate: 12,737 Btu/kWh
Annual Fixed O&M: (1994$) $98.52/kW-yr
Annual Variable O&M: (1994$) $12.74/MWh
Equivalent Availability: 85%

NUCLEAR

1,350-MW Evolutionary Advanced Light Water Reactor
600-MW Nuclear - Passive Safety Light Water Reactor
1,488-MW Advanced Liquid Metal Reactor

In a nuclear plant, a heavy nucleus, such as uranium-235, is struck by neutrons and split and releases energy in a sustained reaction. The reaction occurs in the nuclear reactor. Most nuclear plant designs are light water reactors (LWR), which use light water as a coolant and moderator. The water is turned to steam, which is then used to produce electricity. The vast majority of light-water reactor designs are either the boiling water (BWR) or the pressurized water (PWR) design. These two designs are shown in Exhibit A-7.

Although nuclear power has proven itself to be a safe and cost-effective means of generating electric power, public concern regarding issues of safety and waste disposal have increased the controversy of these plants. No new reactors have been ordered since 1978 in the United States, although there have been several new orders overseas in the recent years. The viability of a nuclear generation option is also increased by the new Energy Policy Act. The new Act provides for certification of standardized designs, streamlined licensing of new plants, and the establishment of a uranium enrichment corporation.

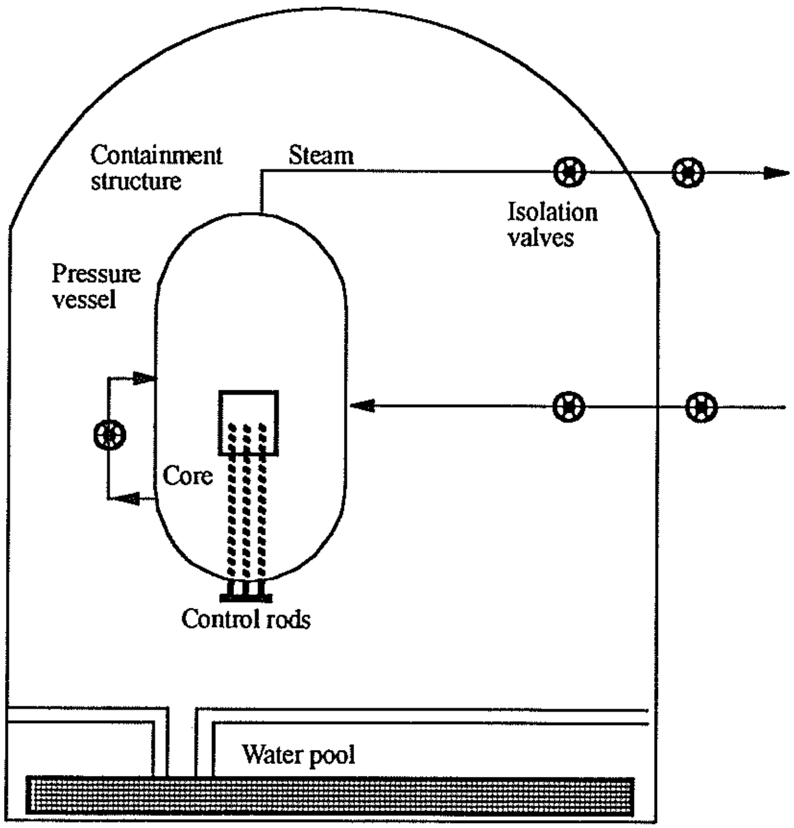
The nuclear industry in the United States has done considerable research investigating the merits of smaller, modular-designed nuclear units. These designs offer the potential advantage of having one or two standardized designs that the NRC would pre-approve to facilitate planning. The smaller units could be prefabricated at a single facility and then shipped to the site location as construction of a number of units located in different states. This approach could potentially reduce construction costs and schedule considerably and improve the relative economic competitiveness of nuclear power in the future.

A number of proposed design developments are currently under research to improve the design of nuclear reactors. Since 1985, these initiatives have been coordinated under the **Advanced Light Water Reactor** (ALWR) Program sponsored by EPRI with participation from U.S. nuclear operators, international operators, and the DOE.

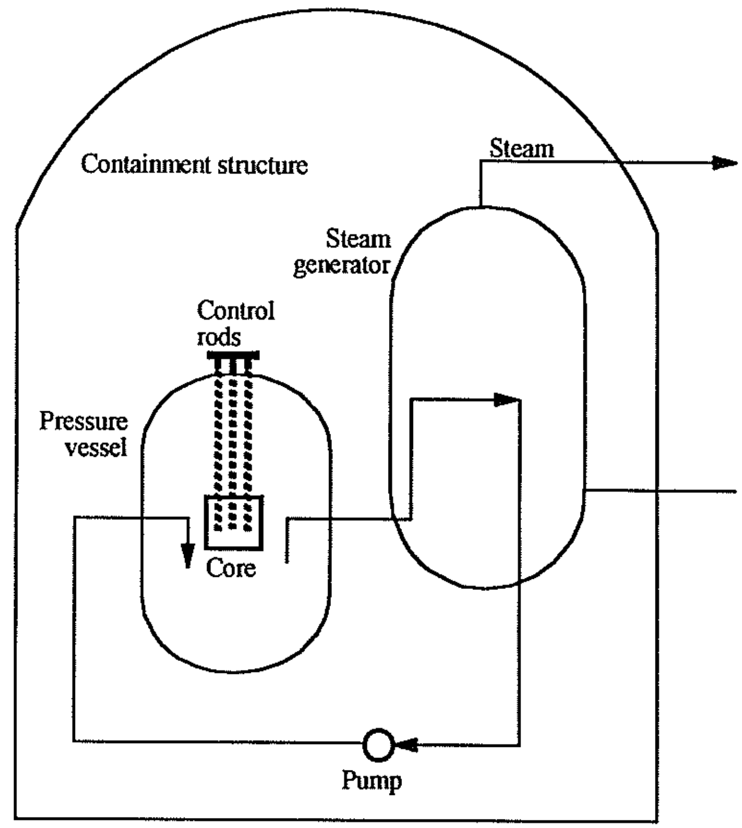
Most improvement efforts are directed at emphasizing simplicity in all aspects of plant design, construction and operation. ALWR designs today appear to offer a clear economic edge compared to other generation options. It is felt that this edge will be necessary to overcome concerns of the investment community and general public if future plants are to be built. The ALWR program goals are to provide a design which offers approximately a 20 percent life-cycle cost advantage over a reference coal plant over a 30-year investment horizon.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

NUCLEAR BWR AND PWR DESIGNS



(a) Boiling-water reactor (BWR)



(b) Pressurized-water reactor (PWR)

EXHIBIT A-7

The integral fast reactor (IFR) is being developed by Argonne Laboratory as an **advanced liquid metal-cooled reactor (ALMR)**. The basic components of the ALMR are metallic fuel, liquid sodium cooling, modular reactor configuration, and an integral fuel cycle, with the fuel cycle facility collocated if so desired.

In the ALMR, liquid sodium coolant operates at atmospheric pressure and maintains a design point margin to boiling greater than 700° Fahrenheit. This eliminates the need for a pressurized primary system and thick-walled pressure vessels. With high thermal conductivity and specific heat capacity, liquid metal cooling enables the ALMR to operate at decay heat levels in natural circulation, without the need for forced flow. Liquid metal cooling also permits a compact core configuration that complements the reaction process. The ALMR program also offers features designed to emphasize safety during fuel manufacture and improved long-term waste management.

The ALMR is sponsored by the DOE and is carried out by a team of industry participants led by General Electric. The ALMR design features modular, smaller-sized reactor construction features. Current program plans call for development of a full-sized, single-reactor prototype to be tested under a variety of operating and accident conditions. It is projected that these results will lead to the completion of an NRC-certified design available sometime after the year 2000.

Unit Statistics

Capacity: 1350 MW

Technology: Evolutionary Advanced Light Water Reactor
Fuel Type: Uranium
Technology Status: Commercial
Duty Cycle: Base
Total Plant Cost: (1994$) $1,266/kW (w/o IDC)
Average Annual Heat Rate: 10,520 Btu/kWh
Annual Fixed O&M: (1994$) $59.13/kW-yr
Annual Variable O&M: (1994$) $0.98/MWh
Equivalent Availability: 82.8%

Capacity: 600 MW

Technology: Passive Safety Light Water Reactor
Fuel Type: Uranium
Technology Status: Demonstration

Duty Cycle: Base
Total Plant Cost: (1994$) $1,479/kW (w/o IDC)
Average Annual Heat Rate: 10,620 Btu/kWh
Annual Fixed O&M: (1994$) $72.04/kW-yr
Annual Variable O&M: (1994$) $0.98/MWh
Equivalent Availability: 85.6%

Capacity: 1488 MW

Technology: Advanced Liquid Metal Reactor
Fuel Type: Uranium
Technology Status: Laboratory
Duty Cycle: Base
Total Plant Cost: (1994$) $1,541/kW (w/o IDC)
Average Annual Heat Rate: 9,515 Btu/kWh
Annual Fixed O&M: (1994$) $68.82/kW-yr
Annual Variable O&M: (1994$) $1.03/MWh
Equivalent Availability: 85.6%

INTEGRATED COAL GASIFICATION COMBINED CYCLE

500-MW Integrated Coal Gasification CC - Entrained Flow/Medium Integration
500-MW Integrated Coal Gasification CC - Entrained Flow/Highly Integrated
500-MW Integrated Coal Gasification CC - Entrained Flow/Nonintegrated
500-MW Integrated Coal Gasification CC - Moving Bed/ Medium & High Integration
500-MW Integrated Coal Gasification Humid Air Turbine (IGHAT)

In the integrated coal gasification combined cycle (IGCC), coal enters the gasifier train and is converted to a low to medium Btu gas. This gas is then treated to remove sulfur, ash, and other residue particles. The end product is a coal gasification fuel which is burned in a CT: the turbine exhaust is then run through an HRSG. Gasification thus offers the potential to provide a coal-based substitute for natural gas. A schematic representation of an integrated coal gasification combined cycle design is shown in Exhibit A-8.

The key advantage of IGCC is that the coal fuel gas can be leaned to whatever level of purity is required, and thus provides a coal-based substitute for natural gas. The major drawback is that the gasifier is essentially a minirefinery which must be integrated into power plant operations and is difficult to operate and maintain. At this stage of development, petrochemical companies posses the majority of the gasification expertise and experience.

At least 10 additional utilities are planning IGCC plants. EPRI has estimated full-scale commercial availability of IGCC based upon the Coolwater design by 1997. IGCC developers are even more optimistic and estimate availability by 1995.

The DOE has said that IGCC offers the potential of "superior environmental performance and lower capital and fuel costs relative to power plants using PC-fired boilers with FGD." There are four major vendors currently promoting this technology:

- Destec Energy, Inc. is an independent power company (a subsidiary of DOW Chemical Company) with a variety of power generation technologies. Destec's showpiece is the 160-MW Plaquemine, Louisiana plant, which has operated successfully for more than five years. This plant was also the basis of the design for the 230-MW Wabash River Generating Station under construction by Public Service Indiana in West Terre Haute, Indiana.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

COAL GASIFICATION DESIGN

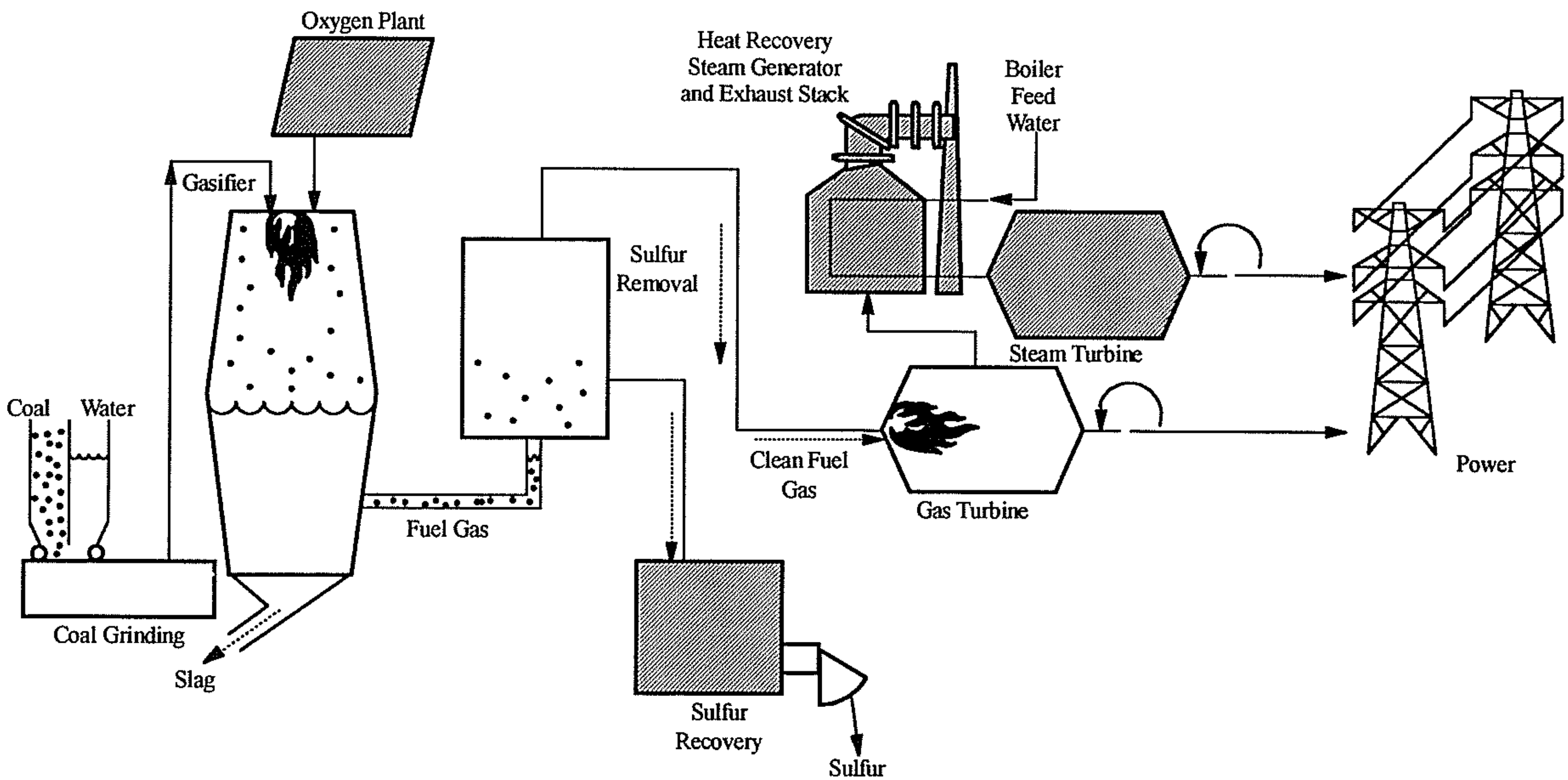


EXHIBIT A-8

- Texaco Syngas, Inc., led the consortium to build and operate the 100-MW Coolwater demonstration plant. Texaco is following this with a 255-MW Delaware Clean Energy Project. Unlike Destec, Texaco feels that IGCC facilities can be readily operated by the utility itself and there is no need for a supplier to operate it.

- Shell Oil Company has a synfuels group that is similar to those of Destec and Texaco. Shell also has a demonstration facility located near Deer Park, Texas. Overall, Shell has experienced stronger interest in IGCC from overseas than from the United States. This is generally attributed to the reluctance of U.S. utilities to incur the risks associated with a developing technology.

- Lurgi Corporation has a number of operating coal gasification facilities already in place. The DOE has announced that, under its Clean Coal Technology program, it will fund 50 percent of the 120-MW repowering project to be located at the Arvah Hopkins plant near Tallahassee, Florida. The plant will cost an estimated $240 million.

IGCC plants are also attractive because current construction approaches allow for a phased development based on a modular approach. The economies of scale, particularly with regard to the gasifier itself, dictate that even the modules themselves should be of moderate size. Typically on the order of 200 to 250 MW are warranted.

IGCC is a very high efficiency design, on the order of 40 percent or better, and offers low emission levels. This also makes it an attractive potential alternative to a traditional PC-based design, especially in light of pending NO_x regulations and the potential requirement to backfit PC units with SCR/SNR.

Under a research contract with EPRI, engineers have been investigating how the waste heat from the turbine exhaust can be recovered and expanded through the primary gas turbine power source instead of requiring a separate steam turbine to generate electricity. One promising concept is the **integrated coal gasification humid air turbine (IGHAT)** design, which diverts the air from the compressor stage of a gas turbine. This air would have normally gone directly to the combustion stage and instead is directed into a saturator where it is made to flow against a stream of water and humidified to between 10 percent and 40 percent water vapor. This humidified air is then sent to the combustor, where fuel is added and burned. An IGHAT design is shown in Exhibit A-9.

Since the power produced by a gas turbine expander is proportional to the density of the combustion products that are being expanded, humidifying the air going into the combustor increases the density of the combustion stream. This then increases the amount of electricity produced from the gas turbine generator. As a result, this type of plant and turbine could be over 40 percent efficient and have a heat rate as low as 8,500 Btu/kWh.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

INTEGRATED GASIFICATION FUEL CELL (IGFC)

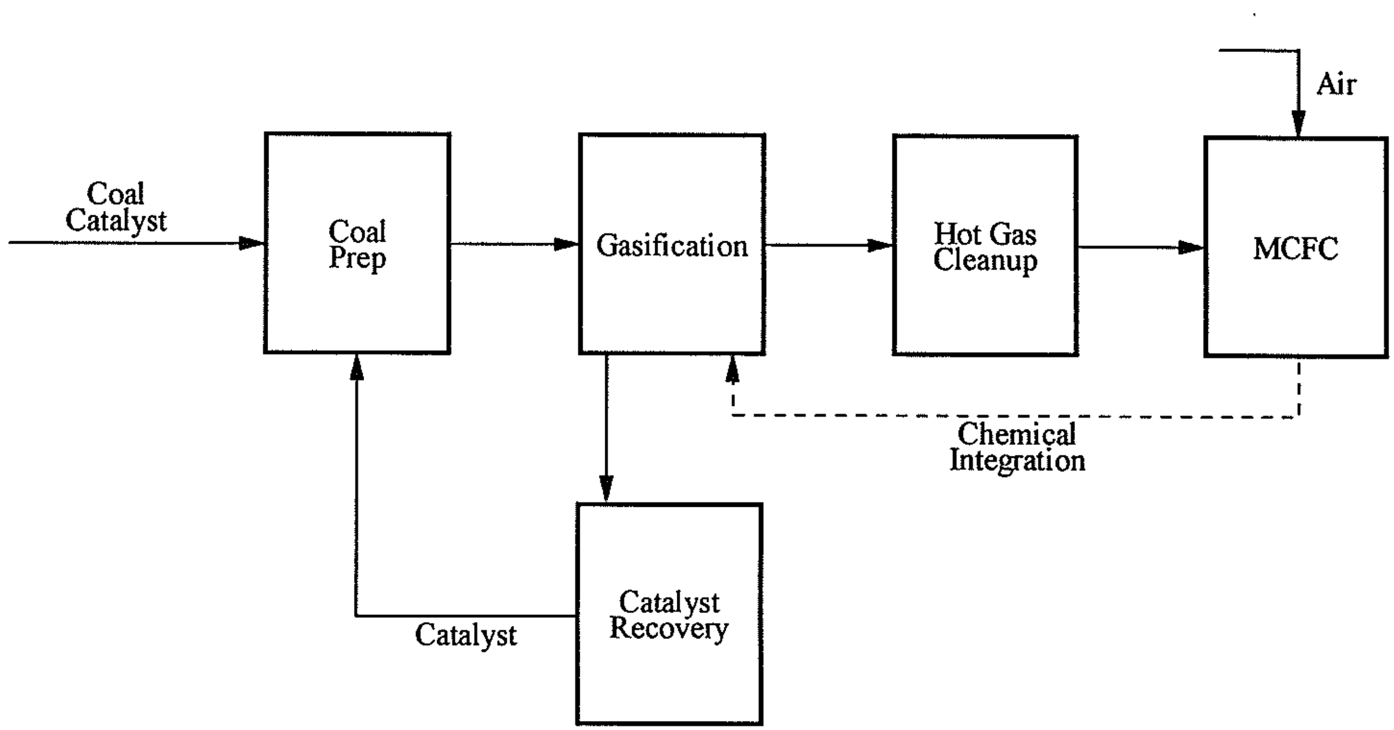


EXHIBIT A-9

The IGHAT cycle could also lower the capital costs required of a comparable coal gasification plant. In a normal IGCC plant, heat for raising steam is obtained by passing the coal gas through large coolers, which can be the most expensive components of a gasification process. In an IGHAT cycle, the gas can simply be quenched with water, and the coolers are not needed. It is estimated that up to 20 percent of the capital construction costs could thus be saved by the IGHAT.

As yet, no demonstration plant utilizes the IGHAT process. However, the major elements of this process are simple modifications to existing technology, and it is estimated that the technology could be developed by 2003. EPRI has recently decided to develop more information about this technology and the necessary cost and schedule to construct one, and has issued an RFP for manufacturers willing to build a humid air turbine prototype.

Unit Statistics

Capacity: 500 MW

Technology: IGCC - Entrained Flow/Medium Integration
Fuel Type: Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $1,493/kW (w/o IDC)
Average Annual Heat Rate: 9,190 Btu/kWh
Annual Fixed O&M: (1994$) $41.26/kW-yr
Annual Variable O&M: (1994$) $1.82/MWh
Equivalent Availability: 87.6%

Capacity: 500 MW

Technology: IGCC - Entrained Flow/Highly Integrated
Fuel Type: Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $1,369/kW (w/o IDC)
Average Annual Heat Rate: 8,710 Btu/kWh
Annual Fixed O&M: (1994$) $48.05/kW-yr
Annual Variable O&M: (1994$) $0.0/MWh
Equivalent Availability: 85.7%

Capacity: 500 MW

Technology: IGCC - Entrained Flow/Nonintegrated
Fuel Type: Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $1,789/kW (w/o IDC)
Average Annual Heat Rate: 8,950 Btu/kWh
Annual Fixed O&M: (1994$) $62.70/kW-yr
Annual Variable O&M: (1994$) $0.64/MWh
Equivalent Availability: 84.3%

Capacity: 500 MW

Technology: IGCC - Moving Bed/Medium Integration
Fuel Type: Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $1,545/kW (w/o IDC)
Average Annual Heat Rate: 8,670 Btu/kWh
Annual Fixed O&M: (1994$) $53.26/kW-yr
Annual Variable O&M: (1994$) $2.65/MWh
Equivalent Availability: 85.7

Capacity: 500 MW

Technology: IGCC - Moving Bed/High Integration
Fuel Type: Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $1,540/kW (w/o IDC)
Average Annual Heat Rate: 8,420 Btu/kWh
Annual Fixed O&M: (1994$) $53.15/kW-yr
Annual Variable O&M: (1994$) $2.44/MWh
Equivalent Availability: 85.7%

Capacity: 500 MW

Technology: IGCC - Humid Air Turbine (IGHAT)
Fuel Type: Coal
Technology Status: Demonstration
Duty Cycle: Base
Total Plant Cost: (1994$) $1,319/kW (w/o IDC)
Average Annual Heat Rate: 8,570 Btu/kWh
Annual Fixed O&M: (1994$) $42.86/kW-yr
Annual Variable O&M: (1994$) $2.23/MWh
Equivalent Availability: N/A

FUEL CELLS

400-MW Integrated Coal Gasification Molten Carbonate Fuel Cell (IGMCFC)
25-MW Integrated Coal Gasification Fuel Cell - Phosphoric Acid
2-MW Fuel Cell - Molten Carbonate

The **integrated coal gasification fuel cell (IGFC)** design is shown in Exhibit A-9. This is an emerging technology, with some demonstration plants just begun. In this process, hydrogen derived from the gasified fuel and oxygen from the air are combined at high temperature in an electrochemical reaction which produces DC current, water vapor and carbon dioxide.

This form of direct conversion potentially offers the highest efficiency and lowest emissions of any coal-based technology yet conceived. Because there is no combustion process, there are no emissions, noise, or discharge issues. As the cost of commercially available hydrogen comes down to approach the cost of natural gas, this technology becomes even more attractive.

The most promising candidate fuel cell currently is the molten carbonate fuel cell (MCFC). Efforts are underway by the industry's Fuel Cell Commercialization Group to develop the commercial potential of the fuel cell. Variations on this technology that would increase the efficiency, reduce the capital costs, and extend the life of the fuel cell are also being tested.

The expected approach would have an MCFC substituted for a gas turbine in a standard IGCC plant. Then the fuel cell could be chemically integrated with the gasifier. This would involve configuring the system in such a manner that the fuel cell's unconverted fuel and the fuel heat content are cycled back into the gasifier. A special methane-producing gasifier would be required to maximize the chemical content of the coal-derived gas. Also, a hot gas cleanup step would be employed to clean the coal gas for use in the fuel cell without first cooling it down.

A number of engineering problems from this process are still to be worked out; however, the potential applications are considerable. It is estimated that chemical integration could achieve a coal pile-to-busbar efficiency approaching 60 percent, as opposed to the 37 percent for today's best PC technology.

In addition to cycle efficiency, MCFC offers short construction times, modular construction with corresponding flexibility to deploy, and virtually no emissions considerations.

The major disadvantage of this technology at this time is the uncertainty of the process itself. The Fuel Cell Commercialization Group estimates commercial development will not be achieved until close to the year 2000. In addition, O&M costs are expected to be higher than those for a standard combustion process, and the fuel cells would have a short life cycle. Finally, the reliability of the technology has not yet been demonstrated. At this time, this technology would still be classified as experimental and should be monitored for further developments and re-evaluated when it has evolved.

There are two other fuel cell designs that operate on natural gas. They are the **Phosphoric Acid Fuel Cell (PAFC)** and the **Molten Carbonate Fuel Cell (MCFC)**. The PAFC has the most actual operating experience to date, with most experience occurring in Japan and Europe. The United States efforts have been primarily with the MCFCs.

The operation of a fuel cell is similar to that of a battery with a continuous addition of chemical energy. In the fuel cell, hydrogen gas is oxidized at the anode, and oxygen is reduced at the cathode. In an ideal system, the fuel cell has an efficiency on the order of 80 percent, since the chemical energy is converted directly to electrical energy without an intermediate thermal stage. However, in real applications, the actual efficiencies have been on the order of 40 to 60 percent because of parasitic losses, including the resistance of the components.

The PAFC is noted for very low emissions and low noise, which is a benefit from an environmental concern for siting the units. The disadvantage of the PAFC is its short fuel cell life, high capital costs, and a requirement for pure hydrogen. A possible future role for the PAFC could be dispersed generation applications because of its modular design.

The MCFCs are considered a second generation fuel cell, are expected to have higher operating efficiencies, and can be used for baseload applications as well as dispersed generation. These units are expected to have very low emissions and low noise, which will continue to make them easier for siting when compared to other technologies. As with the PAFCs, the relatively high capital costs will continue to be a disadvantage as the technology is further developed.

Unit Statistics

Capacity: 400 MW

Technology: Integrated Gasification Molten Carbonate Fuel Cell
Fuel Type: Eastern Kentucky Coal
Technology Status: Demonstration
Duty Cycle: Base

Total Plant Cost: (1994$) $1,984/kW (w/o IDC)
Average Annual Heat Rate: 6,660 Btu/kWh
Annual Fixed O&M: (1994$) $62.85/kW-yr
Annual Variable O&M: (1994$) $1.54/MWh
Equivalent Availability: N/A

Capacity: 25 MW

Technology: Phosphoric Acid Fuel Cell
Fuel Type: Natural Gas
Technology Status: Demonstration
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $1,092/kW (w/o IDC)
Average Annual Heat Rate: 6,450 Btu/kWh
Annual Fixed O&M: (1994$) $21.52/kW-yr
Annual Variable O&M: (1994$) $2.63/MWh
Equivalent Availability: 91.6%

Capacity: 2 MW

Technology: Molten Carbonate Fuel Cell
Fuel Type: Natural Gas
Technology Status: Pilot
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $1,194/kW (w/o IDC)
Average Annual Heat Rate: 8,300 Btu/kWh
Annual Fixed O&M: (1994$) $10.83/kW-yr
Annual Variable O&M: (1994$) $6.11/MWh
Equivalent Availability: 97%

COMPRESSED AIR ENERGY STORAGE

350-MW Compressed Air Energy Storage
350-MW Compressed Air Energy Storage w/Humid Air Turbine

Compressed Air Energy Storage (CAES) is an emerging option which is generating increased interest among utility planners. In CAES, an underground aquifer or other formation is used to store compressed air in a process that is similar to the storage of natural gas. When the power is needed, the compressed air is used to displace the required air from the compressor section of the CT to run a modified combustion turbine. Production costs are lower than for a standard CT, although capital costs are somewhat higher.

