STONE & WEBSTER MANAGEMENT CONSULTANTS, INC.

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September 25, 1998

Mr. A. Calafiore
Executive Vice President
Planning and Bulk Power Markets
Santee Cooper
South Carolina Public Service Authority
One Riverwood Drive
Moncks Corner, SC 29461

Dear Mr. Calafiore:

Stone & Webster is pleased to present this report describing the least-cost Resource Plan developed for Santee Cooper for the years 1998 through 2010. In preparing this report, Stone & Webster with assistance from Santee Cooper's staff collected all available data and analyzed all possible resource options, including purchased power, self-build, and jointly-owned alternatives.

We believe that the recommended plan, which includes purchased power in the next five years and various combined cycle and combustion turbine units is very robust and yet flexible, and capable of responding to future unforeseen developments in customer load growth and the evolving competitive energy market.

We express our gratitude to those members of Santee Cooper who provided the information to perform this study and other assistance in this project.

Should you have any questions or comments regarding this report, please call me at 212-290-7014.

Very truly yours,

Wah Sing Ng
Vice President

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I. EXECUTIVE SUMMARY

Introduction

Santee Cooper has retained Stone & Webster Management Consultants, Inc. (Stone & Webster) to assess the need for additional generating resources to meet future growing customer demands, and to develop the least-cost resource plan to meet those demands. In developing the least-cost plan, Stone & Webster evaluated all available resource options, including purchased power, self-build, and jointly-owned alternatives.

Methodology

The approach used for this study is based on standard electric utility resource planning methods utilizing generation optimization models in developing the least-cost expansion plans. The methodology consists of three parts, namely: economic, sensitivity, and risk analysis. First, the economic analysis develops expansion plans which result in the lowest energy costs to Santee Cooper's customers in the long run. Second, the sensitivity analysis determines the impact on the base results due to changes of key variables. Third, the risk analysis provides an assessment of the uncertainty inherent in the decision-making process.

A state-of-the-art optimization model (Electric Generation Expansion Analysis System or EGEAS) was used to develop the least-cost resource expansion plan. The EGEAS optimization model has been widely used throughout the electric utility industry to develop least-cost resource plans, and in fact Santee Cooper's planning department is currently using this model. EGEAS was also used in the previous Stone & Webster planning study, which recommended the construction of the second unit at the Cross power plant.

Assumptions

The assumptions for this study are presented in Appendix A included at the end of this report. Appendix A includes the details and supporting information for all the necessary data to perform a generation expansion study. Key assumptions include the following: load forecast, existing resources, fuel prices, future resource options, purchase power options, cost of money, and the generation planning criterion. For sensitivity purposes, five key assumptions were varied to assess the impacts on the base results, including: load forecasts, capacity factors of existing generating units, capital costs of new generating units, gas prices, and system load shapes.

Study Results

Based on our detailed economic, sensitivity and risk analyses we derive the following findings:

- Capacity deficits in the near term start at about 100 MW in 1999 and increase to about 400 MW in 2002, some of which can be met with available purchased power options. Santee Cooper issued an RFP for purchased power and received various offers, some of which were determined to be economically attractive for inclusion in the resource plan.

- Three types of generation alternatives were considered in the optimization analysis: gas-fired simple cycle combustion turbines, gas-fired combined cycles, and coal-fired thermal units. However, the analysis indicates that combustion turbines and combined cycle units are the only economic choices for this planning study.

- Based on the economic analysis using "base" assumptions which include Jefferies 1&2 retired in the year 2000, the least-cost resource plan includes purchases for the next few years, six combustion turbines (168 MW each) installed in various years starting in 2001 through 2009, and one combined cycle (255 MW) unit in 2004.

- However, considering the results of the sensitivity and risk analyses, it would be prudent to advance the combined cycle unit from 2004 to as early as 2002.

- Santee Cooper's planning staff reviewed the assumed retirement dates of Jefferies 1&2 in year 2000 and determined that the retirement should be postponed.

Recommendations

Based on the results of our base economic analysis, timing of additions, sensitivity and risk analyses we recommend the following:

- Complete the negotiations and contractual agreements for short-term capacity purchases for 1999 – 2003 period to meet capacity deficits. Firming up these purchases will give Santee Cooper some additional time to decide in which year (2001-2003) to build a new unit, and to determine the best way to mitigate any risks by partnering and/or arranging the sale of energy and capacity. We recommend the following amounts of purchases:

Year	Amounts
1999	100 MW
2000	150 MW
2001	200 MW
2002	200 MW
2003	200 MW

- Postpone the retirement of Jefferies 1&2.

- Develop a plan to install a 255 MW combined cycle unit in the year 2002 . This plan should include the following elements:

    a. Site selection,
    b. Fuel supply,
    c. Gas pipeline,
    d. Transmission line, and
    e. Environmental permits.

II. METHODOLOGY

In developing Santee Cooper's least-cost generation resource plan, we have used a quantitative analysis consisting of three parts: economic, sensitivity, and risk analysis. First, the economic analysis consists of developing expansion plans which result in the lowest energy costs to Santee Cooper's customers in the long run. Second, the sensitivity analysis determines the impact on the base results due to changes of key variables. Third, the risk analysis provides an assessment of the uncertainty inherent in the decision-making process.

The economic analysis is based on developing an expansion plan with the lowest present worth total of annual revenue requirements. These annual revenue requirements consist of both the annual carrying charges associated with new capital investments as well as the fixed and variable costs (production costs) associated with operating the generating system. Carrying charges include interest, principal payment, property taxes, and insurance; fixed operation and maintenance (O&M) expenses consist of expenses which do not vary with the unit's output, such as salaries; variable costs consist of fuel and other variable O&M expenses. In our analysis the annual revenue requirements are discounted (present worth) using the estimated cost of money at 7.0% to reflect the time value of money.

A state-of-the-art optimization model (Electric Generation Expansion Analysis System or EGEAS) was used to determine the least-cost resource expansion plan for each load forecast scenario. A description of this model and some sample results are included in Appendix B. The EGEAS model develops annual production costs based on a detailed economic dispatch; and carrying charges are determined by using levelized fixed charge rates for each type of unit based on the appropriate book life. In this analysis the annual and present value revenue requirements (PVRR) from the EGEAS model do not include all fixed costs for the entire system; fixed costs which are common to the various expansion plans (e.g., embedded costs, transmission and distribution costs, other administrative and general costs, etc.) are omitted since they have no impact on the comparative economic analysis.

The sensitivity analysis determines the impact on the base results due to changes of some key assumptions. Variations in load forecasts, capital costs for combined cycle and combustion turbine plants, and capacity factors for existing generating units were incorporated in the analysis to quantify the changes in present worth revenue requirements. Finally, the risk analysis provides an approach for assessing the impact on the various expansion plans resulting from the uncertainty of five key parameters: (1) load forecasts with and without Economy Power (EP) energy sales (real-time priced energy sales to industrial customers), (2) capacity factors of existing units, (3) capital costs of combined cycle units, (4) natural gas prices, and (5) system load shapes.

III. ASSUMPTIONS

Base assumptions

The key assumptions for this study are summarized in Appendix A, which includes the details and supporting information for the following:

- Santee Cooper's load forecast (LF9701) for base, high and low scenarios, and also with and without Economy Power (EP) energy sales.
- Fuel prices for all existing generating units and future alternatives.
- Emission (SO_2) rates for all existing units and Santee Cooper's annual emission limits.
- Operational and other data required for EGEAS modeling for all existing units and future alternatives; including simple cycle combustion turbines (82 MW & 168 MW), combined cycles (255 MW & 506 MW), and coal units (540 MW).
- Economic data, including cost of money, fixed charge rates, property taxes, and insurance.
- Purchased power options for the short-term (1999 – 2003) and long-term (10 to 15 years).
- Other system data, such as installed reserve margin criterion, spinning reserve requirements, on-and off-peak definitions, and length of the study and extension periods.
- Jefferies 1&2 retired on January 1, 2000.
- No load lost to retail competition.
- No additional DSM due to uncertainty involved in serving customers in the future.

Sensitivity assumptions

In addition to the base economic analysis, we have performed a sensitivity analysis in which some key assumptions were varied to assess the impacts on the least-cost resource plans developed by the EGEAS optimization model. The following summarizes the variations to the base assumptions:

- Load forecast variations:

	Base Load Growth [1]		Sensitivity Cases
-	Base W/O EP	1.88%	3% and 4%
-	Base W/EP	1.88%	3% and 4%
-	High W/EP	2.19%	2.3%, 2.4%, and 2.5%, and 3.0%
-	Base W/EP	1.88%	No load growth after 2005
-	High W/EP	2.19%	No load growth after 2005
-	Low W/EP	1.37%	No load growth after 2005
-	High W/EP	2.19%	With resource plan of base forecast
-	Low W/EP	1.37%	With resource plan of base forecast

[1] In all load forecast scenarios, the peak demands are not affected by the inclusion of EP sales. No new capacity is added for EP sales.

- Capacity factor variations of existing coal-fired units:

	Base Capacity Factor (%)	**Sensitivity Cases (%)**
Existing Thermal Units	≈ 85%	≈ 80%

- Capital cost variations:

Base Site Capital Cost ($/kW)		**Sensitivity Cases ($/kW)**	
		+ 10%	+ 20%
255 MW Combined Cycle			
First Unit	$432	$475	$518
Second Unit	$401	$441	$481
506 MW Combined Cycle			
First Unit	$391	$431	$470
Second Unit	$370	$407	$444

- Natural Gas Price variations:

Base Gas Price ($/MBtu)	**Sensitivity Cases ($/MBtu)**	
	+ 10%	- 10%
$2.549	$2.804	$2.294

The above gas prices are the starting prices in 1998; the escalation rates beyond 1998 were not varied in the sensitivity analysis. These gas prices do not include the gas transportation demand charges, which are modeled as fixed costs in EGEAS.

- Load shape variations:

Base Load Shape	**Sensitivity Load Shape**
- 1997 actual hourly load data	-Weather normalized load shape
- Annual peak in summer (Aug.)	- Annual peak in winter (Jan.)
- Average monthly load factor(73.7%)	- Average monthly load factor (73.2%)

IV. ECONOMIC ANALYSIS

Introduction

Santee Cooper provided six load forecast scenarios based on its Load Forecast 9701, i.e. base, high and low, and each with and without Economy Power (EP) energy sales included in the energy forecast. Using EGEAS we developed least-cost resource plans for each of the six load scenarios. A few key assumptions and definitions related to this optimization analysis are repeated here to help clarify and understand the study results:

a) The peak demand forecasts for the three load forecast scenarios (base-high-low) are not affected by the inclusion of EP energy sales. In other words, the demand for non-firm (economy power and interruptible power) sales is excluded from the monthly peak and, therefore, no new capacity is added for these sales.

b) All cases include various amounts of short-term power purchases in the 1999 - 2003 period to meet capacity deficits. New generation additions, whether self-owned or jointly-owned, are not allowed until year 2001 due to the lead time required to plan and construct new plants.

c) New simple cycle combustion turbines (82 MW or 168 MW) and new combined cycle units (255 MW or 506 MW) can be installed as early as year 2001, whereas new coal units (540 MW) can be installed starting in year 2005.

d) The base economic results (present value revenue requirements or PVRR) from EGEAS do not include any revenues from potential sales of excess capacity or energy.

e) Total present value revenue requirements (PVRR) including an extension period (17 years) are identified as the "long-term PVRR"; and without an extension period (13 years), i.e. only the actual study period of 1998 – 2010, are identified as the "short-term PVRR".

