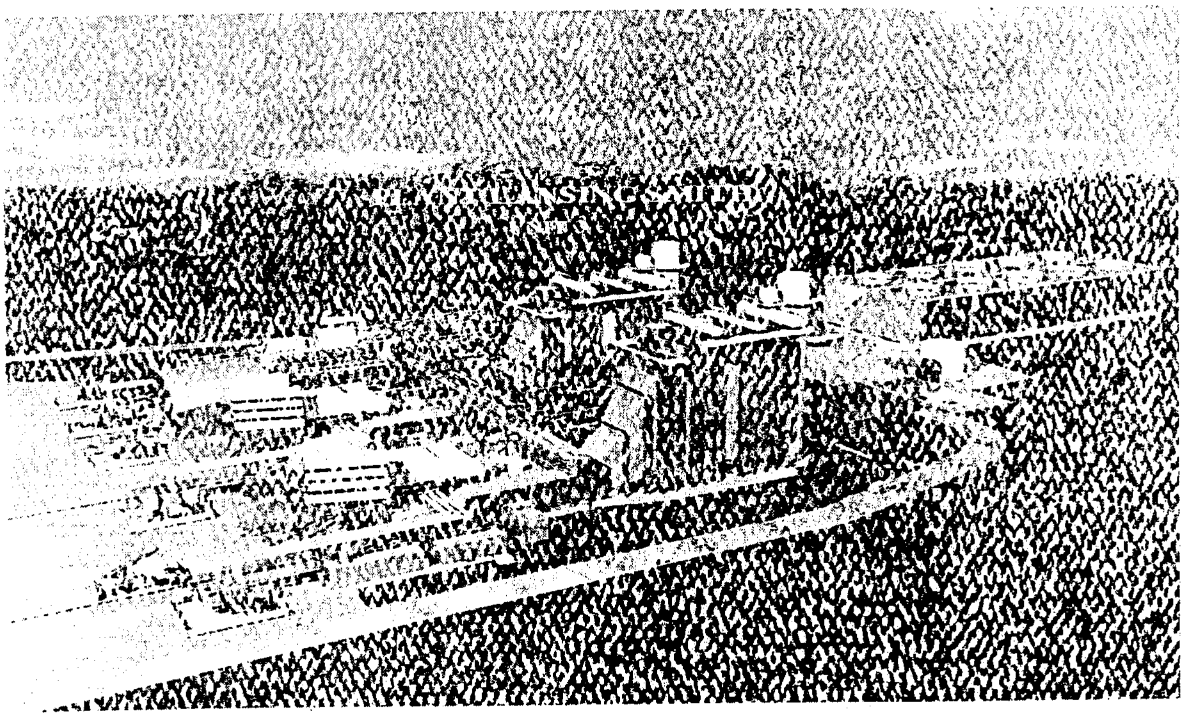
THE NEED STUDY

IN SUPPORT OF

GULF POWER COMPANY'S PETITION FOR DETERMINATION OF NEED OF LANSING SMITH UNIT 3



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

MARCH 15, 1999

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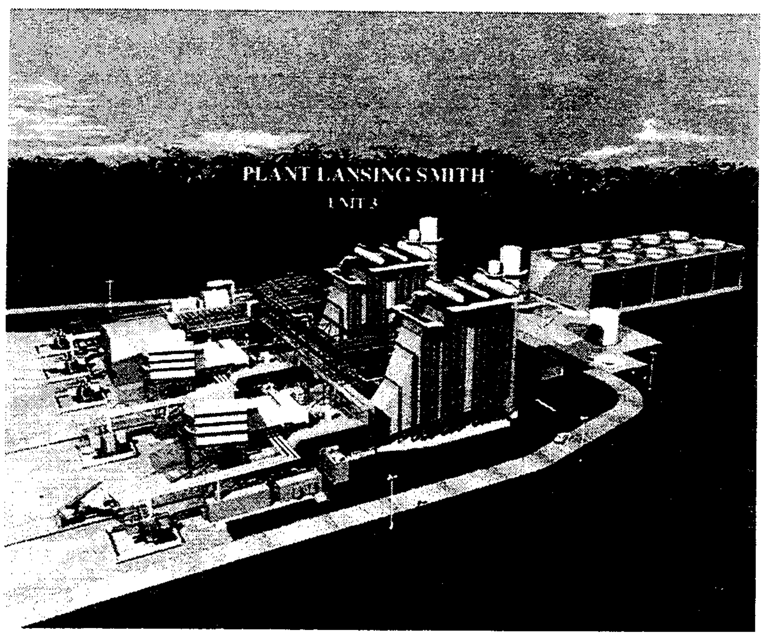

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1. EXECUTIVE SUMMARY

Gulf Power Company (Gulf) has determined that in order to provide reliable, cost-effective service to its customers, it must add at least 427 MW of generating resources to its system by the summer of 2002. The most cost-effective way for Gulf to meet this need is to construct a 540 MW natural gas-fired combined cycle unit at its existing Lansing Smith Electric Generating Plant. This unit will be designated as Smith Unit 3.

Smith Unit 3 is subject to the Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes. This Need Study document is being filed with the Florida Public Service Commission (FPSC) to support Gulf's petition to the FPSC for a determination of need for the project under Section 403.519, Florida Statutes.

This Need Study demonstrates that Gulf has a clear need for more capacity and that Smith Unit 3 is the most cost-effective alternative available, taking into consideration both other Gulf-constructed capacity options and options offered by third parties in response to Gulf's Request for Proposals (RFP) for power supply alternatives.

Gulf is a subsidiary of the Southern Company, which owns operating companies in Florida, Georgia, Alabama and Mississippi. As such, Gulf's planning process is part of the overall Integrated Resource Planning (IRP) process conducted for the Southern electric system (SES). As a member of Southern, Gulf can rely to some extent on system-wide reserves to meet its capacity needs. Gulf has a corresponding obligation, however, to maintain a reasonable share of those reserves.

This Need Study is an outgrowth and continuation of Southern's annual IRP process and of Company-specific studies supporting Gulf's Revised 1998 Ten-Year Site Plan (1998 TYSP) filed with the FPSC in June, 1998. This TYSP contained detailed documentation of Gulf's existing resources, planning processes, load and fuel forecasts, other planning assumptions, and its future capacity needs.

The 1998 TYSP showed that Gulf is relying on firm purchased power contracts totaling 143 MW, along with the Company's reliance on Southern capacity resources, to meet its capacity needs through the year 2001. Due to the decreasing availability of firm power purchases, it is not feasible to replace the purchased power contracts when they expire in 2001. As shown in the 1998 TYSP, Gulf would require an additional 352 MW of capacity in 2002 in order to provide its share of Southern's 13.5% minimum reserve margin target. Subsequent updates to Gulf's planning studies show that the summer 2002 capacity shortfall has increased to 427 MW without the addition of new capacity resources. In fact, if no additional capacity is added by 2002, Gulf will have a negative reserve margin on an individual company basis.

The load forecast on which this 427 MW need is based included substantial demand reductions resulting from Gulf's

DSM programs and other conservation initiatives. These measures reduced Gulf's summer peak demand by 255 MW in 1998 and will reduce it by a total of 365 MW by the end of 2002. Due to the size of Gulf's need in 2002, Smith Unit 3 cannot be avoided or delayed further by additional DSM programs.

Gulf's planning process showed that a 500 MW class combined cycle generating unit located near Panama City (the self-build option) was the most cost-effective way of meeting this need with Gulf-constructed resources. On August 21, 1998, Gulf issued a capacity RFP to approximately 100 potential respondents to seek alternatives to the Gulf-constructed combined cycle unit. Gulf initially received four offers from three separate entities in response to this solicitation. The offers included purchases of varying terms and MW size from proposed combined cycle units, combustion turbine units, and a cogeneration facility.

After evaluating the proposals received in response to the RFP, Gulf determined that the self-build option represented by Smith Unit 3 is the most cost-effective alternative. It has a 20-year net present value (NPV) of costs (2002$) of $279/KW, compared to $496/KW for the next best alternative identified through the RFP process. This amounts to a savings for Gulf's customers of at least $90 million over those 20 years. The location of the proposed unit in the Panama City area eliminates the need for additional transmission to integrate the unit into the Northwest Florida electric grid, and the unit will provide needed voltage support in the eastern portion of Gulf's service territory. Gulf is in the final stages of negotiating a firm natural gas supply for the unit.

Any delay in the licensing of Smith Unit 3 could adversely impact the summer 2002 in-service date. Due to Gulf's deteriorating reserve margin situation, this would leave Gulf short of needed resources during the 2002 peak summer season.

The balance of this document contains a detailed discussion of Gulf's need for capacity and the factors that led to Gulf's conclusion that Smith Unit 3 is the most cost-effective alternative available for meeting that need.

2. Introduction

2. INTRODUCTION

2.1 DESCRIPTION OF GULF POWER COMPANY

Gulf Power Company ("Gulf" or the "Company") is a wholly-owned subsidiary of the Southern Company. Gulf serves approximately 350,000 customers in Northwest Florida. Gulf's service area is bounded by the Apalachicola River on the east and the Florida/Alabama state line on the west. Gulf's service area is shown on the system map contained in Appendix A of this Need Study.

2.2 DESCRIPTION OF EXISTING FACILITIES

2.2.1 GENERATION RESOURCES

Gulf owns and operates eleven fossil steam units, one peaking combustion turbine, and one cogeneration facility in Northwest Florida. In addition, Gulf has a 50% ownership in two coal units at Mississippi Power Company's Plant Daniel, and has a 25% ownership in Georgia Power Company's Plant Scherer Unit #3. The following is a tabulation of Gulf's current generating facilities:

TABLE 2-1

EXISTING GENERATING FACILITIES

UNIT	LOCATION	TYPE	FUEL	COMM. SERVICE DATE	RET. DATE	SUMMER NET CAPACITY IN MW
Crist 1	Escambia Co.	FS	Gas	1/45	12/11	24.0
Crist 2	Escambia Co.	FS	Gas	6/49	12/11	24.0
Crist 3	Escambia Co.	FS	Gas	2/52	12/11	35.0
Crist 4	Escambia Co.	FS	Coal	7/59	12/14	78.0
Crist 5	Escambia Co.	FS	Coal	6/61	12/16	80.0
Crist 6	Escambia Co.	FS	Coal	5/70	12/15	302.0
Crist 7	Escambia Co.	FS	Coal	8/73	12/18	495.0
				CRIST TOTAL		1,038.0
Scholz 1	Jackson Co.	FS	Coal	3/53	12/11	46.0
Scholz 2	Jackson Co.	FS	Coal	10/53	12/11	46.0
				SCHOLZ TOTAL		92.0
Smith 1	Bay Co.	FS	Coal	6/65	12/15	162.0
Smith 2	Bay Co.	FS	Coal	6/67	12/17	192.6
Smith A	Bay Co.	CT	Oil	5/71	12/06	31.6
				SMITH TOTAL		386.2
Pea Ridge	Escambia Co.	Cogen	Gas	5/98	12/28	14.4
		GULF TERRITORIAL UNIT TOTAL				**1,530.6**
Daniel 1	Mississippi	FS	Coal	9/77	12/27	265.0
Daniel 2	Mississippi	FS	Coal	6/81	12/31	265.0
				DANIEL TOTAL		530.0
Scherer 3	Georgia	FS	Coal	1/87	12/42	223.3
		GULF OFF-SYSTEM UNIT TOTAL				**753.3**
		GULF OWNED GENERATION TOTAL				**2,283.9**

As shown in Table 2-1 above, the units owned and operated by the Company within its service area provide a net summer capability totaling 1,531 megawatts. Including Gulf's ownership interests of 753 MW in Daniel Units #1 and #2 and Scherer Unit #3, Gulf has a total net summer generating capability of 2,284 MW and a total net winter generating capability of 2,292 MW as of June 1, 1999. In addition to the Company's installed generating resources, Gulf has a contract with Solutia Corporation for 19 MW of firm capacity that will be in effect until May 31, 2005.

2.2.2 TRANSMISSION FACILITIES

Gulf owns approximately 1,426 miles of 115 kV and 230 kV transmission line. Within this transmission system, the Company has 14 points of interconnection with Alabama Power Company, Georgia Power Company, Alabama Electric Cooperative, and Florida Power Corporation. There are no additional transmission improvements required to integrate Smith Unit 3 into the Northwest Florida grid. The existing Gulf system in Northwest Florida, including generating plants, substations, transmission lines and service area, is shown on the system map designated as Appendix A.

2.3 OVERVIEW OF THE PLANNING PROCESS

The planning process for Gulf is tightly coordinated with Southern's Integrated Resource Planning (IRP) process. The Company participates in that process along with the other Southern operating companies, Alabama Power, Georgia Power, Mississippi Power, and Savannah Electric and Power.

Gulf shares in the benefits gained from planning a large system such as Southern, without the costs of a large planning staff of its own.

The capacity resource needs of Gulf and the entire Southern electric system (SES) are driven by the summer peak demand forecast and by the Southern reliability criterion of a 13.5% reserve margin target. The demand forecast used for capacity planning is a net number, which already reflects the impact of demand-side measures (DSM). Given the demand forecast and the target reserve margin, the planning process uses a computer simulation model called PROVIEW® to produce a listing of preferred capacity resource plans which provide sufficient capacity to reliably meet the system's needs. The best, most cost-effective plan for the entire Southern system is identified by considering the cost of the various plans on a present worth of revenue requirements (PWRR)[1] basis. The resulting system resource needs are allocated among the operating companies based on reserve requirements. Each company then performs the company-specific studies needed to choose the best way to meet its own capacity and reliability needs.