Advantages of CAES include emissions levels that are approximately one-third those of a comparable combustion turbine and reserve life that can be up to 26 hours at full power.

Three primary geological environments are considered suitable for CAES. Mined space, deep solution mined cavities developed in salt formations, and aquifers or similar porous formations such as are associated with natural gas fields. These three environments are shown in Exhibit A-10. A detailed geological survey is generally required to identify suitable formations which offer potential for further development.

Unit Statistics

Capacity: 350 MW

Technology: CAES - Rock Cavern
Technology Status: Demonstration
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $538/kW (w/o IDC)
Energy Requirements:(1 kWh Out=kWh In + Btu Fuel In): 0.74 + 3913
Annual Fixed O&M: (1994$) $6.09/kW-yr
Annual Variable O&M: (1994$) $1.75/MWh
Equivalent Availability: 97.3%

Technology: CAES - Salt Cavern
Technology Status: Commercial
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $418/kW (w/o IDC)

Energy Requirements:(1 kWh Out=kWh In + Btu Fuel In): 0.74 + 3913
Annual Fixed O&M: (1994$) $4.89/kW-yr
Annual Variable O&M: (1994$) $0.83/MWh
Equivalent Availability: 97.3%

Technology: CAES - Aquifer
Technology Status: Demonstration
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $421/kW (w/o IDC)
Energy Requirements:(1 kWh Out=kWh In + Btu Fuel In): 0.74 + 3913
Annual Fixed O&M: (1994$) $4.89/kW-yr
Annual Variable O&M: (1994$) $1.75/MWh
Equivalent Availability: 97.3%

Technology: CAES w/Humid Air Turbine - Rock Cavern
Technology Status: Pilot
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $434/kW (w/o IDC)
Energy Requirements:(1 kWh Out=kWh In + Btu Fuel In): 0.46 + 6035
Annual Fixed O&M: (1994$) $4.98/kW-yr
Annual Variable O&M: (1994$) $1.75/MWh
Equivalent Availability: 97.3%

Technology: CAES w/Humid Air Turbine - Salt Cavern
Technology Status: Pilot
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $369/kW (w/o IDC)
Energy Requirements:(1 kWh Out=kWh In + Btu Fuel In): 0.46 + 6035
Annual Fixed O&M: (1994$) $4.34/kW-yr
Annual Variable O&M: (1994$) $0.83/MWh
Equivalent Availability: 97.3%

Technology: CAES w/Humid Air Turbine - Aquifer
Technology Status: Pilot

Duty Cycle: Intermediate

Total Plant Cost: (1994$) $368/kW (w/o IDC)

Energy Requirements:(1 kWh Out=kWh In + Btu Fuel In): 0.46 + 6035

Annual Fixed O&M: (1994$) $4.34/kW-yr

Annual Variable O&M: (1994$) $0.83/MWh

Equivalent Availability: 97.3%

GEOTHERMAL

26-MW Geothermal - Binary
48-MW Geothermal - Dual Flash

Two types of energy production options utilize steam emanating from geothermal deposits. A binary cycle transfers heat from wet steam via a heat exchanger to a working fluid which is then vaporized and sent to the steam turbine. A flash-steam cycle reduces the pressure of the wet steam from the geothermal deposits and thus causes this wet steam to vaporize, or flash, to dry steam.

Geothermal energy possess a number of advantages, the primary one being that it is a renewable resource, has demonstrated commercial reliability, and has minimal air emissions. The world's largest geothermal development is The Geysers steam field located in northern California. This field has an estimated 2,050 MW of dry steam capacity.

Unit Statistics

Capacity: 26 MW

Technology: Geothermal - Binary
Fuel Type: Brine
Technology Status: Demonstration
Duty Cycle: Renewable
Total Plant Cost: (1994$) $1,805/kW (w/o IDC)
Average Annual Heat Rate: 31,770 Btu/kWh
Annual Fixed O&M: (1994$) $55.15/kW-yr
Annual Variable O&M: (1994$) $3.01/MWh
Equivalent Availability: 92.1%

Capacity: 48 MW

Technology: Geothermal - Dual Flash
Fuel Type: Brine
Technology Status: Demonstration
Duty Cycle: Renewable
Total Plant Cost: (1994$) $1,021/kW (w/o IDC)
Average Annual Heat Rate: 24,154 Btu/kWh
Annual Fixed O&M: (1994$) $27.53/kW-yr

Annual Variable O&M: (1994$) $1.80/MWh
Equivalent Availability: 97%

WIND POWER

50-MW Wind Turbine

Wind power costs and efficiencies have improved substantially over the past decade. Improvements to the basic process have included the development of improved turbine blade shapes that can convert up to 20 percent more power than previous blades, and variable speed rotors which spin faster as the wind picks up speed. Newer designs are also up to three times larger than older models and reach up to 300 kW in size.

Current wind farm developments in California have 1,500 MW of capacity; in fact, all the nation's wind power potential except for 20 MW located in Hawaii is in California. This investment in wind technology requires more than 27,000 acres to site the wind farms. California was especially popular for wind power because of the high sustained winds in the region and the combination of tax incentives and high avoided costs these California utilities possessed during the 1980s.

Unit Statistics

Capacity: 40 MW

Technology Status: Demonstration
Duty Cycle: Intermediate
Total Plant Cost: (1994$) $859/kW (w/o IDC)
Annual Fixed O&M: (1994$) $17.38/kW-yr
Annual Variable O&M: (1994$) $3.51/MWh
Equivalent Availability: 95%

SUPERCONDUCTING MAGNETIC STORAGE

500-MW Superconducting Magnetic Storage

This technology involves the storage of energy in a magnetic field that is formed from large currents flowing through a superconducting coil.

Commercial viability of this technology will depend on the pace of advances achieved in research related to superconductivity. Research is now focused on developing a method to achieve or approach superconductivity properties at a useful working temperature rather than temperature near absolute zero, which have been accomplished in laboratory research. Some success in this research have been achieved over the past few years. In the late-1980s and early 1990s there was a flurry of activity as scientists were able to achieve superconductivity at higher temperatures. However, the goal of the scientific community is to achieve superconductivity at temperatures closer to room temperature.

This technology is still in the very experimental stage. Although there are a number of technical challenges associated with superconductivity, the potential benefits of a commercially feasible technology are considerable.

Unit Statistics

Capacity: 500 MW

Technology Status: Pilot
Duty Cycle: Peak
Total Plant Cost: (1994$) $693/kW (w/o IDC)
Energy Requirement (kWh Input/kWh Output): 1.08
Annual Fixed O&M: (1994$) $4.76/kW-yr
Annual Variable O&M: (1994$) $3.81/MWh
Equivalent Availability: 90.4%

INDUSTRY PERSPECTIVE

With the vast array of technologies to consider, what is the electric utility industry as a whole planning to construct in the future? According to a survey conducted by UDI/McGraw-Hill, the utility industry has approximately 54 GW of new capacity planned, 40 GW of which is planned for the time period between 1994 and 2002. The remaining 14 GW is planned for after 2002, with some of it set for an undetermined date. This amount represents the amount identified by the utilities as necessary to meet load and does not specify the ownership of the capacity (i.e., IPPs, cogeneration, utility owned, etc.).

Of the total 54 GW planned, the majority, or 56 percent, is coal-fired steam capacity at 13 GW and 17 GW of simple-cycle combustion turbine capacity. An additional 10 GW consists of combined cycle capacity. Altogether, this 40 GW of capacity from these three traditional technologies makes up 74 percent of the planned new generation capacity.

Another technology that has been relatively quiet of late is nuclear technology. Based on the results of the survey, though, a total of 9 GW of new nuclear capacity is planned. This planned capacity is expected to be constructed primarily in the western and southeastern United States by the TVA and WPPS. TVA has plans for most of this new capacity around the turn of the century (1998 - 2002). The dates reported by WPPS are undetermined at this time.

The remaining nine percent of the new capacity consists of hydro (2.5 GW), wood-fired (0.2 GW), and waste-heat steam (1.3 GW). Given this breakdown of capacity plans, it is clear that the electric utility industry is concerned about reliability and operating costs first in planning for the next round of capacity additions. This is shown by the preponderance of known, proven technologies selected by the various utilities.

The industry has historically been conservative because of its goal of providing highly reliable power to its customers. Santee Cooper, like most other utilities, is risk-averse towards new, unproven technologies to meet its customers' needs. Its intent is to monitor the development of the newer technologies for future applications as the technologies are proven to meet the operating expectations of the researchers. In the interim, the IRP process will be utilized to identify all available supply-side technologies, screen them for appropriateness, and finally pass to the integration stage those technologies that are proven able to allow Santee Cooper the ability to provide the most economical, reliable power to its customers.

APPENDIX B

APPENDIX B
DSM PROGRAMS

This section presents the process for identifying and screening DSM programs. The process proceeds in several steps. First, measures are identified for possible incorporation in DSM programs. Second, the measures are screened to find those most applicable to the particular utility situation. Third, general programs are built around the most likely measures, either individually or grouped into DSM programs. Fourth, the programs are screened in preparation for conducting economic analysis. To conduct the economic analysis, program designs are then specified to identify target customers, incentives, delivery mechanisms, marketing strategies, participation levels, costs, and impacts. Programs which pass the economic screen are then available for further analysis as part of an integrated resource plan.

The following materials present the results of the first four steps, namely, identification of measures, screening of measures, program identification and program screening. The results are first presented for residential, then for commercial and finally for industrial programs.

RESIDENTIAL CUSTOMER CLASS

In total, 81 residential measures were identified. They were then reduced in number with the criteria of technical applicability or maturity, customer or market acceptance, and impact on demand and energy loads. The remaining measures were combined into 18 programs. In recognition of the Santee Cooper preference for experience, the programs were further screened down to six for economic analysis. These programs represented a combination of some end-use-specific programs and included programs from the 1993 Integrated Resource Plan.

DEMAND-SIDE MANAGEMENT END USES AND MEASURES FOR RESIDENTIAL CUSTOMER CLASS

END-USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
SPACE HEATING		
Air-to-air heat pump	Transfers heat from outside home to inside in winter and from inside to outside in summer using either central or/and room systems	1,2
Groundwater heat pump	Heat pump using groundwater such as from a lake or well, rather than air, as heat source or sink	2
Ground-coupled heat pump	Heat pump using the earth as the heat source or sink	2
Multi-zone heat pump	Single outdoor compressor/heat exchanger connected by refrigerant lines to several indoor fan coil units	2
Insider heat pump	Heat pump components located inside manufactured home	3
Add-on heat pump	Also called dual fuel, hybrid or piggyback heat pumps, they add-on to fossil heating systems which take over heating when heat pump capacity reached	2
Dual fuel heating	Utility control of electric furnace normally or other electric heating in combination with fossil heating to manage winter peaks	2
Integrated heat pump	One system for space heating, air conditioning and water heating	10
Electric furnace	Insulated steel cabinet housing resistance heating elements, a blower and control relays with ductwork	4
Zoned resistance	Sized for one or more rooms where located without ductwork	2
Task heaters	Freestanding or attached baseboard, unit, radiant, and quartz heaters for individual rooms or room areas	2
Humidifier	Converts water to vapor to improve comfort	4
Slab heating	Radiant floor heating combined with heat distribution system buried below or contained within the slab foundation	2
Electric thermal storage	Ceramic bricks or crushed rock heated at night and discharged during the day for central or room uses	2
Passive solar	Using direct gain, thermal storage wall, or sun space without mechanical components to capture and release solar heat	1, 2

END-USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Active solar	Fluid warmed by solar collectors is transfers heat to house supply air either directly or through a heat exchanger	2
WATER HEATING		
Resistance water heating	Insulated storage tank with one or two immersion resistance elements	5
Large storage water heater	80 to 120 gallon tanks with controls to restrict charging times to off-peak periods	17
Heat pump water heater	Transfers heat from surrounding space to water storage tank as integral or separate unit	2
Heat recovery water heater	Transfers excess heat from compressor of air conditioner or heat pump	2
Ventilation heat pump water heater	Takes heat from air of kitchen, laundry and other rooms through heat pump water heater prior to discharge	6
Solar water heater	Transfers solar energy directly or indirectly via a heat exchanger to insulated storage tank	2
Water heater wrap	Blanket of insulation added outside water heater	1
Thermal trap	One way valves to reduce hot water flow back into cold water supply	1
Water saving devices	Lowflow showerheads and faucet aerators	1
Water heater cycling	Direct load control by utility during peak periods	1
Instantaneous water heater	Heats water passing over resistance element at point of use	7
Hot tub	Large tub of heated and circulated water	11
REFRIGERATION		
Energy efficient refrigerators and freezers	Refrigerators and freezers with high efficiency equipment including fans, motors, compressors, anti-sweat heater switches, and extra insulation	1, 2
Super efficient refrigerator	Efficient refrigerator plus fuzzy logic controls, adaptive defrost control and no CFCs	12
SPACE COOLING		
Energy efficient central air conditioner	Ducted systems with larger condenser and evaporator coils, improved coil designs, more efficient motors and fans, and better refrigerant line insulation	2
Energy efficient room air conditioner	Ductless systems with larger coils, improved coil designs, and more efficient motors and fans	2
Whole-house fan	Louvered attic fans drawing air through open windows or doors and exhausting through attic vents	1

END-USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Ceiling fan	Ceiling mounted fans serving individual rooms to improve air circulation and comfort	1
Window fan	Window mounted fans serving individual rooms and located preferably on the leeward side of a home	11
Evaporative cooler	Blows warm, dry air over or through a wet surface	11
Thermal energy (cool) storage	Chills water, creates ice or uses phase change eutectic salts and stores for later use	13
Passive solar cooling	Use of overhanging roof, earth berms and natural ventilation	2
Air conditioner cycling	Direct load control by utility of air conditioners and heat pumps during peak periods	2
De-humidifier	Remove moisture from air in the home	4
BUILDING ENVELOPE		
Ceiling insulation	Fiberglass or rock wool batts or loose fill of fiberglass, rock wool, cellulose, perlite, or vermiculite added to ceilings	1, 2
Wall insulation	Batts, loose fill, rigid boards and foam installed in or attached to wall cavity	1, 2, 14
Floor insulation	Fiberglass batts installed in basement or crawl spaces under floors of heated areas	1, 8
Weatherstripping, caulking, and outlet gaskets	Sealing holes and gaps around doors, windows, sill plates, rim joists, wiring, ducts, pipes and other openings between conditioned and unconditioned spaces	2
Storm and multi-pane windows	Creating two or more layers of glass to produce an insulating air space	2
Storm doors	Creating insulating air space between two doors	2
Window treatments	Interior or exterior thermal shades, shutters, films, curtain liners, window blinds, and awnings	2
Duct and pipe insulation	Fiberglass and foam materials for reducing heat transfer on ducts and pipes for space conditioning and water heating	1,2
Radiant barriers	Low-emissivity foil material placed in an airspace between a heat-radiating surface and heat-absorbing surface	1

END-USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Vapor retarders	Polyethylene sheets and other materials to reduce convection and moisture penetrating insulation and framing	14
LIGHTING		
Compact and other fluorescents	Lamps with self-contained or separate ballasts to provide starting and operating voltages	1, 2
Efficient incandescent	Lower wattage incandescent lamps including tungsten halogen lamps	1, 2
Efficient floodlamps	Ellipsoidal reflector (ER) lamps for interior or exterior use that concentrate light on a focal point beyond the lens and have less heat build-up	1
Daylighting	Additional windows, clerestories, and skylights	2
Controls	Occupancy sensors, dimmers, timers and photosensors to reduce unnecessary lighting	15
COOKING		
Energy efficient oven	Improved insulation, door seals, and heating elements, and controls	1, 2
Induction cooktops	Heating cooking utensil directly via magnetic fields rather than via resistance coil	1, 2
Microwave oven	Heating food and not containers through microwaves of energy	1, 2
Convection oven	Circulating heat air in oven to increase heat transfer	2
WASHING AND DRYING		
Efficient clothes washers	Minimize hot water through water-level and temperature selection controls and reuse of wash water	2
Horizontal axis clothes washer	Front loading machines using less water and energy	16, 18
Efficient dish washers	Reduce hot water per load, have short cycle option, allow air drying without resistance heat, and have booster heaters for hot water	1, 2
Energy efficient clothes drying	Temperature or moisture controls to sense when clothes are dry	1
Microwave clothes dryer	Drying clothes at lower temperatures and quicker with microwave technology	16
SWIMMING POOL		
Pump control	Controlled by customer's timer or direct load control by the utility to reduce peak demand	1, 2

END-USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Solar pool heaters	Routing pool water through parallel black tubes	1
Pool cover	Moveable floating cover to reduce pool heat loss	1
MULTIPLE END USES AND MISC.		
Time-of-use meters	Measures electric usage by time of day thereby affecting many uses	9
Demand subscription service	Monitors house load and interrupts service when demand setpoint is exceeded	2
Prepayment meter	Magnetically coded cards activate meters for designated amounts of electricity	9
Timers	Clock switches, schedulers, and duty cyclers that control loads to limit peak demand, shift usage off-peak, or reduce usage to certain times	2
Appliance interlock (priority relay)	Prevents the simultaneous operation of two or more appliances	2
Programmable controller	Devices composed of a control unit, display unit, and current sensors to measure demand and allow automatic switching-off of schedulable loads	24
Temperature activated switches	Limit the operation of an appliance when outdoor temperature exceeds preset levels	2
Programmable thermostat	Device to program changes in temperature settings according to an advance schedule	24
Load management thermostats	Micro-processor device under utility control to allow gradual increase or decrease of indoor temperature	2
Color TV	Solid state television that uses 7 - 10 times more electricity than black and white TV	11
Lawn mower	Electric cord or cordless mowers	11
Electric blanket	Warming bed	11
Water bed heater	Maintain comfort for water bed	11
Water well pump	Provide potable water to residential dwellings	11

SOURCES FOR DSM MEASURE DESCRIPTIONS

1. Western Area Power Administration. DSM Pocket Guidebook. Volume 1: Residential Technologies. April, 1991.

2. Edison Electric Institute. Demand-Side Management. Volume 3: Technology Alternatives and Marketing Methods. 1984.

3. Consolidated Technology Corp., Olive Hill, KY. Product literature. 1991.

4. Virginia Division of Energy. The Virginia Energy Book. 1990.

5. Electric Power Research Institute. Electric Water Heating News. Summer/Fall, 1990.

6. Therma-Stor Products, Madison, WI. Product literature. 1991.

7. Electric Power Research Institute. Electric Water Heating News. Summer/Fall, 1990.

8. John Randolph, et al. Evaluation of the Virginia Weatherization Program. Virginia Center for Coal and Energy Research. 1991.

9. Wayne Beaty, "Metering technology emphasizes multi-functionality," Electric Light and Power. February, 1991.

10. Electric Power Research Institute, "Powermiser Integrated Heat Pump," Brochure-101458, 1992.

11. Alex Wilson and John Morrill, Consumer Guide to Home Energy Savings, American Council for an Energy Efficient Economy, 1991.

12. Whirlpool Corporation, press kit, February 21, 1994.

13. C. William Uhr, "Smart Storage in Homes Shows Load Shift Benefit," Strategies, Winter, 1992.

14. Philip Russell and Joe Hemmer, Energy-Smart Building, National Association of Home Builders, 1993.

15. Russel P. Leslie and Kathryn M. Conway, The Lighting Pattern Book for Homes, Lighting Research Center, Rensselaer Polytechnic Institute, 1993.

16. John Kesselring, Electric Power Research Institute, personal communication, 3/94.

17. Gary Pfann, "Milking Controls for All They're Worth," Home Energy, January/February, 1992.

18. Association of Professional Energy Managers, "As the Cycle Turns - New Washing Machine Technology to Suds Up Savings," The Professional Energy Manager, May/June, 1994.

RESIDENTIAL TECHNOLOGY SCREENING EVALUATION CRITERIA

TECHNICAL APPLICABILITY OR MATURITY (TA) CRITERION

- Measure does not apply in the utility service area (e.g., evaporative coolers)
- Measure not available or mature in the marketplace (e.g., residential thermal storage)

CUSTOMER ACCEPTANCE (CA) CRITERION

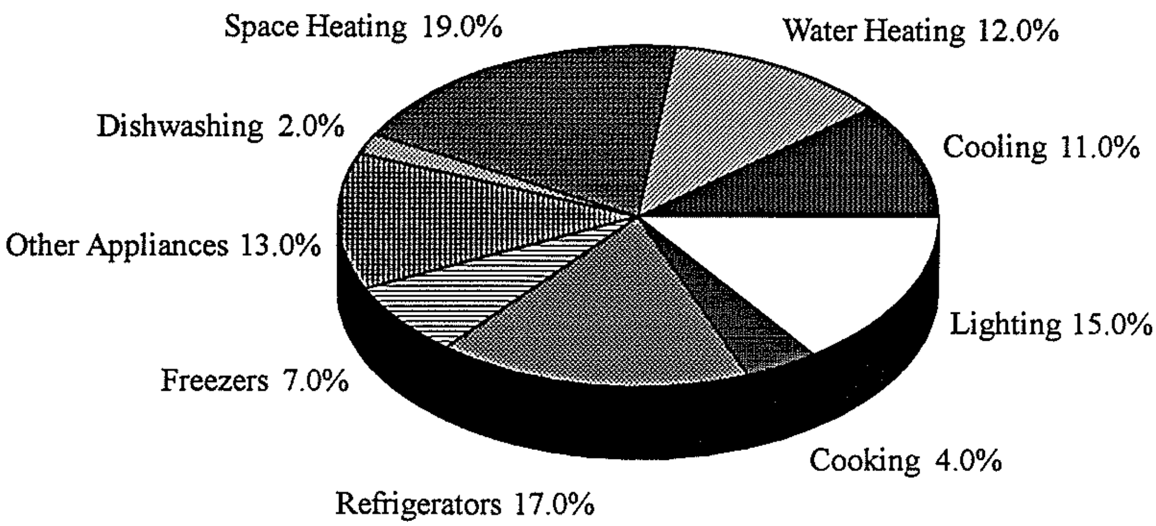
- Measure available but with low customer acceptance (e.g., solar water heating)
- Measure relatively new to utility DSM programs (e.g., horizontal axis washing machines)

LOAD IMPACT (LI) CRITERION

- Measure does not impact peak load (e.g., security lighting)
- Load impacts from measure are minor compared to other alternatives (e.g., energy saver incandescent versus compact fluorescent lamps)

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

RESIDENTIAL ELECTRICITY USE - BY APPLICATION, 1989



Source: Office of Technology Assessment, Energy Efficiency: Challenges and opportunities for Electric Utilities, September, 1993. Based on data from the U.S. Department of Energy and the Electric Power Research Institute.

RESIDENTIAL TECHNOLOGY QUALITATIVE SCREENING

TECHNOLOGIES ELIMINATED FOR FURTHER CONSIDERATION AND REASONS

SPACE HEATING

MULTI-ZONE HEAT PUMPS: Customer acceptance. These systems are relatively new to the U.S. and are not well known or readily available.

ADD-ON HEAT PUMP: Load impact. Low saturation of fossil heating limits application.

DUAL FUEL HEATING: Load impact. Low saturation of fossil heating limits application.

INTEGRATED HEAT PUMP: Technical applicability. The technology is not readily available in the marketplace.

ELECTRIC FURNACE: Load impact. The load impact is not considered as desirable as alternative electric space heating measures.

ZONED RESISTANCE: Load impact. The load impact is not considered as desirable as alternative electric space heating measures.

TASK HEATERS: Load impact. The load impact is not considered as desirable as alternative electric space heating measures.

HUMIDIFIER: Technical applicability. Not appropriate for the climate.

SLAB HEATING: Load impact. The load impact is not considered as desirable as alternative electric space heating measures.

ACTIVE SOLAR: Customer acceptance. Active solar systems have been available for many years but find low customer acceptance because of cost, effectiveness and reliability. Source: National Renewable Energy Laboratory, Utility Workshops on Residential Solar Water Heating, 1992.

WATER HEATING

HEAT PUMP WATER HEATER: Customer acceptance. Both add-on and integral units are not well received because of concerns about cost and reliability.

VENTILATING HEAT PUMP WATER HEATER: Technical applicability. More applicable in northern climates with homes that are superinsulated.

SOLAR WATER HEATER: Customer acceptance. Active solar systems have been available for many years but find low customer acceptance because of cost, effectiveness and reliability. (Source: National Renewable Energy Laboratory, Utility Workshops on Residential Solar Water Heating, 1992.)

THERMAL TRAP: Customer acceptance. Retrofit installations frequently result in faulty connections. New high efficiency water heaters include thermal traps in some models.

HOT TUB: Load impact. Installation of this measure increases load and is not easily controlled.

REFRIGERATION

ENERGY EFFICIENT REFRIGERATORS AND FREEZERS: Load impact. Load impacts are determined by the difference between the high efficiency new refrigerator and the standard efficiency new refrigerator. The new standard efficiency refrigerator is already substantially more efficient and uses half the energy compared to models 10 and 20 years old. The new high efficiency model is not that much more efficient compared to the standard model. Refrigerator efficiencies can vary as much by type of unit, such as manual versus automatic defrost, as by differences within a type of unit. Thus the incremental load impacts of the high efficiency models are not as significant as might be expected. Federal standards have eliminated the least efficient models.

SUPER EFFICIENT REFRIGERATOR: Technical applicability. This refrigerator entered the marketplace in just 24 utility service areas and is therefore not widely available.

SPACE COOLING

WHOLE-HOUSE, CEILING AND WINDOW FANS: Load impact. On peak summer days, these measures are not sufficient to satisfy air conditioning load resulting in the use of air conditioning equipment.

EVAPORATIVE COOLER: Technical applicability. Not suited to humid climates.

THERMAL ENERGY STORAGE: Technical applicability. Cool storage for residential applications is not as developed a technology as for commercial and industrial applications.

DEHUMIDIFIER: Load impact. Demand reductions on summer peak days are reduced little if any.

BUILDING ENVELOPE

RADIANT BARRIERS: Load impact. Not recommended except for southern and western regions of the U.S. where cooling degree days are more than 2,000 and heating degree days are less than 3,000. (Source: Western Area Power Administration, DSM Pocket Guidebook, Volume 1, 1991.) Adding insulation to attic floors can achieve greater energy savings compared to installation of radiant barriers in either a draped configuration from the roof trusses or horizontal configuration on top of attic insulation. (Source: National Insulation Manufacturers Association, "Setting the Record Straight on Radiant Barriers," updated.)

LIGHTING

EFFICIENT INCANDESCENT LAMPS AND FLOODLAMPS: Load impact. Energy savings are relatively higher than demand savings and more efficient alternatives are available with compact fluorescent lamps.

DAYLIGHTING: Load impact. Demand savings are not as certain and may increase because of the affects of solar gain on cooling load.

LIGHTING CONTROLS: Load impact. Demand savings are not significant because of relatively little use of residential lighting during daylight hours and, where there is potential for demand savings, the reductions may not occur during peak hours of the electrical system.

COOKING

OVENS AND COOKTOPS: Load impact. Operation of cooking equipment during peak hours is less than other hours. For energy savings, new Federal standards ensure more efficient equipment for what is currently relatively little use on an annual basis. See U.S. Department of Energy, Energy Conservation Program for Consumer Products: Proposed Rule, Federal Register, 10 CFR 430, March 4, 1994.

WASHING AND DRYING

HORIZONTAL AXIS WASHING MACHINE: Technical availability. While these measures are common in Europe and Asia, use in the U.S. is new and has been concentrated in a few states and communities with extensive DSM programs.

MICROWAVE CLOTHES DRYER: Technical availability. The measure is under development with limited field testing now underway.

OTHER WASHING AND DRYING MEASURES: Load impact. New Federal standards ensure more efficient equipment. Energy considerations are not a significant factor in influencing customer choice among models. See U.S. Department of Energy, Energy Conservation Program for Consumer Products: Proposed Rule, Federal Register, 10 CFR 430, March 4, 1994.

SWIMMING POOL

SOLAR POOL HEATERS AND POOL COVERS: Load impact. Pool water heating is not necessary during summer periods.

MULTIPLE END USES AND MISCELLANEOUS

DEMAND SUBSCRIPTION SERVICE: Load impact. Time-of-use meters and direct load control measures provide greater opportunity or reliability for demand and energy savings.

PREPAYMENT METER: same

TIMERS: same

APPLIANCE INTERLOCK: same

PROGRAMMABLE CONTROLLER: same

TEMPERATURE ACTIVATED SWITCHES: same

PROGRAMMABLE THERMOSTAT: same

LOAD MANAGEMENT THERMOSTAT: same

COLOR TV: Customer acceptance. More energy efficient black and white TV is not preferred by the vast majority of consumers.