Purchased Power

Based on Santee Cooper's projected peak demands, its existing installed capacity, retirement of Jefferies 1&2 in year 2000, and contractual entitlements, there will be a capacity deficit in the next few years as shown in the following table.

Summary of Santee Cooper Power Supply (MW)

	1999 Sum	2000 Sum	2001 Sum	2002 Sum	2003 Sum
Existing Capacity	3,817	3,725	3,725	3,725	3,725
Projected Firm Peak Load	3,499	3,560	3,622	3,687	3,752
Net Planning Reserves	318	165	103	3	(27)
Reserves Required	416	424	432	440	449
Capacity Surplus/(Deficiency)	(98)	(259)	(329)	(402)	(476)

The short-term deficits (1999 - 2000) can not be met by new capacity additions due to the lead time required to plan and construct new generating plants. Therefore, it was necessary to evaluate potential purchased power options to meet the short-term deficits.

On April 16, 1998, Santee Cooper issued a Request For Proposals (RFP) to supply capacity and energy beginning in the winter of 2000 through the fall of 2005. Santee Cooper received responses from eleven utilities and power marketers offering a mixture of financially firm and physically firm proposals. After reviewing and performing a preliminary evaluation of all proposals, Santee Cooper considered only the offers of physically firm capacity as capacity planning alternatives, primarily for reliability reasons. The offers of physically firm capacity totaled more than 4,000 MW of capacity and ranged from a period of five to twenty years. Some bidders made multiple proposals for differing combinations of firmness, duration and quantity.

Based on preliminary evaluations, Santee Cooper prepared a short list for Stone & Webster for incorporation as resource alternatives in the EGEAS model. The least-cost resource plans developed in this study include various combinations/amounts of purchased power for the 1998 – 2003 period.

Resource Plans

The least-cost resource plans developed by EGEAS for each of the six load forecast scenarios are shown in Exhibit 1. The following two tables summarize the least-cost resource plans for the various load forecast scenarios, showing the year and types of additions for each forecast. The first table shows the resource plans for the three load forecasts without EP sales, and the second table shows the plans for the three forecasts with EP sales.

Summary of Resource Plans for Forecast Scenarios Without EP Sales

	Base Forecast		High Forecast		Low Forecast	
	CT	CC	CT	CC	CT	CC
2001	1	-	2	-	1	-
2002	1	-	-	-	-	-
2003	-	-	1	-	1	-
2004	3	-	3	-	2	-
2005	-	-	-	-	-	-
2006	1	-	-	1	-	-
2007	-	-	-	-	1	-
2008	1	-	1	-	-	-
2009	-	-	*1	-	*1	-
2010	1	-	1	-	-	-
Total Units =	8	0	9	1	6	0
Total MW =	1,334	0	1,426	255	922	0

Summary of Resource Plans for Forecast Scenarios With EP Sales

	Base Forecast		High Forecast		Low Forecast	
	CT	CC	CT	CC	CT	CC
2001	1	-	2	-	1	-
2002	1	-	-	-	-	-
2003	-	-	1	-	1	-
2004	1	1	1	1	2	-
2005	1	-	1	-	-	-
2006	-	-	1	-	-	-
2007	1	-	-	-	1	-
2008	-	-	-	1	-	-
2009	1	-	-	-	*1	-
2010	-	-	1	-	-	-
Total Units =	6	1	7	2	6	0
Total MW =	1,008	255	1,176	510	922	0

Note: In the above tables the capacity ratings for simple cycle combustion turbines are 168 MW, unless noted with an asterisk "*" in which case the rating is 82 MW. Combined cycle unit ratings are 255 MW.

In all six scenarios, the first generating unit addition in year 2001 is a 168 MW simple cycle combustion turbine. In fact, the least-cost resource plans for the low load forecasts, with and without EP, and for the base load forecast without EP consists of only simple cycle combustion turbines.

One 255 MW combined cycle is added in the base load forecast with EP and high load forecast without EP scenarios, whereas, two combined cycles are added in the high load forecast with EP scenario. The earliest year for the combined cycle addition occurs in year 2004 for both the base and high load forecast with EP sales.

A comparison of the least-cost plans for the base load forecast vs. the base load forecast with EP scenarios shows that a 255 MW combined cycle unit was added in year 2004 when EP sales are included in the forecast. However, it is important to point out that the combined cycle was added to meet increased energy sales and not for increased peak demand requirements, since Santee Cooper does not install capacity for non-firm energy sales.

In summary, the least-cost plan for the base load forecast with EP scenario includes six 168 MW simple cycle combustion turbines (CT) and one 255 MW combined cycle (CC) unit. Single CT's are installed throughout the study period starting in year 2001 through year 2009, as shown in the above table. The combined cycle unit is installed in year 2004, based on the optimization results. In two other sections of this report ("Timing of Additions" and "Sensitivity and Risk Analyses") we will address the economic timing and size of this combined cycle unit.

Base Economic Results

The short-term and long-term PVRR's for each of the six load forecast scenarios are shown in Exhibit 1. These PVRR's should not be compared to each other, since they are based on different load forecast scenarios. However, they can be used to compare alternative resource plans for the same forecast scenario. For example, the least-cost plan for the base forecast with a combined cycle unit in year 2004 can be compared to a plan for the base forecast with a combined cycle unit advanced to year 2001.

The following table shows the PVRR's for the six load forecast scenarios.

Summary of PVRR
(Millions of Dollars)

Forecast	Short-Term PVRR	Long-Term PVRR
Base	$3,802	$6,639
Base with EP	4,209	7,347
High	4,058	7,200
High with EP	4,454	7,895
Low	3,606	6,167
Low with EP	3,983	6,823

A very important point to remember is that the above revenue requirements are based on the assumption that Santee Cooper is adding capacity only to meet its own customer requirements on a "stand-alone" basis. Advancing the installation of combined cycle units could be beneficial by taking advantage of selling excess capacity and energy at higher prices in tight power market conditions due to higher than expected load growth. These considerations will be addressed in the "Timing of Additions" and the "Sensitivity and Risk Analysis" sections of this report.

Timing of Additions

The economic impacts of advancing the installation of a combined cycle unit from 2004 to 2001 for the Santee Cooper system were also evaluated using the EGEAS program. The 255 MW combined cycle unit was prespecified to be installed in year 2001 for each load forecast scenario, and EGEAS was allowed to reoptimize the resource plan for the remaining study period. The results of this analysis are shown in Exhibit 2, and the economic penalties are plotted in Exhibit 3. The economic penalties are for the 10-year period (2001 – 2010) expressed in 1998 present worth dollars, and summarized as follows:

Present Worth Penalties of Installing a Combined Cycle in Year 2001
(Millions of Dollars)

Load Scenarios	255 MW CC
Low	$52.8
Low with EP	29.9
Base	38.3
Base with EP	8.4
High	19.5
High with EP	3.9

Under the base assumptions the present worth penalties for advancing a combined cycle unit range from a low of $3.9 million to a high of $52.8 million for the various load forecast scenarios analyzed. However, we believe that some or all of these penalties can be eliminated by selling some excess capacity and energy.

Exhibit 4 shows the calculations for the estimated revenues generated from the potential energy and excess capacity sales from the 255 MW combined cycle for the base load forecast with EP sales. The following table summarizes the annual and present worth revenues from the potential energy and capacity sales, as compared to the economic penalties of advancing the combined cycle unit to year 2001 or 2002.

<u>Present Worth Revenues of Energy and Capacity Sales vs. Economic Penalties</u>
(Millions of Dollars)

	CC Advanced To Year 2001		CC Advanced to Year 2002	
	Revenues	**Penalties**	**Revenues**	**Penalties**
2001	$3.5	$5.5	-	-
2002	0.5	1.8	$0.5	$1.8
2003	10.6	6.5	10.6	6.5
Annual Totals =	$14.6	$13.8	$11.1	$8.3
1998 Present Worth =	$10.9	$10.5	$8.0	$6.0

These results show that the potential <u>total</u> revenues from excess energy and capacity sales are sufficient to offset the penalties of advancing a combined cycle unit to the year 2001 or 2002. However, the <u>annual</u> revenues of excess energy and capacity sales are not sufficient to offset the economic penalties in year 2001 and 2002. Additional revenues of $2.0 and $1.3 million are needed to breakeven for a 255 MW combined cycle unit.

There are several other potential benefits for advancing a combined cycle unit to an earlier date, such as:

- additional energy and capacity will be available from the other existing coal units, which can be sold in the market at some profit.
- lower capital costs for installing a combined cycle unit by general inflation of costs, resulting in about $0.5 million decrease in fixed charges over the 20-year book life.

However, there are also some drawbacks to advancing a combined cycle, including:

- possibility of excess capacity and energy which can not be sold due to a lower load growth in the region and/or other entities building too many plants in the region and/or existing customers leaving Santee Cooper.
- possible excess capacity may result in higher power costs, and therefore customers may reduce consumption or leave the system as a result of higher costs.

V. SENSITIVITY AND RISK ANALYSES

Load Forecast

Two sets of load forecasts were provided by Santee Cooper, one with Economy Power (EP) sales and another without EP sales. However, both EP and interruptible demands are not included in the peak demand values for capacity planning purposes. In addition, for each load forecast set there were three load growth scenarios, i.e. base, high, and low. The following table shows the peak demand and energy values for year 2010.

Peak Demand and Energy for Year 2010

With EP Sales	Peak (MW)	Diff. (MW)	Energy (GWh)	Diff. (GWh)
Base	4,395	------	23,980	------
High	4,679	+284	25,434	+1,454
Low	4,112	-283	22,525	-1,455
Without EP Sales				
Base	4,395	------	22,049	------
High	4,679	+284	23,503	+1,454
Low	4,112	-283	20,595	-1,454

The average annual growth rates of peak demand between the six forecast scenarios range from 1.37% to 2.19%, and energy growth rates range from 1.02% to 2.09%. These growth rates are shown in the following table.

Peak Demand and Energy Annual Growth Rates

With EP Sales	Peak (%)	Energy (%)
Base	1.88	1.46
High	2.19	1.86
Low	1.37	1.02
Without EP Sales		
Base	1.88	1.65
High	2.19	2.09
Low	1.37	1.17

An interesting observation is that in all scenarios the energy growth rates are somewhat lower than the peak demand growth rates, resulting in a declining system load factor. With EP sales the load factor declines from 65.5% in 1998 to 62.3% in 2010, and without EP sales the load factor decreases from 58.8% to 57.3%.