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1 Throughout this document, the analyses are conducted on a Present Worth of Revenue Requirement basis, even though the results may appear as Net Present Value (NPV).

2.4 CAPACITY ADDITIONS

Gulf's need for additional supply-side resources through 2001 will come from the reliance upon Southern system generation resources as well as purchased power. However, such purchases are only available on a short-term basis. When these arrangements expire at the end of 2001, Gulf must replace them with additional generating capacity to meet its share of system reserve margin requirements.

Beginning in 1997, Gulf performed a number of economic evaluations of potential supply options to determine the Company's most cost-effective means of meeting its 2002 capacity needs. Based on those evaluations, Gulf determined in early April, 1998, that a 500 MW class combined cycle unit at its Lansing Smith Generating Plant (Smith Unit 3) was its best internal choice for meeting the 2002 needs. This option saved over $40 million NPV (1998 $s) compared to the next best self-build alternative. In order to determine if other more cost-effective alternatives were available, and to comply with the Florida Public Service Commission's (FPSC) rules, Gulf issued a Request for Proposals (RFP) in August, 1998 to solicit alternatives to Gulf's construction of this combined cycle unit. After evaluating the proposals, Gulf determined that the self-build option represented by Smith Unit 3 was the most cost-effective alternative available, providing 20-year savings of over $90 million NPV (2002 $s) compared to the best option resulting from the RFP process.

3. The Integrated Resource Planning Process

3. THE INTEGRATED RESOURCE PLANNING PROCESS

3.1 OVERVIEW

Gulf Power Company's resource planning process begins as a part of the Southern electric system (SES) Integrated Resource Planning (IRP) process. The Company is one of the five operating companies of the Southern Company. Together the five operating companies -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power -- comprise a centrally dispatched resource pool. As such, the companies coordinate resource planning for the entire system. Individually, each company provides input regarding its customers' load and energy needs in the future. These forecasts are used as input into the generation planning process to formulate overall capacity resource needs for the SES.

The SES integrated resource planning process involves a significant amount of manpower and computer resources in order to produce a least-cost, integrated demand-side and supply-side resource plan. The process examines a broad range of alternatives in order to meet the system's projected summer peak demand and energy requirements. The result of the Southern integrated resource planning process is an integrated plan that meets the needs of the system's customers in a cost-effective and reliable manner.

Gulf receives many benefits from being a part of a large system planning process. The Company comprises only about 6.5% of the total Southern summer peak demand. Since Gulf's needs are relatively small compared to the whole system, many times the Company can meet its demand and reserve requirements by relying on temporary surpluses of capacity which are available on the Southern system. This ability to rely on the large system reserves allows Gulf to defer capacity additions until the timing is right to add a cost-effective block of capacity for Gulf's specific customer needs, as opposed to having to add smaller, more costly amounts of capacity. Another important benefit to Gulf is that it does not have to employ an entire planning staff, but can share in the utilization of the staff at Southern Company Services which performs Southern's IRP function.

3.2 INPUTS AND ASSUMPTIONS

The IRP process uses many inputs and assumptions that are ultimately fed into the analysis to develop the SES's most cost-effective capacity resource plan. These inputs and assumptions result from a number of activities that are conducted in parallel with one another in the IRP process. These activities include energy and demand forecasting, fuel price forecasting, technology screening analysis and evaluation, and the development of miscellaneous assumptions. Gulf's load forecast is discussed in Section 4 and Appendix B. The fuel price forecast used in the most recent IRP studies is discussed in Section 5. Financial assumptions are detailed in Section 6. The following subsections discuss the Southern reserve margin criterion and the technology screening process used to identify candidate generating units.

3.2.1 RESERVE MARGIN CRITERION

One of the major assumptions in the IRP process is the Southern summer peak reserve margin target. The reserve margin target is the optimum economic point at which the system can reasonably meet its summer peak energy and demand requirements taking into account load forecast error, abnormal weather conditions, and unit-forced outage conditions. This reserve margin target is developed by comparing (1) the Customer's perceived costs of experiencing outages due to generation and (2) the costs of additional resources to eliminate those outages. Essentially this involves assessing the costs of expected unserved energy (EUE) at various reserve levels along with the costs to install generation to meet that reserve level. The optimum level of reserves is where these two parameters, combined, reach the minimum cost point. Of course, the optimum level of reserves is primarily driven by the customer's perceived cost of outages, EUE, and the cost of adding reliability through generation equipment installations.

The Southern system has, for many years, analyzed the factors that determine target reserve margin. Until 1999, the target reserve margin for the system was set at 15% on an entire Southern basis. It is important to note that due to summer peak demand diversity among the companies of the SES, each individual operating company would be expected to maintain a 14.1% reserve margin as its share of this 15% Southern reserve margin. As a result of a 1996 re-evaluation of the customers' perceived cost of various levels of unavailable power and other factors, it was determined that the optimal target reserve margin for the SES was 13.5% beginning in 1999. This 13.5% Southern reserve margin translates into a 12.6% individual utility share. However, because of capacity supply adequacy issues that affected many utilities during the summer of 1998, and potential changes in that value customers place on not experiencing an outage, Southern is re-evaluating its target reserve margin criterion to account for this new information. After that analysis is completed later this year, there may be an adjustment to the Southern target reserve margin.

3.2.2 TECHNOLOGY ALTERNATIVES

The reasonably acceptable technology alternatives are also analyzed and screened to determine the best options to be included as candidates in the mix analysis. An overview of the SES technology screening process is contained in Appendix C. Once the technologies have been screened to identify those that will be candidates in the mix, the fixed costs of each option are scaled to a common 300 MW block size in order to simplify modeling and put the candidates on a level playing field. This allows the mix program to select a number of technology combinations over the planning horizon without placing undue bias on any particular technology because of its size or other factors.

3.3 GENERATION MIX ANALYSIS

Once the necessary assumptions are determined the technologies are screened to the suitable candidates, and the necessary planning inputs are defined, then the generation mix analysis is initiated. The optimization tool used in the mix analysis is the PROVIEW® model. PROVIEW® uses a dynamic programming technique to develop the optimum resource mix using combinations of the generic supply-side options identified in the technology screening process. This technique allows PROVIEW® to evaluate, for every year, all the combinations of generation additions that satisfy the reserve margin constraint.

In performing its optimization, PROVIEW® calculates a net present value (NPV) for each mix of generating alternatives. This NPV includes the capital costs of the unit additions, together with the operating and maintenance costs for both the existing system and the unit additions. The program produces a report that ranks all of the different combinations by the total net present value (NPV) cost over the entire planning horizon. The leading combinations from the program are then evaluated for reasonableness and validity. It is important to note that supply option additions produced by the PROVIEW® model at this stage of the analysis are for the entire Southern electric system and are reflective of the various technology candidates selected. This process produces the lowest cost resource plan for the entire SES. The additions included in that plan are then allocated, according to reserve needs, to the individual operating companies.

The Integrated Resource Planning process is a very manpower-intensive activity. In the mid-1990s, the Southern electric system decided that it would only perform a "full-blown" IRP every third year, with "updates" for the interim years. Both the full IRP process and the interim updates involve development of fuel forecasts and load and energy forecasts, since these forecasts are required for a number of business purposes in addition to resource planning. The technology assessment, however, needs to be updated only as changing conditions dictate, and typically undergoes a complete review only in connection with the full IRP process.

From a quantitative standpoint, the updates take the changes in the demand and energy forecast and perform a manual remix to assure the companies that their resource requirements are still valid, or to make the necessary resource changes. From a qualitative standpoint, changes in the fuel forecasts and technology improvements are reviewed, and if a major change has occurred in these factors, its effect will be analyzed along with the updated mix.

3.4 RESULTS OF RECENT IRP PROCESSES

Since the decision was made to limit full IRP processes to a three-year cycle, these "full" IRP's were performed in 1995 and 1998, with updated manual mixes in the interim years.

3.4.1 1995 FULL IRP

The Southern IRP for 1995 showed the need for a mixture of combined cycle units and combustion turbines for the entire system with the first need in the year 1999.

The load forecast for Gulf in the 1995 IRP is shown in the table below. The technology screening performed for the 1995 IRP identified (1) Conventional Pulverized, Base-Load Coal, (2) Advanced E-Class Intermediate Combined Cycle, and (3) Standard and Advanced E-Class Peaking Combustion Turbines as the candidate units for all years of the mix analysis. In addition, F-Class Combustion Turbines and F-Class Combined Cycle units which provide a cost and efficiency benefit over the E-Class technology were considered to be suitable for the year 2000 and beyond.

TABLE 3-1

GULF'S FORECASTED DEMAND
AS OF THE 1995 IRP

YEAR	GULF LOAD (MW)
1995	1,944
1996	1,969
1997	1,985
1998	2,013
1999	2,042
2000	2,067
2001	2,093
2002	2,119
2003	2,148
2004	2,178

For Gulf, the 1995 resource plan, as described in its 1995 Ten-Year Site Plan (TYSP), indicated that the Company should construct 200 MW of combustion turbine (CT) capacity to meet its needs beginning in 1999, with an additional 100 MW of CT capacity in 2002. This plan also showed Gulf adding a 48 MW share of a system combined cycle (CC) unit in the year 2004. In total, this 1995 plan indicated that Gulf needed 300 MW of CT capacity by 2002 and an additional 48 MW of combined cycle in 2004. This is much like the mixture of CT's and CC's that formed the entire Southern IRP in 1995.

3.4.2 1996 IRP UPDATE

The 1996 IRP update, which formed the basis of Gulf's 1996 TYSP, showed an increased megawatt demand need for Gulf and a change in the preferred resource plan to meet these needs. The 1996 TYSP indicated that Gulf would purchase 180 MW of capacity beginning in 1999 and replace 80 MW of this purchase with the installation of 200 MW of combustion turbine capacity in 2002. Once again, the Company showed a need for 300 MW of capacity by the year 2002; however, this update indicated that Gulf's intention was to meet its near term need through purchased power.

As a part of the individual utility resource requirement decision process, in 1996, Mississippi Power Company (MPCo) decided to meet its short-term needs by means of capacity purchases through the year 2000, allowing MPCo to procure smaller amounts of power until it was the optimum time to construct a cost-effective generating unit. MPCo's purchased power solicitation in 1996 resulted in a fairly large number of cost-effective offers, as well as a large amount of megawatts offered. Gulf was still a year away from needing to seek short-term power purchases to meet its 1999 needs, but viewed the results of MPCo's solicitation as very promising when considering its future prospects.

Since the 1996 IRP indicated that Southern did not have any need for units to be constructed until after the year 2001, the F-Class technology became the new assumption for combined cycle and combustion turbine unit additions. This change in technology assumption was not significant enough to warrant a new mix analysis.

3.4.3 1997 IRP UPDATE

The 1997 IRP update that formed the basis for Gulf's 1997 TYSP showed that the Company's demand had increased and

SOUTHERN reserves were lower, increasing Gulf's allocated responsibility. As a result, the Company's need for purchased power was advanced from 1999 to 1998 and increased from 180 MW to 235 MW. The Gulf demand forecast for the 1997 IRP is shown in the table below.

TABLE 3-2

GULF'S DEMAND FORECAST
AS OF THE 1997 IRP UPDATE

YEAR	GULF DEMAND (MW)
1997	2,031
1998	2,067
1999	2,102
2000	2,122
2001	2,137
2002	2,154
2003	2,175
2004	2,193

The 1997 TYSP showed the Company purchasing 235 MW beginning in 1998, growing to 335 MW in the year 2002. This plan also indicated that Gulf would install 200 MW of combustion turbine capacity to replace all but 150 MW of this capacity by summer 2003.

The following table provides a comparison of the annual incremental differences for the 1995 - 1997 resource plans for Gulf Power Company. Each of these plans was based on an allocation to Gulf of an appropriate share of the system-wide capacity need resulting from the IRP process.

TABLE 3-3

COMPARISON OF CAPACITY NEEDS
BETWEEN THE 1995, 1996, & 1997
RESOURCES PLANS

	1995 PLAN (MW)			1996 PLAN (MW)			1997 PLAN (MW)		
YEAR	CT	CC	PURCH	CT	CC	PURCH	CT	CC	PURCH
1998	0	0	0	0	0	0	0	0	235
1999	200	0	0	0	0	180	0	0	0
2000	0	0	0	0	0	0	0	0	50
2001	0	0	0	0	0	0	0	0	0
2002	100	0	0	0	0	0	0	0	50
2003	0	0	0	200	0	-80	200	0	-185
2004	0	48	0	0	0	0	0	0	0

The update performed for the 1997 IRP did reveal some changes with regard to technologies and the timing of Gulf's need based on the revised load and energy forecast. On the technology radar screen was the announcement of the design and promotion of the G-Class CT technology. The Southern technology group considered the viability of this new class of CT and determined that it was not mature enough to be considered in the 1997 update cycle. The group decided to continue to monitor its development for possible inclusion in the 1998 IRP.

3.4.4 1997 CAPACITY SOLICITATION

Based on the need shown by the 1997 IRP Update, Southern Company Services issued a solicitation for short-term purchased power on behalf of Gulf Power Company (Gulf), Alabama Power Company (APCo), and Savannah Electric and Power (SEPCo) for up to five years beginning summer of 1998.

The results of this solicitation were quite different from the 1996 MPCo solicitation in that there were far fewer cost-effective offers and a much smaller number of total megawatts offered. This was a fairly strong signal that not only were short-term purchased power offers becoming scarce, but what was available was becoming high-priced and was not cost-effective. As a result of this solicitation, SCS secured 350MW for 1998, 300MW for 1999, and 200MW for the years 2000 and 2001, with the remaining need to come from spot market firm energy and capacity purchases in the future. Gulf's share of these purchases is 178 MW in 1999 and 143 MW for 2000 and 2001.