LAWN MOWER: Load impact. Energy use is low and may aggravate summer demand.

ELECTRIC BLANKET: Load impact. No summer demand or energy impacts.

WATERBED HEATER: Customer acceptance. Control of waterbed heaters to prevent daytime operation may result in reduced comfort at night. Alternatively, removing waterbeds with heaters may not be well received. (See Barrett Consulting Associates, Inc. newsletter, January, 1994.)

WATER WELL PUMP: Load impact. Variation in the levels of efficiency for water well pumps is quite narrow.

NEW DSM PROGRAM OPTIONS FOR RESIDENTIAL BY END USE

SPACE HEATING

HIGH EFFICIENCY HEAT PUMPS: Encourage customers to install high efficiency models in place of lower efficiency units for existing homes and for new homes. Measures would include air-to-air heat pumps, groundwater heat pumps, and ground-source heat pumps.

INSIDER HEAT PUMP: Encourage installation and proper sizing of insider heat pumps for manufactured homes.

ELECTRIC THERMAL STORAGE: Encourage ETS room and central systems as supplements to electric furnace or zoned resistance system for off-peak heating at lower rates.

PASSIVE SOLAR: Encourage the design and construction of new homes with passive solar heating.

DUCT TESTING AND REPAIR: Encourage the use of duct blasters, flow hoods and blower doors to test for and repair leaking ducts that provide space conditioning.

SPACE COOLING

HIGH EFFICIENCY HEAT PUMPS: Same as for heat pumps under space heating

INSIDER HEAT PUMP: Same as for heat pumps under space heating

HIGH EFFICIENCY CENTRAL AIR CONDITIONER: Encourage customers to install high efficiency models in place of lower efficiency units for existing homes and for new homes.

HIGH EFFICIENCY ROOM AIR CONDITIONER: Same as for high efficiency central air conditioner.

AIR CONDITIONER CYCLING: Cycle central air conditioners and heat pumps during peak summer days in exchange for a billing credit.

WATER HEATING

HIGH EFFICIENCY WATER HEATERS: Encourage the installation of high efficiency models in place of lower efficiency units in existing and new homes.

WATER HEATING SAVINGS MEASURES: Encourage the installation of water heater wraps, flow restrictors and low-flow showerheads.

LARGE STORAGE WATER HEATERS: Encourage the installation of larger than normal water heaters and control charging cycles to prohibit on-peak power consumption.

REFRIGERATION

REFRIGERATOR TURN-IN: Sponsor a service for customers to turn-in second and third refrigerators that are old and inefficient.

BUILDING ENVELOPE

TESTING AND SEALING: Sponsor a service to test homes for infiltration and seal gaps, cracks and openings to reduce stack and other convective losses. Both new homes and existing homes would be eligible.

WEATHERIZATION SERVICES: Encourage the installation of insulation to reduce heat losses and heat gains through the thermal envelope.

LIGHTING

COMPACT FLUORESCENT LAMPS: Encourage the purchase and installation of compact fluorescent lamps in place of incandescent lamps.

SWIMMING POOL

SWIMMING POOL PUMP CONTROL: Pumps would be controlled by the utility to prevent operation during peak periods.

NEW PROGRAM OPTIONS REMOVED FROM FURTHER CONSIDERATION

SPACE HEATING

ELECTRIC THERMAL STORAGE: Encourage ETS room and central systems as supplements to electric furnace or zoned resistance system for off-peak heating at lower rates.

Electric furnace and zoned resistance units are the primary heating sources in less than 13% of the homes. Larger energy savings can be achieved by high efficiency heat pumps added to electric furnaces. For zoned resistance units, individual controls offer significant flexibility to emphasize warm rooms and save energy in other parts of the home.

PASSIVE SOLAR: Encourage the design and construction of new homes with passive solar heating.

Rather than adopt a special program, this measure can be encouraged through the existing structure of the Good Cents Home Program.

SPACE COOLING

HIGH EFFICIENCY ROOM AIR CONDITIONER: Encourage customers to install high efficiency models in place of lower efficiency units for existing homes and for new homes.

Purchases of room air conditioners are typically an emergency purchase stimulated by failure of an existing unit or the onset of hot weather. Energy efficiency is not a major consideration in choosing among competing models. Thus a program to encourage the purchase of room air conditioners may be expected to possess heavy free-rider effects. That is, many participants in such a program would have purchased the higher efficiency model regardless of the utility program.

WATER HEATING

HIGH EFFICIENCY WATER HEATERS: Encourage the installation of high efficiency models in place of lower efficiency units in existing and new homes.

Electric water heaters possess high levels of conversion efficiency compared to natural gas. Thus the opportunities for significant increases in efficiency are not as great. Furthermore, the purchase of a water heater is often under emergency conditions, in which efficiency considerations are not a major factor in selecting equipment. Thus a high efficiency water heater program would have a large free-rider effect.

WATER HEATING SAVINGS MEASURES: Encourage the installation of water heater wraps, flow restrictors and low-flow showerheads.

Savings from water heater wraps, flow restrictors and low-flow showerheads are of declining significance. This is partly due to the replacement of old water heaters, which are more efficient because of Federal standards. Also with low-flow showerheads, the expected energy savings have not materialized because of lower than assumed flows in existing showerheads resulting from sediment accumulation over time and from the presence of low water pressure in rural areas. (Source: Mike Warwick and Curtis Hickman, "Everything I Know About Energy-Efficient Showerheads I Learned in the Field," Home Energy, January/February, 1994.) Finally, supply water temperatures in the South will tend to be lower than in the North, where more heating is required to achieve hot water. Since less heating is required in the South, the level of energy savings will be less as well.

LARGE STORAGE WATER HEATERS: Encourage the installation of larger than normal water heaters and control charging cycles to prohibit on-peak power consumption.

The existing load control program for water heaters accomplishes the major benefit that would have been expected from a large storage water heating program.

REFRIGERATION

REFRIGERATOR TURN-IN: Sponsor a service for customers to turn-in second and third refrigerators that are old and inefficient.

Refrigerator turn-in programs have the potential for a high free-rider effect. This results when an existing refrigerator displaced by a new model would have been removed from the premises by the vendor or by the owner. The impacts are also diminished where the existing second or third refrigerator may be unplugged or stop functioning. One of the easiest approaches is through customer education to alert owners of the relative expense in operating old and extra refrigerators.

BUILDING ENVELOPE

TESTING AND SEALING: Sponsor a service to test homes for infiltration and seal gaps, cracks and openings to reduce stack and other convective losses. Both new homes and existing homes would be eligible.

Much of the savings benefit from this type of program can be achieved by consumer education alerting the owner to the need to caulk, weatherstrip and fill gaps in the building envelope.

WEATHERIZATION SERVICES: Encourage the installation of insulation to reduce heat losses and heat gains through the thermal envelope.

This program also lends itself well to consumer education without the necessity of a full program. Furthermore, most residents consider their homes well insulated. It has been over 20 years since the first energy crisis. As a result many homes have received upgrades in insulation levels and new homes have been built to better energy standards since then. Nearly 80% of the residents in the South consider their homes adequately or well insulated. Of the approximately 20% that consider their home poorly insulated, the major component was wall insulation. (Source: U.S. Department of Energy, Housing Characteristics 1990, May, 1992.) Since wall insulation is often not cost-effective on an existing home, the opportunities for significant impact in a weatherization services program are severely limited.

LIGHTING

COMPACT FLUORESCENT LAMPS: Encourage the purchase and installation of compact fluorescent lamps in place of incandescent lamps.

Lighting results primarily in energy savings and secondarily in demand savings. This is especially the case during the summer peak period. Thus customer education is a reasonable opportunity allowing scarce utility program resources to be directed toward end uses and measures with more potential for peak demand savings.

RESIDENTIAL PROGRAM OPTIONS FOR ECONOMIC ANALYSIS

SPACE HEATING

HIGH EFFICIENCY HEAT PUMPS: Encourage customers to install high efficiency models in place of lower efficiency units for existing homes and for new homes. Measures would include air-to-air heat pumps, groundwater heat pumps, and ground-source heat pumps.

INSIDER HEAT PUMP: Encourage installation and proper sizing of insider heat pumps for manufactured homes.

DUCT TESTING AND REPAIR: Encourage the use of duct blasters, flow hoods and blower doors to test for and repair leaking ducts that provide space conditioning.

SPACE COOLING

HIGH EFFICIENCY HEAT PUMPS: Same as for space heating

INSIDER HEAT PUMP: Same as for space heating

HIGH EFFICIENCY CENTRAL AIR CONDITIONER: Encourage customers to install high efficiency models in place of lower efficiency units for existing homes and for new homes.

AIR CONDITIONER CYCLING: Cycle central air conditioners and heat pumps during peak summer days in exchange for a billing credit.

SWIMMING POOL

SWIMMING POOL PUMP CONTROL: Pumps would be controlled by the utility to prevent operation during peak periods.

In summary, the residential DSM programs for further analysis include:

- High efficiency central air conditioner
- High efficiency heat pump
- Insider heat pump for manufactured housing
- Air conditioner cycling
- Duct testing and repair
- Swimming pool pump control.

COMMERCIAL CUSTOMER CLASS

For the commercial customer class, 98 measures were identified. They were reduced in number by considering the criteria of technical availability or maturity, customer or market acceptance, and impact on demand and energy loads. Particular attention was given to the load impact by end use with special focus on those with the largest share of energy usage in the commercial sector. After the screening of measures, programs were identified and then screened down to four significant enough for economic analysis. These programs include programs analyzed as part of the 1993 Integrated Resource Plan.

DEMAND-SIDE MANAGEMENT END USES AND MEASURES FOR COMMERCIAL CUSTOMER CLASS

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
BUILDING ENVELOPE		
Fenestration	Arranging, proportioning and design of windows and doors including with insulated glass such features as tinting, reflective coating, low-E coatings, triple glazing and gas fill	1,4
Passive solar design	Use of the environment to heat, cool, or light space including such features as large window areas with advanced glazing materials, summer self-shading, thermal storage and natural ventilation	1,4
Ceiling insulation	Fiberglass or rock wool batts or loose fill of fiberglass, rock wool, cellulose, perlite or vermiculite added to ceilings	2,3,4
Wall insulation	Batts, loose fill rigid boards and foam installed in or attached to wall cavity	2,3,4,5
Floor insulation	Fiberglass batts installed in basement or crawl space under floors of heated areas	3
Weatherstripping, caulking, and outlet gaskets	Sealing holes and gaps around doors, windows, sill plates, rim joists, wiring, ducts, pipes and other openings between conditioned and unconditioned spaces	3
Duct and pipe insulation	Fiberglass and foam materials for reducing heat transfer on ducts and pipes for space conditioning	2,3
Window treatments	Interior or exterior thermal shades, shutters, films, curtain liners window blinds, and awnings	3,4
Radiant barriers	Low-emissivity foil material placed in an airspace between a heat-radiating surface and heat-absorbing surface	2
SPACE HEATING		
Heat recovery from exhaust air	Transfer of heat energy in exhaust air to incoming air during winter season and removing heat from incoming air to exhaust air during cooling season	1
Double-bundle chiller	Includes second set of tubes in a chiller to recover heat for use in space or water heating in buildings requiring air conditioning	1

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Heat pipe	A closed refrigeration cycle where one end of a pipe is heated and the other end gives up the heat	1
High efficiency heat pump	Air-to-air heat pump with a high coefficient of performance and high seasonal energy efficiency ratio	1
Closed water loop heat pump	Heat pump collects internal heat gains, such as from core areas, redistributes for immediate use, such as to perimeter areas, or stores such as in water heaters, for later use	1
Groundwater heat pump	Heat pump using groundwater such as from a lake or well, rather than air, as the heat source or sink	1
Ground-coupled heat pump	Heat pump using the earth as the heat source or sink	1
Add-on heat pump	Also called dual fuel, hybrid or piggyback heat pumps, that add-on to fossil heating units which takeover heating when heat pump capacity is reached	2
Dual fuel heat pump	Combination heat pump with gas furnace	6
Zonal electric heating	Electric resistance units such as baseboard heaters and wall-mounted heaters, infrared heaters, and heat pumps, all sized for zones	4
Ceramic brick storage Water-based heat storage	Olivine or magnesite bricks designed to accept electric resistance coils for charging at night and discharging heat during the day Water is heated at night and heat is discharged during the day	4 4
Slab storage	Building slabs are heated at night and heat is discharged during the day	4
Phase change heat storage	Phase change materials are heated at night and heat is discharged during the day	4
SPACE COOLING		
Economizers	Use of outside air when it is cool and dry to reduce use of chillers	1
Evaporative cooler	Blows warm, dry air over or through a wet surface	1
Thermal energy (cool) storage	Prepare ice, chilled water, or phase change materials at night for cooling during the day	1,4
Cooling tower	Reliance on cooling tower to chill water for space cooling rather than the chiller	4

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
LIGHTING		
High-efficiency air conditioning	Unitary air conditioners with enhancements such as multispeed compressors and energy-efficient fan motors	4
Fluorescent lamp	Lamps four or five times more efficient than incandescent lamps	1,4
Energy efficient fluorescent lamp	Fluorescent lamps with lower wattage	1,4
Compact fluorescent lamp	Fluorescent lamps with base that screws into incandescent fixtures	1,4
Efficient incandescent	Lower wattage incandescent lamps providing equivalent amount of light as standard incandescent	1,4
Metal halide lamp	Twice as efficient and nearly as long lived as mercury vapor lamps	1,4
High pressure sodium lamp	High efficiency and long life lamps	1,4
Exit light conversion	Compact fluorescent lamps, LED, and miniature incandescent lamps applied to exit lights	1,4
Electronic ballast	Solid-state high efficiency ballasts used to start and operate gaseous-discharge lamps	1,4
Specular reflector	Contoured and mirror like surfaces design to reduce absorption of light within the fixture and deliver light in a desired pattern	1,4
Occupancy sensor	Controls, sensors and wiring that turn off lights automatically in rooms unoccupied for long periods of time	1,4
Photocell	Turns interior or exterior lights on or off depending on the amount of light present	1,4
Daylighting controllers	Manual or automatic systems that control lighting in continuous or stepped fashion	1,4
Dimmer	Control incandescent, fluorescent, mercury vapor, metal halide, and high pressure sodium lamps	1,4
Security lighting	Addition of light for night safety and security	4
WATER HEATING		
Quick recovery electric resistance	Standard water heater with two 4,500-watt elements in 50 to 66 gallon tanks that are steel lined	1,4
Base-loaded electric resistance	One or two elements from 500 to 3,000 watts and 80 to 120 gallon tank	1,4

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Off-peak electric resistance	One or two elements from 500 to 4,500 watts and 80 to 120 gallon tank controlled by timer or remote device such as power line carrier	7
Interruptible electric resistance Point-of-use electric resistance	4,500 watt elements and 50 to 80 gallon tank operated remotely by radio or power line carrier signal 50 to 120 gallon tank near usage to reduce time for hot water to travel and avoid pumped recirculation loops	7 7
Instantaneous electric resistance	Heating elements often above 9,000 watts activated for instantaneous use	7
Electric resistance pipe wrap	Self-temperature-regulating wire wrapped around pipes to prevent heat loss or freezing	7
High efficiency water heaters	Use think insulation and heat rentive materials	7
Unpressurized water heaters	Water stored at atmospheric pressure allowing reduced tank weight	7
Booster heater	Installed in devices such as dishwashers or as stand alone unit between usage and water heater to boost temperature from lower setting	7
Waste heat recovery (desuperheater)	Installed between compressor and condenser of air conditioner, heat pump or refrigerator to recover excess heat	7, 9
Waste heat recovery multifunction	Captures more heat and can operate in several modes including space conditioning	7, 9
Solar water heater	Transfer solar energy directly or indirectly via a heat exchanger to an insulated storage tank	1
Water heater wrap	Blanket of fiberglass or foam insulating material	1
Thermal trap	Small one-way valves in hot and cold water feed lines to reduce flow of hot water out of tank when there is no demand	1
Water saving devices	Low flow showerheads and faucet aerators	1
Heat pump water heater	Transfers heat from air by way of standard refrigeration cycle to water at a higher temperature	4, 7, 8
Water to water heat pump water heater	Uses waste heat from cooling-tower water circuits or other sources such as groundwater	7, 8, 9

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
REFRIGERATION		
Conventional refrigeration	Single compressor for each display case lineup or walk-in refrigerator	1, 4
Multiplex refrigeration	Multiple compressors piped to common suction and discharge manifolds	1, 4
Evaporative condenser	Heat rejection is through the evaporation of water to the ambient air	1, 4
Floating head pressure control	Increases efficiency by dropping compressor-discharge pressure (and hence temperature) in response to drops in ambient temperature drops	1, 4
Heat reclaim	Heat rejected through the refrigeration system that is recovered for space or water heating	1, 4
Hot gas defrost	Melt frost buildup by circulating refrigerant gas from either compressor discharge or the receiver to the display case evaporator	1, 4
Ambient subcooling	Cooling liquid refrigerant below condensing temperature by heat rejection to the ambient surroundings	1, 4
Mechanical subcooling	Evaporating refrigerant at a higher temperature than the main evaporator temperature through the use of a vapor compression system	1, 4
Humidity sensor control	Reduce use of anti-sweat heaters with frost sensors to control defrost operations	4
Display case covers	Plastic strip curtains, roll-down flexible plastic or perforated polyester covers, and glass doors	4
COOKING		
Two-sided griddle	Cooks food faster at a lower temperature than a standard one-sided griddle	4
Energy-efficient fryer	Use of electronic rather than mechanical controls and increased frypot insulation	4
Oven/steamer combination	Cooking with steam, hot air, or combination providing moist heat	4
Energy efficient broiler	Use of controls to match capacity selection to food requirements	4
Energy efficient griddle	Use separate thermostats for different parts of griddle to match heat to load	4
Standard oven	Oven with one coil for baking and another for broiling	4
Deck oven	Standard ovens stacked on top of each other	4

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Convection oven	Use of sophisticated controls including cook and hold which allows food to be cooked at lower temperatures by using oven heat stored from earlier stages of the cooking cycle	4
Microwave oven	Use of microwave energy for quick cooking and adjustable to various energy levels	4
Magnetic induction cooktop	Use of magnetic induction heating which requires no pre-heating	4
Infrared conveyer oven	Panels emit infrared long waves to cook food without heating the oven chamber	4
MOTORS		
Energy efficient motor	Use of additional copper, better magnetic materials and lower friction	1, 4
Adjustable speed drive	Electronic controls to match motor speed with changing load requirements	1, 4
Polyphase motor	More efficient than single-phase motors, present a balanced load to the electric system and lower reactive power losses	1, 4
Motor downsizing	Replacing oversized motors with smaller sizes	1, 4
SWIMMING POOL		
Solar pool heaters	Routing pool water through parallel black tubes	2, 3
Pool cover	Reduces loss of heat from heated pool	2, 3
Pool pump control	Control by customer timer or direct load control by utility to reduce peak demand	2, 3
Heat pump water heater	Swimming pool serves as tank to store hot water provided by heat pump water heater	8
MULTIPLE END USES AND MISC.		
Scheduler	More sophisticated timer controlling multiple circuits on hourly, weekly or seasonal basis	4
Interlock	Simple logic board to prevent simultaneous operation of two or more pieces of equipment	4
Start/stop	Programmed function to shut down electrically operated equipment when not required	4

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Start/stop optimization	Start and stop times controlled by computer based on measurement of outdoor air temperature, solar effects, indoor temperatures, indoor humidities, and consideration of building mass	4
Supply air reset	Resetting supply air and water temperatures for space conditioning based on load requirements	4
Temperature setback/setup	Adjusts building temperature when unoccupied	4
Time-of-use meters	Measures electric use by time of day thereby affecting many uses	4
Standby generators	Generators on customer side of meter providing emergency or load shedding service	10
Demand-limiting	Control of monthly electrical peak demand to a preset practical level	10

REFERENCES FOR DSM MEASURE DESCRIPTION

1. Western Area Power Administration, DSM Pocket Guidebook, Volume 2: Commercial Technologies, April, 1991.

2. _____; reference to Volume 1: Residential Technologies, April, 1991.

3. Edison Electric Institute, Demand-Side Management. Volume 3: Technology Alternatives and Marketing Methods. 1984.

4. _____, Demand-Side Management Volume 4 Commercial Markets and Programs, September, 1987.

5. Philip Russell and Joe Hemmer, Energy-Smart Building, National Association of Home Builders, 1993.

6. Electric Power Research Institute, "Dual-Fuel Heat Pumps," brochure, 1992.

7. _____, "Numerous Water Heating Electrotechnology Options Available," EPRI Electric Water Heating News Special, undated.

8. _____, "Heat Pump Water Heaters: An Efficient Alternative for Commercial Use," brochure EU2020, undated.

9. _____, "Electric Water Heating News Technology Special," Fall, 1992.

10. Edison Electric Institute, Standby Rates: Methods and Descriptions, April, 1991.

COMMERCIAL TECHNOLOGY SCREENING
EVALUATION CRITERIA

TECHNICAL APPLICABILITY OR MATURITY CRITERION

- Measure does not apply in the utility service area
- (e.g., evaporative coolers)
- Measure not available or mature in the marketplace (e.g., residential thermal storage)

CUSTOMER ACCEPTANCE CRITERION

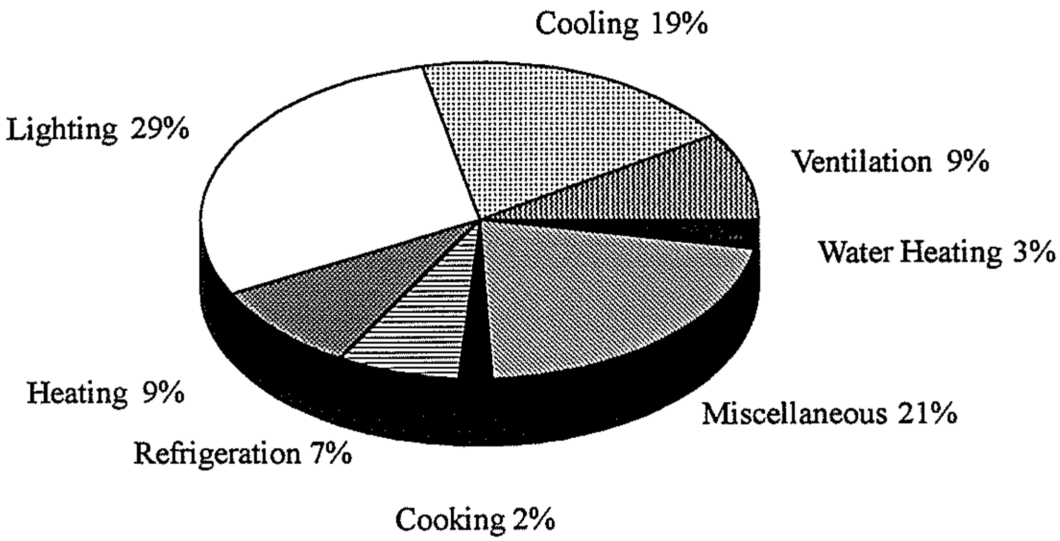
- Measure available but with low customer acceptance (e.g., solar water heating)
- Measure relatively new to utility DSM programs (e.g., horizontal axis washing machines)

LOAD IMPACT CRITERION

- Measure does not impact peak load (e.g., security lighting)
- Load impacts from measure are minor compared to other alternatives (e.g., energy saver incandescent versus compact fluorescent lamps)

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

COMMERCIAL SECTOR ELECTRICITY USE - BY APPLICATION, 1987



Source: Office of Technology Assessment, Energy Efficiency: Challenges and opportunities for Electric Utilities, September, 1993. Based on data from the U.S. Department of Energy and the Electric Power Research Institute.

COMMERCIAL TECHNOLOGY QUALITATIVE SCREENING

TECHNOLOGIES ELIMINATED FOR FURTHER CONSIDERATION AND REASONS

SPACE HEATING TECHNOLOGIES

These technologies may be summarized into two categories. One type of electric space heating depends primarily on electric resistance technologies. The second type depends primarily on vapor compression technologies as embodied in heat pumps.

In terms of the total electric usage in the commercial sector, space heating at 9% on a national basis constitutes a small amount. The proportion could be somewhat higher for Santee Cooper, since the majority of commercial accounts employ electric heat. But the proportion could also be lower, since the heat loss levels are below the national average.

The use of electric resistance heating adds to winter load and aggravates the winter peak demand. The use of vapor compression technologies, including air-to-air and ground-source heat pumps can reduce energy and peak demand in the winter as well as in the summer. Thus electric resistance technologies will be eliminated from further consideration.

SPACE COOLING TECHNOLOGIES

Space conditioning accounts for 19% of electric energy use in commercial buildings on a national basis. This proportion may be even higher for Santee Cooper.

Many space cooling technologies achieve substantial energy savings but not demand savings. Evaporative coolers and economizer cycles are examples of technologies that do not contribute to summer demand savings, since they are not effective during hot and humid times of the year.

Vapor compression technologies, including high efficiency air conditioners and heat pumps, can achieve energy and peak demand savings. Thus these technologies remain as options for DSM programs.

The other promising space cooling technology with peak demand savings is thermal energy storage (TES). Whether partial or full storage systems are adopted, both operate to shift energy and peak demand to off-peak or nighttime periods.

Thus the technologies remaining as options for DSM program include central air conditioners, heat pumps, and TES.

LIGHTING

At 29%, lighting represents the largest end use of electricity in the commercial sector. Furthermore, energy savings in commercial lighting generally translate into peak demand savings because of the large levels of daytime usage. In addition, reductions in lighting load translate into reductions in cooling load. Thus no lighting measures are not eliminated but remain for further consideration in DSM program options.

WATER HEATING

Water heating represents a small amount, only 3%, of the electric end use in the commercial sector. The most promising technology is heat pump water heaters. However, these units have found limited customer acceptance. Therefore, all water heating measures are eliminated from further consideration.

REFRIGERATION

Another small end use of electricity in the commercial sector is refrigeration, with only 7% of the total load. While the refrigeration load can be significant for certain customers, such as supermarkets, for the large majority of commercial accounts the refrigeration load is either not present or quite small. Since the potential load impact is quite small, all refrigeration measures are eliminated from further consideration.

COOKING

Cooking is another small end use at only 2% of commercial electric use on a national basis. Therefore, all refrigeration measures are eliminated from further consideration.

MOTORS

Ventilation accounts for 9% of the electric use in the commercial sector. This is largely due to motors for fans controlling air movement. Motors also are important components in other end uses, including space cooling and refrigeration. Thus motors remain for further consideration in DSM program options.

MULTIPLE END USES AND MISCELLANEOUS

While miscellaneous electric use in the commercial sector is quite high at 21%, the variety of measures is substantial. As a result, single measures have relatively low load impact.

One exception is the use of standby generators. These measures afford substantial reductions in peak demand and relatively small loss of energy sales.

Thus multiple end use and miscellaneous measures, with the exception of standby generators, are eliminated from further consideration.

NEW OPTIONS FOR COMMERCIAL DSM PROGRAMS BY END USE

BUILDING ENVELOPE

COMMERCIAL NEW CONSTRUCTION: Encourage the design and construction of energy efficient buildings. Measures would include those for envelope, space cooling, lighting, motors and measures eligible under other commercial DSM programs.

SPACE COOLING

HIGH EFFICIENCY AIR CONDITIONING: Encourage the purchase and installation of high efficiency air conditioning equipment in new and existing buildings.

THERMAL STORAGE: Encourage the design and installation of thermal storage systems in new and existing buildings.

LIGHTING

ENERGY EFFICIENT LIGHTING: Encourage the design and installation of energy efficient lamps, fixtures, and controls in new and existing buildings.

MOTORS

PREMIUM EFFICIENCY MOTORS: Encourage the installation on a replacement and retrofit basis for existing buildings and for new buildings of premium efficiency motors.

MISCELLANEOUS

STANDBY GENERATORS: Coordinate the operation of existing standby generators during periods of peak demand or system emergency and encourage the installation of standby generators in new buildings.

NEW OPTIONS FOR COMMERCIAL DSM PROGRAMS REMOVED FROM FURTHER CONSIDERATION

BUILDING ENVELOPE

COMMERCIAL NEW CONSTRUCTION: Encourage the design and construction of energy efficient buildings. Measures would include those for envelope, space cooling, lighting, motors and measures eligible under other commercial DSM programs.

For administrative purposes the commercial new construction program will be positioned as an extension of other commercial DSM programs. The building envelope provides relatively small opportunities for energy savings in new commercial buildings compared to the opportunities in lighting, cooling, and motors. Participation of new buildings in programs for other measures will be conditioned on exceeding energy codes for the building envelope by 10%.