For sensitivity analysis we have analyzed the following load forecast scenarios, where the assumed annual load growth rates start from the first year (1998) of the forecast period:

a) Base forecast without EP @ 3% annual growth
b) Base forecast without EP @ 4% annual growth
c) Base forecast with EP @ 3% annual growth
d) Base forecast with EP @ 4% annual growth
e) High forecast with EP @ 2.3% annual growth
f) High forecast with EP @ 2.4% annual growth
g) High forecast with EP @ 2.5% annual growth
h) High forecast with EP @ 3.0% annual growth
i) Base forecast with EP and no growth after 2005
j) High forecast with EP and no growth after 2005
k) Low forecast with EP and no growth after 2005
l) High forecast with EP and fixed Base Expansion plan
m) Low forecast with EP and fixed Base Expansion plan

The detailed resource plans and PVRR's for each of the above cases are included in Appendix B of this report. Based on the analysis of the above sensitivity cases we find the following:

1) Increasing the growth rates of the base forecast without EP from 1.88% to 3% and 4% will make the addition of a combined cycle unit economical in year 2006. (combined cycle units were not economic at 1.88% growth rate).

2) Increasing the growth rates of the base forecast with EP to 3% and 4% will make the addition of a combined cycle unit economical in year 2001. (A combined cycle unit was economic in 2004 at 1.88% growth rate)

3) A slight increase from 2.19% to 2.3% annual growth in the high forecast with EP will make the early installation of a combined cycle unit economical in year 2001. (A combined cycle unit was economic in 2004 at 2.19% growth rate) At 2.5% growth rate, two combined cycle units are economic, and at 3.0% growth rate a third combined cycle unit is economical.

4) When load growth after year 2005 is eliminated, the base load forecast scenario will change the combined cycle unit in 2004 to a combustion turbine unit; in the high forecast scenario the first combined cycle unit in 2004 is not affected but the second combined cycle unit in 2008 was eliminated; in the low forecast scenario none of the combustion turbines installed prior to 2005 were affected. However, in all cases there are no capacity additions after year 2005.

5) The results of maintaining the same least-cost resource plan developed for the base forecast while the load forecast is switched to the high and low scenarios is as follows:

Comparison of Annual PVRR's
(Millions of Dollars)

High Forecast Scenario

Year	High Forecast Optimum Plan	Base Forecast Optimum Plan	Economic Penalty
2001	$441.9	$443.7	$1.8
2002	460.8	460.9	0.1
2003	485.6	487.9	2.3
			$4.2

Low Forecast Scenario

Year	Low Forecast Optimum Plan	Base Forecast Optimum Plan	Economic Penalty
2001	$411.5	$413.3	$1.8
2002	424.1	429.5	5.4
2003	442.1	444.2	2.1
			$9.3

The above results show the annual economic penalties only for the period of 2001 through 2003, since we believe that the resource additions can be adjusted after this 3-year period to reflect changes in load growth. A 3-year period requirement for adjusting resource additions is a reasonable assumption based on the approximate time required to plan and build new simple cycle and combined cycle units.

The 3-year penalty of planning for the base load forecast and actually experiencing a higher forecast is about $4.2 million and for experiencing a lower forecast is about $9.3 million. However, we believe that this difference in penalties between the high and low load growths will be smaller because:

a) In the case of the low forecast, there is a possibility to sell some of the excess capacity and energy, which will reduce the penalty.

b) In the case of the high forecast there is a possibility that the purchases will be at higher costs, which will increase the penalty.

Capacity Factors

In the base economic analysis, the maximum annual capacity factors of Santee Cooper's existing thermal units were limited to about 85%. To test the impact of a lower capacity factor, we have assumed a maximum of 80%, which was accomplished by increasing the forced outage rates by 5%. This sensitivity case was only applied to one load forecast scenario, i.e. base load forecast with EP sales. The EGEAS results of this case are included in Appendix B of this report.

The following table compares the new least-cost resource plan to the base plan.

Comparison of Resource Plans

	Base Plan @ 85% Cap. Factor		New Plan @ 80% Cap. Factor	
	CT	CC	CT	CC
2001	1	-	1	1
2002	1	-	-	-
2003	-	-	1	-
2004	1	1	2	-
2005	1	-	-	-
2006	-	-	-	1
2007	1	-	-	-
2008	-	-	1	-
2009	1	-	-	-
2010	-	-	-	-
Total Units =	6	1	5	2
Total MW =	1,008	255	840	510

These results clearly show that the capacity factor of existing units have a major impact on the least-cost resource plan. A 5% reduction in the annual capacity factor will advance the combined cycle unit in 2004 to 2001; in addition, it makes a second combined cycle unit economical in year 2006.

Capital Costs

The estimates of capital costs used in this study for the various generation alternatives (combustion turbines, combined cycles, and coal units) are within the normal range of engineering cost estimates. Considerable effort by the engineering staff of Santee Cooper went into developing the details of the various components of the capital costs for combustion turbines (CT's) and combined cycles (CC's) in Santee Cooper's service area. The total capital costs for each alternative include:

- Direct costs (Boiler and turbine equipment, structures and improvements, accessory electric equipment, and transformer equipment, etc.)
- Engineering Costs
- Construction Indirects
- Inventory and Startup
- Owner's Costs (gas pipeline, transmission line, land, permitting, financing, etc.)

In this sensitivity analysis we have concentrated on the capital costs of combined cycle units. A 10% and 20% increase in the combined cycle capital costs, without gas pipeline and transmission line costs, was evaluated and shown in the following table.

Combined Cycle Capital Costs Without Gas Pipeline and Transmission Line Costs
($/kW)

	Base	10% Increase	20% Increase
First Unit 255 MW	$432.02	$475.22	$518.42
Second Unit 255 MW	401.78	441.96	482.14
First Unit 506 MW	391.45	430.60	469.74
Second Unit 506 MW	369.94	406.93	443.93

For this sensitivity analysis, we have selected the resource plan for the base with EP forecast scenario, which included a 255 MW combined cycle unit addition in year 2004. However, the resource plan was not re-optimized for this analysis; we calculated only the impact on total costs due to the increase in capital costs for combined cycle units. The sensitivity results are shown in the following table.

Combined Cycle Capital Cost Sensitivity Results
(Millions of Dollars)

	Short Term PVRR	Increase	Long Term PVRR	Increase
Base W/EP	$4,209.0	---	$7,347.2	---
CC +10%	4,213.8	$4.8	7,356.6	$9.4
CC + 20%	4,218.6	9.6	7,366.0	18.8

Natural Gas Prices

The economics of installing combined cycle units are directly related to the delivered price of natural gas. To assess the impacts on the least-cost resource plan, we have varied the delivered gas price of $2.549 per MBtu (1998 $) by ±10% as follows:

Natural Gas Prices
($/MBtu)

Base	$2.549
High (+10%)	$2.804
Low (-10%)	$2.294

The following table shows the resulting least-cost plans for each natural gas price scenario.

Comparison of Resource Plans

	Base Gas Price		High Gas Price		Low Gas Price	
	CT	CC	CT	CC	CT	CC
2001	1	-	1	-	-	1
2002	1	-	1	-	-	-
2003	-	-	-	-	1	-
2004	1	1	1	1	2	-
2005	1	-	1	-	1	-
2006	-	-	-	-	-	-
2007	1	-	1	-	-	1
2008	-	-	-	-	-	-
2009	1	-	1	-	-	-
2010	-	-	-	-	-	-
Total Units =	6	1	6	1	4	2
Total MW =	1,008	255	1,008	255	672	510

The above results show that a 10% increase in gas prices for combined cycles has no impact on the resource plan, i.e., the resource plans for the base and high gas prices are identical. However, a 10% decrease in gas prices will advance the combined cycle unit from year 2004 to 2001, in addition, a second combined cycle unit is economical in year 2007.

Load Shapes

In the base analysis, we used Santee Cooper's actual 1997 hourly load data to develop the monthly load shapes (load duration curves) in EGEAS. The actual 1997 hourly load data reflected a summer peaking system, with the annual peak occurring in August. To evaluate the impacts of a winter peaking system, with the peak occurring in January, we used weather normalized hourly load data as developed by Santee Cooper's planning staff. This sensitivity was performed for the base with EP load forecast scenario, and the resulting least-cost resource plan is shown in the following table.

Comparison of Resource Plans

	Base Plan Summer Peaking System		Alternate Plan Winter Peaking System	
	CT	CC	CT	CC
2001	1	-	1	-
2002	1	-	-	-
2003	-	-	1	-
2004	1	1	-	1
2005	1	-	1	-
2006	-	-	-	-
2007	1	-	1	-
2008	-	-	-	1
2009	1	-	-	-
2010	-	-	-	-
Total Units =	6	1	4	2
Total MW =	1,008	255	672	510

The above results show that the winter load shape has a significant impact on the least-cost resource plan. It reduces the number of combustion turbine units from six to four, but more significantly it adds a second combined cycle unit in 2008. However, the first combined cycle unit is still added in 2004 as in the summer peaking load shape scenario.

VI. CONCLUSIONS AND RECOMMENDATIONS

Conclusions

Based on our detailed economic analyses, using our "base" assumptions in developing the least-cost resource plans we conclude the following:

- With EP sales, combined cycle units are the economic choice in both the base and high load forecast scenarios. However, for the low load forecast scenario simple cycle combustion turbines are the economic choice.

- Without Economy Power (EP) sales, combined cycle units are the economic choice in the high load forecast scenario, but not in the base and low load forecast scenarios.

- For all load forecast scenarios, simple cycle combustion turbines are the economic choice for the 2001 – 2003 period. Combined cycle units are the economic choice starting in year 2004 for the base with EP and high load scenarios.

- Generally, the 168 MW simple cycle combustion turbine unit is the economic unit size, and the 255 MW combined cycle unit is the economic unit size.

- Short-term capacity purchases of up to about 250 MW are needed to meet capacity deficits in the 1999 – 2003 period.

Based on the "Timing of Additions" analysis, where we evaluated the economics of advancing the combined cycle unit from 2004 to possibly 2001 or 2002 in the base with EP forecast scenario, we conclude the following:

- Short-term (1998–2010) present worth penalties of installing a 255 MW combined cycle in year 2001, ranges from a low of $3.9 million for the high load forecast to a high of $52.8 million for the low load forecast.

- Potential revenues ($10.9 million) in the 3-year period (2001-2003) from off-system sales of energy and capacity available from the 255 MW combined cycle unit advanced to year 2001 are sufficient to off set the penalty of $10.5 million.

- Advancing the 255 MW combined cycle unit to only year 2002 will lower the economic penalty from $10.5 to $6.0 million, and revenues from potential off-system sales are much more than sufficient to off set the penalty.

Based on the "Sensitivity and Risk" analyses, where we evaluated the impacts on the base results due to variations in load forecast growth rates, capacity factors of existing units, capital costs of combined cycle units, natural gas prices, and hourly load shapes, we conclude the following:

- Higher load growth rates will favor the economics of installing combined cycle units. Increasing the base with EP forecast from 1.88% to 3%, will advance the combined cycle unit from 2004 to 2001; and a slight increase in the high with EP forecast from 2.19% to 2.3% is enough to advance the combined cycle unit from 2004 to 2001.