The revelation that short-term purchased power was becoming scarce led MPCo and APCo to begin evaluating their options for capacity additions beginning in 2001. These site-specific evaluations determined that the most cost-effective capacity additions were a combined cycle plant at MPCo's existing Daniel plant near Pascagoula and a combined cycle plant at APCo's existing Barry plant near Mobile. The certification for these additions began in August of 1997.

3.4.5 1998 FULL IRP

The 1998 IRP process began in the fall of 1997 and included MPCo's and APCo's plans for constructing combined cycle units at Plants Daniel and Barry.

This study indicated that Gulf Power Company would need 120 MW of combustion turbines (CT) and 240 MW of combined cycle (CC) capacity for the year 2002, when the Company will no longer have any purchased power agreements on which to rely. This advancement and shift in type and timing of Gulf's need was driven by a change in the system summer peak demand requirements and changes in the relative economics of combined cycle technology. The following table shows the results of the 1998 IRP for Gulf:

TABLE 3-4

GULF'S RESOURCE NEEDS AS OUTLINED
IN THE 1998 IRP

YEAR	COMB. TURB.	COMB. CYCLE	PURCHASES
1998	0	0	240
1999	0	0	2
2000	0	0	-15
2001	0	0	-15
2002	240	120	-178
2003	0	30	0
2004	0	30	0
2005	0	60	0
2006	60	0	0

3.5 GULF POWER COMPANY'S SPECIFIC CAPACITY NEEDS

During the latter part of 1997, it was clear that Gulf would need to add significant capacity resources by 2002. As mentioned before, the purchased power on which Gulf is currently relying for part of its resource needs will no longer be available beginning in 2002. Even with this purchased power, Gulf's individual reserves get extremely low by 2001.

As mentioned in Section 3.4.5 above, the 1998 IRP showed Gulf's resource needs to be 120 MW of CT's and 240 MW of CC in the year 2002, which would cover Gulf's 352 MW share of the Southern reserve margin target. This amount of capacity is in the range that can be added to a system of Gulf's size in a cost-effective manner due to technology economies of scale. As a result, it became clear to Gulf that generating capacity additions would need to be explored.

The 1999 IRP Update, whose preliminary results were being distributed in late fall of 1998, indicated that because of some existing generator unit deratings and summer demand increases, Gulf had a larger capacity resource need than indicated in the 1998 IRP. Based on the 1999 Load and Energy Forecast, the new capacity need for the Company to meet its share of the Southern reserve margin target in 2002 is 427 MW. This megawatt need for Gulf further underscores that not only is a large amount of resource capacity needed, but the size of Smith Unit 3 is an appropriate and cost-effective alternative means to meet this need.

After the purchased power contracts expire, Gulf's reserve margin, using the 1999 Load and Energy Forecast, would go negative in 2002 without the addition of capacity resources. The following table shows the reserve situation that evolves through the year 2002, absent any capacity additions:

TABLE 3-5

GULF'S RESERVES WITHOUT THE ADDITION OF CAPACITY RESOURCES

YEAR	PEAK DEMAND (MW)	STARTING CAPACITY (MW)	PURCH. POWER (MW)	ENDING CAPACITY (MW)	PERCENT RESERVES
1999	2,175	2,123	198	2,321	6.7%
2000	2,207	2,321	-55	2,266	2.7%
2001	2,234	2,266	0	2,266	1.4%
2002	2,265	2,266	-143	2,123	-6.3%

Although Gulf is able to call on total SES reserves to reliably serve its customers through 2001, this table shows that Gulf has an obligation to add capacity in 2002 in order to avoid undue dependence on those reserves.

In order to determine the best way to meet its needs for 2002 and beyond, Gulf began site-specific analyses in late 1997. Unlike the earlier system-wide IRP studies, which had considered generic unit additions, Gulf's analysis took into account site-specific factors such as transmission system impacts, construction requirements, and the availability and cost of fuel transportation.

As discussed in Section 7, by April, 1998, Gulf's site-specific studies indicated that Smith Unit 3 was the most cost-effective self-build alternative.

This unit will be a 540 MW combined cycle unit made up of 2 - F Class combustion turbines and 1 - steam turbine of approximately 170 MW, commonly referred to as a 2-on-1 CC unit. Because of its size and configuration, this unit is more cost-effective than a smaller combined cycle unit, that is commonly referred to as a 1-on-1 CC unit. Smith Unit 3 is also of the size that fits Gulf's needs in the 2002 through 2007 time frame without creating excessive amounts of reserves. Based on a 2002 in-service date, the reserves after the addition of Smith Unit 3 would be as shown in the following table:

TABLE 3-6

GULF'S FUTURE RESERVES BEGINNING
IN 2002 WITH THE ADDITION OF SMITH UNIT 3

YEAR	PEAK DEMAND (MW)	STARTING CAPACITY (MW)	CAPACITY ADDITION (MW)	ENDING CAPACITY (MW)	PERCENT RESERVES
2002	2,265	2,123	540	2,655	17.6%
2003	2,280	2,655	0	2,655	16.8%
2004	2,309	2,655	0	2,655	15.4%
2005	2,347	2,655	-19	2,636	12.7%
2006	2,383	2,636	0	2,636	11.0%
2007	2,425	2,636	148	2,784	15.0%
2008	2,466	2,784	0	2,784	12.9%

Table 3-6, above, demonstrates that Smith Unit 3 puts Gulf in the position of having an appropriate level of generating capacity to meet its customers' needs and maintain a suitable level of reserves for reliability purposes. As shown in Section 7, it also is a very cost-effective means of meeting these needs when compared to the other self-build options evaluated.

4. Load Forecast and DSM Process

4. LOAD FORECAST AND DSM PROCESS

4.1 OVERVIEW

The following is a summary of Gulf Power Company's 1999 Load and Energy forecast of customers, energy sales and peak demands. The forecast horizon spans the ten-year period from 1998 through the year 2008. This is the latest in a series of annual forecasts prepared by the Marketing Services section of Gulf's Marketing and Load Management Department.

The forecast includes the estimated impact of conservation programs currently approved by the Florida Public Service Commission, as well as other conservation initiatives designed to influence patterns of demand in a manner that is mutually beneficial to both Gulf and its customers, such as Gulf's GoodCents Home program.

Gulf's annual load forecast is aggregated with those of the other Southern electric system operating companies for use in the Southern IRP process.

4.2 ASSUMPTIONS

Gulf's projections reflect the current economic outlook for its service area as provided by Regional Financial Associates (RFA), a renowned economic service provider. Gulf's forecast assumes that service area population growth will remain near that of the nation. Additionally, the projections incorporate Gulf's most recent electric price assumptions. Natural gas prices are derived from the 1998 Southern Company Services (SCS) Fuel Panel, as described in Section 5. The following tables provide a summary of the assumptions associated with Gulf's forecast:

TABLE 4-1

ECONOMIC SUMMARY
(1998-2008)

GDP Growth	2.9 - 2.3%
Real Interest Rate	5.4 - 3.7%
Inflation	1.7 - 3.1%

TABLE 4-2

AREA DEMOGRAPHIC SUMMARY
(1998-2008)

Population Gain	161,491
Net Migration	115,420
Average Annual Population Growth	1.7%
Average Annual Labor Force Growth	1.5%
Share of Population Served	96.3%

4.3 METHODOLOGY

Gulf's total forecast employs a number of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts. These efforts are predicated on the philosophy of knowing and understanding the needs, perceptions and motivations of Gulf's customers and actively promoting wise and efficient uses of energy which satisfy customer needs. The following provides a brief description of Gulf's forecasting methodology. A more detailed description is provided in Appendix B.

4.3.1 CUSTOMER FORECAST

4.3.1.1 RESIDENTIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by Gulf's district personnel based upon recent historical trends in customer gains and their knowledge of locally planned construction projects from which they are able to estimate the near-term anticipated customer gains.

For the remaining forecast horizon, the Gulf Economic Model, an econometric model developed by RFA, is used in the development of residential customer projections. Projections of births, deaths, household size, and population by age groups are determined by past and projected trends. Migration is determined by economic growth relative to surrounding areas.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model.

4.3.1.2 COMMERCIAL CUSTOMER FORECAST

As in the residential sector, the immediate short-term forecast (0-2 years) of commercial customers is prepared by Gulf's district personnel utilizing recent historical customer gains information and their knowledge of the local area economies and upcoming construction projects.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers and total real disposable income, reflecting the growth of commercial services to meet the needs of new and existing residents.

4.3.2 ENERGY SALES FORECAST

4.3.2.1 RESIDENTIAL SALES FORECAST

The short-term (0-2 years) residential energy sales forecast is developed utilizing multiple regression analyses.

The long-term residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. REEPS produces forecasts of appliance installations, operating efficiencies, and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses for a large number of different population segments. These segments represent households with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population.

The energy forecast output from REEPS reflects the continued impacts of Gulf Power's GoodCents Home program and efficiency improvements undertaken by customers as a result of Residential Energy audits, as well as conversions to higher efficiency outdoor lighting. This output is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the residential conservation programs and program features are provided in Section 4.3.4.

4.3.2.2 COMMERCIAL SALES FORECAST

The short-term (0-2 years) commercial energy sales forecast is also developed utilizing multiple regression analyses.

COMMEND, a commercial end-use model developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for Gulf's long-term commercial energy sales forecast.

Annual building data from RFA and Gulf's most recent Commercial Market Survey provide much of the input data required for the COMMEND model. The model produces forecasts of energy use for the space heating, cooling and ventilation equipment and the lighting, water heating, cooking, refrigeration, and other end-uses within each of 12 different business categories.

The energy forecast output from COMMEND reflects the continued impacts of Gulf Power's Commercial GoodCents building program and efficiency improvements undertaken by customers as a result of Commercial Energy Audits and Technical Assistance Audits, as well as conversions to higher efficiency outdoor lighting. The output from COMMEND is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the Commercial Conservation programs and program features are provided in Section 4.3.4.

4.3.2.3 INDUSTRIAL SALES FORECAST

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Forty-four of Gulf's largest industrial customers are interviewed to identify load changes due to equipment additions, replacements or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and non-manufacturing sectors. The industrial forecast is further refined by accounting for expected self-generation installations. The industrial sales forecast is also adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the conservation programs and program features are provided in Section 4.3.4.

4.3.2.4 STREET LIGHTING SALES FORECAST

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service by fixture type.

The projected numbers of fixtures by fixture type are developed from analyses of recent historical fixture data to discern the patterns of fixture additions and deletions. The estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury vapor to high pressure sodium conversions.

4.3.2.5 WHOLESALE ENERGY FORECAST

The short-term forecast of energy sales to wholesale customers is based on interviews with these customers, as well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced utilizing multiple regression analyses.

The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

4.3.2.6 COMPANY USE ENERGY FORECAST

The annual forecast for Company energy usage is based on recent historical values, with appropriate adjustments to reflect short-term increases in energy requirements for anticipated new Company facilities. The monthly spreads are derived using historical relationships between monthly and annual energy usage.

4.3.3 PEAK DEMAND FORECAST

The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors such as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The HELM model provides forecasts of hourly class and system load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for user-specified end-uses. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

4.3.4 CONSERVATION PROGRAMS

Gulf has been a pacesetter in the energy efficiency market since the development and implementation of the GoodCents Home program in the mid-70's. This program brought customer awareness, understanding and expectations regarding energy efficient construction standards in Northwest Florida to levels unmatched elsewhere. Since that time, the GoodCents Home program has seen many enhancements, and has been widely accepted not only by customers, but by builders, contractors, consumers, and other electric utilities throughout the nation, providing clear evidence that selling efficiency to customers can be done successfully.

Gulf's forecasts of energy sales and peak demand reflect the continued impacts of the Company's conservation programs. These forecasts also reflect the anticipated impacts of the new programs submitted in Gulf's Demand Side Management plan filed February 22, 1995 (Docket No. 941172-EI) as approved by the FPSC. The demand and energy reductions associated with these new programs have been updated to reflect a revised implementation schedule for the Advanced Energy Management (AEM) program in the residential sector.

The following is a listing of Gulf's conservation programs:

Residential Programs:

1. GoodCents New Home
2. Heat Pump Upgrade
3. Resistance Heat to Heat Pump Upgrade
4. Air Conditioning Upgrade
5. Residential Energy Audit
6. Residential Mail-In Audit
7. *In Concert With The Environment®*
8. Geothermal Heat Pump
9. Advanced Energy Management
10. Outdoor Lighting Conversion

Commercial Programs:

1. Commercial GoodCents Bldg.
2. Commercial Energy Audit
3. Technical Assistance Audit
4. Commercial Mail-In Audit
5. Real Time Pricing Pilot
6. Outdoor Lighting Conversion

Street Lighting Conversion

Table 4-3, below, provides estimates of the total savings (reductions in peak demand and net energy for load) resulting from Gulf's conservation programs. These estimates include the impacts of Gulf's existing programs that have been in place for several years and the anticipated impacts of Gulf's newer programs, submitted in Gulf's Demand Side Management Plan filed in 1995. These reductions are verified through on-going monitoring of Gulf's major conservation programs and reflect estimates of conservation undertaken by customers as a result of Gulf's involvement. Conservation which has taken place without Gulf's involvement has contributed to further unquantifiable reductions in demand and net energy for load. These unquantifiable additional reductions are captured in the time series regressions in the energy forecasts and in demand model projections. Additional detail on Gulf's conservation programs is provided in Appendix B.