SPACE COOLING

HIGH EFFICIENCY AIR CONDITIONING: Encourage the purchase and installation of high efficiency air conditioning equipment in new and existing buildings.

The range of efficiencies on packaged rooftop and unitary equipment for commercial buildings is relatively limited compared to residential equipment. Furthermore, national standards have established a floor that eliminates the least efficient equipment. A program for this measure would have relatively little net impact over activity expected in the marketplace.

COMMERCIAL DSM PROGRAMS PROPOSED FOR FURTHER ANALYSIS

The following programs are proposed for further analysis. These include:

- Commercial lighting
- Thermal storage
- Motors
- Standby generation.

INDUSTRIAL CUSTOMER CLASS

For the industrial customer class, 48 measures was identified. These measures are in addition to the commercial customer class measures, since industrial space also uses them. The measures were screened by end-use category with particular attention to considerations of load impact. Programs covering the largest end use were identified. Also, it is recognized that programs directed at the commercial customer class of customers would be available to industrial customers.

DEMAND-SIDE MANAGEMENT END USES AND MEASURES FOR INDUSTRIAL CUSTOMER CLASS

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
SPACE COOLING		
Condenser water temperature reset	Reduce the temperature of condenser water to reduce work of the compressor	1
Chilled water supply temperature reset	Increase the temperature of chilled water supply to reduce work of the compressor	1
Hot-gas defrost	Refrigerant gas from compressor is circulated through evaporator coil to reduce frost buildup	1
Two-speed or variable speed motors on cooling tower fans	Reduce cooling tower air flow when outdoor temperature and humidity allows	1
HEATING SYSTEMS		
Destratification fans	Mixing warm ceiling air with cooler floor air	1
Comfort radiant heating	Radiation of wavelengths longer than visible light to heat workers rather than using convective systems	1
Process radiant heating	Infrared radiation applied to heating, drying and curing objects	1
Quartz radiant heating	Envelopes of quartz to control infrared radiation	1
Microwave heating	Tempering, cooking, drying, and preheating with microwave energy	2
Direct-arc melting	Melting scrap metal with electric arc furnaces	2
Resistance melting	Melting of glass and other materials with high electric resistance using an electric current that passes directly through the material or by radiation and convection with indirect melting	2
Resistance heating	Heating of objects directly by passing electric current through the material to be heated or indirectly by transferring heat through conduction and radiation	2
Electroslag processing	Ferrous and non-ferrous metals serve as an electrode that is lowered into a slag pool	2
Induction melting	Metal inside an induction coil melts due to current induced in the metal	2
SPACE COOLING		
Induction heating	Use of induction coils for forging, forming, heat treatment and joining	2

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Plasma processing	Plasma arc torch that generates ionized gases at temperatures to 10,000°F	2
Electrical discharge machining	Removal of metal from workpieces with an electric arc	2
Electrochemical machining	Removal of metal from workpieces with an electrolyte between a cathode tool and anode workpiece	2
Electron beam heating	Focused beam of electrons for heating	2
Laser processing	Direct and localized heat source using lasers to convert electric power into high-intensity electromagnetic radiation	2
Ultraviolet and electron beam curing	Transforming a liquid to solid coating through ultraviolet or electron beam radiation	2
AIR COMPRESSORS		
Outside air usage	Piping of outside air to compressor versus use of inside air	1
Leakage reduction	Sealing leaks around valves and fittings	1
Cooling water heat recovery	Pre-heat water for process or boiler use	1
Waste heat recovery	Heat processes or space with compressor waste heat	1
Pressure reduction	Lower settings on pressure controls to minimum necessary	1
Screw compressor controls	Shut off compressors particular when several operate together when loads are reduced	1
Compressor replacement	Installing smaller compressors to serve loads when not operating at capacity	1
Low pressure blowers	Substitute blowers for compressors where low pressure air can be applied to processes	1
INSULATION		
Steam lines and hot water pipes	Pipe wraps and insulation to prevent heat loss from hot fluids	1
Chilled water pipes	Pipe wraps and insulation to prevent heat gain and condensation on process cooling pipes	1
Hot tanks	Blanket and rigid insulation to prevent heat loss in tanks	1
Cold tanks	Blanket and rigid insulation to prevent heat gain in tanks	1

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Injection mold barrels	Insulating barrels on injection molding machines prevents heat loss and adding to cooling load	1
Dock doors	Installing styrofoam or fiberglass in door panels	1
INDUSTRIAL PROCESS HEAT RECOVERY		
Process heat exchanger	Cooling a hot waste stream or heating a cool process stream with rotary or wheel devices, shell and tube configurations, finned tube, plate, plate-and-frame or heat pipe systems	1
Cogeneration	Using fossil fuel to produce hot water or steam along with electric energy	1, 2
Industrial process heat pumps	Take heat from a low temperature source, increase the temperature and deliver the heat to a process stream	1
ELECTROLYTICS		
Electrolytic cells	Improved designs to reduce energy in low-temperature electrolysis	2
Electro-organic synthesis	Production of chemicals through electrolytic processes	2
SOLAR ENERGY		
Solar industrial process heating	Preheating or direct heating of air, water steam for process use with simple flat place collectors or parabolic troughs, evacuated tube and combinations of solar systems	1
Once-through solar heated ventilation and process air	Unglazed transpired collectors and glazed wall collectors to heat air for process or space purposes	1
Solar photocatalytic water detoxification	Combining a photocatalyst with sunlight to convert hazardous waste into carbon dioxide, water and dilute mineral acids	1
LOAD MANAGEMENT AND CONTROLS		
Demand controls	Scheduling, cycling and shedding to reduce peak demand	1
Interruptible service	Discontinuing operations to reduce peak demand	1
Curtailable service	Curtailing some but not all operations to reduce peak demand	1

END USE & DSM MEASURE NAME	DSM MEASURE DESCRIPTION	SOURCES
Power factor	Ratio of resistive to reactive power than may be improved by installing capacitors	1
Battery storage	Charging batteries off-peak for use during peak periods	2

SOURCES:

1. Western Area Power Administration, DSM Pocket Guidebook Volume 4: Industrial Technologies, undated for 1993.

2. Edison Electric Institute, Demand-Side Management Volume 5 Industrial Markets and Programs, March, 1988.

OTHER INDUSTRIAL ENERGY END USES

The end uses and measures presented above are intended to supplement end uses and measures presented in the commercial sector. Rather than repeat the end uses and measures for the industrial sector, it is sufficient to recognize that end uses and measures in commercial buildings are applicable in the industrial sector.

NEW OPTIONS FOR INDUSTRIAL DSM PROGRAMS

The largest end-use by far for industrial customers is with motor drives, as may be observed in the chart on the previous page. Of the electrical energy consumed in the industrial sector, an estimated 68% is used for motor drives. Three other uses account for about 10% each, namely, lighting, process heat and electrolytics.

The electrolytic and process heat uses of electricity are often quite specific and difficult to address with generic DSM measures. Applications of DSM measures in industrial situations frequently require special data and analysis that can change from project to project.

Motors and lighting have the advantage of being somewhat more generic in terms of DSM program design and implementation. Recommendations for these technologies are not as application-specific, which simplifies the data collection and analysis to participate in utility DSM programs. Fortunately, motors and lighting collectively account for the largest part of electrical use in industrial facilities.

Industrial facilities can also benefit from commercial DSM programs. In addition to commercial motors and lighting programs, industrial accounts would be eligible for thermal storage, standby generation and other DSM programs. Thus industrial DSM program options for further analysis will include:

- Motors
- Lighting
- Thermal storage
- Standby generation.

DSM PROGRAM OPTIONS

PROGRAM TITLE

Ground Source Heat Pump Program

PROGRAM OBJECTIVE

To reduce peak demand and save energy during summer and winter seasons by stimulating the installation of ground source heat pumps.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be new residential accounts, although existing customers would also be eligible. Target customers would include those in single family homes, although other types of dwellings would not be excluded from participating.

Eligible equipment would include heat pumps equal to or exceeding 1.5 tons. Closed loop systems would be encouraged, although open loop systems would also be eligible.

Heat recovery will be encouraged as a feature of ground source systems. This will save additional energy for water heating purposes.

INCENTIVES

$500 per unit paid to the customer for a ground source heat pump with a minimum of a 14 EER and a 4 COP. According to a manufacturer of ground source heat pumps, Water Furnace International, their 14.3 EER unit is equivalent to a 17 SEER unit.

Over the ten life of the program, the threshold for eligibility can be raised from the estimated 14 EER to higher levels. The incentive will be graduated according to efficiency level so that the rebate will increase as efficiency increases.

The incentives will start in 1996 and continue for ten years. After ten years it is assumed that market forces will be sufficient to encourage the adoption of higher EER equipment.

Systems providing water heating in addition to space heating and cooling would be eligible for additional incentives. However, just the heating and cooling impacts are assumed for purposes of incentives and program analysis at this time.

DELIVERY CHANNEL

Success of the program will depend largely on the participation of contractors that install ground source heat pumps. Consumers rely primarily on the advice of contractors in selecting equipment.

The number of contractors will need to be expanded to handle the growth in demand for ground source equipment. Training on how to sell, install and service systems will be important to smooth program implementation.

Installation would be self-certified by the customer submitting a copy of the paid invoice with the rebate application. Verification will be conducted on all units by the utility.

MARKETING PLAN

Eligible customers would be alerted through bill inserts timed before the beginning of the cooling season. Another bill insert can be provided prior to the heating season. A marketing brochure will be produced to supplement the bill insert with more information. The bill insert will be designed as an application form.

The coop magazine will be used to build awareness and educate consumers on the types of ground source heat pumps and their advantages.

Advertising will be conducted on a cooperative basis with the contractors.

Extra effort will be undertaken by the utility to educate service and sales staff of contractors on the benefits and features of ground source equipment. Also sales training will be provided to contractors on selling the customer up to high efficiency models.

Dealers would be provided with promotional materials and incentive application materials.

MEASURE LIFE

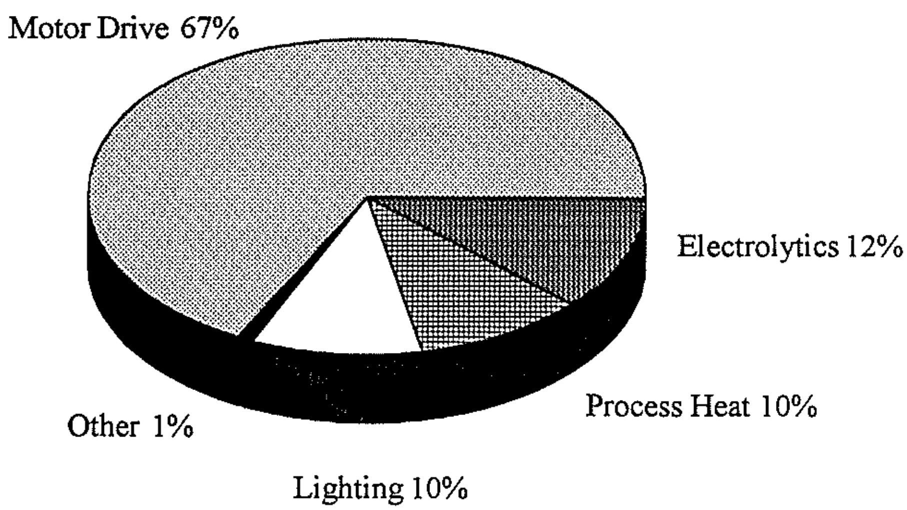
Ground source heat pumps are expected to last 20 plus years. (Water Furnace International, Inc.)

GOALS FOR PARTICIPATION

Santee Cooper serves approximately 96,000 retail accounts and another 350,000 accounts through wholesale customers. Of the retail accounts, 84 percent or 81,000 are residential. Of the 350,000 wholesale accounts, 91 percent or 320,000 are residential. The total residential account population totals 401,000.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

INDUSTRIAL ENERGY USE BY APPLICATION - 1987



Source: Office of Technology Assessment, Energy Efficiency: Challenges and Opportunities for Electric Utilities, September, 1993. Based on data from the Electric Power Research Institute.

The number of residential accounts is estimated to be growing at the rate of 2.4 percent per year. This is based on Central Electric Cooperative forecasts.

At a growth rate of 2.4 percent, residential accounts would be added at the rate of 9,600 per year. (401,000 x .024). This is the target population for ground source heat pump systems.

Current estimates are that about 100 customers per year are installing ground source systems for a penetration rate of about 1 percent for new homes.

It is estimated that the rebate would triple the penetration rate to about 3 percent. Thus the participation goal is estimated at 300 homes per year.

IMPACTS PER PARTICIPANT

For purposes of analysis, it is estimated that the average unit will be 2.5 tons in cooling capacity with efficiencies of 16 EER and 4.0 COP. In the absence of a ground source heat pumps it is assumed the customer would have installed a 12 SEER heat pump under the Good Cents program. The reason for choosing a relatively high threshold is that consumers of ground source heat pumps are more inclined to purchase energy efficient units rather basic units.

Energy savings are calculated at 1,815 kWh per year for cooling and 2,159 kWh per year for heating. Demand savings are calculated at 0.5 kW in the summer and 3.8 kW in the winter.

These savings are for a closed loop system and were calculated by Water Furnace International comparing a 12 SEER air to air system with a 14.3 EER ground source system. The system was designed for a 24,611 Btuh heat gain and 41,229 Btuh heat loss for an 1,800 square foot home. In other words the designs were to Good Cents new home standards. Assumed weather data was for Charleston, SC.

Additional savings would be realized from water heater savings when included as an option.

NET-TO-GROSS RATIO

It is estimated that free rider effects will be 33 percent since many systems are currently being installed. Thus the net-to-gross ratio is 0.67.

COSTS PER PARTICIPANT WITHOUT INCENTIVES

The incremental cost for high efficiency units is estimated to be $4,000 for a unit with 2.5 tons of cooling capacity according to Water Furnace International.

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an engineering analysis comparing installed equipment with estimates of what would have been installed based on market research.

ANNUAL PROGRAM COSTS

ADMINISTRATION		
	2/5 program coordinator @ $55,000	$22,000
	2/5 field inspector @ 45,000 plus travel	22,000
	1/5 clerical @ 25,000	5,000
INCENTIVES		
	300 @ $500	150,000
MARKETING		
	bill inserts, co-operative advertising, training	15,000
	EVALUATION	
	5 percent approximately of above costs	10,000
TOTAL		224,000

ASSUMPTIONS FOR SENSITIVITY ANALYSIS

Incentives

$750

Participation

600 per year

Net to Gross Ratio

.80

Annual Costs

$248,000

DSM PROGRAM OPTIONS

PROGRAM TITLE

Good Cents Manufactured Home Heat Pump Enhanced Program

PROGRAM OBJECTIVE

To reduce peak demand and save energy during summer and winter seasons by stimulating thermal envelope upgrades and the installation of high efficiency heat pumps in manufactured homes.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be residential customers purchasing new manufactured housing. This would include individuals as well as communities that purchase manufactured housing for sale or lease to their residents.

Eligible equipment include split and packaged systems. Split systems are not installed at the factory but are installed at the site by the retailer or a contractor to the retailer. Packaged systems can be installed at the factory as a complete heating and cooling system.

It is common for retailers to over-size equipment for heating and cooling manufactured homes. Through education and training, the utility will work with retailers to specify properly sized equipment. Also the utility will work with manufacturers to educate retailers on the benefits of proper sizing.

The importance of this program will increase starting in October, 1994 when more stringent HUD Code requirements take effect. The higher thermal insulation standards of the new HUD Code will allow at least a half ton reduction in sizing of cooling equipment according to one heat pump manufacturer.

To be eligible customers must upgrade the insulation of manufactured homes to Good Cents standards. They must also install a heat pump of at least 12 SEER.

The present Good Cents program for manufactured homes would be enhanced with more marketing, closer working relationships with home manufacturers and heat pump manufacturers and incentives to retailers of homes.

INCENTIVES

The incentives are a bill credit of $12 per month for qualifying homes. In addition the customer will receive energy bill savings through reduced usage of air conditioning and heating. Bill savings will occur from a tighter thermal envelope as well as from a more efficient heat pump that is properly sized.

An additional incentive of $50 per home would be paid to the dealer for qualifying manufactured homes.

DELIVERY CHANNEL

Trade allies are the key to success in this program. The delivery process is quite elaborate in the manufactured home industry since it involves home manufacturers, distributors, and retailers. The space heating and cooling industry also has a role to play since there is a parallel structure of heat pump manufacturers, distributors and contractors.

The utility will work with the manufacturers of heat pumps and home manufacturers to alert them of efforts to encourage improved thermal installations and proper sizing of heat pumps. The utility will also work with manufactured home retailers that place the orders for heating and cooling equipment to help educate them on the value of increased insulation and proper sizing as well as to build confidence that lower capacity units can meet heating and cooling requirements. Finally the utility will work with heating and cooling contractors that install split systems on-site for manufactured homes to increase their confidence in recommending properly sized high efficiency units.

MARKETING PLAN

The utility will develop a multi-media approach to marketing the benefits of well insulated manufactured homes with high efficiency heat pumps. This will include consumer literature, color videos and perhaps a computer analysis for use by retailers in analyzing and demonstrating the benefits of increased insulation and heat pump efficiency. These marketing tools may be developed alone or on a cost shared basis with heat pump manufacturers, home manufacturers and other utilities.

The utility will develop special analyses showing the benefits in annual energy costs of Good Cents manufactured homes. These comparisons will be developed into customer literature that will be made available to consumers and retailers of manufactured homes. The benefits of the Good Cents manufactured home will be included in bill inserts, media stories, and advertising.

The utility will conduct co-operative advertising with retailers that promote Good Cents manufactured homes. If co-operative advertising is not feasible other approaches will be undertaken to recognize and reward retailers that sell Good Cents homes.

The utility will not need to proceed unilaterally but may link up with neighboring utilities holding similar DSM program objectives. The fact that a manufactured home can be built in one service territory, sold in a second and shipped to a third splits the incentives among utilities and complicates coordination with market channels. It is further compounded when the manufacturers of heat pumps are in other service territories and have independent distribution channels.

MEASURE LIFE

Heat pumps are expected to last on average 15 years. It is assumed for purposes of analysis that when a heat pump is retired at the end of its useful life another unit of at least equivalent efficiency will be installed.

GOALS FOR PARTICIPATION

The goal is to obtain 1,200 participants per year.

Santee Cooper serves approximately 96,000 retail accounts and another 350,000 accounts through wholesale customers. Of the retail accounts, 84 percent or 81,000 are residential. Of the 350,000 wholesale accounts, 91 percent or 320,000 are residential. The total residential account population totals 401,000.

The number of residential accounts is estimated to be growing at the rate of 2.4 percent per year. This is based on Central Electric Cooperative forecasts.

At a growth rate of 2.4 percent, residential accounts would be added at the rate of 9,600 per year. (401,000 x .024). This is the target population for ground source heat pump systems.

Manufactured homes are a large share of new service connections. The wholesale customer of the utility has estimated that about 38 percent of new homes are manufactured homes. This is about twice the level for the retail sector. For purposes of analysis it is assumed the some 33 percent of new homes are manufactured homes.

Based on 9,600 new residential customers each year and 33 percent of the customers in manufactured housing the eligible population is estimated at 3,200 per year.

Current levels of participation in the Good Cents manufactured home program are estimated at the annual rate of 100 for the retail utility and 700 for the wholesale utility or 800 in total. This is based on year to date utility reports ending December, 1993 and ending April, 1994.

A more aggressive program may increase the participation level to 1,200 per year.

IMPACTS PER PARTICIPANT

Calculated savings for the typical manufactured home are 750 kWh/year for cooling and 1,244 kWh for heating. Demand savings are calculated at .68 kW in the summer and .76 kW in the winter.

These estimates were based on the following assumptions. The assumed home was 1,196 square feet which approximates the average size of 1,202 square feet reported in the 1992 Residential Customer Survey.

The Good Cents home was assumed to have insulation at the levels of R-30 in the ceiling, R-12 in the walls, and R-19 under the floor. The heat pump was sized at 2 tons with a rating of 12 SEER.

The base case home was assumed to meet the October 1994 HUD standards with R-21 in the ceiling and R-11 in the walls and under the floor. The base case heat pump was sized at 2.5 tons and rated at 10.5 SEER.

The estimates were developed in consultation with a major insulation manufacturer and heat pump manufacturer.

NET-TO-GROSS RATIO

The net-to-gross ratio is 1.0. This is because of an existing program for Good Cents manufactured homes that requires 12 SEER units. Thus the analysis is incremental to the existing program.

COSTS PER PARTICIPANT WITHOUT INCENTIVES

The incremental cost is $440 per home. This is composed of $240 incremental costs for upgrading insulation from the Zone I HUD Code requirements to the Good Cents home requirements. The second component is $200 incremental cost for a 12 SEER 2.0 ton heat pump compared to a 10.5 SEER 2.5 ton heat pump. The heat pump incremental cost is net of savings for downsizing.

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an engineering analysis comparing installed equipment with estimates of what would have been installed based on market research.

ANNUAL PROGRAM COSTS

ADMINISTRATION

1/5 program coordinator @ $55,000	$11,000
1/2 field inspector @ $45,000 plus transportation @ $10/home	26,000
1/5 clerical @ $25,000	5,000

INCENTIVES

$12/month x 12 months x 400 additional homes per year	57,600
$50/home/dealer sale x 1,200 current and additional homes	60,000

MARKETING

Education, training, videos, bill inserts, co-operative advertising	10,000

EVALUATION

5 percent approximately of above costs	8,400
TOTAL	178,000

July 15, 1994

DSM PROGRAM OPTIONS

PROGRAM TITLE

Residential Duct Testing and Repair

PROGRAM OBJECTIVE

To reduce peak demand and save energy during summer and winter seasons by testing and repairing space conditioning distribution systems.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be those with central air conditioning and space heating systems. Customers of particular interest would be those with high bills. Site-built homes would be the primary target, but manufactured homes and small apartment buildings would also be eligible.

Eligible equipment would include any electrically heated or cooled home. Homes with central air conditioning and fossil heating would be eligible.

Ducts will be tested with a duct blaster although flow hoods and blower doors may also be employed. Trained and certified field workers will conduct the tests and repair ducts. Materials will be specified in duct repair that are high quality with long durability.

INCENTIVES

The utility will absorb most of the cost for testing of $75 of the $100 cost. The utility will also underwrite 1/2 of the repair expense or $150 of the $300 cost. An option could be to charge homes with gas heating and electric central air a higher amounts for the testing, but for purposes of analysis a uniform fee is assumed at this time. Also for homes with gas heating $225 would be charged for the repair. For purposes of analysis at this stage it is assumed participants are all electric.

DELIVERY CHANNEL

The utility will contract with testing and sealing contractors. The utility will recruit participants and forward the customer commitments to the contractors. The contractors will schedule the work, conduct the testing and perform repairs agreed to by the customer. The utility will handle invoicing and collections for both the testing and the repair services.

Contractors will be qualified to provide the service upon successful completion of a course on duct testing and repair. The course is expected to cost about $3,000 per student based on experience of Duke Power. Contractors would be responsible course costs at $1,500 per attendee. The utility would underwrite the costs of tailoring existing courses offered in other areas to the local service territory. The utility would absorb the costs of marketing and organizing the courses and the contractors receiving the training would absorb the travel, time, materials and instruction costs. The utility would absorb about $1,500 per student.

The utility would inspect a sample of tests while the testing is being performed and a sample of repairs when completed.

MARKETING PLAN

The utility will recruit participants through bill inserts. These will be phased during the course of the year so that contractor workloads are as even as possible. Marketing will be done on a limited basis through the media to build awareness and recognize successful participants.

Where contractors are not trained to perform duct testing and repair, the utility will sponsor courses and tests to insure the availability of certified field workers.

MEASURE LIFE

With the use of quality materials, measure lives should average 15 years.

GOALS FOR PARTICIPATION

Santee Cooper serves approximately 96,000 retail accounts and another 350,000 accounts through wholesale customers. Of the retail accounts, 84 percent or 81,000 are residential. Of the 350,000 wholesale accounts, 91 percent or 320,000 are residential. The total residential account population totals 401,000. Some 55 percent cool with a heat pump and 29 percent with a central system for a total of 84 percent (1993 Residential Survey). The number of ducted space conditioning systems is therefore about 337,000 (401,000 x .84).

A participation rate of 0.4 percent to subscribe to the testing and of that half would undertake the repairs. Thus about 1,400 would take the test and 700 complete the repairs.

IMPACTS PER PARTICIPANT

Savings are estimated at 15 percent of cooling energy usage and 13 percent for heating usage. (Source: Cyril Penn, "Duct Fixing in America," Home Energy, September/October, 1993.)

This translates in an average home to savings of about 630 kWh per year for cooling and 790 kWh per year for heating. This is based on an average usage of 4,200 kWh per year for cooling and 6,040 kWh per year for heating for a well insulated home. Cooling and heating consumption is based on a Good Cents Home with a 2.5 ton heat pump with a 10 SEER and 6.8 HSPF.

Demand impacts are estimated at .22 kW in the summer and .33 kW in the winter. This is half the expected .45 kW summer and .66 kW winter demand reductions based on 1,400 cooling load hours and 1,200 heating load hours. Reducing demand impacts further is appropriate since homes with leaky ducts will be operating closer to design conditions whereas before the repairs this was not the case.

NET-TO-GROSS RATIO

It is estimated that no duct testing and repair will be done in the absence of this service. Hence the net-to-gross ratio is 1.0

COSTS PER PARTICIPANT WITHOUT INCENTIVES

The cost of the testing is about $100. The utility would absorb $75 for the testing. The customer would be responsible for the other $25.

Duct repair costs are estimated at $300 per home. The utility would contribute 1/2 of the repair cost or $150 per home. The customer would contribute $150 per home which would bring the payback down to about 1.5 years. (1,420 kWh/yr x $.077/kWh = $109/yr savings.)

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an billing analysis comparing usage prior to and after the repairs.

ANNUAL PROGRAM COSTS

ADMINISTRATION

1/9 program manager @ $55,000	$9,000
1/5 field coordinator @ $45,000	9,000
2/5 clerical @ 25,000	10,000

INCENTIVES

testing of 1,400 @ 75	105,000
repair of 700 @ 150	105,000

MARKETING

Publications, bill inserts, media: 1,400 @ $10	14,000
Training: 8 @ 1,500	12,000

EVALUATION

5 percent approximately of above costs	13,000
TOTAL	277,000

Note:

Note 1: Training costs are estimated annually. Although, most of the expense will probably be in the first two years and then courses say every two years thereafter to train new testing and repair contractor personnel that replace turnover among existing ones or expand the total base of trained personnel.

Note 2: The program will operate for ten years. Costs disappear starting in year 11. Impacts start to decline starting in year 16.

DSM PROGRAM OPTIONS

PROGRAM NAME

Residential Load Control for Air Conditioners

OBJECTIVE

To reward residential customers for reducing demand by cycling air conditioning equipment

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

New and existing residential customers would be targeted for the installation of radio-controlled receivers on central air conditioners. Cycling would be conducted on up to 18 times during the summer months of June, July and August. The on-peak hours are defined in the time-of-use tariff of Santee Cooper as from 1 p.m. and 10 p.m. including weekdays and weekends for the six months of May through October. It is assumed that equipment will be cycled on 6 times per month for an average of 4 hours each occasion. A 43 percent cycling strategy will be employed, that is 13 minutes off out of each half hour of control.

INCENTIVES

A credit of $30/year would be provided or $2.50 per month. The credit would be shown in each monthly bill.

DELIVERY CHANNEL

The utility would identify and recruit participants. The utility would also coordinate the installation of switches for direct load control. Installation would be performed under contract by licensed and trained contractors.

MARKETING PLAN

Bill inserts, direct mail, and media placement would be utilized. Geo-demographic analysis would be performed to identify most likely participants according to attitudes about energy and lifestyles. This would allow more effective use of direct mail and media messages and targeting of marketing information.

TV and radio ads would be employed in early years to build awareness and interest in participating. In later years the media placements would be directed to reinforce commitment to participate and satisfaction with the program.

MEASURE LIFE

Switches last 10 years. Thus participants from year 1 will receive switches in the first year or year one and again 10 years later of year 11. Participants from year 2 will receive replacement switches in year 12, etc.

ELIGIBLE PARTICIPANTS

Santee Cooper serves approximately 96,000 retail accounts and another 350,000 accounts through wholesale customers. Of the retail accounts, 84 percent or 81,000 are residential. Of the 350,000 wholesale accounts, 91 percent or 320,000 are residential. The total residential account population totals 401,000. Some 84 percent have central air conditioning (48 percent heat pumps plus 36 percent central air), according to the Santee Cooper 1992 Residential Survey. Thus about 337,000 (401,000 x .84) residential accounts would be eligible to participate.