- Eliminating load growth after year 2005 for the base load forecast scenario will change the combined cycle unit in 2004 to a combustion turbine unit; in the high forecast scenario the first combined cycle unit in 2004 is not affected but the second combined cycle unit in 2008 was eliminated; in the low forecast scenario none of the combustion turbines installed prior to 2005 were affected. However, in all cases there are no capacity additions after year 2005.

- The economic penalty of planning for the base load forecast while actual load growth is coming in at higher or lower rates ranges from about $4 million to $9 million, but there are various ways to mitigate some of these penalties. However, the penalties will only last for about three years, since the resource plan can be adjusted in that time period due to the shorter lead time required to build new plants.

- A reduction of about 5% in the availability (capacity factor) of existing baseload coal-fired units will have a significant impact on the least-cost resource plan. It will advance the combined cycle unit from 2004 to 2001 and it will also add a second combined cycle unit in 2006.

- A 10% higher initial gas price does not have any impact on the least-cost plan for the base with EP scenario, i.e. a 255 MW combined cycle is still added in 2004. However, a 10% lower gas price will advance the combined cycle unit from 2004 to 2001, and it will also add a second combined cycle unit in 2007.

- Changing from a summer peaking system to a winter peaking system will change the mix of unit additions; a second combined cycle unit was added and less simple cycle combustion turbines were needed. However, the first combined cycle unit was added in 2004 in both summer and winter peaking load shapes.

In addition, Santee Cooper's planning and operating staffs have reviewed the assumed retirement dates of Jefferies 1&2 (January 1, 2000) used in the base economic analysis. Santee Cooper's retirement analysis is included in Appendix C at the end of this report. The main conclusion of the retirement analysis is to postpone the retirement dates of Jefferies 1&2. Stone & Webster has reviewed Santee Cooper's retirement analysis and concurs with their results and conclusion.

Based on our detailed economic, sensitivity, risk, timing of additions, and Santee Cooper's retirement analyses, we recommend the following resource plan:

Recommended Resource Plan

Year	CT	CC	Purchases
1999	-	-	100 MW
2000	-	-	150 MW
2001	-	-	200 MW
2002	-	1	200 MW
2003	-	-	200 MW
2004	2	-	-
2005	1	-	-
2006	1	-	-
2007	-	-	-
2008	1	-	-
2009	-	-	-
2010	1*	-	-
Total Units =	6	1	1
Total MW =	922	255	100-200

Note: In the above table the capacity ratings for simple cycle combustion turbines are 168 MW, unless noted with an asterisk (*), in which case the rating is 82 MW. The combined cycle unit rating is 255 MW.

Recommendations

Based on the results of our base economic analysis, timing of additions, sensitivity and risk analyses we recommend the following:

- Complete the negotiations and contractual agreements for short-term capacity purchases for 1999 – 2003 period to meet capacity deficits. Firming up these purchases will give Santee Cooper some additional time to decide in which year (2001-2003) to build a new unit, and to determine the best way to mitigate any risks by partnering and/or arranging the sale of energy and capacity. We recommend the following amounts of purchases:

Year	Amounts
1999	100 MW
2000	150 MW
2001	200 MW
2002	200 MW
2003	200 MW

- Postpone the retirement of Jefferies 1&2.

- Develop a plan to install a 255 MW combined cycle unit in the year 2002 . This plan should include the following elements:

  a. Site selection,
  b. Fuel supply,
  c. Gas pipeline,
  d. Transmission line, and
  e. Environmental permits.

Exhibit 1
Comparison of Results
EGEAS Optimization For Base, High, and Low Load Forecasts

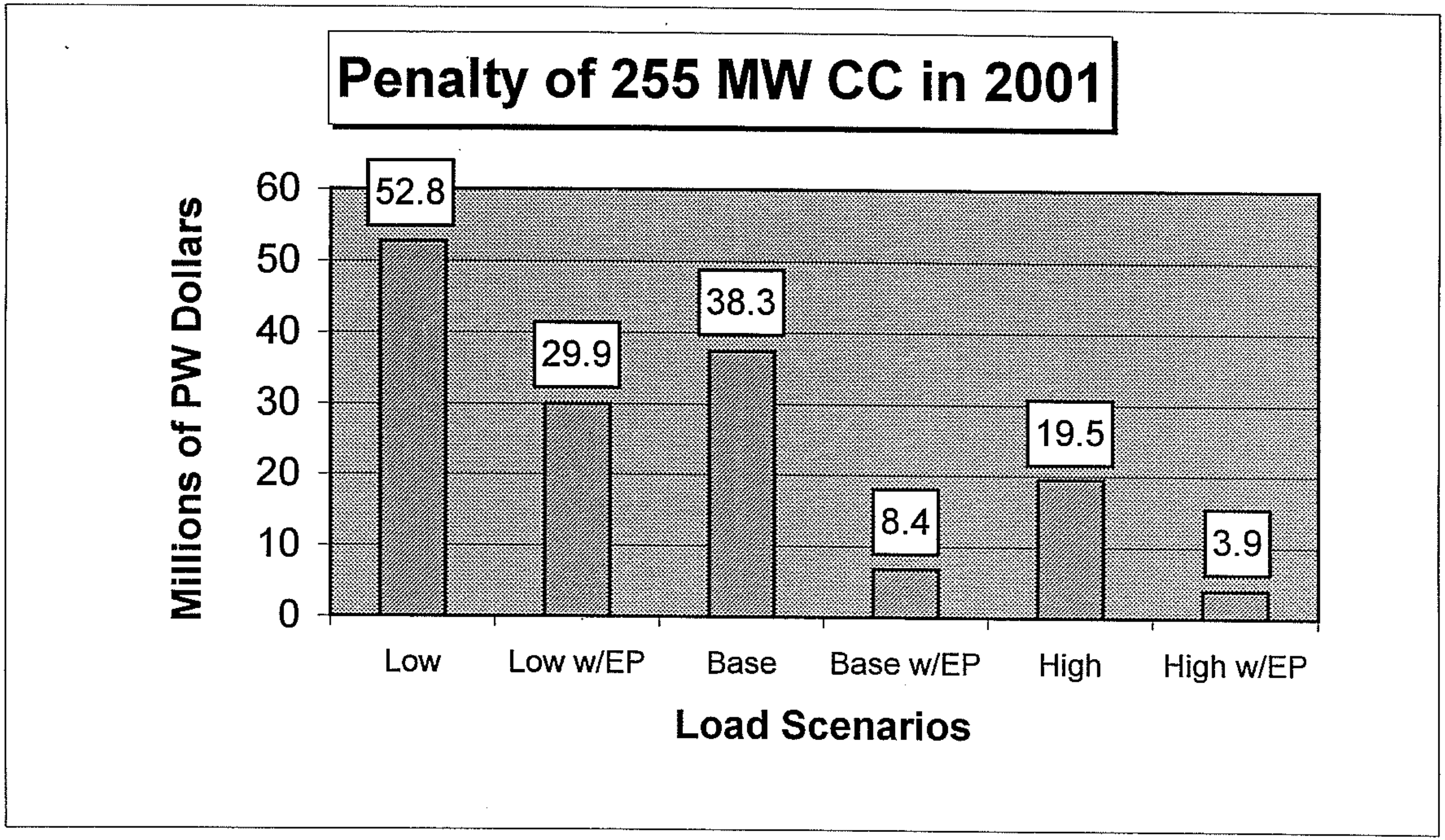
EGEAS CASES	Short-Term PVRR (Million $)	Long_Term PVRR (Million $)	1998 - 2010 Levelized Rate ($/MWh)	255 MW CC	506 MW CC	168 MW CT	82 MW CT	500 MW Coal	Purchase 1998	Purchase 1999	Purchase 2000
Base	3,802.0	6,639.3	21.01			1 - 2001 1 - 2002 3 - 2004 1 - 2006 1 - 2008 1 - 2010 (1344 MW)			6 x Purch '98 (120 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid K Sum 99 (100 MW) 1-year	5 x Bid E (250 MW) 4-year 2 x Bid I Sum 00 (100 MW) 1-year
Base with EP	4,209.0	7,347.2	21.11	1 - 2004 (255 MW)		1 - 2001 1 - 2002 1 - 2004 1 - 2005 1 - 2007 1 - 2009 (1008 MW)			6 x Purch '98 (120 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid K Sum 99 (100 MW) 1-year	5 x Bid E (250 MW) 4-year 2 x Bid I Sum 00 (100 MW) 1-year
High	4,057.6	7,200.0	21.50	1 - 2006 (255 MW)		2 - 2001 1 - 2003 3 - 2004 1 - 2008 1 - 2010 (1344 MW)	1 - 2009 (82 MW)		8 x Purch '98 (160 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid M (variable MW) 2-year	5 x Bid E (250 MW) 4-year
High with EP	4,454.3	7,895.4	21.52	1 - 2004 1 - 2008 (510 MW)		2 - 2001 1 - 2003 1 - 2004 1 - 2005 1 - 2006 1 - 2010 (1176 MW)			8 x Purch '98 (160 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid M (variable MW) 2-year	5 x Bid E (250 MW) 4-year
Low	3,605.6	6,167.0	20.78			1 - 2001 1 - 2003 2 - 2004 1 - 2007 (840 MW)	1 - 2009 (82 MW)		2 x Purch '98 (40 MW) 1-year	3 x Bid E (150 MW) 1-year	4 x Bid E (200 MW) 4-year 1 x Bid I Sum 00 (50 MW) 1-year
Low with EP	3,982.8	6,822.6	20.81			1 - 2001 1 - 2003 2 - 2004 1 - 2007 (840 MW)	1 - 2009 (82 MW)		2 x Purch '98 (40 MW) 1-year	3 x Bid E (150 MW) 1-year	4 x Bid E (200 MW) 4-year 1 x Bid I Sum 00 (50 MW) 1-year