TABLE 4-3

CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	Summer Peak (MW)			Winter Peak (MW)			Net Energy for Load (GWH)		
	Existing	New	Total	Existing	New	Total	Existing	New	Total
1997	214	30	244	263	6	269	514	9	523
2002	253	112	365	295	128	423	573	77	650
2008	290	199	489	334	256	590	625	145	770

As indicated in this table, in 1997, Gulf's DSM programs successfully reduced summer peak demand by 244 megawatts (MW), winter peak demand by 269 MW, and net energy for load by 523 million kilowatt-hours (KWH). By the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from

1997 through 2002. These reductions are expected to grow to a total savings of 489 MW of summer peak demand, 590 MW of winter peak demand and an annual energy savings of over 770 million KWH by the year 2008.

4.3.5 RENEWABLE ENERGY

Gulf has begun implementation of a "Green Pricing" pilot program, *Solar for Schools,* to obtain funding for the installation of solar technologies in participating school facilities combined with energy conservation education of students. Initial solicitation began in September, 1996 and has resulted in participation of over 333 customers contributing $18,171 through December, 1998. A prototype installation at a local middle school has been completed and the experience gained at this site will be used to design future *Solar for Schools* installations.

4.4 FORECAST RESULTS

The following table summarizes the major forecast results. Detailed forecast results are provided in Appendix B.

Table 4-4

History and Forecast Summary							
	1989 history	1998 history	2003 forecast	2008 forecast	CAAG 1989-1998	CAAG 1998-2003	CAAG 1998-2008
Population	662,784	810,649	891,566	960,867	2.3%	1.9%	1.7%
Residential Customers	250,038	304,413	337,784	367,016	2.2%	2.1%	1.9%
Customer Gains					54,375	33,371	62,603
KWH / Customer	13,173	14,577	14,677	14,995	1.1%	0.1%	0.3%
Energy (GWH)	3,294	4,438	4,958	5,503	3.4%	2.2%	2.2%
Commercial Customers	33,500	45,510	51,208	55,836	3.5%	2.4%	2.1%
KWH / Customer	64,761	68,379	68,275	69,507	0.6%	0.0%	0.2%
Energy (GWH)	2,169	3,112	3,496	3,881	4.1%	2.4%	2.2%
Net Energy for Load (GWH)	8,378	10,402	11,658	12,661	2.4%	2.3%	2.0%
Summer Peak Demand	1,698	2,154	2,280	2,466	2.7%	1.1%	1.4%
Winter Peak Demand	1,554	1,692	2,139	2,258	0.9%	4.8%	2.9%
Load Factor (%)	56.3%	55.1%	58.4%	58.6%			

The growth rates associated with the 1999 peak demand forecast are slightly higher than the 1998 TYSP. The summer peak demand projections for the 1999 forecast are about 31 MW higher than the 1998 TYSP forecast by 2002, the proposed in-service date of Smith Unit 3. As described in Section 3, the 1998 TYSP forecast was used to establish the need for Smith Unit 3. The additional summer peak demand projected in the most recent forecast simply underscores the need for additional capacity in 2002.

4.5 DEMAND SIDE MANAGEMENT (DSM) PROGRAM RESULTS

As shown in Table 4-3 in Section 4.3.4, by the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from 1997 through 2002. The impacts of Gulf's conservation programs are shown in Figures 4-1 through 4-3.

It should be noted that Gulf's conservation goals are currently being reviewed and revised in a separate docket and the reductions achieved as a result of these revisions may vary slightly from those included in the 1999 Forecast. However, because of the factors driving the need for additional capacity in 2002, including the expiration of purchased power contracts and dwindling reserve margins, the need for Smith Unit 3 cannot be avoided or delayed any further by additional DSM.

Figure 4-1

Gulf Power Company

History and Forecast of Summer Peak Demand

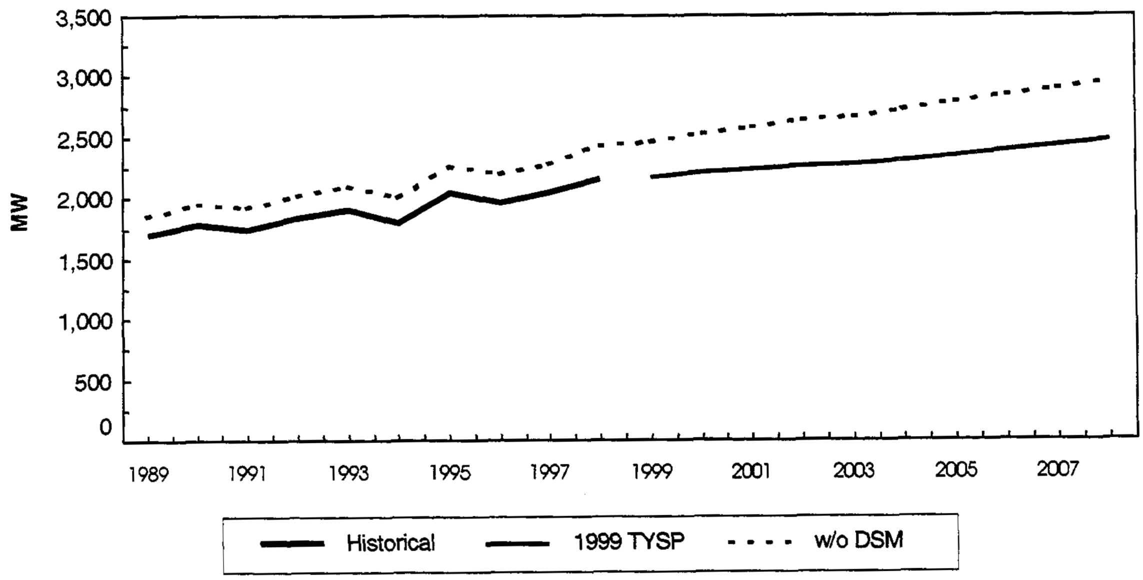


Figure 4-2

Gulf Power Company

History and Forecast of Winter Peak Demand

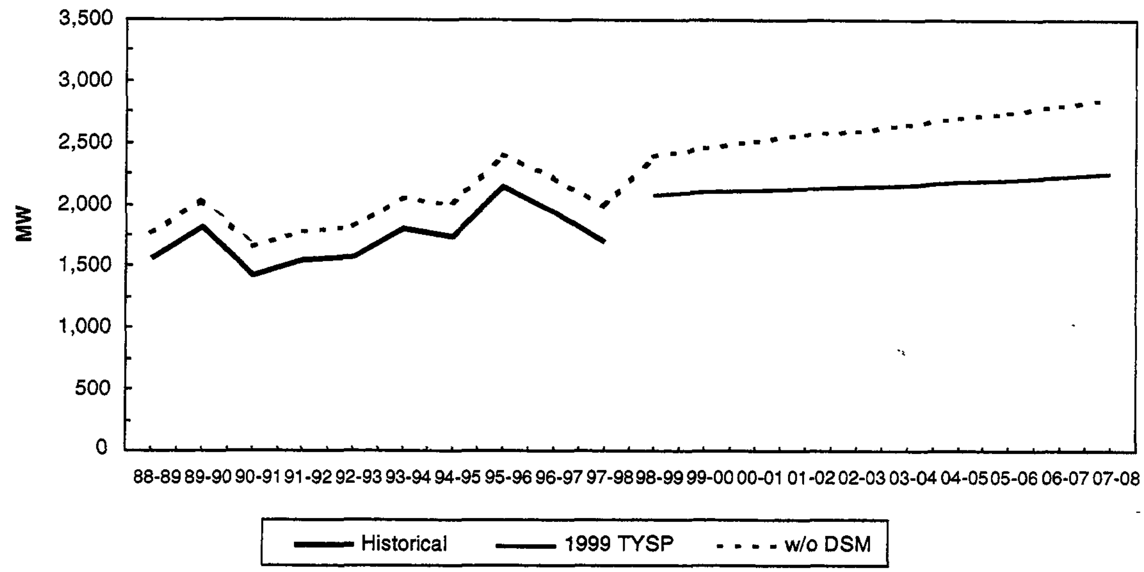
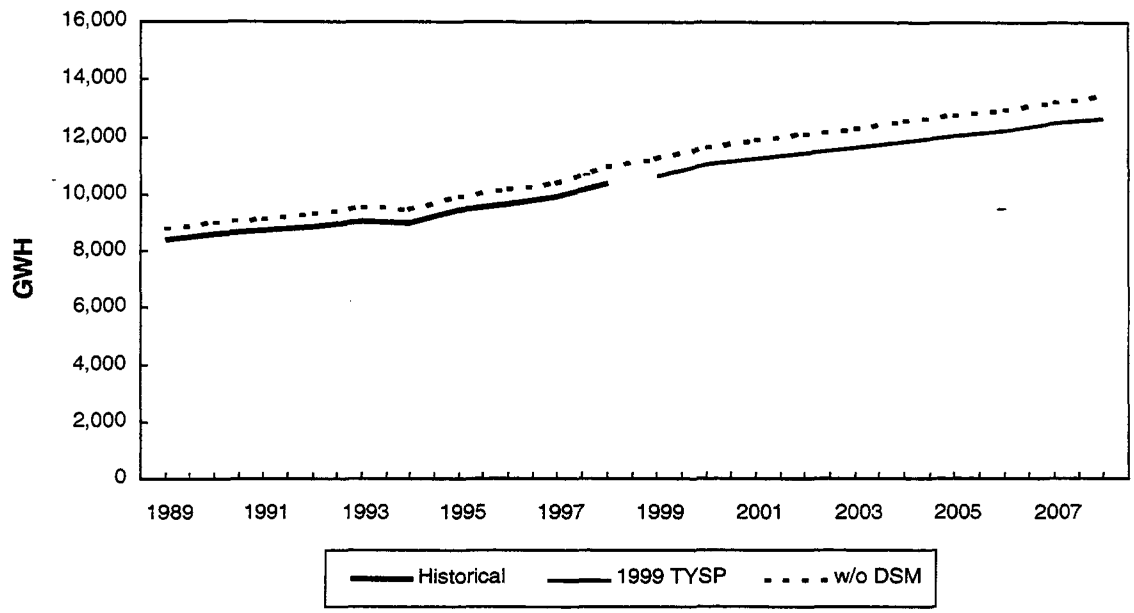


Figure 4-3

Gulf Power Company

History and Forecast of Annual Net Energy for Load



4.6 HISTORICAL FORECAST PERFORMANCE

Gulf's forecasts have traditionally been accurate. The FPSC's Review of Electric Utility 1998 Ten-Year Site Plans indicated that, of the nine reporting utilities in the state with sufficient available historical data, Gulf's average absolute percent error in retail sales forecast accuracy for the period from 1993 through 1997 was 2.5% and ranked third best in the state. Gulf's average forecast error for the same period was estimated to be an under-forecast of 1.19%, which also ranked third in the state.

5. Fuel Price Forecast Process

5. FUEL PRICE FORECAST PROCESS

5.1 FUEL PRICE FORECASTS

Fuel price forecasts are used for a variety of purposes within the Southern electric system (SES), including such diverse uses as long-term generation planning and short-term fuel budgeting. Southern's fuel price forecasting process is designed to support these various uses.

The delivered price of any fuel consists of two components, the commodity price and the transportation cost. Commodity prices are forecast as mine-mouth prices for coal or well-head prices for natural gas. Because mine-mouth coal prices vary by source, sulfur content and Btu level, Southern prepares commodity price forecasts for 12 different coal classifications used on the Southern system. Because natural gas and oil prices do not experience the same variations, Southern prepares a single commodity price forecast for each of these fuels.

The level of detail with which transportation costs are projected depends on the purpose for which the forecast will be used. Generic transportation costs that reflect an average cost for delivery within Southern's territory are used in the delivered price forecast used for modeling generic unit additions in the Integrated Resource Planning (IRP) process. Site-specific transportation costs are developed for existing units to produce delivered price forecasts for use both in the IRP process and in fuel budgeting. Similarly, when site-specific unit additions are under consideration, site-specific transportation costs are developed for each option.

Given the purpose of this Need Study, the following discussion will focus on the commodity price forecasts for coal and natural gas, and on the site-specific forecasts for Smith Unit 3 and the generating facilities proposed in response to Gulf's Request for Proposals (RFP).

5.2 SOUTHERN GENERIC FORECAST

Each year, Southern develops a fuel price forecast for coal, oil, and natural gas, which extends through the Company's 10-year planning horizon. This forecast is developed by a fuel panel consisting of fuel procurement managers at each of the five operating companies, with input from Southern Company Services fuel staff and outside consultants ("Fuel Panel").

The fuel price forecasting process begins with an annual Fossil Fuel Price Workshop that is held with representatives from recognized leaders in energy-related economic forecasting and transportation-related industries. Presenters at the last fuel price workshop included representatives from Resource Data International, J. D. Energy Inc., Hill and Associates, Data Resource International, Fieldston Company, and Criton Company.

During the Fossil Fuel Price Workshop, each fuel procurement representative presents their "base case" forecast and assumptions, and high and low fuel price scenarios are discussed. A question and answer period allows for opposing views and debates on forecasts.

After the workshop, presentations by the SCS Fuel Services group reference the outside consultant forecasts and identify any major assumption differences. The Fuel Panel then consolidates both internal and external forecasts and assumptions to derive its commodity forecast for each type of fuel. The Fuel Panel's 1998 commodity price forecasts for 1.0% sulfur coal, oil, and natural gas, which were used in the economic analysis of Gulf's generating alternatives, are included in Table 5-1 below.