PARTICIPATION RATE PER YEAR

Participation rates are estimated at 2 percent per year or 20 percent over ten years. This is based on the experience of some utilities with participation cumulative participation rates ranging from below 15 percent to over 40 percent and the experience of the H2O Advantage Program for water heaters.

PARTICIPANTS PER YEAR

For purposes of simplifying the analysis the assumption is that about 6,700 customers would join each year (337,000 x .02). This annual participation would increase as new homes connect to the system and become eligible for the program. At the same time there will be some attrition as customers drop out of the program for various reasons. The natural growth and attrition are assumed to cancel each other, thus the net growth will be 6,700 per year.

IMPACTS PER PARTICIPANT

Based on program results the air conditioning peak load reduction is estimated at 1 kW per unit. This is based on estimates by Central Electric Cooperative, a review of surveys by EPRI, and management experience with air conditioning cycling programs by the consulting team. The typical customer will have one air conditioning unit.

For purposes of analysis the savings will occur for the four hours of 4 to 8 p.m. Of the energy saved during the cycling period, 50 percent will be recovered from 8 to 10 p.m. (Based on load impact studies by PEPCO.)

COSTS PER PARTICIPANT WITHOUT INCENTIVES

There is no cost to the participant.

NET TO GROSS RATIO

Free rider estimates are accounted for in the load impact per participant. That is the estimated savings per participant takes into account that some homes would have not operated their air conditioner at the time of the cycling.

EVALUATION PLAN

Billing, metering and process evaluations will be conducted. Metering will be conducted to assess the timing and level of demand reductions.

ANNUAL PROGRAM COSTS

ADMINISTRATION

1 program manager @ 55,000	$55,000
2 project coordinator @ 45,000	90,000
1 clerical @ 25,000	25,000
INCENTIVES	
6,700 @ $30/year	201,000
MARKETING	
bill inserts and media @ $6/recruit	40,000
OTHER	
switch cost and installation	
($150 per participant)(6,700)	1,005,000
EVALUATION	
2 percent approximately of above costs	28,000
TOTAL	1,444,000

OTHER ONE TIME COSTS

Enhancements to billing system and control system	100,000
End-use metering data collection and analysis	
100 units @$1,000	100,000
Installation of central station control system and transmitters	250,000
Other total	450,000

Note 1: Starting in year eleven costs drop to $1,325,000 per year. This is because the program has reached a plateau and the expenses are for replacement of old units and recruiting of participants from new customers to replace drop outs. The cost estimates are as follows:

- Administrative costs are cut in half
- Marketing costs are cut in half, since existing participants will need to be renewed
- Evaluation costs are cut in half, since there will be an ongoing need to assure equipment is operating and customers are satisfied
- Expenses continue each year as before for incentives and equipment installation

Note 2: Incentive costs: These costs will escalate each year as new participants are added at the rate of 6,700 participants per year and $30 per participant per year.

Note 3: Marketing costs are incremental to the H20 Advantage Program marketing costs.

Note 4: Evaluation costs. These costs will continue higher in some years and lower in others to assess customer satisfaction and motivation as well as confirm performance of switches.

Note 5: One time costs may well be less for billing system enhancements since a direct load control program for water heaters is in operation. Also the end-use metering may be less if equipment remains from other load research projects and protocols are sufficient for data collection and analysis from these other programs.

Note 6: Central station control systems and transmitters are needed since the Central Electric Cooperative system lacks sufficient capacity to a greatly expanded program.

Note 7: End-use metering assumes that meters from existing load research projects can be redeployed. Otherwise the cost could be $2,000 per site.

DSM PROGRAM OPTIONS

PROGRAM TITLE

Residential Swimming Pool Load Management

PROGRAM OBJECTIVE

To reduce peak demand during summer and winter by cycling off swimming pool pumps during system peak hours.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be those with a swimming pool equipped with a pump. Customers will be targeted with opportunities for multiple switch installations to save on installation costs. Thus a customer may receive at one time switches for both the swimming pool pump and the water heater or air conditioner.

A radio control switch will be installed to control the pump during hours of peak demand on the utility system. The control period will be as long as necessary during the peak hours from 1 p.m. to 10 p.m. It is assumed the control will average 6 hours and be from 2 to 8 p.m. The maximum number of days of control will be 18 in any summer season. For purposes of analysis there will be six days of control for each month of June, July and August. In addition control will be exercised four days each month in December, January and February.

INCENTIVES

The switch will be installed at no charge to the customer. The customer will receive $18 a year which translates to $1.50 per month. The credit will be paid each month.

DELIVERY CHANNEL

The utility will identify and recruit participants. The utility would also coordinate the installation of switches for direct load control. Installation would be performed under contract by licensed and trained contractors. Contractors would handle service calls forwarded by the utility from the customer.

MARKETING PLAN

The program would be marketed in conjunction with other direct load control programs. This provides economies in marketing as well as delivery.

Bill inserts, direct mail, and media placement would be utilized. Geo-demographic analysis would be performed to identify most likely participants according to attitudes about energy and lifestyles. This would allow more effective use of direct mail and media messages and targeting of information.

TV and radio ads would be employed in early years to build awareness and interest in participating. In later years the media placements would be directed to reinforce commitment to participate and satisfaction with the program.

The utility would also work with trade allies in the swimming pool business. In particular, the utility would work with retailers who sell and install swimming pool equipment. It would encourage retailers at the time of installation or later during service calls to build customer awareness and provide to the consumer application forms supplied by the utility.

MEASURE LIFE

Switches last 10 years. Thus participants from year 1 will receive replacement switches in year 11, participants from year 2 will receive replacement switches in year 12, and continue accordingly through year 20 for a program horizon of 20 years.

ELIGIBLE PARTICIPANTS

Santee Cooper serves approximately 96,000 retail accounts and another 350,000 accounts through wholesale customers. Of the retail accounts, 84 percent or 81,000 are residential. Of the 350,000 wholesale accounts, 91 percent or 320,000 are residential. The total residential account population totals 401,000. Some 3 percent have swimming pool filters according to the 1992 Residential Survey. Thus about 12,000 residential accounts would be eligible to participate. However, customers on time-of-use rates would not be eligible since the use of simple timeclocks can provide them with the full benefit of saving peak energy. It is estimated that 12 percent of the accounts with swimming pools are under time-of-use rates, leaving about 10,600 eligible to participate in the program.

PARTICIPATION RATE PER YEAR

Participation rates are estimated at 2 percent per year for 10 years for a cumulative participation of 20 percent and remaining at that level. It may happen that participation rates could be double or more in the early years with heavy promotion and lower in later years as the saturation of participants increases.

PARTICIPANTS PER YEAR

Participation amounts to about 200 customers per year. Participation will escalate at the rate of growth of residential customers. There will also be attrition of existing participants due to changes in customer attitudes and behavior. The addition of new participants through the growth of new service connections is assumed to offset the loss of existing participants due to attrition.

IMPACTS PER PARTICIPANT

Estimates of demand savings are .67 kW. (Sources: Western Area Power Administration, DSM Pocket Guidebook Volume 1: Residential Technologies, April, 1991, discussion with Ron Calcaterra, Central Electric Coop, and discussion with Jim Stoval of ANB, a contractor who manages of DLC programs for utilities). Energy savings will amount to 4 kWh (.67 kW x 6 hrs) period of control or 56 kWh for the year. Some 50 percent of the energy savings will be recovered after the control period equally over the course of four hours, or for purposes of analysis from 8 to 12 midnight.

COSTS PER PARTICIPANT WITHOUT INCENTIVES

There is no cost to the participant.

NET TO GROSS RATIO

The net-to-gross ratio is estimated at 0.9 based on the assumption that 10 percent of the eligible participants will be using timeclocks to save energy prior to the installation of the pump control switch.

EVALUATION PLAN

Billing, metering and process evaluations will be conducted. Metering will be conducted to assess the timing and level of demand reductions.

ANNUAL PROGRAM COSTS

ADMINISTRATION

1/10 program manager @ 55,000	$5,000
1/5 project coordinator @ 45,000	9,000
1/5 clerical @ 25,000	5,000

INCENTIVES

200 @ $18/season	3,600

MARKETING

bill inserts and media @ $5/participant	1,000

OTHER

switch cost and installation ($150 per participant)(200)	30,000

EVALUATION

10 percent approximately of above costs	5,400
TOTAL	59,000

OTHER ONE TIME COSTS

Enhancements to billing system, changes to control system	100,000
End-use metering data collection and analysis: 30 units @ $1,000	30,000
Other total	130,000

Notes

Note 1: Starting in year eleven costs drop to $46,000 per year. While costs for incentives and equipment installation remain the same, it is assumed that other costs are reduced in half. In the second ten years, half the costs in the first ten years would be needed for administration, marketing to retain customers and evaluating equipment operation and satisfaction.

Note 2: Incentive costs: These costs will escalate each year as new participants are added at the rate of 200 participants per year and $18 per participant per year.

Note 3: Evaluation costs. These costs will continue higher in some years and lower in others to assess customer satisfaction and motivation as well as confirm performance of switches.

Note 4: One time costs may well be less for billing system enhancements since a direct load control program for water heaters is in operation. Also the end-use metering assumes some equipment is available from other load research projects and protocols are sufficient for data collection and analysis from these other programs.

Note 5: Central control station systems and transmitters are not included since it is assumed that swimming pool pumps will controlled through either the Central Electric Coop system, which has sufficient capacity, or through another system obtained to support a central air conditioning direct load control program.

DSM PROGRAM OPTIONS

PROGRAM TITLE

Commercial High Efficiecy Lighting

PROGRAM OBJECTIVE

To save peak demand and energy by encouraging the installation of high efficiency lighting.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be commercial and industrial accounts with significant lighting loads. Both large and small accounts would be targeted in new and existing buildings.

INCENTIVES

Customers would receive an incentive of $120/kW of peak demand reduction. Prescriptive incentives would be developed for individual measures such as T8 lamps, electronic ballasts, energy saving exit lights, and high efficiency lamps and ballasts. Also a custom incentive would be available based on $120/kW for large or complex projects involving multiple measures and retrofits of lighting systems.

DELIVERY CHANNEL

The utility would work closely with trade allies including lighting distributors and contractors. Trade allies or customers may submit incentive applications. No pre-approval will be required for small jobs. Inspections will be performed on all jobs to verify the installation of new measures.

MARKETING PLAN

The utility would build awareness and provide information through brochures, application forms, and education materials for customers and trade allies. The marketing strategy would rely primarily on lighting distributors and electrical contractors to identify opportunities and persuade customers to take part in the program. Large accounts would be approached directly by the utility. Publications, case studies and other materials that expound on the success of similar programs for other utilities will be employed and once experience develops, local case studies will be developed.

Some advertising will be done to recognize successful jobs and increase awareness of the program.

MEASURE LIFE

The measure life will average 10 years. Some measures last longer such as certain exit lamps that are advertised as lasting 15 to 20 years. Other measures last shorter periods of time, particularly if the hours use are constant as can be the case for facilities operating 24 hours per day.

GOALS FOR PARTICIPATION

The goals for participation are to recruit 0.5 percent each year of the 45,000 commercial and industrial accounts or 225 participants per year. The participation rate of 0.5 percent per year is based on a review of the NORDAX data base of utilities in the northeastern United States that operated lighting rebated program.

There are about 45,000 commercial and industrial accounts made up of 15,000 from the retail utility and 30,000 from the wholesale utility. Of these accounts about 2/3 are non-demand accounts with less than 7,500 kWh usage per month. This is based on the retail utility split between demand and non-demand accounts.

IMPACTS PER PARTICIPANT

Demand reductions are estimated at 4.5 kW per participant. Energy savings are based on an average operation of 4,000 hours or 18,000 kWh per year. The per participant demand and energy savings are based on NORDAX database of northeast U.S. utilities adjusted roughly in half for the large number of non-demand accounts being served by Santee Cooper.

The thresholds on qualifying equipment would be raised periodically during the course of the program. This would be done to reflect the expected change toward more efficient products in the marketplace, the impact of federal standards and the desire to limit free rider effects. Thus the impacts per participant would be expected to remain about the same over time whereas the impacts would increase as well as the cost of the incentives if the thresholds were not increased.

NET-TO-GROSS RATIO

The net-to-gross ratio is 0.6 since many of the energy savings will be achieved because of growing use of efficient technologies due to market forces and due to federal standards. Also many customers claim to be using energy efficient lighting (Santee Cooper, Commercial Survey, 1992, p.49).

COSTS PER PARTICIPANT WITHOUT INCENTIVES

Costs for lighting without the incentives are estimated at $450/kW. This is based on experience in 1993 and 1994 with an energy service company providing energy efficient lighting.

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an engineering analysis comparing installed equipment with estimates of what would have been installed based on market research.

ANNUAL PROGRAM COSTS

ADMINISTRATION

2/5 program coordinator @ $55,000	$22,000
2/5 field inspector $45,000	18,000
2/5 clerical @ 25,000	10,000

INCENTIVES

$120/kW @ 4.5 kW/participant @ 225 participants/year	1,215,000

MARKETING

brochures, publications, case studies, and advertising	20,000

EVALUATION

about 2 percent of above costs	25,000
TOTAL	1,310,000

Notes

Note 1: The program would operate for years 1 through 10. Starting year 11 the costs would cease.

Note 2: Also in year 11, the impacts would start to decline at the same rate the impacts grew, since the measures are expected to last 10 years on average.

DSM PROGRAM OPTIONS

PROGRAM TITLE

Premium Efficiency Motors

PROGRAM OBJECTIVE

To save peak demand and energy by encouraging the installation of premium efficiency motors.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be commercial and industrial accounts with significant motors loads. Both large and small accounts would be targeted in new and existing buildings.

Motors would be eligible from below 5 horsepower up to 250 horsepower. Sizes larger than 250 horsepower are typically operated a large number of hours per year which justifies the extra expense of purchasing premium efficiency motors. Various types of motors would be eligible including totally enclosed fan cooled and open drip-proof. Adjustable speed drives on motors would also be eligible.

To qualify motors customers would certify operation greater than 2,000 hours per years.

INCENTIVES

Customers would receive an incentive of $120/kW of peak demand reduction. Prescriptive incentives would be developed for individual motor sizes ranging from below 5 horsepower up to 250 horsepower. Incentives would also vary by type of motor including totally enclosed fan cooled and open drip-proof. Finally a custom incentive would be provided to special situations requiring extra effort to estimate energy and demand savings, including adjustable speed drives for motors.

DELIVERY CHANNEL

The utility would work closely with trade allies including motor vendors and distributors. Trade allies or customers may submit incentive applications. No pre-approval will be required for small jobs. Inspections will be performed on all jobs to verify the installation of new measures.

MARKETING PLAN

The utility would build awareness and provide information through brochures, application forms, and education materials for customers and trade allies. Utility personnel would market to trade allies and to large customers. The main marketing strategy would be to rely on motor vendors and distributors since they are the first to know about customer needs which often do not materialize until a failure or problem occurs. Publications, case studies and other materials that expound on the success of similar programs for other utilities will be employed and once experience develops, local case studies will be developed.

Some advertising will be done to recognize successful jobs and build awareness of the program.

MEASURE LIFE

The measure life is assumed to be 15 years. Operational life will depend on the hours use per year. The engineering life of 15 years is taken from Steven Nadel and others, Energy Efficient Motor Systems, American Council for an Energy Efficient Economy, 1992.

GOALS FOR PARTICIPATION

The goals for participation are to recruit .01 percent of commercial and industrial accounts each year or 45 participants per year. The participation rate is based on a review of utility experience (Nadel, 1992).

There are about 45,000 commercial and industrial accounts made up of 15,000 from the retail utility and 30,000 from the wholesale utility. Of these accounts about 2/3 are non-demand accounts with less than 7,500 kWh usage per month. This is based on the retail utility split between demand and non-demand accounts.

IMPACTS PER PARTICIPANT

Demand reductions are estimated at 3 kW per participant. Energy savings are based on an average operation of 4,000 hours or 12,000 kWh per year. The per participant demand and energy savings are based on the experience of other utilities with motor programs (Nadel, 1992) and then adjusted for the high proportion of small customers served by Santee Cooper.

Incentive thresholds would be raised periodically during the course of the program. This would be done to reflect the expected change toward more efficient products in the marketplace, the impact of federal standards and the desire to limit free rider effects. Thus the impacts per participant would be expected to remain about the same over time. If the incentives were not increased, the impacts would increase as well as the cost of the incentives.

NET-TO-GROSS RATIO

The net-to-gross ratio is 0.8 which is based on the experience of utilities in New England. Also a survey of Santee Cooper commercial accounts reports that about 15 percent of the respondents claim to be using high efficiency electric equipment. (Santee Cooper, Commercial Survey, 1992, p. 48.)

COSTS PER PARTICIPANT WITHOUT INCENTIVES

Costs for motors without the incentives are estimated at $400/kW. This is based on estimates derived from reported industry data (Nadel, 1992).

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an engineering analysis comparing installed equipment with estimates of what would have been installed based on market research. Some equipment monitoring may be done in the case of large projects and those with adjustable speed drives.

ANNUAL PROGRAM COSTS

ADMINISTRATION

1/9 program coordinator @ $55,000	$6,000
1/9 field inspector @ $45,000	5,000
1/10 clerical @ 25,000	3,000

INCENTIVES

$120/kW @ 3 kW/participant @ 45 participants/year	16,200

MARKETING

brochures, publications, case studies, and advertising	10,000

EVALUATION

about 10 percent of above costs	4,800
TOTAL	45,000

DSM PROGRAM OPTIONS

PROGRAM TITLE

Commercial Air Conditioning

PROGRAM OBJECTIVE

To save peak demand and energy by encouraging the installation of high efficiency air conditioning.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be commercial and industrial accounts with significant air conditioning loads. Both large and small accounts would be targeted in new and existing buildings.

Eligible measures would include packaged air conditioning units. Future program additions could include split systems and central systems. Both air conditioning and heat pump units would qualify. However, for purposes of analysis, packaged air conditioning only units are assumed for now.

INCENTIVES

Customers would receive an incentive equivalent to $120/kW of peak demand reduction. Prescriptive incentives would be developed based on size of unit and would be based on size of unit in tons. Also the incentives would vary according to the efficiency of the unit allowing the most efficient units to receive higher rebates than just high efficiency units.

For purposes of this analysis a unit providing ten tons per hour of cooling is assumed as the average size unit. Based on the expected demand savings in increasing from a 9 to 10 EER, the rebate for a ten ton unit would be about $100 or $10 per ton.

DELIVERY CHANNEL

The utility would work closely with trade allies including heating and cooling contractors as well as distributors. Trade allies or customers may submit incentive applications. No pre-approval will be required for small jobs. Inspections will be performed on a large fraction of jobs to verify the installation of new measures.

MARKETING PLAN

The utility would build awareness and provide information through brochures, application forms, and education materials for customers and trade allies. The marketing strategy would rely primarily on lighting distributors and electrical contractors to identify opportunities and persuade customers to take part in the program. Large accounts would be approached directly by the utility. Publications, case studies and other materials that expound on the success of similar programs for other utilities will be employed and once experience develops, local case studies will be developed.

Some advertising will be done to recognize successful jobs and increase awareness of the program.

MEASURE LIFE

The measure life will average 15 years. Some utilities use 20 years. ASHRAE uses 15 years. (Aaron York, Cross Over into Commercial HVAC," Contracting Business, June, 1994, p. 22).

GOALS FOR PARTICIPATION

The goals for participation are to stimulate the purchase of higher efficiency equipment in 20 percent the installations each year. This amounts to systems each year.

The estimate is derived from the total population of commercial and industrial customers of 45,000 accounts. Over 50 percent of the accounts have equipment that is expected to be eligible. Of all the accounts 64 percent have cooling. (Santee Cooper, Commercial Survey, 1992, p. 7). Most of these have central systems or heat pumps, but many have window units, ceiling fans and attic fans for cooling.

Over 50 percent of the accounts have air conditioning systems or about 22,500 accounts. This estimate is based on the reported number of frequency of heat pump and central air conditioning systems reported (Ibid, pp. 37 - 38).

Each account is estimated to operate with an average of 6,000 square feet of cooling load (Santee Cooper, Commercial Survey: 1992, p.8).

The typical building is assumed to operate with 2 units of 10 tons capacity or 20 tons of cooling capacity. The actual experience varies widely from 200 to 400 square served per ton of cooling capacity. The estimate for this analysis is that each ton of cooling serves 300 square feet of space. Thus 20 tons is required for the average building with 6,000 square feet.

It is assumed each of the 22,500 accounts operates with 2 units of ten tons each. Thus some 45,000 units are on the utility systems.

Assuming an average life of 15 years for the 45,000 units results in a need to replace about 3,000 units per year.

If 20 percent of these units upgrade to high efficiency models the goal becomes about 600 per year.

IMPACTS PER PARTICIPANT

It is assumed that the average upgrade for a ten ton unit will be of 1 EER, such as from 9.5 to 10.5. An estimate for a one EER upgrade for a packaged air conditioner from 9 to 10 EER was .82kW savings in peak demand (The Trane Corporation). The equivalent full load hours is estimated at 2,500 according to the Trane Corporation for Charleston, SC.

Thus the impacts per participant are estimated at 0.8 kW in summer demand reduction and 2,000 kWh in summer energy savings.

NET-TO-GROSS RATIO

The net-to-gross ratio is 0.9. This is based on utility data recorded by HL&P after their review of the estimates of other utilities. The ratio might be higher except for the presumption that many replacements are done on an emergency basis upon failure. In new construction, there is an opportunity to install higher efficiency units more readily.

COSTS PER PARTICIPANT WITHOUT INCENTIVES

The cost per participant without incentives is estimated at $550 for a ten ton unit.

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an engineering analysis comparing installed equipment with estimates of what would have been installed based on market research.

ANNUAL PROGRAM COSTS

ADMINISTRATION

2/5 program coordinator @ $55,000	$22,000
2/5 field inspector $45,000 (1 hour x 600 inspections) and travel	20,000
2/5 clerical @ 25,000	10,000

INCENTIVES

$100 @ 600 participants/year	60,000

MARKETING

brochures, publications, case studies, and advertising	20,000

EVALUATION

about 10 percent of above costs	13,000
TOTAL	145,000

DSM PROGRAM OPTIONS

PROGRAM TITLE

Thermal Energy Storage

PROGRAM OBJECTIVE

To shift demand and energy from daytime to nighttime hours through the use of thermal energy storage systems.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be commercial and industrial accounts with daytime cooling loads that can be supplied with nighttime cool storage. Both new and existing buildings would be eligible with particular focus on new or expanded facilities since the incremental costs can be less than on a retrofit basis. While it is expected that large facilities with experienced building engineers will be the source of major projects, small projects may be developed in other facilities, such as churches.

In the commercial sector, the most likely candidates will be hotels, casinos, hospitals, office buildings, retail stores, schools and museums. In the industrial sector, the most likely candidates will be those with significant cooling loads such as chemical plants, food and beverage processing plants, and refrigerated warehousing.

Eligible cool storage systems would include chilled water, ice, and eutectic salts. Full systems would be eligible allowing complete supply of on-peak cooling with nighttime storage. Partial systems would be eligible also allowing on-peak cooling to be met by nighttime storage and daytime chiller operations. TES systems based on packaged units and chillers would be eligible.

It is expected that systems participating in the early years will be larger built-up units. In later years, smaller DX systems may become more common if current research and development by manufacturers proceeds satisfactorily as is expected.

INCENTIVES

$200 per kW of shifted load would be paid upon satisfactory commissioning of the system.

In addition, design feasibility incentives would be offered to help defray the extra costs for analysis of cool storage systems and help assure the energy and demand impacts on the utility system. . Feasibility studies would be covered up to 50 percent of the cost up to $2,500.

Construction invectives would be paid to the building owner. Design incentives would be paid to the building owner or to the design organization with the approval of the building owner.

DELIVERY CHANNEL

Success of the program will depend greatly on the cooperation of trade allies. In particular, the architects, consulting engineers and mechanical contractors are important to program success. Thus program delivery will involve working with these professions to increase awareness and commitment to TES. In turn these professions will help sell the building owners and managers on the merits of TES.

MARKETING PLAN

Personal marketing will be the primary strategy for selling building owners and trade allies on the benefits of TES. This will be supplemented by brochures, case studies, and publications about TES. Every two years a TES seminar will be held mixing presentations by outside experts with presentations by utility personnel. The seminar will be educational as well as serve to recognize successful projects, organizations and individuals involved with TES in the utility service area.

MEASURE LIFE

TES systems are estimated to operate for at least 20 years. (Based on ASHRAE Technical Committee TC 1.8, reported in Contracting Business, June, 1994.)

GOALS FOR PARTICIPATION

The goals for participation are for no projects the first year and 2 projects per year thereafter. No projects are expected for the first year, since the lag from planning, to design, to construction, to commissioning can take a year. In effect, the goals assume two commitments will be signed with the customer in the first year with operation by the peak season of the second year.

IMPACTS PER PARTICIPANT

Demand reductions are estimated at 75 kW per participant. The impacts are expected to occur between 1 p.m. and 9 p.m. each summer day.

Energy savings during the day are estimated to be fully recovered during recharging at night. While some systems result in net energy savings, others result in net energy increases, for purposes of analysis these are assumed to balance out.

The energy shifted to off-peak periods is 600 kWh per day (75 kW x 8 h). Systems are expected to be recharged between 10 p.m. and 6 a.m.

Impacts will start in 1997 assuming the program begins in 1996.

NET-TO-GROSS RATIO

The net-to-gross ratio is 1.0 since in the absence of the program incentives, projects would not be undertaken by building owners.

COSTS PER PARTICIPANT WITHOUT INCENTIVES

The costs per participant are estimated at $720/kW of demand reduction. The incremental cost depends significantly on the age of facility, nature of existing equipment, type of TES system, size of system, and many other factors. Some proponents claim there are no incremental costs for ice storage systems with low temperature air distribution, particularly for high rise buildings where rental floor space may be added to the height. The incremental cost per participant assumed for purposes of this analysis is based on a review of case studies found in industry publications, utility analyses, and manufacturer literature.

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an engineering analysis comparing installed equipment with estimates of what would have been installed based on market research.

ANNUAL PROGRAM COSTS

ADMINISTRATION

1/5 program engineer @ $45,000	$9,000
1/10 clerical @ 25,000	3,000

INCENTIVES

$200/kW @ 150 kW	30,000
$2,500/feasibility study @ 4 studies	10,000

MARKETING

brochures, case studies, and seminars	5,000

EVALUATION

about 5 percent of above costs	3,000
TOTAL	60,000

DSM PROGRAM OPTIONS

PROGRAM TITLE

Standby Generation

PROGRAM OBJECTIVE

To shift curtail peak demand by encouraging operation by customers of standby generators.

DESCRIPTION OF TARGET CUSTOMERS AND ELIGIBLE MEASURES

The target customers would be commercial and industrial accounts with emergency or standby generators. Customers would be encouraged to operate generators under load conditions during a few days each year of system peak demand. Customers would be contacted by phone and asked to curtail by operating standby generators for a fixed amount of time up to 8 hours but averaging 6 hours on each occasion. Commitments would be expected for up to 12 days a year but averaging 6 days a year including one per month for June, July, August, September, January and February.

Target customers would include hospitals, computer operations, communications centers, publics works facilities, and military bases. Customers with existing generators will be the primary targets for participation, since little on not investment is required on their part. New facilities that are likely to require generators such as hospitals will be targeted in order to encourage larger sizes of units.

INCENTIVES

Customers would receive a billing credit of $8/kW of load reduced for each occasion. In billing months with multiple reductions, the largest reduction would be used to figure the billing credit. While penalties for no performance could be considered, this is often an inhibition to participate. When sufficient customers are participating, the inability of any one customer to achieve all of its expected load reduction is not as significant a problem.

DELIVERY CHANNEL

The utility would work directly with the customer to assist that standby generators are properly installed and operated in a manner that is compatible with the electric system. Vendors of standby generators will be notified and encouraged to add this program as another benefit of installing the equipment.

MARKETING PLAN

Personal marketing will be the primary strategy for selling building owners and managers. Publications, case studies and other materials that expound on the success of similar programs for other utilities will be employed and once experience develops, local case studies will be developed.

MEASURE LIFE

The measure life is expected to be 20 years.

GOALS FOR PARTICIPATION

The goals for participation are to recruit 2 participants per year.

IMPACTS PER PARTICIPANT

Demand reductions are estimated at 500 kW per participant. Energy savings are based on an average operation of 6 hours per curtailment and 1 curtailment per month.

NET-TO-GROSS RATIO

The net-to-gross ratio is 1.0 since in the absence of the program incentives, curtailments would not have been undertaken.