Exhibit 2
Comparison of Results
Cases with 255 MW CC Forced in 2001

Case	Short-Term PVRR (Million $)	Long_Term PVRR (Million $)	1998 - 2010 Levelized Rate ($/MWh)	255 MW CC	506 MW CC	168 MW CT	82 MW CT	500 MW Coal	Purchase 1998	Purchase 1999	Purchase 2000
Case1a - Base Case with 255MW CC forced in 2001	3,840.3	6,675.7	21.13	1 - 2001 * (255MW)		1 - 2003 2 - 2004 1 - 2005 1 - 2007 1 - 2009 (1008 MW)			6 x Purch '98 (120 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid K Sum 99 (100 MW) 1-year	5 x Bid E (250 MW) 4-year 2 x Bid I Sum 00 (100 MW) 1-year
Case1b - Base w/EP with 255MW CC forced in 2001	4,217.4	7,351.1	21.12	1 - 2001 * (255MW)		1 - 2003 2 - 2004 1 - 2005 1 - 2007 1 - 2009 (1008 MW)			6 x Purch '98 (120 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid K Sum 99 (100 MW) 1-year	5 x Bid E (250 MW) 4-year 2 x Bid I Sum 00 (100 MW) 1-year
Case1c - Low Case with 255MW CC forced in 2001	3,658.4	6,249.8	20.99	1 - 2001 * (255MW)		2 - 2004 1 - 2006 1 - 2008 (672 MW)			2 x Purch '98 (40 MW) 1-year	3 x Bid E (150 MW) 1-year	4 x Bid E (200 MW) 4-year 1 x Bid I Sum 00 (50 MW) 1-year
Case1d - Low w/EP with 255MW CC forced in 2001	4,012.7	6,850.8	20.88	1 - 2001 * (255MW)		2 - 2004 1 - 2006 1 - 2008 (672 MW)			2 x Purch '98 (40 MW) 1-year	3 x Bid E (150 MW) 1-year	4 x Bid E (200 MW) 4-year 1 x Bid I Sum 00 (50 MW) 1-year
Case1e - High Case with 255MW CC forced in 2001	4,077.1	7,214.1	21.56	1 - 2001 * (255 MW)		1 - 2002 3 - 2004 1 - 2005 1 - 2006 1 - 2008 1 - 2010 (1344 MW)	1 - 2009 (82 MW)		8 x Purch '98 (160 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid M (variable MW) 2-year	5 x Bid E (250 MW) 4-year
Case1f - High w/EP with 255MW CC forced in 2001	4,458.2	7,895.9	21.51	1 - 2001 * 1 - 2008 (510 MW)		1 - 2002 3 - 2004 1 - 2005 1 - 2006 1 - 2010 (1176 MW)			8 x Purch '98 (160 MW) 1-year	3 x Bid E (150 MW) 1-year 1 x Bid M (variable MW) 2-year	5 x Bid E (250 MW) 4-year

Note - * denotes unit is forced in

EXHIBIT 3



Penalty of 255 MW CC in 2001
Millions of PW Dollars
60
50
40
30
20
10
0
52.8
29.9
38.3
8.4
19.5
3.9
Low
Low w/EP
Base
Base w/EP
High
High w/EP
Load Scenarios

Exhibit 4

POTENTIAL ENERGY AND CAPACITY SALES FROM 255 MW COMBINED CYCLE UNIT IN 2001
BASE LOAD FORECAST WITH EP SALES

Year	Energy Generated (GWh)	Maximum Potential Energy (1) (GWh)	Cost of Energy Generated ($/MWh)	Cost of Peaking Energy ($/MWh)	Potential Energy Sales (GWh)	Price of Energy Sales (2) ($/MWh)	Profit of Energy Sales ($/MWh)	Profit of Energy Sales (Millions $)	Revenues Capacity Sales (Millions $)	Tot Revenues from Capacity and Energy Sales (Millions $)	Annual Penalties of CC in 2001 (Millions $)
1998								$0.0	$0.0	$0.0	$0.0
1999								$0.0	$0.0	$0.0	$0.0
2000								$0.0	$0.0	$0.0	$0.0
2001	1735	1800	17.63	42.70	65	26.69	9.06	$0.6	$3.0	$3.5	$5.5
2002	1741	1800	18.29	43.81	59	27.38	9.09	$0.5	$0.0	$0.5	$1.8
2003	909	1800	19.55	45.06	891	28.16	8.61	$7.7	$3.0	$10.6	$6.5
						Annual Totals (2001-2003)		**$8.8**	**$5.9**	**$14.7**	**$13.8**
						Annual Totals (2002-2003)		**$8.2**	**$3.0**	**$11.2**	**$8.3**
						Present Value (2001-2003)		**$6.4**	**$4.5**	**$10.9**	**$10.5**
						Present Value (2002-2003)		**$5.9**	**$2.1**	**$8.0**	**$6.0**

Year	Excess Capacity Installed (MW)	Annual Cost of CC Cap. ($/kW)	Annual Cost of Pk. Cap ($/kW)	Potential Capacity Sales (MW)	Price of Capacity Sales (3) ($/kW)	Revenues Capacity Sales (Millions $)
1998						$0.0
1999						$0.0
2000						$0.0
2001	87	41.00	27.00	87	34.00	$3.0
2002	0	41.00	27.00	0	34.00	$0.0
2003	87	41.00	27.00	87	34.00	$3.0
					Annual Totals =	$5.9
					Present Value =	$4.5

Notes: (1) Maximum potential energy generated based on annual capacity factor of 80.8%.
(2) Price of combined cycle energy sales based on 10% @ peaking price, 30% @ 75% peaking price, and 60% @ 50% peaking price.
(3) Price of capacity sales based on 50% @ peaking combustion turbine price and 50% @ combined cycle price.

APPENDIX A

ASSUMPTIONS FOR PLANNING STUDY

APPENDIX A

ASSUMPTIONS
SANTEE COOPER PLANNING STUDY

Load Forecasts

There are six load scenarios to be evaluated: base, low and high forecasts; each with and without Economy Power (EP) included in the energy forecast. Tables 1 and 2 show the peak and energy forecasts for all six scenarios. Charts 1 and 2 show the energy forecasts for all six scenarios. In all cases Standard Interruptible power is not contained in the peak forecast, but is included in the energy forecast. Base, high and low load scenarios are based on Santee Cooper's Load Forecast 9701.

Table 1
Load Forecast with EP in Energy

	High		Low		Base	
Year	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)
1998	3,607	20,384,021	3,491	19,950,863	3,516	20,157,612
1999	3,720	21,096,852	3,570	20,473,082	3,593	20,760,821
2000	3,740	21,539,646	3,616	20,704,874	3,658	21,122,260
2001	3,803	21,718,088	3,664	20,673,326	3,733	21,195,707
2002	3,898	22,043,714	3,713	20,811,608	3,805	21,427,661
2003	3,997	22,453,367	3,764	21,026,227	3,880	21,739,797
2004	4,090	22,870,245	3,819	21,243,869	3,954	22,057,057
2005	4,190	23,290,865	3,873	21,461,231	4,031	22,376,048
2006	4,291	23,712,854	3,918	21,675,560	4,104	22,694,207
2007	4,386	24,136,427	3,971	21,887,221	4,178	23,011,824
2008	4,483	24,565,397	4,018	22,100,187	4,250	23,332,792
2009	4,583	24,995,598	4,066	22,310,794	4,324	23,653,196
2010	4,679	25,434,054	4,112	22,525,236	4,395	23,979,645
Avg. Growth Rate	2.19%	1.86%	1.37%	1.02%	1.88%	1.46%

Chart 1
Load Forecast with EP in Energy

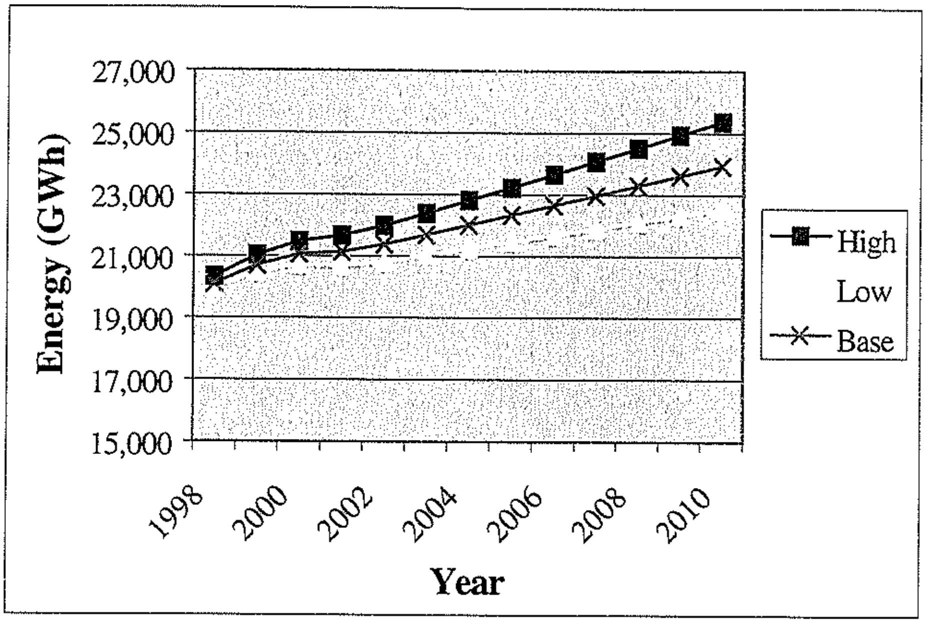
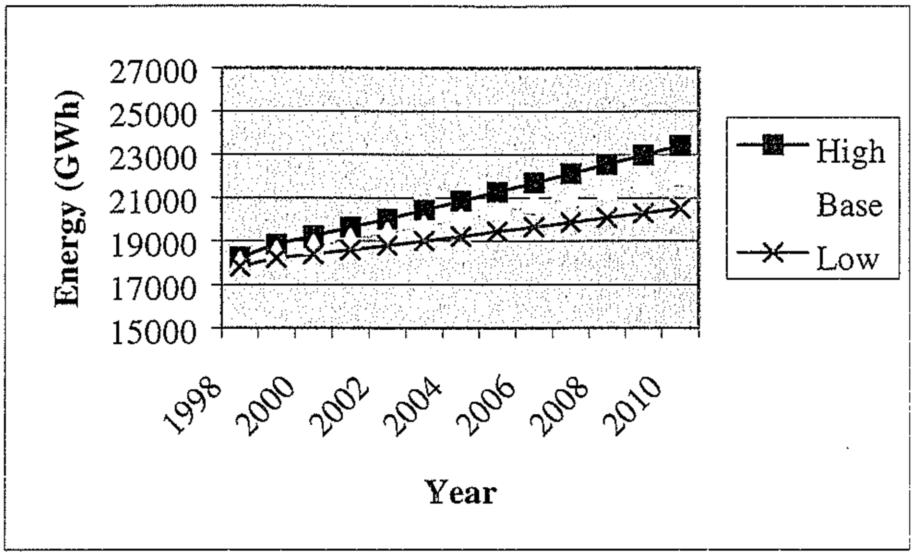


Table 2
Load Forecast without EP in Energy

Year	High		Low		Base	
	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)
1998	3,607	18,342,492	3,491	17,909,334	3,516	18,116,083
1999	3,720	18,938,286	3,570	18,314,516	3,593	18,602,255
2000	3,740	19,322,404	3,616	18,487,632	3,658	18,905,018
2001	3,803	19,715,851	3,664	18,671,089	3,733	19,193,470
2002	3,898	20,113,144	3,713	18,881,038	3,805	19,497,091
2003	3,997	20,522,797	3,764	19,095,657	3,880	19,809,227
2004	4,090	20,939,675	3,819	19,313,299	3,954	20,126,487
2005	4,190	21,360,295	3,873	19,530,661	4,031	20,445,478
2006	4,291	21,782,284	3,918	19,744,990	4,104	20,763,637
2007	4,386	22,205,857	3,971	19,956,651	4,178	21,081,254
2008	4,483	22,634,827	4,018	20,169,617	4,250	21,402,222
2009	4,583	23,065,028	4,066	20,380,224	4,324	21,722,626
2010	4,679	23,503,484	4,112	20,594,666	4,395	22,049,075
Avg. Growth Rate	2.19%	2.09%	1.37%	1.17%	1.88%	1.65%

Chart 2
Load Forecast without EP in Energy



Fuel Costs

Fuel costs for generating plants were supplied by Santee Cooper's Fuel Procurement department.