TABLE 5-1

SOUTHERN GENERIC FUEL PRICE FORECAST
($/MMBtu)

	COAL	NAT. GAS	OIL
1999	1.071	2.28	3.94
2000	1.080	2.28	4.06
2001	1.089	2.28	4.18
2002	1.098	2.28	4.30
2003	1.107	2.28	4.43
2004	1.115	2.28	4.58
2005	1.125	2.47	4.72
2006	1.134	2.62	4.87
2007	1.143	2.79	5.02
2008	1.152	2.96	5.18

5.3 COAL PRICE FORECAST

The information provided during the Fuel Panel meeting is used to develop the SES forecast of generic coal prices. The major influences that drive the assumptions for the coal forecast are relative expected demand for specific qualities of coal and transportation from the source. As Phase II of the Clean Air Act of 1990 approaches, the variety of suitable coal quality narrows and tends to have an upward pressure on coal commodity prices. However, as more substitution of natural gas for coal as an energy resource for new resource additions takes place, it is expected that coal prices will once again stabilize.

The generic coal price used in the IRP process is based on an average expectation of coal commodity cost combined with average transportation fees. This serves as a basis for the fuel costs associated with the pulverized coal candidate technology in the mix analyses. This generic fuel commodity price is also used with plant specific transportation fees in combination with a plant's contract coal prices to develop the existing fuel price projection for the Company's budget process.

5.4 NATURAL GAS PRICE FORECAST

The natural gas price forecast for wellhead natural gas reflects a "relaxed" view of the scarce resource theory. Past views by consultants and the U.S. Department of Energy

(DOE) would suggest that natural gas resources were rapidly declining and that reserves would be more difficult and costly to find. However, new technological innovations have resulted in a paradigm shift in the "scarce resource" theory. The new consensus is that gas resources are sufficient to meet the growing demand with moderate nominal dollar increases in price during the planning period. Dramatic improvements in producers' ability to find and develop natural gas reserves have prompted suppliers to have a bullish outlook on future markets. In the past two years, success rates in drilling offshore exploration wells have improved from 25% to 90% for most producers. In addition, new completion techniques such as horizontal drilling have increased production per well substantially. Lastly, new production methods are allowing producers to drill in very deep water at a lower cost. The result is expected to be a plentiful supply of relatively inexpensive volumes of gas in the near future.

5.5 NATURAL GAS AVAILABILITY

Assuming the construction of additional pipeline facilities, there are sufficient natural gas supplies available in the Southeastern United States to support full load operation of Smith Unit 3.

During the winter months, U.S. natural gas demand can reach 100 billion cubic feet (Bcf) per day. Unfortunately, the current maximum natural gas supplied through imports and domestic production volumes peaks at 56 to 60 Bcf per day. In order to offset this capacity shortage, storage delivery is necessary.

Since U.S. natural gas demand in the summertime is significantly less, only about 42 to 45 Bcf per day, large end users and local distribution companies, such as Alagasco, buy extra volumes to fill huge underground gas storage fields. Typically, the markets purchase from 10 to 12 Bcf per day to fill storage during the summer months. This activity results in average gas demand reaching usage levels of 52 to 57 Bcf per day. This allows producers to operate wells at 90-95% of capacity year round.

There are indicators that during the time period 1999 and 2005, gas supply in the SES region will improve substantially. Major producers and interstate pipelines have proposed wide-scale expansion of pipelines in the Louisiana, Mississippi, and Alabama offshore areas. Suppliers forecast that an additional 2 Bcf per day will be delivered to the market by 1999. Another 4 Bcf per day should be available by the year 2005. Additionally, Canadian producers and pipelines have announced their plans to increase gas imports by 2 Bcf per day by 2000. These developments suggest that by 2005, U.S. gas supplies (specifically the SES region) should increase 15-16% above current levels. This translates into sufficient gas being available for all new gas-fired electric generation, including Smith Unit 3. It also means that average annual gas prices should drop in the 1998 to 2000 time period as reflected in the natural gas price forecast discussed in Section 5.2 above.

5.6 SITE-SPECIFIC FUEL PROJECTIONS

Although the generic fuel forecast is useful in the IRP process for determining the preferred type of generating unit additions, it is inappropriate for use when evaluating site specific generation alternatives. For site-specific reviews, it is necessary to develop a fuel projection that specifically addresses the fuel supply that would be available to that site. This is the process that was used during both the self-build and RFP evaluations for Gulf.

The evaluations of both the RFP responses and the final self-build option were based on the gas commodity prices contained in the Fuel Panel's 1998 forecast. This provided a uniform basis for comparison. If necessary, adjustments were made to reflect any cost differences due to natural gas supply at a point other than the Henry hub, and any differences due to the specifics of the proposal, such as a commodity price adder.

To obtain site-specific costs for each alternative, transportation costs were added to the commodity forecast. In the case of the RFP respondents, the transportation adders were those quoted in the respective proposals. In the case of Gulf's self-build option, the transportation adders reflected the rates offered in response to Gulf's September, 1998 solicitation for firm natural gas transportation.

In some cases, an RFP respondent stated that it planned to use either interruptible transportation or recallable released firm transportation, but would supply fuel oil backup. In those cases, fuel oil was assumed to be used for periods when gas transportation would likely be unavailable. The Fuel Panel's generic oil price forecast was used for this purpose, with transportation adjustments for delivery to the specific plant site.

By using the Fuel Panel's commodity price forecast in all the evaluations, SCS ensured that the competing proposals were compared on a fair, consistent basis.

6. Financial Assumptions

6. FINANCIAL ASSUMPTIONS

The following financial assumptions were developed by Southern Company Services Financial Planning Department based on its annual assessment of regional and national economic factors. These assumptions were applied on a uniform basis in the analysis of Gulf's self-build options, the offers from respondents to Gulf's RFP, and the transmission improvements that were necessary for the alternatives. These financial factors are representative of what the Company could expect to experience when raising equity and debt at this time. Even if these assumptions turn out to be slightly different from actual rates in the near future, the relative rankings of the alternatives would not be changed.

The financial assumptions used in the evaluation processes are as follows:

Cost of Debt	7.29 %
Cost of Preferred	6.79 %
Cost of Equity	13.50 %
Percentage of Debt	45.00 %
Percentage of Preferred	10.00 %
Percentage of Equity	45.00 %
Construction Escalation	3.02 %
General Inflation	2.78 %
Ad Valorem Tax Rate	1.08 %

State Tax Rate	5.50 %
Federal Tax Rate	35.00 %
Depreciation Life	20 Years

7. Self-Build Option Selection Process

7. SELF-BUILD OPTION SELECTION PROCESS

7.1 INITIATION OF SITE-SPECIFIC STUDIES

By the summer of 1997, it was apparent that Gulf would need to add generating resources by 2002 to reliably meet its customers' needs. This need was the result of several factors. Gulf's existing short-term power purchase agreements were scheduled to expire at the end of 2001, at which time the Company would be left with a negative reserve margin. Continuing to meet Gulf's capacity needs with new short-term power purchase options was not feasible, since such purchases were becoming not only scarce, but extremely expensive as a resource option. In addition, total SES reserve margins were declining, and Gulf could no longer rely on system-wide reserves to offset its own reserve shortfall. Two of the other operating companies in the Southern electric system, Alabama Power Company (APCo) and Mississippi Power Company (MPCo) had engaged in a study to determine their best self-build alternatives in the early part of 1997. This led to the filing for certification of APCo's Barry combined cycle unit and MPCo's Daniel combined cycle unit in August of 1997. As a member of the Southern system, Gulf was offered the opportunity to participate in the ownership of the proposed Daniel CC unit.

Based on all these circumstances, the Company in late 1997 began evaluating a number of site-specific, self-build generation options for meeting its future demand needs. The following is a listing of the self-build alternatives that were ultimately considered in this evaluation process:

- Participation in MPCo's Daniel Combined Cycle Unit scheduled for a 2001 in-service date
- Construction of CT's at Smith Plant
- Construction of a CC unit at Smith Plant
- Participation in a cogeneration unit in the Pensacola area

The self-build evaluation process required the development of plant-specific cost and operating data for each of the alternatives. This data was then used to calculate the total 20-year net present value (NPV) of costs for each of the generating alternatives. The components of cost considered in the analysis included capital expenditures, fuel supply and transportation costs, operating and maintenance expense, transmission improvements, and system energy savings. These options were compared on both a $/KW and total NPV basis.

7.2 SELF-BUILD UNIT SIZE

The initial self-build evaluation began by analyzing projects of comparable size to a 1-on-1, F-Class combined cycle unit, which has an output of approximately 266 MW. If a particular option being evaluated was of a different size, its characteristics were scaled either up or down to make it comparable to the 1-on-1 CC unit. This allowed the alternatives to be evaluated on an equal basis.

This size of self-build option was initially used in the evaluation process. It became apparent that a 500 MW, F-Class, 2-on-1 combined cycle unit not only better matched the Company's demand needs, but also provided an alternative with attractive economies of scale. The major economic difference in going from a 1-on-1 to a 2-on-1 configuration is that the Company could get twice the generating capability for only about 70% in additional capital costs. Once again, some scaling was necessary to put all alternatives on equal footing in the analysis.

7.3 SIGNIFICANT COST DRIVERS

There are several significant cost drivers in the 20-year NPV cost analysis of site-specific alternatives. These include the cost of natural gas transportation, the cost of required transmission improvements, and the amount of energy savings that result from the displacement of less efficient generation.

7.3.1 NATURAL GAS TRANSPORTATION COSTS

One of the key elements in the cost analyses was the development of natural gas (fuel) supply costs for the self-build options. As discussed in Section 5, the Southern electric system's Fuel Panel creates a forecast of generic fuel costs by type; however, a more refined and site-specific projection must be used in the self-build analysis. Since most of the self-build options were natural gas fired alternatives, a number of different fuel assumptions were explored in the evaluation.

Natural gas commodity prices and storage costs are fairly competitive throughout the region and can be treated as basically equivalent for any of the specific sites under consideration. On the other hand, there is a great variety in the natural gas transportation rates, particularly when the cost of gas delivered into the state of Florida is compared to gas delivered outside of Florida.

The gas transportation cost for the Daniel CC unit is quite low, since the plant is located only about 5 miles away from a natural gas pipeline called the Destin Dome pipeline. This gave the option of participation in the Daniel CC a distinct fuel cost and energy savings advantage over the other self-build options. The cogeneration project, referred to in the analysis as Mulat Tower, is located near Pensacola and would receive its gas from the Koch Gas Transmission System in that area. Therefore, its transportation costs are fairly well established by existing tariffs. In contrast, there is no existing gas supply to the Smith Plant and therefore, the analyses explored a number of possible alternative supply options.

The closest natural gas pipeline to the Smith site is operated by Florida Gas Transmission (FGT) and would require the installation of approximately a 29-mile section of gas lateral to the plant. It was assumed for purposes of this analysis that FGT would build the new lateral and Gulf could either transport the gas over FGT's system at the published tariff rate or could arrange to get release-firm gas transportation from others not using their capacity all of the time. The other alternative investigated for the Smith CC unit was the possibility of Gulf constructing its own pipeline to the Atmore, Alabama area. This new pipeline would offer the benefits of lower gas transportation costs from that area. This benefit would be impacted by the pipeline construction costs that would have to be considered in the overall economics of the option.

7.3.2 SYSTEM ENERGY SAVINGS

Another key economic factor is the amount of system energy savings associated with each alternative. System energy savings are dependent on the marginal fuel cost of the alternative. Units with lower delivered fuel prices will dispatch earlier and will run at higher capacity factors than units with higher fuel costs. In turn, these units displace a greater amount of high-priced generation from other units and maximize system energy savings. This factor tended to penalize lower efficiency combustion turbine units, as well as units with fuel purchased under currently existing gas tariff rates inside the state of Florida. The Daniel CC provided the greatest system energy savings because of its low gas transportation costs. The energy savings of the Smith CC with the new pipeline option were slightly less than those of the Daniel unit, although the pipeline capital cost would be an offset to any savings of this option.

7.3.3 TRANSMISSION COSTS

The geographic location of the alternatives surfaced as a major factor in the cost evaluations due to the impact of location on the electric transmission system and the associated cost of needed improvements. Each of the self-build options was analyzed separately to determine any incremental transmission impacts resulting from its installation. These studies revealed that the prevailing network flows through Gulf's system are from the west to the east. As generation is added, particularly west of Gulf's service area, transmission improvements are required to reliably transport the power and provide voltage support to the Company's load centers. It was determined that capacity additions located almost anywhere except near the Panama City, Florida area had some negative impact on the transmission system. In fact, the study revealed that the further west the generation alternative was located, the greater the impact on Gulf's transmission system. The cost of overcoming these impacts was added to the overall cost of each self-build alternative in the evaluation.

7.3.4 CAPITAL AND O&M COSTS

The various options' capital and operating and maintenance costs were probably the most straight forward elements of the evaluation. It was clear that participating in a sister company project would have the least capital cost by enabling Gulf to take advantage of economies of scale. It was also clear that combustion turbines had lower capital cost and higher operating costs than the combined cycle units.

7.4 ECONOMIC EVALUATION

The economic evaluation of the self-build alternatives was approached from a total cost basis using common financial factors to develop a total net present value (NPV) for each alternative over a 20-year period. The capital costs for the units, pipeline, and transmission were calculated for each self-build alternative as a traditional present worth of revenue requirement (PWRR). The capacity costs of the cogeneration project and other fixed annual costs were treated like an expense and discounted to yield a NPV of cost. Each self-build option was modeled as an input to the entire Southern electric system to determine its effect on the total production and energy costs or savings to the system. The final result of combining these cost components was the total NPV of cost for all of the self-build options.