COSTS PER PARTICIPANT WITHOUT INCENTIVES

There are no incremental costs to the participant since the target customer will have an existing standby generator. New customers with the a potential need for standby generation, such as hospitals, will be encouraged to obtain as large a unit as feasible, given the utility incentive. Regarding operating costs, these will be small since the customer would be expected to test the generator during the course of the year, although not under load. Furthermore, the incentive plus bill savings is expected to offset most if not all the operating costs

EVALUATION PLAN

Both impact and process evaluations will be conducted. They will be performed in alternate years starting with a process evaluation at the end of the first year of the program. The impact evaluation will be in the form of an engineering analysis comparing installed equipment with estimates of what would have been installed based on market research.

ANNUAL PROGRAM COSTS

ADMINISTRATION

1/9 program coordinator @ $55,000	$5,000
1/10 clerical @ 25,000	3,000

INCENTIVES

$8/kW @ 500 kW @ 6 times per year @ 2 participants/year	48,000

MARKETING

brochures and case studies	2,000

EVALUATION

about 7 percent of above costs	4,000
TOTAL	62,000

APPENDIX C

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
HIGH EFFICIENCY LIGHTING

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	26	-	42	15	164	73	29	0.36	1.46	-
1996	56	-	44	16	172	76	61	0.74	2.95	126
1997	89	-	46	17	179	79	95	1.11	4.45	255
1998	135	-	48	17	186	82	132	1.49	5.97	384
1999	184	51	49	18	193	85	170	1.87	7.48	515
2000	229	63	51	18	201	89	213	2.25	9.01	645
2001	298	76	53	19	208	93	258	2.64	10.57	778
2002	387	90	55	20	217	97	307	3.03	12.14	912
2003	457	106	58	21	227	100	361	3.45	13.79	1,047
2004	583	122	60	21	236	105	417	3.85	15.40	1,190
2005	588	126	0	0	0	0	434	3.87	15.48	1,329
2006	672	130	-	-	-	-	451	3.89	15.55	1,336
2007	765	135	-	-	-	-	469	3.91	15.63	1,342
2008	866	140	-	-	-	-	488	3.92	15.70	1,349
2009	869	145	-	-	-	-	507	3.94	15.78	1,355
2010	904	148	-	-	-	-	527	3.96	15.82	1,362
2011	826	250	-	-	-	-	549	3.98	15.92	1,365
2012	845	259	-	-	-	-	571	4.00	16.01	1,374
2013	947	264	-	-	-	-	594	4.02	16.09	1,381
2014	1,047	264	-	-	-	-	618	4.05	16.18	1,389
2015	0	0	-	-	-	-	0	0.00	0.00	1,396
NPV	$4,650	$985	$357	$128	$1,395	$620	$3,266			
RIM	1.29	PART	2.78	TRC	3.00	UTIL	5.10			

EXHIBIT C-1

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
<u>THERMAL ENERGY STORAGE</u>

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	13	2	-	-	-	-	-	-
1997	-	-	14	2	74	22	5	0.09	-	1
1998	-	-	14	2	77	23	10	0.18	-	2
1999	2	0	15	2	80	24	15	0.28	-	3
2000	4	10	15	2	83	25	19	0.37	-	5
2001	5	13	16	2	86	26	24	0.46	-	6
2002	7	16	17	2	90	27	30	0.56	-	7
2003	12	20	17	2	94	28	34	0.66	-	8
2004	14	24	18	2	98	29	40	0.85	-	9
2005	19	27	19	2	102	30	45	0.86	-	11
2006	20	28	0	3	-	-	45	0.86	-	11
2007	21	29	0	3	-	-	46	0.86	-	11
2008	26	30	0	3	-	-	46	0.87	-	11
2009	30	31	0	3	-	-	46	0.87	-	11
2010	28	32	0	3	-	-	46	0.88	-	11
2011	29	33	0	3	-	-	46	0.88	-	11
2012	27	56	0	4	-	-	47	0.88	-	11
2013	27	58	0	4	-	-	47	0.89	-	11
2014	31	59	0	4	-	-	47	0.89	-	11
2015	34	59	0	4	-	-	47	0.90	-	11
NPV	$132	$204	$105	$26	$502	$149	$298			
RIM	0.58	PART	0.89	TRC	0.53	UTIL	1.20			

EXHIBIT C-2

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
STANDBY GENERATION

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	6	2	-	29	-	0.60	0.02	1
1997	1	-	6	2	-	60	1	1.22	0.04	2
1998	1	-	6	3	-	94	1	1.83	0.07	3
1999	3	-	7	3	-	131	2	2.46	0.09	5
2000	4	84	7	3	-	169	3	3.08	0.11	6
2001	5	104	7	3	-	211	3	3.71	0.13	7
2002	6	126	8	3	-	256	4	4.35	0.16	8
2003	9	149	8	3	-	304	5	5.00	0.18	9
2004	11	174	8	4	-	358	5	5.67	0.20	11
2005	13	200	9	4	-	414	6	6.34	0.23	12
2006	15	208	9	4	-	431	6	6.37	0.23	12
2007	16	214	10	4	-	448	7	6.40	0.23	12
2008	17	222	10	4	-	466	7	6.43	0.23	12
2009	19	230	10	4	-	484	7	6.46	0.23	12
2010	19	238	10	4	-	503	7	6.49	0.23	12
2011	19	244	11	4	-	522	8	6.51	0.23	12
2012	19	412	12	4	-	545	8	6.55	0.24	12
2013	20	427	12	5	-	567	9	6.59	0.24	12
2014	22	435	12	5	-	590	9	6.62	0.24	12
2015	23	436	13	5	-	614	9	6.66	0.24	12
NPV	$97	$1,523	$86	$34	$0	$3,041	$45			
RIM	0.51	PART	Inf.	TRC	13.49	UTIL	0.51			

EXHIBIT C-3

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
PREMIUM EFFICIENCY MOTORS

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	4	-	15	3	26	10	5	0.06	0.26	25
1997	10	-	15	3	27	10	11	0.13	0.53	51
1998	16	-	16	3	28	11	17	0.20	0.79	77
1999	24	-	17	3	29	11	23	0.27	1.06	103
2000	33	9	17	3	30	11	30	0.33	1.33	129
2001	41	12	18	3	32	12	38	0.40	1.60	156
2002	53	13	19	3	33	12	46	0.47	1.88	182
2003	69	16	19	4	34	13	55	0.54	2.16	209
2004	82	19	20	4	36	14	64	0.61	2.45	238
2005	104	22	21	4	37	14	74	0.68	2.74	266
2006	105	23	-	-	-	-	77	0.69	2.75	267
2007	120	23	-	-	-	-	80	0.69	2.77	268
2008	136	24	-	-	-	-	84	0.69	2.78	270
2009	154	25	-	-	-	-	87	0.70	2.79	271
2010	155	25	-	-	-	-	90	0.70	2.80	272
2011	161	26	-	-	-	-	94	0.70	2.81	273
2012	147	45	-	-	-	-	98	0.71	2.83	275
2013	150	46	-	-	-	-	102	0.71	2.85	276
2014	169	47	-	-	-	-	106	0.72	2.86	278
2015	186	47	-	-	-	-	110	0.72	2.88	279
NPV	$778	$165	$116	$23	$207	$78	$545			
RIM	1.24	PART	3.01	TRC	2.72	UTIL	4.34			

EXHIBIT C-4

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
MANUFACTURED HOME HEAT PUMP PROGRAM

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	26	-	31	5	316	139	28	0.49	1.43	671
1997	55	-	33	5	331	255	60	0.99	2.91	1,360
1998	87	-	34	6	345	378	93	1.50	4.39	2,050
1999	133	-	36	6	359	511	130	2.01	5.88	2,748
2000	181	62	37	6	372	651	168	2.48	7.36	3,440
2001	228	76	38	6	387	804	210	3.03	8.87	4,149
2002	293	92	39	6	402	968	254	3.50	10.41	4,864
2003	378	109	41	6	419	1,144	302	4.02	11.95	5,586
2004	456	127	43	7	438	1,339	355	4.57	13.58	6,347
2005	572	146	45	7	456	1,542	411	5.11	15.17	7,090
2006	578	151	-	8	-	1,550	428	5.13	15.24	7,126
2007	672	156	-	8	-	1,613	445	5.16	15.32	7,159
2008	747	162	-	8	-	1,677	462	5.18	15.39	7,193
2009	838	168	-	8	-	1,743	480	5.20	15.46	7,226
2010	868	173	-	9	-	1,813	500	5.23	15.53	7,261
2011	888	178	-	9	-	1,882	519	5.24	15.58	7,281
2012	813	301	-	10	-	1,960	540	5.28	15.68	7,328
2013	850	311	-	10	-	2,040	562	5.31	15.76	7,368
2014	941	317	-	10	-	2,122	585	5.33	15.85	7,408
2015	1,038	318	-	11	-	2,209	609	5.36	15.93	7,447
NPV	$4,311	$1,112	$249	$72	$2,530	$11,240	$3,019			
RIM	0.37	PART	5.64	TRC	1.90	UTIL	0.47			

EXHIBIT C-5

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
<u>LOAD CONTROL AIR CONDITIONING</u>

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	991	17	-	120	-	4.02	0.01	3,746
1997	2	-	757	18	-	253	1	8.14	0.06	7,591
1998	3	-	788	18	-	394	2	12.28	0.09	11,447
1999	7	-	819	19	-	547	4	16.46	0.19	15,345
2000	10	563	849	19	-	708	5	20.61	0.24	19,209
2001	13	698	883	21	-	884	6	24.85	0.27	23,163
2002	19	842	919	21	-	1,073	9	29.14	0.36	27,158
2003	24	997	956	22	-	1,276	12	33.47	0.47	31,191
2004	38	1,167	999	23	-	1,500	18	38.02	0.69	35,435
2005	48	1,342	1,039	24	-	1,734	23	42.48	0.83	39,588
2006	80	1,531	978	12	-	1,984	34	46.96	1.20	43,763
2007	65	1,724	1,017	13	-	2,250	29	51.46	0.98	47,964
2008	88	1,933	1,057	14	-	2,536	37	56.02	1.22	52,210
2009	87	2,157	1,099	14	-	2,838	34	60.60	1.10	56,480
2010	110	2,388	1,144	15	-	3,164	44	65.25	1.38	60,814
2011	132	2,617	1,187	15	-	3,502	56	69.79	1.69	65,047
2012	98	4,694	1,237	16	-	3,876	44	74.63	1.26	69,554
2013	115	5,148	1,287	17	-	4,271	50	79.45	1.40	74,048
2014	137	5,531	1,339	17	-	4,691	58	84.32	1.57	78,584
2015	158	5,835	1,393	18	-	5,138	67	89.23	1.75	83,160
NPV	$462	$14,282	$10,147	$187	$0	$16,785	$202			
RIM	0.54	PART	Inf.	TRC	1.43	UTIL	0.54			

EXHIBIT C-6

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
COMMERCIAL AIR CONDITIONING

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	12	-	43	8	178	36	13	0.26	0.65	335
1997	25	-	45	8	186	38	27	0.53	1.31	680
1998	40	-	47	9	194	39	42	0.79	1.98	1,025
1999	62	-	49	9	202	41	58	1.06	2.65	1,374
2000	84	36	51	9	209	42	76	1.33	3.32	1,720
2001	107	45	53	10	218	44	95	1.60	4.01	2,074
2002	137	54	55	10	226	46	115	1.88	4.70	2,432
2003	176	65	57	10	236	48	136	2.16	5.39	2,793
2004	214	75	60	11	246	50	161	2.45	6.13	3,173
2005	261	86	62	11	256	52	185	2.74	6.85	3,545
2006	271	90	-	-	-	-	193	2.75	6.88	3,563
2007	338	92	-	-	-	-	200	2.77	6.91	3,579
2008	334	96	-	-	-	-	209	2.78	6.95	3,597
2009	372	99	-	-	-	-	217	2.79	6.98	3,613
2010	382	103	-	-	-	-	226	2.80	7.01	3,631
2011	387	106	-	-	-	-	234	2.81	7.03	3,641
2012	360	178	-	-	-	-	244	2.83	7.08	3,664
2013	376	184	-	-	-	-	254	2.85	7.12	3,684
2014	408	188	-	-	-	-	264	2.86	7.15	3,704
2015	446	188	-	-	-	-	275	2.88	7.19	3,724
NPV	$1,957	$658	$346	$62	$1,423	$288	$1,363			
RIM	1.27	PART	1.16	TRC	1.43	UTIL	3.76			

EXHIBIT C-7

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
DUCT TESTING AND REPAIR

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	11	-	64	8	168	94	12	0.09	0.60	391
1997	23	-	67	8	176	99	25	0.19	1.21	793
1998	36	-	69	9	183	103	39	0.28	1.82	1,196
1999	56	-	72	9	191	107	54	0.38	2.44	1,603
2000	76	9	75	9	197	111	70	0.47	3.06	2,007
2001	96	11	78	10	205	115	87	0.57	3.69	2,420
2002	124	13	81	10	214	120	106	0.67	4.32	2,837
2003	162	16	84	10	222	125	126	0.77	4.96	3,259
2004	195	18	88	11	232	130	147	0.87	5.64	3,702
2005	248	21	92	11	242	136	171	0.98	6.30	4,136
2006	247	22	-	12	-	-	177	0.98	6.33	4,157
2007	291	22	-	12	-	-	185	0.99	6.36	4,176
2008	325	23	-	13	-	-	192	0.99	6.39	4,196
2009	369	24	-	13	-	-	199	0.99	6.42	4,215
2010	378	25	-	14	-	-	208	1.00	6.45	4,236
2011	386	26	-	14	-	-	216	1.00	6.47	4,247
2012	353	43	-	15	-	-	225	1.01	6.51	4,275
2013	368	45	-	15	-	-	234	1.01	6.55	4,298
2014	409	46	-	16	-	-	243	1.02	6.58	4,321
2015	451	46	-	17	-	-	253	1.03	6.62	4,344
NPV	$1,860	$160	$509	$112	$1,341	$755	$1,255			
RIM	0.77	PART	1.50	TRC	1.03	UTIL	1.47			

EXHIBIT C-8

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
<u>HIGH EFFICIENCY HEAT PUMPS</u>

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	20	0	64	15	1,078	674	22	0.43	1.10	2,516
1997	43	0	67	15	1,131	706	46	0.88	2.23	5,098
1998	68	0	70	16	1,177	735	72	1.32	3.37	7,688
1999	107	0	73	17	1,224	765	99	1.77	4.51	10,307
2000	146	60	76	17	1,269	793	129	2.22	5.65	12,902
2001	184	75	78	18	1,320	825	161	2.67	6.81	15,558
2002	238	90	82	19	1,372	858	195	3.13	7.98	18,240
2003	310	107	85	19	1,427	892	232	3.60	9.17	20,949
2004	373	125	89	20	1,492	933	273	4.09	10.42	23,799
2005	470	144	92	21	1,553	970	315	4.56	11.64	26,589
2006	474	150	-	21	-	-	328	4.59	11.70	26,721
2007	551	155	-	23	-	-	341	4.61	11.75	26,846
2008	613	160	-	23	-	-	355	4.63	11.81	26,974
2009	691	166	-	24	-	-	369	4.65	11.86	27,096
2010	707	171	-	25	-	-	384	4.67	11.92	27,230
2011	721	176	-	26	-	-	398	4.69	11.95	27,305
2012	664	297	-	27	-	-	415	4.72	12.03	27,480
2013	692	308	-	28	-	-	431	4.74	12.10	27,630
2014	765	313	-	30	-	-	449	4.77	12.16	27,779
2015	840	313	-	30	-	-	467	4.79	12.23	27,927
NPV	$3,513	$1,096	$513	$208	$8,624	$5,389	$2,317			
RIM	0.55	PART	0.89	TRC	0.49	UTIL	0.75			

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
SWIMMING POOL LOAD MANAGEMENT

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	108	3	-	2	-	0.07	-	112
1997	-	-	31	3	-	5	-	0.15	0.00	227
1998	-	-	32	3	-	7	-	0.22	0.00	342
1999	-	-	34	3	-	10	-	0.30	0.00	458
2000	-	10	35	4	-	13	-	0.37	0.00	573
2001	-	13	37	4	-	16	-	0.45	0.00	691
2002	1	15	38	4	-	19	0	0.52	0.01	811
2003	1	18	40	4	-	23	0	0.60	0.01	931
2004	1	21	42	5	-	27	0	0.68	0.03	1,058
2005	2	24	43	5	-	31	1	0.76	0.03	1,182
2006	2	27	36	2	-	36	1	0.84	0.04	1,306
2007	2	31	38	2	-	41	1	0.93	0.03	1,432
2008	4	35	39	2	-	46	2	1.01	0.06	1,559
2009	4	39	40	3	-	51	1	1.09	0.05	1,686
2010	5	43	42	3	-	57	2	1.17	0.07	1,815
2011	5	47	44	3	-	62	2	1.26	0.07	1,942
2012	5	84	45	3	-	70	2	1.34	0.06	2,076
2013	5	93	47	3	-	77	2	1.43	0.06	2,210
2014	6	99	49	3	-	84	2	1.52	0.07	2,346
2015	6	105	51	4	-	92	3	1.61	0.07	2,482
NPV	$17	$257	$460	$36	$0	$301	$8			
RIM	0.34	PART	Inf.	TRC	0.55	UTIL	0.34			

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
<u>GROUND SOURCE HEAT PUMP</u>

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	8	-	39	6	481	90	9	0.06	0.48	168
1997	18	-	40	6	505	94	20	0.12	0.97	340
1998	28	-	42	6	526	98	31	0.18	1.46	513
1999	42	-	44	7	547	102	43	0.25	1.96	687
2000	56	1	45	7	567	106	56	0.31	2.46	860
2001	71	1	47	7	589	110	70	0.37	2.96	1,037
2002	93	1	49	8	613	115	85	0.44	3.47	1,216
2003	121	2	51	8	638	119	101	0.50	3.99	1,397
2004	147	2	53	8	666	125	119	0.57	4.53	1,587
2005	190	2	55	9	694	129	137	0.64	5.06	1,773
2006	184	2	-	-	-	-	143	0.64	5.09	1,781
2007	228	2	-	-	-	-	148	0.64	5.11	1,790
2008	258	3	-	-	-	-	154	0.65	5.14	1,798
2009	288	3	-	-	-	-	161	0.65	5.16	1,806
2010	303	3	-	-	-	-	167	0.65	5.19	1,815
2011	312	3	-	-	-	-	173	0.65	5.20	1,820
2012	280	5	-	-	-	-	180	0.66	5.23	1,832
2013	292	5	-	-	-	-	188	0.66	5.26	1,842
2014	331	5	-	-	-	-	195	0.67	5.29	1,852
2015	366	5	-	-	-	-	203	0.67	5.32	1,862
NPV	$1,451	$18	$306	$48	$3,852	$719	$1,008			
RIM	0.71	PART	0.45	TRC	0.35	UTIL	1.37			

EXHIBIT C-11

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
HIGH EFFICIENCY LIGHTING

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	20	-	33	12	129	57	29	0.29	1.15	99
1997	43	-	34	12	131	59	59	0.57	2.26	195
1998	67	-	34	12	135	60	90	0.84	3.37	291
1999	100	-	35	13	139	62	124	1.11	4.46	385
2000	137	38	37	13	143	64	159	1.39	5.56	480
2001	168	47	38	14	147	66	197	1.66	6.63	572
2002	216	56	39	14	152	67	236	1.92	7.68	663
2003	278	65	40	14	156	69	277	2.18	8.72	753
2004	320	74	41	14	159	71	318	2.42	9.68	835
2005	404	84	42	15	163	72	363	2.67	10.67	921
2006	403	86	-	-	-	-	373	2.65	10.59	914
2007	455	88	-	-	-	-	383	2.63	10.52	908
2008	512	90	-	-	-	-	394	2.61	10.44	901
2009	572	92	-	-	-	-	405	2.59	10.37	895
2010	567	94	-	-	-	-	416	2.57	10.30	888
2011	585	96	-	-	-	-	429	2.56	10.25	885
2012	527	160	-	-	-	-	439	2.54	10.15	876
2013	531	163	-	-	-	-	451	2.52	10.06	869
2014	587	164	-	-	-	-	463	2.49	9.98	861
2015	640	162	-	-	-	-	475	2.47	9.89	854
NPV	$2,941	$618	$248	$89	$969	$430	$2,619			
RIM	1.05	PART	3.15	TRC	2.73	UTIL	4.64			

EXHIBIT C-12

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
THERMAL ENERGY STORAGE

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	11	1	-	-	-	-	-	-
1997	-	-	10	1	57	17	5	0.07	-	1
1998	-	-	11	1	58	17	9	0.14	-	2
1999	1	-	11	2	60	18	14	0.21	-	3
2000	3	8	12	2	62	18	18	0.27	-	3
2001	3	10	12	2	64	19	22	0.34	-	4
2002	5	12	12	2	65	19	27	0.41	-	5
2003	9	14	13	2	67	20	31	0.47	-	6
2004	9	16	13	2	68	20	35	0.60	-	7
2005	13	19	13	2	70	21	39	0.59	-	7
2006	14	19	-	2	-	-	39	0.59	-	7
2007	15	20	-	2	-	-	39	0.58	-	7
2008	18	20	-	2	-	-	38	0.58	-	7
2009	19	21	-	2	-	-	38	0.58	-	7
2010	19	21	-	2	-	-	38	0.57	-	7
2011	19	21	-	2	-	-	38	0.57	-	7
2012	18	35	-	2	-	-	37	0.56	-	7
2013	17	36	-	2	-	-	37	0.56	-	7
2014	20	36	-	2	-	-	37	0.55	-	7
2015	21	36	-	2	-	-	36	0.55	-	7
NPV	$88	$136	$78	$18	$368	$110	$256			
RIM	0.49	PART	0.99	TRC	0.48	UTIL	1.09			

EXHIBIT C-13

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
STANDBY GENERATION

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	0	-	5	2	-	22	0	0.47	0.02	1
1997	1	-	5	2	-	46	1	0.93	0.03	2
1998	1	-	5	2	-	71	1	1.39	0.05	3
1999	2	-	5	2	-	97	2	1.83	0.07	3
2000	3	62	5	2	-	126	2	2.29	0.08	4
2001	4	77	6	2	-	155	3	2.73	0.10	5
2002	5	91	5	2	-	186	4	3.16	0.11	6
2003	6	107	6	2	-	219	4	3.59	0.13	7
2004	7	122	6	2	-	251	5	3.98	0.14	7
2005	9	139	6	2	-	287	5	4.39	0.16	8
2006	11	142	6	2	-	294	5	4.36	0.16	8
2007	11	145	6	2	-	303	6	4.33	0.16	8
2008	11	148	6	2	-	311	6	4.30	0.15	8
2009	12	152	7	3	-	320	6	4.27	0.15	8
2010	13	155	7	3	-	329	6	4.24	0.15	8
2011	12	158	7	3	-	339	6	4.22	0.15	8
2012	12	263	7	3	-	347	6	4.18	0.15	8
2013	13	268	7	3	-	356	7	4.14	0.15	8
2014	13	269	8	3	-	365	7	4.11	0.15	8
2015	14	266	8	3	-	375	7	4.07	0.15	8
NPV	$65	$1,017	$60	$24	$0	$2,068	$39			
RIM	0.49	PART	Inf.	TRC	12.89	UTIL	0.50			

EXHIBIT C-14

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
PREMIUM EFFICIENCY MOTORS

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	4	0	11	2	20	7	5	0.05	0.21	20
1997	8	0	12	2	21	8	10	0.10	0.40	39
1998	12	0	12	3	22	8	16	0.15	0.60	58
1999	18	0	12	3	22	8	22	0.20	0.79	77
2000	24	7	13	3	23	9	28	0.25	0.99	96
2001	30	8	13	3	23	9	35	0.29	1.18	114
2002	38	10	13	3	24	9	42	0.34	1.37	133
2003	50	12	14	3	25	9	49	0.39	1.55	151
2004	57	13	14	3	25	9	56	0.43	1.72	167
2005	72	15	14	3	26	10	65	0.47	1.90	184
2006	72	15	-	-	-	-	66	0.47	1.88	183
2007	81	16	-	-	-	-	68	0.47	1.87	182
2008	91	16	-	-	-	-	70	0.46	1.86	180
2009	102	16	-	-	-	-	72	0.46	1.84	179
2010	101	17	-	-	-	-	74	0.46	1.83	178
2011	104	17	-	-	-	-	76	0.46	1.82	177
2012	94	28	-	-	-	-	78	0.45	1.80	175
2013	95	29	-	-	-	-	80	0.45	1.79	174
2014	104	29	-	-	-	-	82	0.44	1.77	172
2015	114	29	-	-	-	-	84	0.44	1.76	171
NPV	$524	$110	$86	$17	$153	$57	$466			
RIM	1.01	PART	3.42	TRC	2.48	UTIL	3.95			

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
MANUFACTURED HOME HEAT PUMP PROGRAM

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	20	-	25	4	250	110	68	0.39	1.13	529
1997	42	-	25	4	254	195	138	0.76	2.23	1,040
1998	66	-	26	4	261	286	213	1.13	3.32	1,550
1999	100	-	26	4	268	381	291	1.50	4.39	2,052
2000	134	46	27	4	277	485	377	1.84	5.48	2,560
2001	168	56	28	5	285	591	465	2.23	6.53	3,051
2002	213	67	29	5	293	704	557	2.55	7.57	3,536
2003	271	78	30	5	301	822	654	2.89	8.59	4,014
2004	320	89	30	5	307	939	751	3.21	9.53	4,453
2005	396	101	31	5	315	1,068	857	3.54	10.50	4,910
2006	396	104	-	5	-	1,061	881	3.51	10.43	4,874
2007	455	106	-	5	-	1,090	906	3.49	10.36	4,841
2008	499	108	-	6	-	1,120	931	3.46	10.28	4,807
2009	554	111	-	6	-	1,152	957	3.44	10.21	4,774
2010	566	113	-	6	-	1,183	983	3.41	10.14	4,739
2011	576	115	-	6	-	1,219	1,014	3.40	10.09	4,719
2012	518	192	-	6	-	1,250	1,038	3.36	10.00	4,672
2013	534	196	-	6	-	1,282	1,065	3.34	9.91	4,632
2014	584	197	-	7	-	1,316	1,093	3.31	9.82	4,592
2015	634	195	-	6	-	1,350	1,122	3.28	9.74	4,553
NPV	$2,903	$743	$184	$51	$1,870	$7,661	$6,189			
RIM	0.26	PART	7.41	TRC	1.73	UTIL	0.46			

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
LOAD CONTROL AIR CONDITIONING

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	782	13	-	95	-	3.17	0.01	2,954
1997	1	-	579	13	-	193	3	6.23	0.04	5,809
1998	2	-	595	14	-	298	4	9.28	0.07	8,653
1999	6	-	612	14	-	408	9	12.29	0.14	11,455
2000	7	418	632	15	-	527	12	15.33	0.18	14,291
2001	9	514	650	15	-	650	14	18.28	0.20	17,037
2002	13	612	668	16	-	780	19	21.18	0.26	19,742
2003	18	717	686	16	-	916	25	24.04	0.34	22,409
2004	27	819	701	16	-	1,052	39	26.68	0.49	24,865
2005	34	930	720	17	-	1,201	47	29.41	0.58	27,412
2006	54	1,047	669	9	-	1,357	69	32.12	0.82	29,937
2007	44	1,166	688	9	-	1,522	58	34.80	0.66	32,436
2008	58	1,291	707	9	-	1,694	74	37.44	0.82	34,890
2009	57	1,426	727	9	-	1,876	68	40.04	0.73	37,320
2010	72	1,559	746	9	-	2,064	87	42.58	0.90	39,686
2011	86	1,696	769	10	-	2,270	109	45.23	1.09	42,153
2012	62	2,993	788	10	-	2,471	84	47.58	0.81	44,346
2013	72	3,237	809	10	-	2,685	94	49.95	0.88	46,552
2014	85	3,429	830	11	-	2,908	108	52.27	0.98	48,716
2015	96	3,568	852	11	-	3,141	123	54.55	1.07	50,840
NPV	306	$9,406	$7,145	$133	$0	$11,246	$404			
RIM	0.51	PART	Inf.	TRC	1.33	UTIL	0.52			

EXHIBIT C-17

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
<u>COMMERCIAL AIR CONDITIONING</u>