Table 3
Santee Cooper Fuel Data

Fuel Name	Fuel Type	Unit of Mass	Heat Content (MBtu/u.o.m.)	1998 Fuel Cost ($/MBtu)	Growth Rate (%)	SO2 Content (Tons/MBtu)
CROSS12	Coal	Ton	25.52	1.52	1.72	9.15E-04
JEFF34	Coal	Ton	26.00	1.39	1.72	9.00E-04
GRAIN12	Coal	Ton	26.00	1.57	1.72	9.00E-04
WINY1-4	Coal	Ton	25.42	1.47	1.72	9.20E-04
SC_#2	Oil-#2	BBL	5.88	4.64	2.33	1.35E-04
SC_#6	Oil-#6	BBL	6.20	2.89	2.3	1.14E-03
SUMMER	Nuclear	kWh	0.01	0.462	1.917	----

Gas prices for the planning alternatives are based on Stone & Webster's Henry Hub forecast, an average of four published gas price forecasts by DRI, AGA, GRI and EIA. The price for non-firm gas delivered to the Santee Cooper region for use by the combustion turbine planning alternatives were developed using the HESI transportation adder escalated at 1% below inflation. The Henry Hub prices in Tables 4 and 5 are in nominal dollars including a 3% inflation rate.

Table 4
Combustion Turbine Gas Price Forecast

Year	Henry Hub Gas Price ($/Mbtu)	Transport. Cost ($/Mbtu)	Regional Gas Price ($/Mbtu)
1998	2.49	0.520	3.006
1999	2.42	0.530	2.952
2000	2.35	0.541	2.893
2001	2.44	0.551	2.993
2002	2.53	0.562	3.097
2003	2.63	0.573	3.205
2004	2.73	0.584	3.316
2005	2.84	0.596	3.432
2006	2.95	0.608	3.557
2007	3.07	0.620	3.687
2008	3.19	0.632	3.823
2009	3.32	0.644	3.963
2010	3.45	0.657	4.109

The price for gas used by the combined cycle planning alternatives is based on a 70,000 dt/day contract with Transco which includes a $0.063/Mbtu variable component and a $5,457,480 per year fixed charge. The fixed charge is modeled as a detailed cost for the combined cycles equal to the same per unit cost of $10.91/kW-yr for both the 500 MW CC and for the 250 MW CC.

Table 5
Combined Cycle Gas Price Forecast

Year	Henry Hub Gas Price ($/Mbtu)	Transport. Cost ($/Mbtu)	Regional Gas Price ($/Mbtu)
1998	2.49	0.063	2.549
1999	2.42	0.064	2.486
2000	2.35	0.066	2.418
2001	2.44	0.067	2.509
2002	2.53	0.068	2.603
2003	2.63	0.069	2.701
2004	2.73	0.071	2.802
2005	2.84	0.072	2.908
2006	2.95	0.074	3.023
2007	3.07	0.075	3.143
2008	3.19	0.077	3.267
2009	3.32	0.078	3.397
2010	3.45	0.080	3.532

Emissions Information

- Santee Cooper has the following SO2 emission limits beginning in 2000:

Table 6
SO2 Emission Limits

Year	Tons
1998	0
1999	0
2000	46,042
2001	46,042
2002	46,042
2003	46,042
2004	46,042
2005	46,042
2006	46,042
2007	46,042
2008	46,042
2009	46,042
2010	42,996

- SO2 content by fuel in tons per MBtu is contained in Table 3.
- SO2 emission allowances are priced at the current market value of $140/ton with no escalation.
- Jefferies 3&4, Grainger 1&2, Winyah 1, and Cross 1&2 are all scheduled to switch to lower sulfur coal in 2000.
- SO2 removal rates for Santee Cooper units are included in Table 7 below.
- Emission allowances will be purchased as needed; no inventory will be maintained.

Table 7
SO2 Removal Rates

Unit Name	1998-1999 SO2 Removal (%)	2000-2010 SO2 Removal (%)
Jefferies 1	0%	0%
Jefferies 2	0%	0%
Jefferies 3	0%	0%
Jefferies 4	0%	0%
Grainger 1	0%	0%
Grainger 2	0%	0%
Winyah 1	0%	0%
Winyah 2	46%	55%
Winyah 3	74%	79%
Winyah 4	74%	79%
Cross 1	86%	90%
Cross 2	73%	85%

Unit Data

Existing unit operational data provided by Santee Cooper Generation Production Department. Table 8 contains Santee Cooper's unit-specific data.

Table 8
EXISTING UNIT DATA - SANTEE COOPER 1998--updated to 1998 budget data

Unit Name	Install Date	Maint (Weeks)	MCR Rating (1) (MW)	Peak Rating (1) (MW)	Full Load Heat Rate (Btu/kWh)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Forced Outage (%)	Fuel Name	Fuel Price ($/Mbtu)	SO2 Prod. Rate (Ton/MBtu)
Jefferies 1	1954	2	46	46	11472	37.98	5.00	3.23	SC_#6	2.89	1.14E-03
Jefferies 2	1954	2	46	46	11472	37.98	5.00	16.81	SC_#6	2.89	1.14E-03
Jefferies 3	1970	4	153	153	10014	5.36	2.00	12.93	JEFF34	1.39	9.00E-04
Jefferies 4	1970	4	153	153	9977	5.36	2.00	7.23	JEFF34	1.39	9.00E-04
Grainger 1	1966	4	85	85	10398	14.17	1.72	5.74	GRAIN12	1.57	9.00E-04
Grainger 2	1966	4	85	85	10207	14.17	1.72	2.66	GRAIN12	1.57	9.00E-04
Winyah 1	1975	4	280	295	9542	8.53	2.00	8.44	WINY1-4	1.47	9.20E-04
Winyah 2	1977	4	280	295	9814	8.53	2.00	5.32	WINY1-4	1.47	9.20E-04
Winyah 3	1980	4	280	295	10048	8.53	2.00	7.59	WINY1-4	1.47	9.20E-04
Winyah 4	1981	4	260	270	10338	8.53	2.00	3.44	WINY1-4	1.47	9.20E-04
Cross 1	1995	4	590	620	9583	6.98	1.09	1.92	CROSS12	1.52	9.15E-04
Cross 2	1984	4	520	540	9617	6.98	1.09	2.92	CROSS12	1.52	9.15E-04
Hilton Head 1	1973	1	19	20	16804	2.75	3.50	6.10	SC_#2	4.64	1.35E-04
Hilton Head 2	1974	1	19	20	16804	2.75	3.50	6.10	SC_#2	4.64	1.35E-04
Hilton Head 3	1979	1	52	57	15000	2.75	3.70	6.10	SC_#2	4.64	1.35E-04
Myrtle Beach 1	1962	1	10	10	16766	3.72	6.30	6.10	SC_#2	4.64	1.35E-04
Myrtle Beach 2	1962	1	10	10	16766	3.72	6.30	6.10	SC_#2	4.64	1.35E-04
Myrtle Beach 3	1972	1	19	20	16766	3.72	3.50	6.10	SC_#2	4.64	1.35E-04
Myrtle Beach 4	1972	1	19	20	16766	3.72	3.50	6.10	SC_#2	4.64	1.35E-04
Myrtle Beach 5	1976	1	27	30	16766	3.72	2.50	6.10	SC_#2	4.64	1.35E-04
Jefferies Hydro	1942	0	128	128	---	20.69	1.96	---	---	---	---
St. Stephen Hydro	1985	0	84	84	---	9.27	0.00	---	---	---	---
Spillway Hydro	1950	0	2	2	---	20.69	1.96	---	---	---	---
SEPA Hydro	1985	0	215	215	---	27.12	7.21	---	---	---	---
Summer	1983	4	318	318	10383	99.77	1.46	3.017	SUMMER	0.462	---

(1) Data represents summer ratings

- Fixed and Variable O&M
  - Henwood Energy Services Inc. (HESI) regional database for SERC is used to provide generic plant data, where needed.
  - Fixed and variable O&M costs of existing units are based on Santee Cooper 1998-2000 budgets.
  - Jefferies 1 & 2 variable O&M has been capped at $5.00/MWh with fixed O&M adjusted upward consistent with how similar units in the HESI SERC database are handled.
  - V.C. Summer Station variable O&M has been capped at $1.46/MWh with fixed O&M adjusted upward to be consistent with the HESI SERC database.
  - Escalation rates for fixed and variable O&M are set at 3% annually (see exceptions below).
  - SEPA fixed and variable costs are held flat throughout the study period.
  - St. Stephens fixed O&M is based on projected net settlement dollars from the 1998 CY budget. Budget is through 2007 and cost is held flat through the remainder of the study.
  - Fixed O&M $/kW for all units are based on summer (MCR) rating.

- Forced Outage Rate – Historical data, provided by Generation Operations, is averaged (with high and low values thrown out) to calculate equivalent forced outage rates for all units except for MB and HH CTs (HESI generic forced outage rates for CTs used).

- Capacities –
  - In determining O&M and construction costs on a per kW basis, the summer (MCR) rating is used.
  - Jefferies 1&2 are retired Jan 1, 2000; Myrtle Beach 1&2 are retired Jan 1, 2008.

- Hydro - SEPA hydro energy limitation includes 43% Santee Cooper share and 57% Central, Georgetown and Bamberg share.

- Must-Run Status – Cross 1&2, Winyah 1-4and Jefferies 3&4 are designated as "must-run" meaning that these units will be running at or above their minimum load at all times.

- Other Operational Considerations – Capacity factors on all units have been limited to a maximum of 85%.

Table 9
Hydro Energy Forecast (GWh)

Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Spillway	1.35	1.22	1.35	1.30	1.35	1.31	1.35	1.35	1.31	1.35	1.31	1.35
Jefferies	16.41	14.82	16.41	15.88	16.41	15.88	16.41	16.41	15.88	16.41	15.88	16.41
St. Stephen	41.77	37.61	41.10	29.09	22.53	18.61	15.82	16.50	12.10	15.27	17.49	25.82
SEPA	42.75	37.94	53.53	40.45	31.35	31.33	36.96	38.50	33.07	38.64	39.50	50.45

Cost Analysis

Capital fixed charges for new units are calculated using installation cost and a levelized fixed charge rate. Construction costs are not modeled.