The evaluation process, which began the previous fall, was completed in April of 1998. As mentioned earlier, in the final analysis the evaluation considered options that were comparable in size to a 2-on-1, F-Class combined cycle technology (~540 MW) and included all incremental costs associated with the installation of each alternative.

7.5 RESULTS

The results of the evaluation showed that the Smith combined cycle unit, with the construction of a new pipeline, was the lowest cost alternative. Although energy savings was a major factor in the evaluation process, the primary factor that eliminated many of the options was the cost of the transmission improvements required to support new generation at any location outside the Panama City area. The table below provides the results of the self-build analyses which demonstrate that Smith Unit 3 is the Company's most cost-effective self-build alternative.

TABLE 7-1

SELF-BUILD ALTERNATIVE	NET PRESENT VALUE OF COSTS (98$ MIL)
Smith Unit 3	117.1
Smith Combustion Turbine	158.5
Daniel Combined Cycle	236.7
Mulat Tower (cogeneration)	239.0

The selection of a combined cycle unit of the size of Smith Unit 3 dictated that Gulf Power follow the rules established pursuant to the Florida Electrical Power Plant Siting Act (PPSA). This included initiating a solicitation process under Rule 25-22.082 Florida Administrative Code, which must be completed prior to filing for a determination of need before the FPSC. The results of that solicitation process are covered in Section 8 of this Need Study.

8. Request for Proposal (RFP) Process

8. REQUEST FOR PROPOSALS (RFP) PROCESS

8.1 OVERVIEW

Gulf began working with Southern Company Services' purchase power team early in 1998 on development of a Request for Proposals (RFP) for supply-side resources needed beginning in the summer of 2002. The Company desired a market test to determine what potential new generation option was the most cost-effective alternative for its customers. Gulf's RFP process began with the development of the RFP document, and moved through stages which included distributing the RFP, receiving proposals from respondents, initial screening of the proposals, requesting additional information from respondents, and final screening and results.

8.2 DEVELOPMENT OF THE RFP

Southern Company Services began to draft a solicitation for Gulf in February 1998, during the same time period Gulf was finalizing the study of its self-build options. The solicitation incorporated the requirements of the Commission RFP rule, such as the requirement for published notice of the respondents' sites and for Gulf's disclosure of costs for its next planned generating unit.

The RFP solicited proposals for all types of generating resources to meet all or part of a 350 - 500 MW need beginning in the summer of 2002. The RFP requested long-term proposals lasting at least five years and specified a 50 MW minimum proposal size. The RFP advised potential respondents that resources in the Panama City area would have a significant transmission advantage. A copy of Gulf's RFP is contained in Appendix E.

8.3 DISTRIBUTION OF THE RFP

On August 21,1998, Southern Company Services publicly issued the RFP on behalf of Gulf to approximately 100 potential respondents. As a normal course of business, Southern Company Services maintains a mailing list of developers who are active in the Southeastern United States. This list was updated for Gulf's RFP.

Additionally, Gulf published a notice of the solicitation in appropriate local and statewide newspapers and three national trade journals. All of the public notices included the name and address of the RFP contact in Birmingham as well as a schedule of critical dates for the RFP process. Gulf's objective was to attract any interested developers who may not have been on Southern Company Services' original distribution list.

8.4 PROPOSALS RECEIVED

On October 16, 1998, Southern Company Services received, on behalf of Gulf, four offers from three separate respondents. The proposals were of various terms and MW sizes, but all offers were in the form of new generating facilities:

- A combined cycle unit in Hardee County, Florida
- A combustion turbine facility in Holmes County, Florida
- A combined cycle unit in Holmes County, Florida
- A family of cogeneration facilities in Mobile, Alabama and in Santa Rosa County, Florida

After receiving additional required information from one respondent, all offers were determined to be 'responsive' and the initial screening analysis began.

8.5 INITIAL SCREENING

In any supply side evaluation, the goal is to determine which alternative is the most cost-effective on a $/KW basis. Although it penalizes the self-build alternative, Gulf chose to make the cost comparisons on a 20-year NPV of costs basis. Theoretically, the cost of any new generating facility constructed by Gulf would be recovered from its customers using declining revenue requirements over a thirty-year or longer time frame. A uniform 20-year analysis compresses all of those costs into a shorter timeframe, making the self-build alternative appear more expensive than what customers would really be asked to pay on a year-by-year basis.

For the initial screening in October and November, 1998, all of the proposals were modeled in PROVIEW® using only the costs contained within the offers. To facilitate this evaluation, SCS-Fuel Services provided a forecast of delivered natural gas prices for each of the facilities offered. Although the same fundamental commodity price for natural gas was used for all of the offers, there are additional site- specific variable costs of the natural gas which must be accounted for in the production cost model. To ensure the fairness of the evaluation, it is critical that the basis of the fuel forecast for the candidate unit is consistent with the fuel forecasts for generic unit additions and other competing units in the dispatch order.

To place all of the offers on equal footing, each proposal was scaled to a 600 MW size in the production cost run. This scaling method allows all offers to be compared equally, against the same base case, and it provides a consistent method of calculation on a $/KW basis. This evaluation technique is critical to smaller projects which may have more value on a $/KW basis, but may not meet the entire needs of the utility. Southern Company Services' goal was to evaluate the offers on an "apples to apples" basis and to eliminate any size bias in the evaluation.

Because none of the original proposals were 20-year offers, Southern Company Services allowed the PROVIEW® model to replace each offer at the end of its term with the most appropriate generic resource addition. In Southern Company Services' experience, this technique is the best method for direct comparison of alternatives with unequal lives. When using this technique, SCS always reviews the year-by-year results to ensure that the replacement technology does not skew the results for the alternative being evaluated.

The results of the initial screening are shown below:

TABLE 8-1

INITIAL SCREENING RESULTS

Summer Rating	Proposal	Location	NPV ($/KW)
500 MW	Combined Cycle	Holmes County, FL	273.8
486 MW	Combustion Turbine	Holmes County, FL	332.1
350 MW	A family of cogeneration facilities	Mobile, AL and Santa Rosa County, FL	432.3
532 MW	Combined Cycle	Hardee County, FL	565.2

Because this initial screening was based entirely on numbers supplied by the respondents, it was clear that Gulf Power needed to understand more about these proposals before proceeding to the final detailed evaluation. For example, the relative firmness of fuel supply was an important issue for these proposals. After conducting the initial screening analysis, formal correspondence was initiated by Southern Company Services to allow respondents to provide the additional information required.

8.6 REQUESTS FOR FURTHER INFORMATION

On November 19, 1998, letters were sent to each of the respondents asking clarifying questions that would potentially resolve any outstanding issues. Most of the uncertainty at this stage of the analysis concerned the firmness of the fuel supply, unit ratings, unit heat rates, and overall availability of the offers.

The Company wanted to make sure that all of the alternatives would have reliability and other characteristics comparable to those of its self-build option in order to make a fair assessment.

As a result of this dialogue with the respondents, the original proposals were modified and five additional proposals were made to Gulf from these participants. All of these offers were carried forward into the next phase of the evaluation.

8.7 GULF'S SELF-BUILD COSTS FOR SMITH UNIT 3

Concurrent with receipt by SCS of the RFP responses, Gulf submitted a site-specific cost estimate for Smith Unit 3. This submission did not include fuel transportation costs, which were the subject of a separate RFP issued in September, 1998, for firm natural gas service to the Lansing Smith site.

Six separate offers to build and own new pipeline facilities necessary to supply firm natural gas to the Smith site were received on October 16, 1998. These proposals were significantly less expensive than was originally anticipated. Negotiations continue with a short list of respondents with the best offers. In addition to the solicited offers, SCS-Fuel Services developed an independent cost estimate for a Gulf self-build pipeline that was used to determine if having a third party perform this service was the least cost alternative.

8.8 DETAILED EVALUATION AND ANALYSIS RESULTS

In January 1999, a final detailed evaluation was conducted which directly compared the revised proposals to the Smith Unit 3 self-build alternative. The analysis methods for the detailed evaluation were similar to the screening analysis. Both the scaling technique and the replacement technology techniques were continued for the detailed evaluation. In addition to the generation analysis, transmission interconnection costs, system losses and transmission grid improvement costs were calculated and included for each of the supply side alternatives. Table 8-2 provides a summary of the relative ranking resulting from this detailed evaluation.

Although this detailed evaluation could have led to a list of finalists, the updated fuel cost for Smith Unit 3 really distinguished it as the best supply side alternative for Gulf's customers. As shown in the table, Smith Unit 3 produces over a $200/KW advantage over 20 years compared to the best external proposal. Based on these results, Gulf advised each of the respondents that its proposal was not the most cost-effective alternative.

8.9 CONCLUSION

Gulf's RFP process fully complied with both the letter and the spirit of the Florida Public Service Commission's rules governing the selection of generating capacity. Consequently, the process has confirmed that the best capacity resource alternative for Gulf's customers is Smith Unit 3. Because the size of the steam turbine exceeds 75 MW, Gulf now seeks a determination of need and certification of this unit under the Florida Electrical Power Plant Siting Act (PPSA).

TABLE 8-2

Gulf RFP Relative Ranking

Rank	MW	Respondents	NPV Total Cost $/KW (2002$)
1	540	Self-Build	279
2	486	Respondent B CT (20 Year Pricing)	496
3	500	Respondent B CC (10 Year Pricing)	505
4	532	Respondent C	511
5	500	Respondent B CC (7 Year Pricing)	522
6	486	Respondent B CT (10 Year Pricing)	527
7	486	Respondent B CT (7 Year Pricing)	539
8	500	Respondent B CC (20 Year Pricing)	553
9	350	Respondent A	592
10	532	Respondent C (Fixed Energy)	616

9. Summary of Smith Unit No. 3

9. SUMMARY OF SMITH UNIT 3

9.1 OVERVIEW

Smith Unit 3 will be what is commonly referred to as a 2-on-1 combined cycle unit, using the General Electric "F" Class combustion turbine technology. The two combustion turbines (CT) comprising this unit will have a net generating capability of approximately 176 megawatts each in the absence of power augmentation. The exhaust gases from each of these CTs will flow through its own heat recovery steam generator (HRSG). On a combined basis, the HRSG's will produce 1,800 psig steam in sufficient quantities to power about 170 megawatts of steam turbine/generator capacity.

Smith Unit 3 will be a highly efficient, state-of-the-art combined cycle generating unit. Because the new unit will be fueled by natural gas, the environmental concerns associated with the project are minimal. Smith Unit 3 is expected to provide the customers of Gulf with many years of low cost, clean energy.

Smith Unit 3 will have a firm supply of natural gas that will come from a new pipeline installation to the Smith Plant. Currently, the Company does not have any plans to provide for a secondary fuel source for this unit because of the expected firmness of the natural gas supply. Since this new natural gas pipeline is to be built and owned by someone other than Gulf, the cost estimate does not include any major gas pipeline costs, but does include connection and metering costs.

Smith Unit 3 will be located approximately 1,000 feet north of the existing Smith Plant substation. The unit's output will reach the Company's transmission grid by means of less than 1,000 feet of 230 KV bus. The existing transmission system out of Smith Plant is sufficient to handle the unit's output.

Smith Unit 3 will have an average annual output of 521 megawatts at an efficiency of 6,741 Btu/KWH. The unit will have the capability for power augmentation by steam injection to generate up to 540 megawatts of peaking generation at a reduced efficiency of 7,139 Btu/KWH. The costs for the necessary equipment associated with the power augmentation operation are included in the estimate below.

The following is a listing of some of the specific unit characteristics:

Forced outage rate	3.4%
Scheduled maintenance outage	2 weeks/year (Ave.)
Equivalent availability	92%
Expected average capacity factor	62%
Fuel consumption (full load)	3,900 MMBtu/hour
Annual fixed O & M (98$)	$2.84/KW-yr.
Variable O & M (98$)	$1.89/mWh

9.2 PROJECTED UNIT CONSTRUCTION COSTS

The following is a breakdown of estimated installed costs for Smith Unit 3, excluding any costs associated with the construction of the natural gas pipeline. This estimate is based on a combination of actual vendor quotes and refined engineering cost analyses and includes the costs necessary to comply with all applicable environmental regulations. With respect to most of the components that comprise the following costs, this estimate can be considered relatively firm (±10%).

TABLE 9-1

INSTALLED COST ESTIMATE FOR SMITH UNIT 3

DESCRIPTION:	AMOUNT
Indirects	$ 23,661,966
Site, General	2,701,846
Steam Generator Area	36,741,570
Turbine & Generator Area	91,143,505
Fuel Facilities (metering only)	856,111
Plant Water Systems	13,443,351
Electrical Distribution & Switchyard	12,177,183
Plant Instrumentation & Controls	2,591,303
Other	3,935,190
TOTAL	$187,252,025

9.3 ENVIRONMENTAL CONSIDERATIONS

Subsequent to filing the Petition for Need Determination before the Commission, the Company will file its Site Certification Application (SCA) with the Florida Department of Environmental Protection under the Florida Electrical Power Plant Siting Act (PPSA). Smith Unit 3 will be operated in compliance with all applicable federal and state environmental laws and regulations. Two principal environmental issues to be considered are air emissions and any thermal impacts due to the discharge of cooling water from Smith Unit 3.