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	9	-	34	6	140	28	13	0.20	0.51	265
1997	20	-	35	6	143	29	26	0.40	1.00	520
1998	31	-	36	6	147	30	40	0.60	1.50	775
1999	47	-	37	6	151	30	55	0.79	1.98	1,026
2000	63	27	38	7	156	32	71	0.99	2.47	1,280
2001	79	33	39	7	160	32	87	1.18	2.95	1,526
2002	99	40	40	7	165	33	105	1.37	3.42	1,768
2003	127	46	41	8	169	34	123	1.55	3.88	2,007
2004	150	53	42	7	173	35	141	1.72	4.30	2,227
2005	180	60	43	8	178	36	161	1.90	4.74	2,455
2006	185	61	-	-	-	-	166	1.88	4.71	2,437
2007	228	63	-	-	-	-	170	1.87	4.68	2,421
2008	224	64	-	-	-	-	175	1.86	4.64	2,403
2009	246	66	-	-	-	-	180	1.84	4.61	2,387
2010	249	67	-	-	-	-	185	1.83	4.58	2,369
2011	250	68	-	-	-	-	191	1.82	4.56	2,359
2012	230	114	-	-	-	-	195	1.80	4.51	2,336
2013	236	116	-	-	-	-	200	1.79	4.47	2,316
2014	253	116	-	-	-	-	206	1.77	4.44	2,296
2015	272	115	-	-	-	-	211	1.76	4.40	2,276
NPV	$1,320	$440	$256	$46	$1,052	$213	$1,164			
RIM	1.05	PART	1.31	TRC	1.30	UTIL	3.42			

EXHIBIT C-18

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
DUCT TESTING AND REPAIR

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	8	-	50	6	132	75	29	0.07	0.47	309
1997	17	-	51	6	134	76	57	0.14	0.93	607
1998	28	-	53	6	138	78	89	0.21	1.38	904
1999	42	-	54	6	142	80	121	0.28	1.82	1,197
2000	57	7	56	7	147	83	157	0.35	2.28	1,493
2001	71	8	57	7	151	85	193	0.42	2.71	1,780
2002	91	10	59	7	155	87	231	0.49	3.14	2,063
2003	116	11	61	8	160	90	272	0.55	3.57	2,341
2004	136	13	62	7	163	92	312	0.61	3.96	2,598
2005	171	15	63	8	167	94	356	0.68	4.36	2,864
2006	169	15	-	8	-	-	366	0.67	4.33	2,843
2007	197	15	-	8	-	-	377	0.67	4.30	2,824
2008	218	16	-	8	-	-	386	0.66	4.27	2,804
2009	243	16	-	9	-	-	397	0.66	4.24	2,785
2010	246	16	-	9	-	-	408	0.65	4.21	2,764
2011	250	17	-	9	-	-	421	0.65	4.19	2,753
2012	225	28	-	9	-	-	432	0.64	4.15	2,725
2013	231	28	-	10	-	-	443	0.64	4.12	2,702
2014	253	28	-	10	-	-	454	0.63	4.08	2,679
2015	275	28	-	10	-	-	466	0.63	4.05	2,656
NPV	$1,251	$107	$377	$78	$992	$558	$2,572			
RIM	0.38	PART	3.16	TRC	0.94	UTIL	1.34			

EXHIBIT C-19

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
HIGH EFFICIENCY HEAT PUMPS

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	15	-	51	11	850	531	52	0.34	0.87	1,984
1997	33	-	52	12	865	541	106	0.67	1.71	3,902
1998	51	-	53	12	889	556	163	1.00	2.54	5,812
1999	79	-	54	12	914	571	224	1.32	3.37	7,693
2000	108	45	56	13	944	590	289	1.65	4.20	9,598
2001	135	55	58	13	970	606	356	1.96	5.01	11,442
2002	173	66	59	13	998	623	427	2.28	5.80	13,260
2003	223	77	61	14	1,026	641	502	2.58	6.59	15,051
2004	261	88	62	14	1,047	654	577	2.87	7.31	16,701
2005	326	100	64	14	1,075	672	658	3.16	8.06	18,411
2006	324	102	-	15	-	-	677	3.14	8.00	18,279
2007	373	104	-	15	-	-	695	3.12	7.95	18,154
2008	410	107	-	16	-	-	714	3.09	7.89	18,026
2009	457	109	-	16	-	-	734	3.07	7.84	17,904
2010	462	112	-	17	-	-	754	3.05	7.78	17,770
2011	468	114	-	17	-	-	778	3.04	7.75	17,695
2012	424	189	-	18	-	-	797	3.01	7.67	17,520
2013	435	193	-	18	-	-	817	2.98	7.60	17,370
2014	474	194	-	18	-	-	839	2.96	7.54	17,221
2015	514	192	-	19	-	-	860	2.93	7.47	17,073
NPV	$2,365	733	379	145	$6,376	$3,984	$4,748			
RIM	0.33	PART	1.37	TRC	0.45	UTIL	0.69			

EXHIBIT C-20

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
SWIMMING POOL LOAD MANAGEMENT

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	85	3	-	2	-	0.06	-	88
1997	-	-	24	3	-	3	-	0.11	0.00	173
1998	-	-	25	3	-	5	-	0.17	0.00	258
1999	-	-	25	3	-	7	-	0.22	0.00	342
2000	-	8	26	3	-	9	-	0.28	0.00	427
2001	-	9	27	3	-	11	-	0.33	0.00	509
2002	0	11	28	3	-	14	1	0.38	0.01	589
2003	0	13	28	3	-	16	1	0.43	0.01	669
2004	1	15	29	3	-	19	1	0.48	0.02	742
2005	1	17	30	3	-	22	2	0.53	0.02	818
2006	2	19	24	2	-	24	2	0.58	0.03	894
2007	1	21	25	2	-	27	2	0.63	0.02	968
2008	3	23	26	2	-	30	4	0.67	0.04	1,041
2009	2	25	27	2	-	33	3	0.72	0.03	1,114
2010	4	28	27	2	-	37	5	0.77	0.05	1,185
2011	4	31	28	2	-	41	5	0.81	0.05	1,258
2012	3	54	29	2	-	44	4	0.86	0.04	1,324
2013	3	58	30	2	-	48	5	0.90	0.04	1,390
2014	3	62	31	2	-	52	5	0.94	0.04	1,454
2015	4	64	31	2	-	56	5	0.98	0.05	1,518
NPV	$11	$169	$330	$26	$0	$201	$16			
RIM	0.32	PART	Inf.	TRC	0.51	UTIL	0.32			

EXHIBIT C-21

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
GROUND SOURCE HEAT PUMP

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)	Number of Participants
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	7	-	30	5	380	71	22	0.05	0.38	132
1997	14	-	31	5	386	72	46	0.09	0.74	260
1998	21	-	31	5	397	74	71	0.14	1.11	387
1999	31	-	32	5	408	76	97	0.18	1.46	513
2000	42	1	34	5	421	78	126	0.23	1.83	640
2001	53	1	34	6	434	81	155	0.27	2.18	763
2002	68	1	35	5	446	83	186	0.32	2.53	884
2003	87	1	36	6	458	85	219	0.36	2.87	1,003
2004	104	1	37	6	468	87	251	0.40	3.18	1,113
2005	132	2	38	6	480	90	287	0.44	3.51	1,227
2006	126	2	-	-	-	-	294	0.44	3.48	1,219
2007	154	2	-	-	-	-	302	0.44	3.46	1,210
2008	172	2	-	-	-	-	311	0.43	3.43	1,202
2009	191	2	-	-	-	-	320	0.43	3.41	1,194
2010	197	2	-	-	-	-	328	0.43	3.38	1,185
2011	202	2	-	-	-	-	338	0.42	3.37	1,180
2012	178	3	-	-	-	-	347	0.42	3.34	1,168
2013	184	3	-	-	-	-	356	0.42	3.31	1,158
2014	205	3	-	-	-	-	365	0.41	3.28	1,148
2015	224	3	-	-	-	-	374	0.41	3.25	1,138
NPV	$975	$12	$226	$35	$2,848	$531	$2,066			
RIM	0.35	PART	0.91	TRC	0.32	UTIL	1.24			

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
COMMERCIAL GOOD CENTS

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)
1994	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-
1996	3	-	80	-	-	28	4	0.16	0.15
1997	7	-	97	-	-	34	9	0.37	0.35
1998	11	-	120	-	-	41	15	0.61	0.58
1999	20	-	150	-	-	48	24	0.90	0.86
2000	31	37	169	-	-	54	34	1.25	1.19
2001	41	50	198	-	-	57	46	1.63	1.55
2002	59	62	224	-	-	60	59	1.99	1.91
2003	81	77	232	-	-	63	73	2.39	2.29
2004	98	92	254	-	-	65	88	2.80	2.69
2005	133	110	287	-	-	67	105	3.22	3.10
2006	154	128	296	-	-	69	123	3.65	3.51
2007	193	147	317	-	-	70	143	4.09	3.94
2008	248	168	354	-	-	72	165	4.54	4.37
2009	306	190	371	-	-	74	188	5.01	4.82
2010	334	214	403	-	-	76	214	5.49	5.29
2011	375	236	412	-	-	78	241	5.88	5.76
2012	372	267	425	-	-	81	270	6.47	6.24
2013	406	296	434	-	-	82	301	6.98	6.73
2014	490	326	443	-	-	84	336	7.46	7.23
2015	573	361	452	-	-	86	372	8.04	7.76
NPV	$1,443	$1,034	$2,514	$0	$0	$606	$1,065		
RIM	0.59	PART	Inf.	TRC	0.99	UTIL	0.79		

Note: The screening of the existing DSM programs did not include an estimated number of participants since this data was not required.

EXHIBIT C-23

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
RESIDENTIAL GOOD CENTS

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)
1994	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-
1996	26	-	435	-	-	27	86	1	2
1997	57	-	453	-	-	76	187	2	3
1998	93	-	472	-	-	111	301	3	5
1999	150	-	491	-	-	156	425	4	7
2000	209	170	511	-	-	202	561	6	9
2001	260	213	552	-	-	470	710	7	10
2002	350	260	574	-	-	519	873	8	12
2003	466	311	597	-	-	569	1,050	10	14
2004	550	366	621	-	-	621	1,243	11	16
2005	724	424	646	-	-	674	1,454	12	19
2006	813	487	672	-	-	729	1,683	14	21
2007	1,021	555	698	-	-	786	1,931	15	23
2008	1,291	631	727	-	-	844	2,201	17	25
2009	1,586	708	755	-	-	904	2,494	19	28
2010	1,720	791	786	-	-	966	2,811	20	30
2011	1,928	882	817	-	-	1,030	3,155	22	33
2012	1,893	981	850	-	-	1,085	3,527	24	35
2013	2,064	1,084	884	-	-	1,145	3,928	26	38
2014	2,488	1,199	919	-	-	1,215	4,362	27	41
2015	2,917	1,318	956	-	-	1,290	4,831	29	44
NPV	$7,682	$3,930	$6,370	$0	$0	$5,511	$14,609		
RIM	0.44	PART	Inf.	TRC	1.82	UTIL	0.98		

Note: The screening of the existing DSM programs did not include an estimated number of participants since this data was not required.

EXHIBIT C-24

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - RETAIL
$H_2$0 ADVANTAGE

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)
1994	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-
1996	(0)	-	353	-	-	96	-	0	-
1997	(0)	-	369	-	-	128	-	0	-
1998	0	-	377	-	-	158	-	0	-
1999	3	-	378	-	-	165	-	1	-
2000	5	20	372	-	-	215	-	1	-
2001	6	26	363	-	-	242	-	1	-
2002	11	34	354	-	-	284	-	1	-
2003	19	42	346	-	-	330	-	1	-
2004	22	51	338	-	-	379	-	2	-
2005	33	60	333	-	-	431	-	2	-
2006	32	65	332	-	-	462	-	2	-
2007	41	69	323	-	-	474	-	2	-
2008	52	74	321	-	-	488	-	2	-
2009	62	79	321	-	-	502	-	2	-
2010	60	84	317	-	-	514	-	2	-
2011	64	88	314	-	-	526	-	2	-
2012	61	93	310	-	-	537	-	2	-
2013	61	98	308	-	-	549	-	2	-
2014	72	103	305	-	-	561	-	2	-
2015	78	108	303	-	-	574	-	2	-
NPV	$258	$434	$3,570	$0	$0	$3,357	$0		
RIM	0.10	PART	Inf.	TRC	0.19	UTIL	0.10		

Note: The screening of the existing DSM programs did not include an estimated number of participants since this data was not required.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
COMMERCIAL GOOD CENTS

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)
1994	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-
1996	2	-	83	-	-	26	3	0	0
1997	6	-	101	-	-	32	9	0	0
1998	11	-	124	-	-	39	15	1	1
1999	20	-	156	-	-	46	23	1	1
2000	30	36	175	-	-	51	33	1	1
2001	40	48	206	-	-	55	44	2	1
2002	56	60	233	-	-	58	56	2	2
2003	78	74	242	-	-	60	70	2	2
2004	94	89	264	-	-	63	85	3	3
2005	128	105	298	-	-	64	101	3	3
2006	147	123	308	-	-	66	119	4	3
2007	185	141	329	-	-	67	138	4	4
2008	239	161	369	-	-	69	158	4	4
2009	294	183	387	-	-	71	181	5	5
2010	321	206	419	-	-	73	205	5	5
2011	361	226	428	-	-	74	231	6	6
2012	357	257	443	-	-	77	260	6	6
2013	390	285	451	-	-	79	290	7	6
2014	471	313	461	-	-	80	322	7	7
2015	550	347	471	-	-	82	358	8	7
NPV	$1,387	$994	$2,616	$0	$0	$582	$1,023		
RIM	0.56	PART	Inf.	TRC	0.91	UTIL	0.74		

EXHIBIT C-26

Note: The screening of the existing DSM programs did not include an estimated number of participants since this data was not required.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
RESIDENTIAL GOOD CENTS

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)
1994	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-
1996	90	-	137	-	-	365	127	4	5
1997	204	-	143	-	-	1,012	277	7	11
1998	331	-	149	-	-	1,473	445	12	16
1999	530	-	155	-	-	2,066	628	16	22
2000	743	603	162	-	-	2,679	829	20	29
2001	924	754	174	-	-	6,240	1,049	25	35
2002	1,243	922	181	-	-	6,889	1,289	29	41
2003	1,652	1,104	188	-	-	7,558	1,551	34	48
2004	1,948	1,296	196	-	-	8,247	1,837	39	55
2005	2,566	1,503	204	-	-	8,957	2,148	44	62
2006	2,881	1,727	212	-	-	9,687	2,487	49	70
2007	3,622	1,969	221	-	-	10,439	2,853	55	77
2008	4,578	2,235	229	-	-	11,215	3,252	60	85
2009	5,622	2,510	239	-	-	12,014	3,685	66	93
2010	6,097	2,806	248	-	-	12,837	4,153	72	101
2011	6,834	3,126	258	-	-	13,684	4,661	78	110
2012	6,710	3,478	268	-	-	14,417	5,210	84	119
2013	7,316	3,842	279	-	-	15,213	5,803	91	128
2014	8,819	4,249	290	-	-	16,143	6,444	97	137
2015	10,343	4,674	302	-	-	17,132	7,137	104	147
NPV	$27,237	$13,934	$2,011	$0	$0	$73,221	$21,582		
RIM	0.43	PART	Inf.	TRC	20.47	UTIL	0.55		

EXHIBIT C-27

Note: The screening of the existing DSM programs did not include an estimated number of participants since this data was not required.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
1994 INTEGRATED RESOURCE PLANNING ANALYSIS

SUMMARY OF PROPOSED DSM PROGRAMS - WHOLESALE
H_20 ADVANTAGE

Year	Change In Prod. Costs ($000)	Change In Cap. Cost ($000)	DSM Expenses ($000)	Evaluation Expenses ($000)	Customer Costs ($000)	Incentive Payments ($000)	Revenue Change ($000)	Demand Reduction (MW)	Energy Savings (GWh)
1994	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-
1996	(5)	-	2,166	-	-	2,308	-	3	-
1997	(3)	-	2,266	-	-	3,079	-	6	-
1998	2	-	2,316	-	-	3,794	-	10	-
1999	73	-	2,323	-	-	3,972	-	13	-
2000	125	480	2,286	-	-	5,154	-	16	-
2001	149	636	2,230	-	-	5,819	-	21	-
2002	274	812	2,176	-	-	6,811	-	26	-
2003	467	1,018	2,124	-	-	7,919	-	32	-
2004	534	1,234	2,075	-	-	9,090	-	37	-
2005	796	1,450	2,047	-	-	10,347	-	43	-
2006	763	1,556	2,042	-	-	11,082	-	45	-
2007	988	1,668	1,981	-	-	11,380	-	46	-
2008	1,259	1,784	1,974	-	-	11,723	-	48	-
2009	1,491	1,895	1,969	-	-	12,043	-	50	-
2010	1,437	2,006	1,948	-	-	12,347	-	51	-
2011	1,536	2,123	1,927	-	-	12,629	-	53	-
2012	1,464	2,244	1,907	-	-	12,900	-	54	-
2013	1,455	2,359	1,891	-	-	13,179	-	56	-
2014	1,731	2,484	1,875	-	-	13,470	-	57	-
2015	1,862	2,602	1,859	-	-	13,772	-	58	-
NPV	$6,200	$10,423	$21,933	$0	$0	$80,561	$0		
RIM	0.16	PART	Inf.	TRC	0.76	UTIL	0.16		

Note: The screening of the existing DSM programs did not include an estimated number of participants since this data was not required.

There were three methods used to estimate the hour-by-hour impacts for DSM programs. The methods involved:

1) Manually specifying the hour-by-hour impacts for each month for every year. This approach was used for the Thermal Energy Storage (TES) and H_20 Advantage programs only since it required a zero net loss of energy and the load building impacts were mirror images of the load shaving impacts. The actual impacts for this program can be seen in Exhibit C-30, for a single typical week in July of 2001. Since this impact is representative of the TES program impact in all other weeks/years for which the program was active, additional weekly impacts have not been provided.

2) Dynamically calculating the hour-by-hour impacts using a 'Peak Shaving' technique. This approach was used for High Efficiency HP, Residential Duct Testing and Repair, Manufactured Housing HP, Standby Generation, High Efficiency Lighting, Industrial Motors, Commercial AC, Ground Source HP. Under this approach the maximum peak reduction of the program reduces the system peak and surrounding hours subject to the available energy of the program. This impact is dynamically calculated by PROSCREEN II for each typical week. Exhibit C-29 demonstrates the effect of this technique for the Commercial Lighting program. In general, the peak impact will taper off to zero as the program's available energy is used up. Although the actual impact for each week/year will vary as the program's maximum peak and energy vary, the general pattern of applying that impact will be the same. This holds true for all the 'Peak Shave' programs above, hence detailed impacts for every program for every week/year have not been provided.

3) Dynamically calculating the hour-by-hour impacts using a 'Direct Load Control' technique. This approach was used for DLC AC, and DLC Swimming Pool Pumps. The technique involves specifying a number of parameters such as maximum peak impact, hours available to control, hours available for payback, number of actions power week, program costs, minimum savings, etc. Using these parameters and the dynamically calculated hourly marginal costs PROSCREEN II will calculate the economically effective impacts for each typical week for each year. A sample of he hour-by-hour data for these impacts can be seen in Exhibit C-31.

All of these load shape curves shown in Exhibits C-29 through C-31 may vary on a season by season basis.

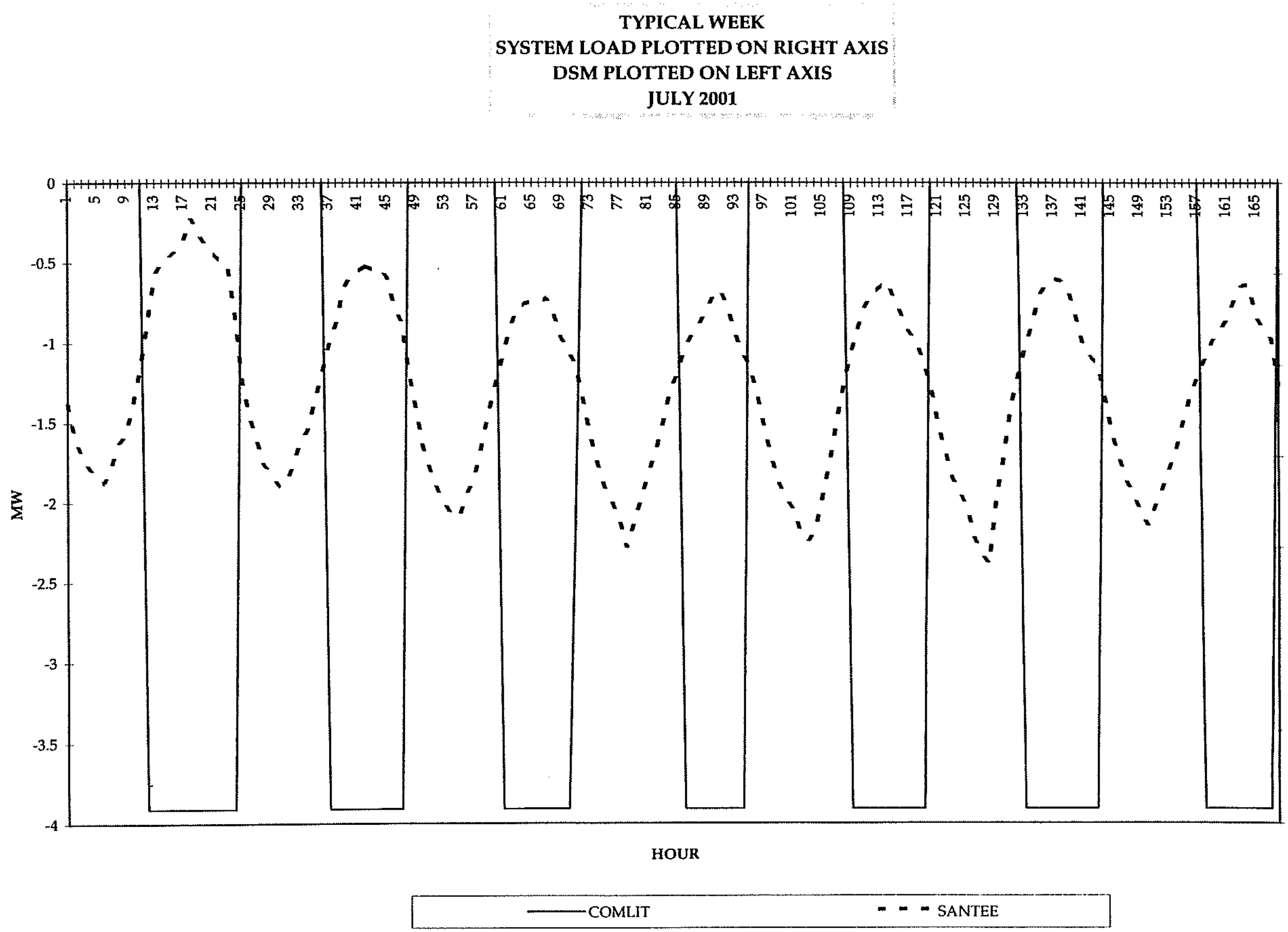
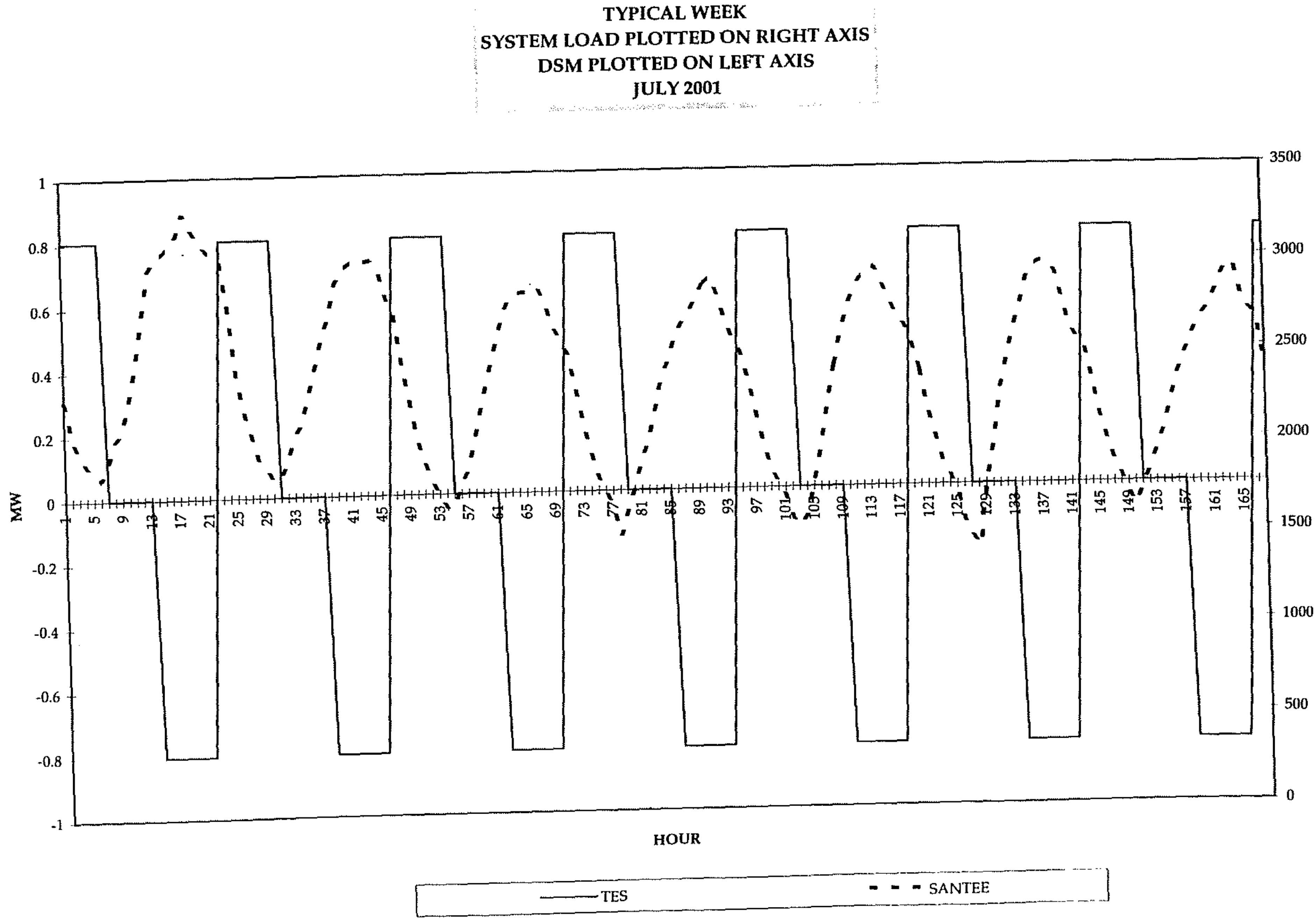

TYPICAL WEEK
SYSTEM LOAD PLOTTED ON RIGHT AXIS
DSM PLOTTED ON LEFT AXIS
JULY 2001
MW
HOUR
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
3500
3000
2500
2000
1500
1000
500
0
COMLIT
SANTEE

EXHIBIT C-29



TYPICAL WEEK
SYSTEM LOAD PLOTTED ON RIGHT AXIS
DSM PLOTTED ON LEFT AXIS
JULY 2001
MW
HOUR
TES
SANTEE

EXHIBIT C-30

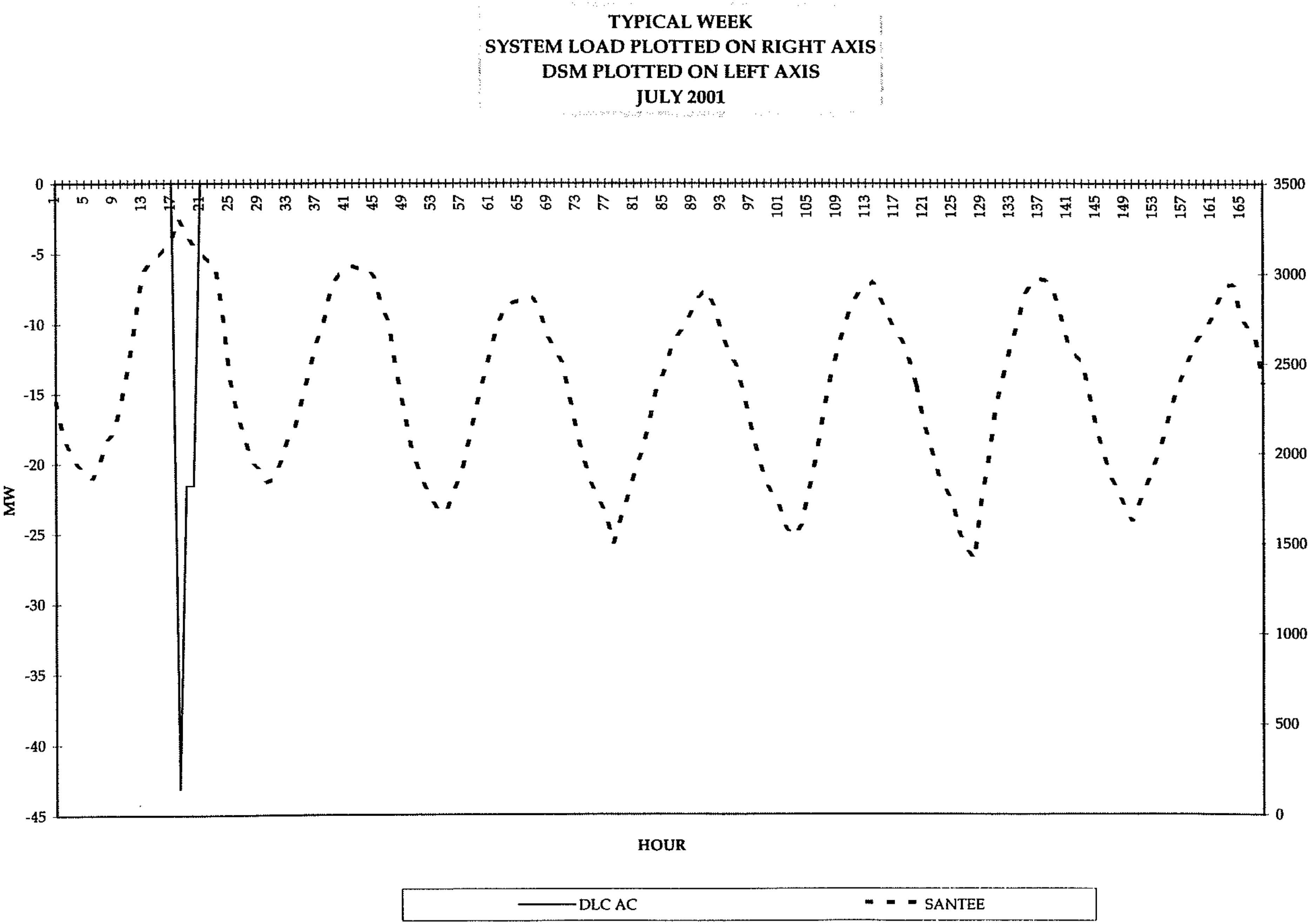

TYPICAL WEEK
SYSTEM LOAD PLOTTED ON RIGHT AXIS
DSM PLOTTED ON LEFT AXIS
JULY 2001
MW
HOUR
0
-5
-10
-15
-20
-25
-30
-35
-40
-45
3500
3000
2500
2000
1500
1000
500
0
1 5 9 13 17 21 25 29 33 37 41 45 49 53 57 61 65 69 73 77 81 85 89 93 97 101 105 109 113 117 121 125 129 133 137 141 145 149 153 157 161 165
DLC AC
SANTEE

EXHIBIT C-31

April 27, 1994

«Name»
«Title»
«Address»
«City», «State» «Zip»

Dear «FirstName»:

In March of this year, Santee Cooper authorized Metzler & Associates (M&A) to perform an Integrated Resource Planning (IRP) Study. The purpose of this study will be to review the utility's projected loads and resources and to recommend a future course of action to meet the needs of its customers.