- Fixed charge rates are based on depreciation schedules of 15 years for a gas turbine and 20 years for combined cycles and coal steam units. Carrying charges include property taxes and insurance (see below) and are as follows:
  Combined Cycles and Coal-fired Steam Turbine– 9.491%
  Simple Cycle CTs – 11.031%
- Cost of Capital at 100% taxable debt = 7%
- Discount Rate = 7%
- Income Taxes = 0%
- AFUDC Rate = 0%
- Property Taxes = $27,285
- Insurance = $1,014,826
- Together, property taxes and insurance are = 0.051% of gross production plant.

Self-build Planning Alternatives

Stone & Webster will evaluate five Santee Cooper self-build generating options for this planning study.

- Unit types and sizes:
  - Simple cycle combustion turbines at 80 MW and 150 MW (summer capacity).
  - Combined cycle turbines at 250 and 500 MW (summer) consisting of one or two 170 MW simple cycle unit(s) and one 170 MW steam unit.
  - Coal fired steam turbine at 540 MW.
- Sites considered for combined cycles and/or simple cycle combustion turbines:
  - Aiken @ SONAT line
  - Aiken @ substation
  - Aiken @ Savannah River
  - Anderson @ Belton
  - Anderson/Greenville
  - Anderson @ Savannah River
- The 540 MW coal unit is evaluated at one of Santee Cooper's existing sites and its installation requires concurrent installation of an FGD system addition at Winyah Unit 1. The FGD addition is levelized over a period of 15 years with a fixed charge rate of 11.031%.
- Capital costs for these options include (where applicable): gas line costs, transmission to the nearest substation, and site costs (including construction of the unit and purchase of the property). Costs per kW were calculated using the winter capacity rating.

Table 10
Capital Costs for Simple Cycle Combustion Turbines

	82 MW Simple Cycle (Winter)			168 MW Simple Cycle (Winter)		
Site	Gas Line Cost ($/kW)	Trans. Cost ($/kW)	Site Cost ($/kW)	Gas Line Cost ($/kW)	Trans. Cost ($/kW)	Site Cost ($/kW)
First Unit Cost	$10.89	$27.33	$293.33	$6.88	$84.63	$244.55
Second Unit Cost		$3.48	$282.67		$4.08	$235.60

Table 11
Capital Costs for Combined Cycles

	255 MW Combined Cycle (Winter)			506 MW Combined Cycle (Winter)		
Site	Gas Line Cost ($/kW)	Trans. Cost ($/kW)	Site Cost ($/kW)	Gas Line Cost ($/kW)	Trans. Cost ($/kW)	Site Cost ($/kW)
First Unit Cost	$12.35	72.89	$432.02	$6.23	$36.73	$391.45
Second Unit Cost		$7.59	$401.78		$3.82	$369.94

Table 12
Capital Costs for Coal Fired Steam Turbines

Site	Site Cost ($/kW)
Cross Unit 3 - 540 MW	$1,314.72
Winyah 1 - FGD Addition	$163.58

- 80 MW CTs are evaluated using costs at the Aiken/Substation site which supports up to three 80 MW units and 150 MW CTs are at the Anderson/Belton site which supports up to five 150 MW units. Combined Cycles are evaluated using costs at the Anderson/Savannah site which supports up to two 500 MW units.
- Combustion Turbines are first available in 2000, Combined Cycles are first available 2001 and coal options are available in 2005.
- Operational data for simple cycle turbine and combined cycle planning alternatives was provided by Stone & Webster based on Stone & Webster Engineering Corp. estimates.
- Operational data for Cross Unit 3 is based on Cross 2 operating characteristics and data for Winyah 1 FGD is based on operating characteristics of Winyah 1.
- Both Cross Unit 3 and Winyah 1 FGD are 95% scrubbed.

Table 13
Unit Data - Planning Alternatives

Unit Name	Maint (Weeks)	Rated Capacity (MW)	Full Load Heat Rate (Btu/kWh)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Forced Outage (%)
CT 80	2	80	11633	0.26	4.02	4
CT 150	2	150	10390	0.15	2.22	4
CC 250	3	250	6973	10.4	0.07	5
CC 500	3	500	7014	10.4	0.07	5
Coal	4	540	9565	1.09	8.22	2.92

Purchased Power Planning Alternatives

Stone & Webster also evaluated both short and long term purchased power proposals in order to meet short-term capacity shortfalls in the 1999-2000 time frame and as alternatives to Santee Cooper's self-build options. Purchased power proposals were obtained from RFPs issued by Santee Cooper and TEA. Table 14 outlines the contract size (MW) and duration of all the proposals evaluated. Some of the contracts offer power in incremental blocks and some of the short-term contracts offer Santee Cooper the opportunity to purchase individual seasons as needed. Pricing and operational characteristics of long and short-term contracts are shown in Tables 15 and 16 respectively.

- Long term purchased power options include:
  - BidA – 10 years
  - BidB – 5 years
  - BidC – 5 years
  - BidD – 6 years
  - BidE – 5 years
  - BidF – 6 years
  - BidG – 1 year
  - BidH – 15 years
- Short term purchased power options include:
  - BidI
  - BidJ
  - BidK
  - BidL
  - BidM

Table 14
Short and Long Term Bid Capacity (MW) and Availability

Bid		1999				2000				2001				2002			
		Winter	Spring	Summ	Fall	Winter	Spring	Summ	Fall	Winter	Spring	Summ	Fall	Winter	Spring	Summ	Fall
BidA	10 yr.													250-1000	250-1000	250-1000	250-1000
BidB	5 yr.									150-300	150-300	150-300	150-300	150-300	150-300	150-300	150-300
BidC	5 yr.					170-510	170-510	170-510	170-510	170-510	170-510	170-510	170-510	170-510	170-510	170-510	170-510
BidD	6 yr.					150	150	150	150	150	150	150	150	150	150	150	150
BidE	5 yr.	150	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300	50-300
BidF	6 yr.					50-	50-	50-	50-	50-	50-	50-	50-	50-	50-	50-	50-
BidG	1 yr.	50-	50-	50-	50-												
BidH	15 yr.									100-500	100-500	100-500	100-500	100-500	100-500	100-500	100-500
BidI-Summer1999				100													
BidI-Winter2000						200											
BidI-Summer2000								100									
BidI-Fall2000									100								
BidJ-Winter1999		200															
BidJ-Fall1999					125												
BidJ-Winter2000						200											
BidJ-Fall2000									100								
BidJ-Winter2001										150							
BidJ-Spring2001											100						
BidJ-Fall2001													100				
BidK-Winter99		100															
BidK-Summer99				100													
BidK-Fall99					100												
BidK-Winter00						100											
BidK-Spring00							100										
BidL-Winter		275				475				500							
BidL-Fall					125				100				225				
BidM		100		200	125	325		400	100								

Table 15
Long Term Bids - Pricing and Operational Data

Bid		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
BidA	Capacity				250-1000	250-1000	250-1000	250-1000	250-1000	250-1000	250-1000	250-1000	250-1000
(baseload)	Cap Price ($/kW-yr)				$73.80	$75.42	$77.23	$79.16	$81.22	$83.50	$85.84	$88.32	$90.97
S&W gas forecast	Energy Price ($/MWh)				$2.07	$2.13	$2.20	$2.26	$2.33	$2.40	$2.47	$2.55	$2.62
	Fuel Price ($/MMBtu)				$3.10	$3.21	$3.32	$3.43	$3.56	$3.69	$3.82	$3.96	$4.11
	Transmission				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Heat Rate (Btu/kWh)				7000	7000	7000	7000	7000	7000	7000	7000	7000
	Availability (%)				90%	90%	90%	90%	90%	90%	90%	90%	90%
BidB	Capacity			150-300	150-300	150-300	150-300	150-300					
(peaking)	Cap Price ($/kW-yr)			$36.68	$37.16	$37.40	$37.76	$38.12					
60 starts assumed (no cost)	Energy Price ($/MWh)			$1.97	$2.01	$2.06	$2.10	$2.14					
Delivered to ITS	Fuel Price ($/MMBtu)			$3.02	$3.13	$3.24	$3.35	$3.46					
S&W gas forecast	Transmission			$23.40	$23.40	$23.40	$23.40	$23.40					
+ $0.03/MMBtu	Heat Rate (Btu/kWh)			11000	11000	11000	11000	11000					
	Availability (%)			92%	92%	92%	92%	92%					
BidC	Capacity		170-510	170-510	170-510	170-510	170-510						
(peaking)	Cap Price ($/kW-yr)		$41.40	$42.12	$42.86	$43.61	$44.37						
60 starts @ $6000/unit start	Energy Price ($/MWh)		$2.00	$2.04	$2.09	$2.13	$2.18						
---> $2.12/kW-yr	Fuel Price ($/MMBtu)		$2.89	$2.99	$3.10	$3.21	$3.32						
Delivered to ITS	Transmission		$23.40	$23.40	$23.40	$23.40	$23.40						
S&W gas forecast	Heat Rate (Btu/kWh)		9500	9524	9548	9571	9595						
	Availability (%)		95%	95%	95%	95%	95%						
BidD	Capacity		150	150	150	150	150	150					
(peaking)	Cap Price ($/kW-yr)		$34.80	$37.20	$39.00	$40.20	$41.40	$43.80					
16 hours minimum	Energy Price ($/MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00					
Energy Limited 1200 hrs	Fuel Price ($/MMBtu)		$2.89	$2.99	$3.10	$3.21	$3.32	$3.43					
Jun-Sep; 700 hrs Dec-Mar	Transmission		$23.40	$23.40	$23.40	$23.40	$23.40	$23.40					
Unlmtd Oct-Nov, Apr-May	Heat Rate (Btu/kWh)		15000	15000	15000	15000	15000	15000					
Delivered to ITS	Availability (%)		100%	100%	100%	100%	100%	100%					

Table 15 Cont.