As a state-owned, public power electric utility serving parts of the State of South Carolina, Santee Cooper is always interested in working for its customers to offer them low cost, reliable power. This IRP Study is another example of this effort.

The future plans of the county governments in the parts of the state served by Santee Cooper (directly and through electric cooperatives and municipals) can greatly affect the projected electricity requirements of the utility. Therefore, M&A has been directed by Santee Cooper to contact these county governments to explore their possible future plans for the construction of waste-to-energy projects.

It is our understanding that personnel from your county have already been in contact with Santee Cooper to discuss the possibility of a waste-to-energy facility at some point in the future. It would be helpful to the Santee Cooper study to know if you have any additional information on the previously proposed projects, or if there have been any significant changes to the project that you feel Santee Cooper should be made aware of.

With Santee Cooper personnel planning for the future, it is important for them to know and understand what actions their customers may be considering. You may recall a similar request by Santee Cooper in a letter dated June 14, 1989. As in the earlier request, for your information, we have enclosed a map of your county indicating the location of Santee Cooper's transmission facilities.

If you have any questions or comments, please contact either Bill Sutton of Santee Cooper at (803) 761-4098, or me at (708) 945-0001. If you have any information involving the waste-to-energy project, we would like to hear from you by May 6, 1994. As a representative of Santee Cooper, we thank you for your interest and time in helping us make the IRP Study a success for all customers served by Santee Cooper.

Sincerely,

William T. Clarke
Senior Associate

Enclosure

Rec_Num	Name	Title	Company	Address	City	State	Zip	Salutation
1	Mr. Mitchell S. Tibshrany, Jr.	Vice President, T&D Engineering and Power Delivery	South Carolina Electric & Gas Company	P.O. Box 764	Columbia	South Carolina	29218	Mr. Tibshrany
2	Mr. Bobby Montague	Vice President, System Planning and Operations	Carolina Power & Light	P.O. Box 1551	Raleigh	North Carolina	27602-1551	Mr. Montague
3	Mr. William F. Reinke	Vice President, System Planning and Operations	Duke Power Company	P.O. Box 1006	Charlotte	North Carolina	28201-1006	Mr. Reinke
4	Mr. Larry W. Ellis	Senior Vice President, Power Operations and Planning	Virginia Power	P.O. Box 26666	Richmond	Virginia	23261-6666	Mr. Ellis
5	Mr. James G. Tulloss	Bulk Power Marketing	Southern Company Services	P.O. Box 2625	Birmingham	Alabama	35202	Mr. Tulloss
6	Mr. P. G. Para	Division Chief of System Planning	Jacksonville Electric Authority	21 West Church Street	Jacksonville	Florida	32202	Mr. Para
7	Mr. Douglas Calvert	Manager of System Control	Oglethorpe Power Corporation	P.O. Box 1349	Tucker	Georgia	30085-1349	Mr. Calvert
8	Mr. James J. Weaver	Bulk Power Marketing Coordinator	Cajun Electric Power Cooperative, Inc.	P.O. Box 15540	Baton Rouge	Louisiana	70895	Mr. Weaver

9	Mr. William E. Scott	Principal Engineer, Power Coordination	Municipal Electric Authority of Georgia	1470 Riveredge Parkway Northwest	Atlanta	Georgia	30328-4640	Mr. Scott
10	Mr. James A. Bauer	General Manager	Piedmont Municipal Power Agency	121 Village Drive	Greer	South Carolina	29651	Mr. Bauer
11	Mr. William F. Watson	Manager of Power Supply Operations	North Carolina Eastern Municipal Power Agency	P.O. Box 29513	Raleigh	North Carolina	27626-0513	Mr. Watson
12	Mr. Gary D. Tipps	Vice President, Power Supply Division	North Carolina Electric Membership Corporation	P.O. Box 27306	Raleigh	North Carolina	27611-7306	Mr. Tipps
13	Mr. K. Adjemian	Manager, IRP	Florida Power & Light Company	P.O. Box 029100	Miami	Florida	33102-9100	Mr. Adjemian
14	Mr. Bill Aycock	Manager of Dispatch	Entergy Electric System	P.O. Box 6100	Pine Bluff	Arkansas	71611	Mr. Aycock
15	Mr. C. A. Falcone	System Transactions Department - 27th Floor	American Electric Power Service Corporation	P.O. Box 16631	Columbus	Ohio	43216-6631	Mr. Falcone

16	Mr. Damon Morgan	System Planning Department Manager	Alabama Electric Cooperative, Inc.	P.O. Box 550	Andalusia	Alabama	36420	Mr. Morgan
17	Mr. Maurice H. Phillips	Executive Vice President	Florida Power Corporation	P.O. Box 14042	St. Petersburg	Florida	33733	Mr. Phillips
18	Mr. Troy W. Todd	Executive Vice President and General Manager	Orlando Utilities Commission	P.O. Box 3193	Orlando	Florida	32802	Mr. Todd
19	Mr. H. I. Wilson	Vice President, Transmission and Distribution	Tampa Electric Company	P.O. Box 111	Tampa	Florida	33601	Mr. Wilson

APPENDIX D

APPENDIX D

1994 INTEGRATED RESOURCE PLAN

SURVEYS

As part of the 1994 Integrated Resource Plan, survey letters were sent to:

- Neighboring electric utilities
  - To identify power purchase or sales opportunities
- County governments within Santee Cooper's service territory
  - To identify potential waste-to-energy projects
- Industrial customers served by Santee Cooper
  - To identify potential cogeneration projects

Included in this appendix are sample copies of the letters sent to each group, the mailing list for each group, and a review of the responses received as a result of these letters.

NEIGHBORING UTILITIES

A total of nineteen survey letters were sent out to utilities surrounding Santee Cooper, plus to others up to three states away. A list of the utilities contacted is attached at the end of this appendix. A sample copy of the survey letter is included as Exhibit D-1. As indicated in the sample survey letter, Santee Cooper was investigating the status of the wholesale power market for either the opportunity to purchase or sell capacity.

Either verbal or written responses were received from every utility, most of which were for the opportunity to sell power to Santee Cooper. Included at the end of the appendix are four written responses received by Metzler & Associates as a result of the survey. The other contacts were by telephone conversation, or were written responses sent directly to Santee Cooper.

Upon receipt of the responses, all information was turned over to Santee Cooper for follow-up contacts. Purchased power or power sales were not considered as part of the IRP, however, now that Santee Cooper's future resource requirements have been identified, follow-up with these utilities may provide alternatives to constructing new resources or allow deferrals of new units.

COUNTY GOVERNMENTS

Survey letters were sent to each of the county governments in which Santee Cooper serves load. The purpose of this survey was to identify any potential waste-to-energy projects that these governments may be contemplating. At this time, only Charleston County has such a facility in operation.

Attached at the end of this appendix is the mailing list used for this survey. Exhibit D-2 is a sample of the letters sent. The responses received from these government agencies indicate that no new waste-to-energy facilities are currently planned. Therefore, for the purposes of this IRP, no such facilities were considered.

INDUSTRIAL CUSTOMERS

The purpose of conducting a survey of Santee Cooper's industrial customers was to identify any plans for new cogeneration facilities. A sample of the survey letters sent to these customers is included as Exhibit D-3. The mailing list for this survey is included as an attachment to this appendix.

Most of the industrial customers did not respond directly to this survey, but all were contacted by telephone to solicit their plans. The responses to these conversations indicated that no plans are in place by Santee Cooper's industrial customers for new cogeneration facilities in the foreseeable future.

April 12, 1994

«Name»
«Title»
«Company»
«Address»
«City», «State» «Zip»

Dear «Salutation»:

In March of this year, Santee Cooper authorized Metzler & Associates (M&A) to perform an Integrated Resource Planning (IRP) Study. The purpose of this study will be to review the utility's projected loads and resources and to recommend a future course of action to meet the needs of its customers.

As a state-owned, public power electric utility serving parts of the State of South Carolina, Santee Cooper is always interested in working for its customers to offer them low cost, reliable power. This IRP Study is another example of this effort.

The future plans of the industrial customers served by Santee Cooper can greatly affect the projected electricity requirements of the utility. Therefore, M&A has been directed by Santee Cooper to contact the utility's large industrial customers to explore their possible future plans for cogeneration.

With Santee Cooper personnel planning for the future, it is important for them to know and understand what actions their customers may be considering. By incorporating their customers' plans into its planning process, Santee Cooper will be able to develop the most cost-effective plan for meeting the needs of all of its customers. Therefore, if your firm has plans for developing a cogeneration facility at your plant site in the Santee Cooper service territory, we would appreciate your contacting us about these plans.

In summary, we will follow this letter with a telephone call within the next two weeks to make sure you received the letter and to answer any questions you might have. In the meantime, if you have any questions or comments, please contact either Bill Sutton of Santee Cooper at (803) 761-4098, or me at (708) 945-0001. Due to our study schedule, we would like to know about any cogeneration plans your firm might have by April 29, 1994. As a representative of Santee Cooper, we thank you for your interest and time in helping us make the IRP Study a success for all customers served by Santee Cooper.

Sincerely,

William T. Clarke
Senior Associate

CAJUN ELECTRIC POWER COOPERATIVE, INC.
10719 AIRLINE HIGHWAY • P. O. BOX 15540 • BATON ROUGE, LOUISIANA 70895
PHONE: (504) 291-3060
FAX: (504) 296-1746

July 5, 1994

Mr. William T. Clarke, P.E.
METZLER & ASSOCIATES
520 Lake Cook Road
Deerfield, IL 60015

Dear Mr. Clarke:

We are in receipt of your letter of June 21, 1994. Cajun's generation mix is dominated by coal fired facilities which lends itself more toward intermediate or base load types of transactions. However, Cajun is presently in the Bulk Power Market as an active seller of spot, intermediate and long term power (if the financial return warrants it), in amounts up to 200 MW. Regarding Diversity Transactions, in the past we have not found a great deal of diversity between our two systems, however, we do not rule out such a transaction should the opportunity present itself.

Because of our predominant reliance on coal fired capacity our price structure is driven in large part by the cost of coal and its transportation. In both cases we have been able to negotiate very favorable pricing with our suppliers.

The future is yet to be unfolded, but we anticipate our transition from seller to buyer of short and/or long term power in amounts up to 200 MW.

Should you need additional information please contact me or Jack Miller, Director of System Planning for Cajun.

Yours very truly,

James J. Weaver
Bulk Power Marketing Coordinator

cc: V.J. Elmer
J.M. Miller
S. Rickenbaker, Santee Cooper

Address List

Mr. Tim Gamble
Production Superintendent
Airco Industrial Gases
85 Airco Boulevard
Aiken, South Carolina 29802

Mr. Ralph K. Hendricks
Plant Engineer
Albany International Corporation
(Felt Division)
Post Office Box 608
St. Stephen, South Carolina 29479

Mr. Michael A. Mitchell
Controller
Albright & Wilson Americas
2151 King Street Extension
Charleston, South Carolina 29415

Mr. Rick J. Pharris
Plant Controller
Allied Signal, Inc.
440 Allied Drive
Conway, South Carolina 29526

Mr. Donald Taylor
Controller
Alumax of South Carolina
Post Office Box 1000
Goose Creek, South Carolina 29445

Mr. David C. Anderson
Materials Management Supervisor
Amoco Chemical Company
Post Office Box 987
Mt. Pleasant, South Carolina 29464

Mr. Dan Henson
Facility Maintenance Manager
AVX Corporation
Post Office Box 867
Myrtle Beach, South Carolina 29577

Mr. Tom Clark

Plant Manager
C.R. Bard, Incorporated
Santee Circle
Moncks Corner, South Carolina 29461

Mr. Dick Powell
Plant Manager
CHF Industries, Inc.
Aberdeen Manufacturing Corporation
Post Office Box 126
Loris, South Carolina 29565

Mr. Pat Orman
Account Manager
Conbraco Industries, Inc.
Highway 501
Post Office Box 970
Conway, South Carolina 29526

Mr. Ray La Macchia
Manager, Purchasing & Data Processing
The Gates Rubber Company
(Power Transmission Division)
One Belt Drive
Moncks Corner, South Carolina 29461

Mr. Steve Robertson
Controller
Georgetown Steel Corporation
Post Office Box 619
Georgetown, South Carolina 29442

Mr. L.G. Henderson
Plant Manager
Georgia Pacific Corporation
Post Office Box 128
Russellville, South Carolina 29476

Mr. Mike Kirlin
Vice President, Operations
Giant Cement Company
Post Office Box 218
Harleyville, South Carolina 29448

Mr. Mark J. Hill
Process Control Superintendent

Mr. Joseph B. Davis, Jr.
Council Chairman
141 North Main Street
Sumter, South Carolina 29150

Mr. Alex Chatman
Supervisor
P.O. Box 330
Kingstree, South Carolina 29556

North Carolina Electric Membership Corporation

CAROLINA Electric Cooperatives

NCEMC is the power supply organization of Carolina Electric Cooperatives.

Mr. William T. Clarke
Senior Associate
Metzler & Associates
520 Lake Cook Road
Deerfield, IL 60015

Dear Mr. Clarke:

RE: May 18, 1994, Letter

North Carolina Electric Membership Corporation is interested in purchasing approximately 200 MW of firm capacity in each of the years 2001, 2002, and 2003 for a time period of approximately ten to fifteen years for each of the purchases. This would equate to 600 MW of purchases for the time period. An alternative to the purchases would be a joint project with another entity.

As we are located geographically close to Santee Cooper, we are interested in pursuing joint projects that may be of mutual benefit.

Please contact me or David Beam, Manager of Planning, if you would like to pursue this further.

Sincerely,

Gary D Tipps

Gary D. Tipps, P.E.
Vice President of Power Supply

GDT:bp

cc: David Beam

Holnam, Inc.
Holly Hill Plant
Post Office Box 698
Holly Hill, South Carolina 29059

Mr. R.L. Poulin
Manager, Manufacturing
International Paper (Pulp and Paper)
Kaminski Street
Georgetown, South Carolina 29440

Mr. Hugh Tims
Maintenance Superintendent
International Paper (Sawmill)
Post Office Box 807
Georgetown, South Carolina 29440

Mr. Bill Schneider
Vice-President, Engineering
MacCalloy Corporation
Post Office Box 130
Charleston, South Carolina 29402

Mr. Tom McCoy
Plant Manager
National Welders
Route 2
Box 234-A
Gaston, South Carolina 29053

Mr. Walter Hardee
Manager, Facilities & Environmental
PPM Cranes, Inc.
Post Office Box 260002
Conway, South Carolina 29526-7002

Mr. T.A. Mayberry
Executive Vice-President, Plusa, Inc.
Plusa, Inc.
Post Office Box 98
Jamestown, South Carolina 29453-0098

Mr. Ken Carlson
Plant Manager
Praxair, Inc.

Linde Division
Post Office Box 310
Lugoff, South Carolina 29078

Mr. Ellis Jones
Plant Manager
Rappahannock Wire Company
Post Office Box 3
Andrews, South Carolina 29510

Mr. Steve Ulmer
Vice-President of Operations & Plant Manager
Showa Denko Carbon, Inc.
Post Office Box 2947201
Ridgeville, South Carolina 29472

Mr. Larry T. Hawkins
Manager, Engineering Services
A.O. Smith Corporation
Post Office Box 187
McBee, South Carolina 29101

Mr. Lenair Stevens
Plant Controller
Uniblend Spinners
Conway Plant
4701 Adrian Highway
Conway, South Carolina 29526

Mr. Richard I. Vance
Manager, Engineering & Maintenance
J.W. Aluminum Company
Post Office Box 2941905
Charleston, South Carolina 29419-9005

Mr. Eldon Rice
Senior Project Engineer
Wellman, Inc.
Post Office Drawer 188
Johnsonville, South Carolina 29555

SCE&G
A SCANA Company

South Carolina Electric & Gas Company
Columbia, SC 29218
(803) 748-3518

Charles A. White
Manager
System Engineering & Control

June 20, 1994

Mr. William T. Clarke
Senior Associate
Metzler & Associates
520 Lake Cook Road
Deerfield, Illinois 60015

Dear Mr. Clarke:

I am in receipt of your letter of May 18, 1994, concerning any interest in discussing power sales between South Carolina Electric & Gas Company and Santee Cooper. We are always willing to discuss any purchase or sales requirements with Santee Cooper and would be interested in any opportunities that you identify within your study.

Sincerely,

CAWhite

C. A. White

/jf

cc: Mr. M. S. Tibshrany
Mr. W. R. Sutton

Florida
Power
CORPORATION

June 6, 1994

Mr. William T. Clarke, Senior Associate
Metzler & Associates Management Consultants
520 Lake Cook Road
Deerfield, Illinois 60015

Dear Mr. Clarke:

It was a pleasure talking with you on May 27, 1994 concerning your Santee Cooper initiative. Subsequently I was able to discuss Santee Cooper's transmission interconnections with Mr. Bill Sutton as you suggested. I was also able to discuss this matter with Mr. Barry Inabinette who reports to Mr. Sutton.

Based on these conversations, Florida Power Corporation has an interest in discussing what could be a unique sales opportunity to Santee Cooper. This purchase could enable Santee Cooper to enhance their ability to competitively market a levelized sales contract of their excess coal-fired steam capacity. Also, we would be interested in discussing several supply options available to Florida Power including a possible jointly-owned unit that could meet Santee Cooper's indicated peaking needs later this decade.

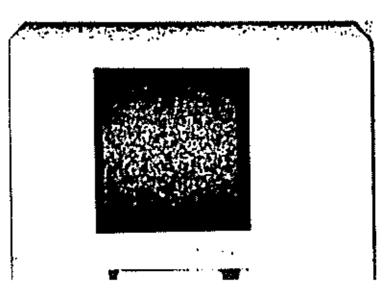
I look forward to the scheduling of a meeting at Santee Cooper's offices to discuss a potential offer in the near future. You can contact me by phone at 813-866-4077.

Sincerely,

Gary D. Nagel

GDN/yv
cc: R.C. Bonner
Joe Lander
Don Jones
George Matzke
Bob Knight

GENERAL OFFICE
3201 Thirty-fourth Street South • Post Office Box 14042 • St. Petersburg, Florida 33733-4042 • (813) 866-4542 • Fax: (813) 866-5368
A Florida Progress Company



Mr. Isaiah Odom
Council Chairman
P.O. Box 548
Denmark, South Carolina 29042

Mr. James H. Kearse
Council Chairman
Route 1, Box 140
Barnwell, South Carolina 29812

Mr. Thomas C. Taylor
Council Chairman
P.O. Box 7923
Hilton Head, South Carolina 29938

Mr. David K. Summers, Jr.
Council Chairman
P.O. Box 645
Cameron, South Carolina 29030

Mr. R. Carlisle Roddey
Supervisor
P.O. Box 580
Chester, South Carolina 29706

Mr. Andrew Ingram
Council Chairman
P.O. Box 591
Cheraw, South Carolina 29520

Ms. Betty Roper
Council Chairman
P.O. Box 400
Manning, South Carolina 29102

Mr. Floyd Buckner
Council Chairman
P.O. Box 127
Walterboro, South Carolina 29488

Mr. Jim Stone
Council Chairman
325 Orange Street
Darlington, South Carolina 29532

Mr. James Webster
Council Chairman
Route 2, Box 115
Dillon, South Carolina 29536

Mr. Ben Cole
Council Chairman
101 Lakeview Drive
Summerville, South Carolina 29484

Mr. C. Monroe Kneece
Council Chairman
1 Edisto Street
Johnston, South Carolina 29832

Mr. Carnell Murphy
Council Chairman
P.O. Drawer 60
Winnsboro, South Carolina 29180

Mr. K.G. Rusty Smith, Jr.
Council Chairman
130 North Acline Street
Lake City, South Carolina 29560

Mr. James W. Nichols
Council Chairman
P.O. Box 2368
Gerogetown, South Carolina 29442

Mr. D.P. Lowther
Council Chairman
Route 3, Box 163
Ridgeland, South Carolina 29936

Mr. Ray E. Gardner
Council Chairman
P.O. Box 398
Heath Springs, South Carolina 29058

Mr. Bruce E. Rucker
Council Chairman
363 Calvary Church Road
Swansea, South Carolina 29160

Mr. George McIntyre
Council Chairman
P.O. Box 419
Bennettsville, South Carolina 29512

Mr. Henry B. Summer
Council Chairman
1508 Lindsay Street
Newberry, South Carolina 29108

Ms. Harriet G. Fields
Council Chairman
412 Juniper Street
Columbia, South Carolina 29203

Mr. Lee S. Bowers
Council Chairman
201 Jackson Street, West
Hampton, South Carolina 29924

Mr. Steve S. Kelly, Jr.
Council Chairman
827 Pine Oak Road
Camden, South Carolina 29020

Mr. Herman H. Felix
Council Chairman
Box 55
Lynchburg, South Carolina 29080

Mr. Jasper Eaddy
Council Chairman
P.O. Box 581
Marion, South Carolina 29571

Mr. Alonzo Harrison
Council Chairman
Route 1, Box 27
Plum Branch, South Carolina 29845

Mr. Vernon Ott, Jr.
Council Chairman
P.O. Box 216
Branchville, South Carolina 29432

Mr. Ted L. Coleman
Council Chairman
Route 1, Box 242
Saluda, South Carolina 29138

June 13, 1994

«Name»
«Title»
«Address»
«City», «State» «Zip»

Dear «FirstName»:

In March of this year, Santee Cooper authorized Metzler & Associates (M&A) to perform an Integrated Resource Planning (IRP) Study. The purpose of this study will be to review the utility's projected loads and resources and to recommend a future course of action to meet the needs of its customers.

As a state-owned, public power electric utility serving parts of the State of South Carolina, Santee Cooper is always interested in working for its customers to offer them low cost, reliable power. This IRP Study is another example of this effort.

The future plans of the county governments in the parts of the state served by Santee Cooper (directly and through electric cooperatives and municipals) can greatly affect the projected electricity requirements of the utility. Therefore, M&A has been directed by Santee Cooper to contact these county governments to explore their possible future plans for the construction of waste-to-energy projects.

If you are considering a waste-to-energy facility in the near future and are not already in contact with Santee Cooper, then Santee Cooper would like to hear from you. With Santee Cooper personnel planning for the future, it is important for them to know and understand what actions their customers may be considering. You may recall a similar request by Santee Cooper in a letter dated June 14, 1989. As in the earlier request, for your information, we have enclosed a map of your county indicating the location of Santee Cooper's transmission facilities.

By incorporating their customers' plans into its planning process, Santee Cooper will be able to develop the most cost-effective plan for meeting the needs of all of its customers. Therefore, if your local governing body has plans for developing a waste-to-energy facility in the Santee Cooper service territory, we would appreciate your contacting us about these plans.

If you have any questions or comments, please contact either Bill Sutton of Santee Cooper at (803) 761-4098, or me at (708) 945-0001. If you have an active study involving a waste-to-energy project, we would like to hear from you by June 24, 1994. As a representative of Santee Cooper, we thank you for your interest and time in helping us make the IRP Study a success for all customers served by Santee Cooper.

Sincerely,

William T. Clarke
Senior Associate

Enclosure

APPENDIX E

APPENDIX E
CUSTOMER FEEDBACK

In an endeavor to obtain feedback from Santee Cooper customers on this Integrated Resource Planning Study, Santee Cooper personnel presented information and results contained in a preliminary draft Executive Summary of this Integrated Resource Planning Report to three (3) groups of customers as follows, with comments from each class noted.

The responses to these questions were prepared by Santee Cooper for the Customer Advisory Council and the Industrial Customer Association.

SANTEE COOPER CUSTOMER ADVISORY COUNCIL

The Santee Cooper Customer Advisory Council is a group of Santee Cooper residential and commercial customers.

1. Question: Why is Santee Cooper planning to use combustion units in the future, rather than steam?

   Answer: Combustion units use high-priced fuel and are expensive to operate, but they are cheaper to purchase and are cheaper overall when used only a few hours per year.

2. Question: Will the emissions requirements of the Clean Air Act ever be rescinded?

   Answer: This Act was the result of several years of study by environmentalists and no changes are expected in the near future. It was noted that one-third of the cost of a power plant is for pollution control equipment.

   Follow-up Statement: Santee Cooper should vigorously push their DSM programs.

3. Question: What is Santee Cooper's position on nuclear energy?

   Answer: It is not a viable option for additional generation due to federal regulations. It may be a long-range solution.

SANTEE COOPER INDUSTRIAL CUSTOMER ASSOCIATION

The Santee Cooper Industrial Customer Association is a group composed of all customers of Santee Cooper on the Industrial Rate Schedule.

Representatives from the Industrial Customer Association accepted the information contained in the draft Executive Summary with virtually no comment, except that one industrial customer did ask a question, as follows:

1. Question: Our company is in the process of installing high-efficiency lighting at our industrial plant. Is Santee Cooper going to implement a rebate program to industrial customers that install high-efficiency lighting?

   Answer: No rebate program is contemplated. Industrial customers that install high-efficiency lighting get immediate reductions in demand and energy charges from Santee Cooper, and this power cost reduction provides the benefit to industrial customers for high-efficiency lighting.

CENTRAL ELECTRIC POWER COOPERATIVE, INC.

Central Electric Power Cooperative, Inc. is an organization representing 15 electric cooperatives in South Carolina. These 15 cooperatives buy Santee Cooper power through Central Electric Power Cooperative, Inc. In addition to reviewing the Executive Summary, Central also reviewed the entire draft report and their comments are as follows:

1. In general, we can support the methodology and process used in the 1994 IRP.

2. Section IV D of the report addressing Retail versus Wholesale appears to use "cents per kWh" as the measure of the revenue impact on SCPSA as opposed to the actual Coordination Agreement pricing mechanism. Central believes the use of the actual Coordination Agreement pricing mechanism should be used when addressing the Retail versus Wholesale impact on the benefit-cost ratios.

3. Additional work will be needed before the rate impact on cooperative's can be addressed.

4. Additional information on the existing DSM programs must be obtained before the cooperative's benefit-cost ratios can be determined.