BidE	Capacity	150	50-300	50-300	50-300	50-300							
(peaking)	Cap Price ($/kW-yr)	$43.56	$43.56	$46.80	$48.12	$51.00							
Energy Price from SC SERC	Energy Price ($/MWh)	$0.00	$0.00	$0.00	$0.00	$0.00							
Prosym run (CP&L price)	Fuel Price ($/MMBtu)	$3.42	$3.35	$3.44	$3.53	$3.63							
Heat Rate = 11600 * 7.0%	Transmission	$0.00	$0.00	$0.00	$0.00	$0.00							
	Heat Rate (Btu/kWh)	12412	12412	12412	12412	12412							
	Availability (%)	100%	100%	100%	100%	100%							
BidF	Capacity		50-	50-	50-	50-	50-	50-					
(peaking)	Cap Price ($/kW-yr)		$60.00	$60.32	$62.61	$63.99	$65.52	$67.16					
Sched. ½ hr prior=$2/MWh	Energy Price ($/MWh)		$21.02	$22.37	$23.49	$25.94	$28.37	$28.09					
Start up fee, 2 hrs min run	Fuel Price ($/MMBtu)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00					
Schedule day ahead = no	Transmission		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00					
Start fee, 8 hrs min run	Heat Rate (Btu/kWh)		—	—	—	—	—	—					
SC SERC energy price (LG&E)+5%	Availability (%)		100%	100%	100%	100%	100%	100%					
BidG	Capacity	50-											
Firm Capacity, On-peak	Cap Price ($/kW-yr)	$27.00											
Energy call	Energy Price ($/MWh)	$17.28											
16 hours minimum	Fuel Price ($/MMBtu)	$0.00											
Mkt-based energy capped	Transmission	$47.28											
@ $200; Set to SC price	Heat Rate (Btu/kWh)	—											
From Prosym SERC study	Availability (%)	96%											
BidH	Capacity			100-500	100-500	100-500	100-500	100-500	100-500	100-500	100-500	100-500	100-500
(baseload)	Cap Price ($/kW-yr)			$75.96	$77.04	$78.12	$79.20	$80.28	$81.48	$82.68	$83.76	$84.96	$86.28
Participation in CC project	Energy Price ($/MWh)			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Gas Price = NYMEX +	Fuel Price ($/MMBtu)			$2.84	$2.93	$3.03	$3.13	$3.24	$3.35	$3.47	$3.59	$3.72	$3.84
$0.4/MMBtu	Transmission			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Price includes	Heat Rate (Btu/kWh)			6800	6800	6800	6800	6800	6800	6800	6800	6800	6800
3.73% losses	Availability (%)			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 16
Short Term Bids - Pricing and Operational Data

		1999				2000				2001			
Bid		**Winter**	**Spring**	**Summ**	**Fall**	**Winter**	**Spring**	**Summ**	**Fall**	**Winter**	**Spring**	**Summ**	**Fall**
BidI	Capacity (MW)			100		200		100	100				
Any season/any year	Cap. Price ($/kW-yr)			$0.00		$0.00		$0.00	$0.00				
5x16	Energy Price ($/MWh)			$67.72		$30.49		$68.49	$27.10				
Delivered to ITS	Transmission ($/kW-yr)			$5.85		$5.85		$5.85	$7.80				
In 50 MW blocks up to max	Availability			100%		100%		100%	100%				
BidJ	Capacity (MW)	200			125	200			100	150	100		100
Any season/any year	Cap. Price ($/kW-yr)	$6.60			$6.00	$8.55			$6.60	$10.20	$7.80		$7.20
Available during peak hours	Energy Price ($/MWh)	$35.00			$30.00	$35.00			$30.00	$35.00	$30.00		$30.00
Delivered to ITS	Transmission ($/kW-yr)	$5.85			$5.85	$5.85			$5.85	$5.85	$5.85		$5.85
In 25 MW blocks up to max	Availability	100%			100%	100%			100%	100%	100%		100%
BidK	Capacity (MW)	100		100	100	100	100						
Any season/any year	Cap. Price ($/kW-yr)	$0.83		$0.83	$0.83	$0.83	$0.83						
Reserv pymt = $27,500/mo.	Energy Price ($/MWh)	$18.37		$18.37	$18.37	$20.02	$20.02						
Energy Price from SC SERC	Transmission ($/kW-yr)	$5.85		$5.85	$5.85	$5.85	$5.85						
Prosym analysis	Availability	100%		100%	100%	100%	100%						
BidL	Capacity (MW)	275			125	475			100	500			225
3-yr contract fall or winter	Cap. Price ($/kW-yr)	$0.00			$0.00	$0.00			$0.00	$0.00			$0.00
5x16	Energy Price ($/MWh)	$27.00			$22.00	$28.00			$22.50	$29.00			$23.00
Delivered to ITS	Transmission ($/kW-yr)	$5.85			$5.85	$5.85			$5.85	$5.85			$5.85
	Availability	100%			100%	100%			100%	100%			100%
BidM	Capacity (MW)	100		200	125	325		400	100				
2-yr contract (all seasons)	Cap. Price ($/kW-yr)	$0.00		$0.00	$0.00	$0.00		$0.00	$0.00				
5x16	Energy Price ($/MWh)	$29.61		$72.02	$29.04	$30.71		$74.18	$29.68				
	Transmission ($/kW-yr)	$0.00		$0.00	$0.00	$0.00		$0.00	$0.00				
	Availability	100%		100%	100%	100%		100%	100%				

System Data

- Reserve Margin = 10% winter, 13% summer
- Peak and Off Peak Periods are defined in the standard 5x16 format as follows:
  Peak = Monday through Friday, hour beginning 7 A.M. through 10 P.M.

  Off-peak = Monday through Friday, hour beginning 11 P.M. through 6 A.M. and all of Saturday and Sunday.
- Spinning Reserve = 91 MW
- Study Period is 1998 through 2010 with a 17-year extension period.

APPENDIX B

EGEAS RESULTS FOR SENSITIVITY ANALYSIS

RESOURCE PLANS FOR SENSITIVITY CASES

Years	Base w/o EP - 3% Growth				Base w/o EP - 4% Growth				Base w/EP - 3% Growth				Base w/EP - 4% Growth			
	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC
2001	-	2	-	-	-	3	-	-	-	-	1	-	-	1	1	-
2002	-	1	-	-	-	1	-	-	-	1	-	-	-	1	-	-
2003	-	1	-	-	-	1	-	-	-	1	-	-	-	-	1	-
2004	-	2	-	-	-	-	-	1	-	1	1	-	-	3	-	-
2005	-	1	-	-	-	2	-	-	-	1	-	-	-	2	-	-
2006	-	-	1	-	-	1	-	-	-	1	-	-	-	1	-	-
2007	1	-	-	-	-	-	-	1	-	1	-	-	-	-	-	-
2008	-	1	-	-	-	-	-	-	-	1	-	-	-	-	-	-
2009	-	-	1	-	1	1	-	-	-	-	1	-	-	-	-	1
2010	-	1	-	-	1	1	-	-	-	1	-	-	-	-	-	-
Cost w/o Ext ($M)	4167.4				4541.0				4597.3				5009.5			
Cost w/Ext ($M)	7645.8				8667.9				8439.3				9544.6			

Years	High w/EP -2.3% Growth				High w/EP - 2.4% Growth				High w/EP - 2.5% Growth				High w/EP - 3% Growth			
	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC
2001	-	-	1	-	-	1	1	-	-	1	1	-	-	1	1	-
2002	-	1	-	-	-	-	-	-	-	-	-	-	-	1	-	-
2003	-	1	-	-	-	1	-	-	-	1	-	-	-	1	-	-
2004	-	2	-	-	-	3	-	-	-	1	1	-	-	1	1	-
2005	-	-	1	-	-	-	-	-	-	1	-	-	-	1	-	-
2006	-	-	-	-	-	-	1	-	-	1	-	-	-	1	-	-
2007	-	1	-	-	-	-	-	-	-	1	-	-	-	1	-	-
2008	1	-	-	-	-	1	-	-	-	1	-	-	-	1	-	-
2009	-	1	-	-	-	1	-	-	-	-	-	-	-	1	-	-
2010	-	1	-	-	1	-	-	-	-	1	-	-	-	-	1	-
Cost w/o Ext ($M)	4508.3				4546.2				4586.4				4776.3			
Cost w/Ext ($M)	8020.7				8112.1				8210.3				8744.5			

APPENDIX B

RESOURCE PLANS FOR SENSITIVITY CASES

Years	Base w/EP -Flat after 2005				High w/EP - Flat after 2005				Low w/EP - Flat after 2005				High w/EP - Fixed Plan			
	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC
2001	-	1	-	-	-	2	-	-	-	1	-	-	-	1	-	-
2002	-	1	-	-	-	-	-	-	-	-	-	-	-	1	-	-
2003	-	-	-	-	-	1	-	-	-	1	-	-	-	-	-	-
2004	-	3	-	-	-	1	1	-	-	2	-	-	-	1	1	-
2005	-	-	-	-	1	-	-	-	-	-	-	-	-	1	-	-
2006	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
2008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost w/o Ext ($M)	4099.9				4316.9				3919.3				4410.7			
Cost w/Ext ($M)	6885.3				7277.2				6535.2				7862.1			

	Low w/EP - Fixed Plan				Base w/EP - EFOR +5%				Base w/EP -Fixed Plan CC +10%				Base w/EP -Fixed Plan CC +20%			
	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC	82CT	168CT	255CC	506CC
2001	-	1	-	-	-	1	1	-	-	1	-	-	-	1	-	-
2002	-	1	-	-	-	-	-	-	-	1	-	-	-	1	-	-
2003	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-
2004	-	1	1	-	-	2	-	-	-	1	1	-	-	1	1	-
2005	-	1	-	-	-	-	-	-	-	1	-	-	-	1	-	-
2006	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-
2007	-	1	-	-	-	-	-	-	-	1	-	-	-	1	-	-
2008	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-
2009	-	1	-	-	-	-	-	-	-	1	-	-	-	1	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost w/o Ext ($M)	4037.1				4385.3				4213.8				4218.6			
Cost w/Ext ($M)	6916.1				7635.2				7356.6				7366.0			

APPENDIX B

APPENDIX C

RETIREMENT ANALYSIS OF JEFFERIES 1 & 2

APPENDIX C

RETIREMENT ANALYSIS OF JEFFERIES UNITS 1 AND 2

Projected system savings associated with not retiring Jefferies Units 1 and 2 were determined by the Santee Cooper planning staff and reviewed by Stone and Webster. This projection was done using the EGEAS Model and the same input data and assumptions as used for the Stone and Webster Generation Resource Plan.

Projected savings were determined for the period beginning in the year 2000 through the year 2010. The Stone and Webster study ("base case") was used for comparison because it assumed the units were retired at the beginning of the year 2000. The study which did not retire the Jefferies units (the Retention Study) assumed the base load forecast with Economy Power, the same load scenario as the S&W study. The Retention Study assumed zero fixed costs for the Jefferies units so that the total difference in system costs for the two studies would represent the maximum fixed O&M costs which could be spent over the study period to break even, or which would make Santee Cooper indifferent to the decision to retire or retain the units.

Both studies used the same variable cost, and assumed the same purchases—250 MW of capacity for the years 2000 through 2003.

EGEAS modeled both studies by bringing in new combustion turbines or combined cycle units to meet system load and reserve requirements on an optimum or lowest cost basis. The low cost basis is the total present value of system costs.

The yearly differences in the total system costs for the model outputs for the two studies were determined. The cost differences varied because the optimum construction schedule for each study was different due to the 92 MW of capacity represented by the Jefferies Units. Therefore, the operating costs and capital costs are different each year.

Finally, the Jefferies variable costs were added to the annual system cost difference based on the model's total yearly generation from those units.

The net result was a schedule of yearly cost savings which represented the breakeven point for Jefferies O&M costs. These savings had, in the year 2000, a present value of $22 million. On an annual basis, about $2 million (in present-value dollars) could be spent on the combined units as total O&M beginning in year 2000. The Santee Cooper Operations Staff has indicated that these maximum total O&M expenditures are reasonable constraints which can be adhered to. Further evaluation will be undertaken during the units' next scheduled maintenance inspection.

The conclusion, therefore, is that Santee Cooper should not retire the Jefferies Units 1 and 2 at this time.