As mentioned above, Smith Unit 3 will be fueled by natural gas and therefore the only major air emission issue is that of NO_x. Gulf is pursuing an air emission strategy that will reduce NO_x emissions from one of the existing Smith generating units leading to a net reduction in total NO_x emissions for the entire plant. However, in an abundance of conservatism, the cost estimate used in the self-build and RFP evaluations included the capital and O&M costs of a Selective Catalytic Reduction (SCR) system for Smith Unit 3 if needed to control NO_x emissions beyond levels achieved through this strategy.

Condenser cooling for Smith Unit 3 will be accomplished by a closed-cycle cooling tower system, which will minimize cooling water withdrawals and discharge. Make-up water for the closed-cycle cooling system will be withdrawn from the existing once-through cooling water discharge canal that serves existing Smith Units 1 and 2. Blow-down from the cooling tower will be routed to the existing discharge canal, downstream of the make-up structure. The blow-down, which will be taken from the cold side of the cooling tower, will result in a slight decrease in the temperature of the cooling water of the discharge canal.

The Company believes that Smith Unit 3 will be permitted for construction and operation under the conditions and strategy that Gulf plans to propose in its SCA. From an environmental standpoint, the proposed facility will have net positive impacts.

9.4 CONSEQUENCES OF PROJECT DELAY

Beginning with the decision in April 1998 to pursue the installation of Smith unit 3, Gulf established a project timeline to pinpoint critical dates associated with the successful completion of this unit. Among the major elements in this timeline are the RFP, need determination, fuel supply negotiations, environmental permitting, equipment procurement, and unit construction. Each one of these components has a time range for its successful completion and some elements may overlap others along the timeline. Figure 9-1 represents the timeline for Smith Unit 3.

The most rigorous element in the process leading to the in-service date of Smith Unit 3, is the environmental permitting. It is estimated that the permit process will last approximately 12 to 14 months.

There are a number of elements in the timeline that can and most likely will overlap. For example, the need determination can precede and overlap the permitting, which can overlap equipment procurement. The fact that these elements overlap does not necessarily affect the other processes. However, there are some elements that can affect other elements. For instance, if the need determination were delayed or denied, the environmental permitting would not proceed until the need is resolved. Of course, there can be no construction

FIGURE 9-1

SMITH UNIT 3 - PROJECT TIMELINE

August 21, 1998	Issue Request for Proposals (RFP)
October 16, 1998	Receive proposals and begin evaluations
November 13, 1998	Initial Screening complete
December 15, 1999	Begin Detailed Screening
January 9, 1999	Select Short list for negotiations or Move forward with Self-build option.
January 15, 1999	Begin final selection process for gas supplier
February 1, 1999	Solicit vendor proposals for equipment
March 15, 1999	Lock down preliminary engineering for environmental study work for SCA
March 31, 1999	File application for need determination
June 1, 1999	File environmental Site Certification Application (SCA)
June/July, 1999	Need Determination Hearings
July 21, 1999	Land use hearings for Bay Co. site
August 25, 1999	Final decision on Need Determination
October 31, 1999	Finalize plant design
November 22, 1999	Order remaining equipment
August 1, 2000	Issue bid package for erection of the unit
September 15, 2000	Receive environmental permits
October 1, 2000	Award Erection contract
November 1, 2000	Begin site preparation and begin construction and substation work
January 15, 2002	Complete natural gas supply to plant
February 1, 2002	Begin unit testing and performance checks
May 31, 2002	Project complete

activity for the unit until the environmental permits have been approved and issued, even if the equipment were procured and located on-site.

As mentioned in Section 3.4.4, recent inquiries in the purchased power market have resulted in fewer and far more costly offers for capacity and energy. Gulf has demonstrated through the steps taken to date that its selection of Smith Unit 3 is the most cost-effective available for the Company to meets its customers' load requirements beginning in 2002. Even with some minor delays, Gulf believes that its timeline is reasonable and achievable for a summer 2002 commercial in-service date for Smith Unit 3 in order to prevent having to use this high-priced purchased power. However, if there is a delay of Smith unit 3 that prevents meeting its June, 2002 in-service date, at a minimum Gulf's customers will pay more for their electrical energy than necessary. The Company is also concerned with the possibility that without this unit's timely installation, which helps to support Southern system reserves, there are additional reliability issues that could affect customer service.

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Appendices

A. System Map

GULF POWER COMPANY
TRANSMISSION SYSTEM MAP

B. Load Forecasts and DSM Detail

LOAD FORECAST AND DSM DETAIL

OVERVIEW

This appendix includes a detailed description of Gulf's load forecasting methodology, a detailed discussion of its conservation programs, and tables presenting Gulf's detailed forecast results.

B.1 METHODOLOGY

Gulf's total forecast employs a number of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts. These efforts are predicated on the philosophy of knowing and understanding the needs, perceptions and motivations of its customers and actively promoting wise and efficient uses of energy which satisfy customer needs. The following provides a description of Gulf's forecasting methodology.

B.1.1 CUSTOMER FORECAST

B.1.1.1 RESIDENTIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by Gulf's district personnel. The districts remain abreast of local market and economic conditions within their service territories through direct contact with economic development agencies, developers, builders, lending institutions and other key contacts. The projections prepared by the districts are based upon recent historical trends in customer gains and their knowledge of locally planned construction projects from which they are able to estimate the near-term anticipated customer gains. These projections are then analyzed for consistency and the incorporation of major construction projects and business developments is reviewed for completeness and accuracy. The end result is a near-term forecast of residential customers.

For the remaining forecast horizon, the Gulf Economic Model, an econometric model developed by Regional Financial Associates (RFA), is used in the development of residential customer projections. Projections of births, deaths, household size, and population by age groups are determined by past and projected trends. Migration is determined by economic growth relative to surrounding areas.

The number of households located in the eight counties in which Gulf provides service is computed by applying a household formation trend to the population by age group, and then by summing the number of households in each of five adult age categories. As indicated, there is a relationship between households, or residential customers, and the age structure of the population of the area, as well as household formation trends. The household formation trend is the product of initial year household formation rates in the Gulf service area and projected U.S. trends in household formation.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model. The number of residential customers Gulf expects to serve is calculated by multiplying the total number of households located in Gulf's service area by the percentage of customers in these eight counties for which Gulf currently provides service.

B.1.1.2 COMMERCIAL CUSTOMER FORECAST

As in the residential sector, the immediate short-term forecast (0-2 years) of commercial customers, is prepared by Gulf's district personnel utilizing recent historical customer gains information and their knowledge of the local area economies and upcoming construction projects. A review of the assumptions, techniques and results for each district is undertaken, with special attention given to the incorporation of major commercial development projects.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers and total real disposable income, reflecting the growth of commercial services to meet the needs of new and existing residents.

B.1.2 ENERGY SALES FORECAST

B.1.2.1 RESIDENTIAL SALES FORECAST

The short-term (0-2 years) residential energy sales forecast is developed utilizing multiple regression analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather and projected price. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total residential class.

The long-term residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. The REEPS model integrates elements of both econometric and engineering end-use approaches to energy forecasting. Market penetrations and energy consumption rates for major appliance end-uses are treated explicitly. REEPS produces forecasts of appliance installations, operating efficiencies and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses. Each of these decisions is responsive to energy prices and demand-side initiatives, as well as household/dwelling characteristics and geographical variables.

The major behavioral responses in the simulation model have been estimated statistically from an analysis of household survey data. Surveys provide the data source required to identify the responsiveness of household energy decisions to prices and other variables.

The REEPS model forecasts energy decisions for a large number of different population segments. These segments represent households with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population. The total service area forecast of residential energy decisions is represented as the sum of the choices of various segments. This approach enhances evaluation of the distributional impacts of various demand-side initiatives.

For each of the major end-uses, REEPS forecasts equipment purchases, efficiency and utilization choices. The model distinguishes among appliance installations in new housing, retrofit installations and purchases of portable units. Within the simulation, the probability of installing a given appliance in a new dwelling depends on the operating and performance characteristics of the competing alternatives, as well as household and dwelling features. The installation probabilities for certain end-use categories are highly interdependent.

The functional form of the appliance installation models is the multinomial logit or its generalization, the nested logit. The parameters of these models quantify the sensitivity of appliance installation choices to costs and other characteristics. The magnitudes of these parameters have been estimated statistically from household survey data.

Appliance operating efficiency and utilization rates are simulated in the REEPS model as interdependent decisions. Efficiency choice is dependent on operating cost at the planned utilization rate, while actual utilization depends on operating cost given the appliance efficiency. Appliance and building standards affect efficiency directly by mandating higher levels than those otherwise expected.

The sensitivity of efficiency and utilization decisions to costs, climate, household and dwelling size, and income has been estimated from historical survey data. Energy prices, income, and household and dwelling size significantly affect space conditioning and residual energy use. Household and dwelling size also influence water heating usage. Climate significantly impacts space heating and air conditioning.

Major appliance base year unit energy consumption (UEC) estimates are based on data developed by Regional Economic Research, Inc. (RER), the current EPRI contractor, from metered appliance data or conditioned energy demand regression analysis. The latter is a technique employed in the absence of metered observations of individual appliance usage, and involves the disaggregation of total household demand for electricity into appliance specific demand functions. All of the weather sensitive UEC estimates were adjusted for Gulf Power's weather conditions.

The energy forecast output from REEPS reflects the continued impacts of Gulf Power's GoodCents Home program and efficiency improvements undertaken by customers as a result of Residential Energy audits, as well as conversions to higher efficiency outdoor lighting. This output is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the residential conservation programs and program features are provided in Section B.1.4.

B.1.2.2 COMMERCIAL SALES FORECAST

The short-term (0-2 years) commercial energy sales forecast is also developed utilizing multiple regression analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather and projected price. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total commercial class.

COMMEND, a commercial end-use model developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for Gulf's long-term commercial energy sales forecast. The COMMEND model is an extension of the capital-stock approach used in most econometric studies. This approach views the demand for energy as a product of three factors. The first of these factors is the physical stock of energy-using capital, the second factor is base year energy use, and the third is a utilization factor representing utilization of equipment relative to the base year.

Changes in equipment utilization are modeled using short-run econometric fuel price elasticities. Fuel choice is forecast with a life-cycle cost/behavioral microsimulation submodel, and changes in equipment efficiency are determined using engineering and cost information for space heating, cooling and ventilation equipment and econometric elasticity estimates for the other end-uses (lighting, water heating, ventilation, cooking, refrigeration, and others).

Three characteristics of COMMEND distinguish it from traditional modeling approaches. First, the reliance on engineering relationships to determine future heating and cooling efficiency provides a sounder basis for forecasting long-run changes in space heating and cooling energy requirements than a pure econometric approach can supply. Second, the simulation model uses a variety of engineering data on the energy-using characteristics of commercial buildings. Third, COMMEND provides estimates of energy use detailed by end-use, fuel type and building type.

Annual building data from RFA and Gulf's most recent Commercial Market Survey provided much of the input data required for the COMMEND model. The model produces forecasts of energy use for the end-uses mentioned above, within each of the following business categories:

1. Food Stores
2. Offices
3. Retail and Personal Services
4. Public Utilities
5. Automotive Services
6. Restaurants
7. Elementary/Secondary Schools
8. Colleges/Trade Schools
9. Hospitals/Health Services
10. Hotels/Motels
11. Religious Organizations
12. Miscellaneous

The energy forecast output from COMMEND reflects the continued impacts of Gulf Power's Commercial GoodCents building program and efficiency improvements undertaken by customers as a result of Commercial Energy Audits and Technical Assistance Audits, as well as conversions to higher efficiency outdoor lighting. The output from COMMEND is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the Commercial Conservation programs and program features are provided in Section B.1.4.

B.1.2.3 INDUSTRIAL SALES FORECAST

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Forty-four of Gulf's largest industrial customers are interviewed to identify load changes due to equipment additions, replacements or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and non-manufacturing sectors. The industrial forecast is further refined by accounting for expected self-generation installations. The industrial sales forecast is also adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the conservation programs and program features are provided in Section B.1.4.

B.1.2.4 STREET LIGHTING SALES FORECAST

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service, for each of the following fixture types:

HIGH PRESSURE SODIUM	MERCURY VAPOR
5,400 Lumen	3,200 Lumen
8,800 Lumen	7,000 Lumen
20,000 Lumen	9,400 Lumen
25,000 Lumen	17,000 Lumen
46,000 Lumen	48,000 Lumen

The projected number of fixtures by fixture type is developed from analyses of recent historical fixture data to discern the patterns of fixture additions and deletions. The estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury vapor to high pressure sodium conversions.

B.1.2.5 WHOLESALE ENERGY FORECAST

The short-term forecast of energy sales to wholesale customers is based on interviews with these customers, as well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced utilizing multiple regression analyses.

The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

B.1.2.6 COMPANY USE ENERGY FORECAST

The annual forecast for Company energy usage is based on recent historical values, with appropriate adjustments to reflect short-term increases in energy requirements for anticipated new Company facilities. The monthly spreads are derived using historical relationships between monthly and annual energy usage.

B.1.3 PEAK DEMAND FORECAST

The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

Load shape forecasts have always provided an important input to traditional system planning functions. Forecasts of the pattern of demand have acquired an added importance due to structural changes in the demand for electricity and increased utility involvement in influencing load patterns for the mutual benefit of the utility and its customers.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. Rapid increases in energy prices during the 1970's and early 1980's brought about changes in the efficiency of energy-using equipment. Additionally, sociodemographic and microeconomic developments have changed the composition of electricity consumption, including changes in fuel shares, housing mix, household age and size, construction features, mix of commercial services, and mix of industrial products.

In addition to these naturally occurring structural changes, utilities have become increasingly active in offering customers options which result in modified consumption patterns. An important input to the design of such demand-side programs is an assessment of their likely impact on utility system loads.

HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors such as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The HELM model provides forecasts of hourly class and system load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for the user-specified end-uses. Inputs are also required to reflect new technologies, rate structures and other demand-side programs. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

The methodology embedded in HELM may be referred to as a "bottom-up" approach. Class and system load shapes are calculated by aggregating the load shapes of component end-uses. The system demand for electricity in hour i is modeled as the sum of demands by each end-use in hour i:

$$L_i = \sum_{R=1}^{N_R} L_{R,i} + \sum_{C=1}^{N_C} L_{C,i} + \sum_{I=1}^{N_I} L_{I,i} + Misc_i$$

Where:

L_i = system demand for electricity in hour i;

N_R = number of residential end-use loads;

N_C = number of commercial end-use loads;

N_I = number of industrial end-use loads;

$L_{R,i}$ = demand for electricity by residential end-use R in hour i;

$L_{C,i}$ = demand for electricity by commercial end-use C in hour i;

$L_{I,i}$ = demand for electricity by industrial end-use I in hour i;

$Misc_i$ = other demands (wholesale, street lighting, losses, company use) in hour i.

B.1.4 CONSERVATION PROGRAMS

Gulf Power Company has been a pacesetter in the energy efficiency market since the development and implementation of the GoodCents Home program in the mid-70's. This program brought customer awareness, understanding and expectations regarding energy efficient construction standards in Northwest Florida to levels unmatched elsewhere. Since that time, the GoodCents Home program has seen many enhancements, and has been widely accepted not only by customers, but by builders, contractors, consumers, and other electric utilities throughout the nation, providing clear evidence that selling efficiency to customers can be done successfully.

Gulf's forecast of energy sales and peak demands reflect the continued impacts of the Company's conservation programs. These forecasts also reflect the anticipated impacts of the new programs submitted in Gulf's Demand Side Management plan filed February 22, 1995 (Docket No. 941172-EI) as approved by the FPSC. The demand and energy reductions associated with these new programs have been updated to reflect a revised implementation schedule for the Advanced Energy Management (AEM) program in the residential sector.

The following provides a listing of Gulf's conservation programs:

Residential Programs:

1. GoodCents New Home
2. Heat Pump Upgrade
3. Resistance Heat to Heat Pump Upgrade
4. Air Conditioning Upgrade
5. Residential Energy Audit
6. Residential Mail-In Audit
7. *In Concert With The Environment®*
8. Geothermal Heat Pump
9. Advanced Energy Management
10. Outdoor Lighting Conversion

Commercial Programs:

1. Commercial GoodCents Bldg.
2. Commercial Energy Audit
3. Technical Assistance Audit
4. Commercial Mail-In Audit
5. Real Time Pricing Pilot
6. Outdoor Lighting Conversion

Street Lighting Conversion

The remainder of this section provides detailed descriptions of the conservation programs and program features in effect and estimates of reductions in peak demand and net energy for load reflected in the forecast as a result of these programs.

B.1.4.1 RESIDENTIAL CONSERVATION

In the residential sector, Gulf's GoodCents New Home program is designed to make cost effective increases in the efficiencies of the new home construction market. This is being achieved by placing greater requirements on cooling and water heating equipment efficiencies, proper HVAC sizing, increased insulation levels in walls, ceilings, and floors, and tighter restrictions on glass area and infiltration reduction practices. In addition, Gulf monitors proper quality installation of all the above energy features.

Gulf has several programs designed to make cost effective increases in efficiencies in the existing home market by requiring increased efficiency requirements on heating and cooling systems and improvements in air distribution system leakage. The A/C Upgrade program is designed to increase the efficiency of older central air conditioning units. The Heat Pump Upgrade program is designed to increase the efficiency of older heat pump units. The Resistance Heat to Heat Pump Upgrade program is designed to replace older heating and air conditioning systems with new high efficiency heat pump systems.

Further conservation benefits are achieved in the existing home market with Gulf's Residential Energy Audit program which is designed to provide existing residential customers with cost-effective energy conserving recommendations and options that increase comfort and reduce energy operating costs. The goal of this program is to upgrade the customer's home to the GoodCents Improved Home standard by providing specific whole house recommendations. As an extension to this program, Gulf offers a Residential mail-in audit option to enhance customer participation and increase the overall program effectiveness.

In Concert With The Environment® is an environmental and energy awareness program that is being implemented in the 8th and 9th grade science classes in Gulf Power Company's service area. The program shows students how everyday energy use impacts the environment and how using energy wisely increases environmental quality. *In Concert With The Environment®* is brought to students who are already making decisions which impact the country's energy supply and the environment. Wise energy use today can best be achieved by linking environmental benefits to wise energy-use activities and by educating both present and future consumers on how to live "in concert with the environment". The program encourages participation by all household members through a take-home Energy Survey, Energy

Survey Results, and student educational handbook and is considered an extension of Gulf's Residential Audit Program.

The Residential Geothermal Heat Pump Program reduces the demand and energy requirements of new and existing residential customers through the promotion and installation of advanced and emerging geothermal systems. Geothermal heat pumps also provide significant benefits to participating customers in the form of reduced operating costs and increased comfort levels, and are superior to other available heating and cooling technologies with respect to source efficiency and environmental impacts. Gulf Power's Geothermal Heat Pump program is designed to overcome existing market barriers, specifically, lack of consumer awareness, knowledge and acceptance of this technology. The program additionally promotes efficiency levels well above current market conditions.

The Advanced Energy Management (AEM) Program provides Gulf Power's customers with a means of conveniently and automatically controlling and monitoring their energy purchases in response to prices that vary during the day and by season in relation to the Company's cost of producing or purchasing energy. The AEM System allows the customer to control more precisely the amount of electricity purchased for heating, cooling, water heating, and other selected loads; to purchase electric energy on a variable spot price rate; and to monitor at any time, and as often as desired, the use of electricity and its cost in dollars, both for the billing period to date and on a forecast basis to the end of the period. The various components of the AEM System installed in the customer's home, as well as the components installed at Gulf Power, provide constant communication between customer and utility. The combination of the AEM System and Gulf's innovative variable rate concept will provide consumers with the opportunity to modify their usage of electricity in order to purchase energy at prices that are somewhat lower to significantly lower than standard rates a majority of the time. Further, the communication capabilities of the AEM System allow Gulf to send a critical price signal to the customer's premises during extreme peak load conditions. The signal results in a reduction attributable to predetermined thermostat and relay settings chosen by the individual participating customer. The customer's pre-programmed instructions regarding their desired comfort levels adjust electricity use for heating, cooling, water heating and other appliances automatically. Therefore, the customer's control of their electric bill is accomplished by allowing them to choose different comfort levels at different price levels in accordance with their individual lifestyles.

Additional conservation benefits are realized in the residential sector through Gulf's Outdoor Lighting program by conversion of existing, less efficient mercury vapor outdoor lighting to higher efficient high pressure sodium lighting.

B.1.4.2 COMMERCIAL/INDUSTRIAL CONSERVATION

In the commercial sector, Gulf's GoodCents Building program is designed to make cost effective increases in efficiencies in both new and existing commercial buildings with requirements resulting in energy conserving investments that address the thermal efficiency of the building envelope, interior lighting, heating and cooling equipment efficiency, and solar glass area. Additional recommendations are made, where applicable, on energy conserving options that include thermal storage, heat recovery systems, water heating heat pumps, solar applications, energy management systems, and high efficiency outdoor lighting.

The Commercial Energy Audit (EA) and Technical Assistance Audit (TAA) programs are designed to provide commercial customers with assistance in identifying cost effective energy conservation opportunities and introduce them to various technologies which will lead to improvements in the energy efficiency level of their business. The program is designed with enough flexibility to allow for a simple walk through analysis (EA) or a detailed economic evaluation of potential energy improvements through a more in-depth audit process (TAA) which includes equipment energy usage monitoring, computer energy modeling, life cycle equipment cost analysis, and feasibility studies. As an extension to this program, Gulf offers a Commercial mail-in audit option to enhance customer participation and increase the overall program effectiveness.

Gulf's Real Time Pricing pilot program is designed to take advantage of customer price response to achieve peak demand reductions. Initial participation was limited to a maximum of 12 customers with actual demand of 2,000 KW or higher for this pilot program. In 1997 Gulf received approval to increase the participation level to a maximum of 24 customers. Customer participation is voluntary. Due to the nature of the pricing arrangement included in this program, there are some practical limitations to a customer's ability to participate. These limitations include the ability to purchase energy under a pricing plan which includes price variation and unknown future prices; the transaction costs associated with receiving, evaluating, and acting on prices received on a daily basis; customer risk management policy; and other technical/economic factors. The RTP Pilot program has been very successful and is expected to play a major role in affording Gulf Power the opportunity to meet its conservation objectives. Information gained through this program is being used to design a permanent RTP program.

B.1.4.3 STREET LIGHTING CONVERSION

Gulf's Street Lighting conversion program is designed to achieve additional conservation benefits by conversion of existing less efficient mercury vapor outdoor, street and roadway lighting to higher efficient high pressure sodium lighting.

B.1.4.4 CONSERVATION RESULTS SUMMARY

The following Tables B-1 through B-11 provide detailed estimates of the reductions in peak demand and net energy for load resulting from Gulf's conservation programs. These reductions are verified through on-going monitoring of Gulf's major conservation programs and reflect estimates of conservation undertaken by customers as a result of Gulf Power Company's involvement. Conservation which has taken place without Gulf's involvement has contributed to further unquantifiable reductions in demand and net energy for load. These unquantifiable additional reductions are captured in the time series regressions in Gulf's energy forecasts and in the demand model projections.

Tables B-1 through B-4 reflect the total impacts of Gulf's new and existing conservation programs. The impacts of the existing programs that have been in place for several years are shown separately in Tables B-5 through B-8 and the anticipated impacts of Gulf's newer programs, submitted in Gulf's Demand Side Management Plan filed in 1995, are provided in tables B-9 through B-11.

Table B-1, below, provides the total savings in peak demand and net energy for load achieved by Gulf through its conservation programs. In 1997, Gulf's DSM programs successfully reduced summer peak demand by 244 megawatts

(MW), winter peak demand by 269 MW, and net energy for load by 523 million kilowatt-hours (KWH).

As shown in this table, by the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from 1997 through 2002. These reductions are expected to grow to a total savings of 489 MW of summer peak demand, 590 MW of winter peak demand and an annual energy savings of over 770 million KWH by the year 2008.

TABLE B-1

HISTORICAL
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	243,928	268,522	522,804,539

1999 FORECAST
TOTAL CONSERVATION PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	10,865	13,620	22,225,417
1999	30,489	36,692	30,353,374
2000	29,077	37,123	30,034,257
2001	25,943	34,501	22,988,653
2002	24,236	32,955	21,829,790
2003	23,875	32,408	21,756,342
2004	24,095	32,793	21,948,046
2005	20,322	27,386	19,861,207
2006	20,353	27,393	19,872,752
2007	17,717	23,522	18,348,712
2008	17,729	23,526	18,324,246

1999 FORECAST
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	254,793	282,143	545,029,957
1999	285,282	318,835	575,383,331
2000	314,359	355,958	605,417,587
2001	340,301	390,460	628,406,241
2002	364,536	423,414	650,236,032
2003	388,410	455,821	671,992,375
2004	412,506	488,615	693,940,422
2005	432,828	515,999	713,801,629
2006	453,180	543,392	733,674,381
2007	470,897	566,914	752,023,094
2008	488,625	590,440	770,347,340

TABLE B-2

HISTORICAL
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	106,849	163,319	271,253,667

1999 FORECAST
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	10,922	11,511	11,755,771
1999	25,804	34,591	20,028,692
2000	25,592	35,022	19,718,790
2001	24,159	33,387	18,698,570
2002	22,585	31,842	17,553,458
2003	22,162	31,295	17,469,787
2004	22,369	31,680	17,700,793
2005	18,626	26,273	15,667,821
2006	18,633	26,280	15,682,688
2007	15,993	22,409	14,159,565
2008	15,995	22,413	14,165,936

1999 FORECAST
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	117,771	174,831	283,009,439
1999	143,575	209,422	303,038,131
2000	169,167	244,444	322,756,920
2001	193,326	277,832	341,455,491
2002	215,910	309,674	359,008,948
2003	238,072	340,968	376,478,736
2004	260,442	372,649	394,179,529
2005	279,068	398,921	409,847,350
2006	297,701	425,201	425,530,038
2007	313,694	447,610	439,689,603
2008	329,689	470,023	453,855,539

TABLE B-3

HISTORICAL
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	137,080	105,203	241,038,261

1999 FORECAST
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	(58)	2,109	10,242,169
1999	4,685	2,101	10,115,326
2000	3,485	2,101	10,115,326
2001	1,784	1,114	4,092,695
2002	1,651	1,113	4,092,695
2003	1,713	1,113	4,092,695
2004	1,726	1,113	4,092,695
2005	1,696	1,113	4,092,695
2006	1,720	1,113	4,092,695
2007	1,724	1,113	4,092,695
2008	1,734	1,113	4,092,695

1999 FORECAST
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	137,022	107,312	251,280,430
1999	141,707	109,413	261,395,756
2000	145,192	111,514	271,511,082
2001	146,975	112,628	275,603,777
2002	148,626	113,740	279,696,473
2003	150,338	114,853	283,789,168
2004	152,064	115,966	287,881,864
2005	153,760	117,078	291,974,559
2006	155,479	118,191	296,067,254
2007	157,203	119,304	300,159,950
2008	158,936	120,417	304,252,645

GULF POWER COMPANY

TABLE B-17
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1989	8,763	221	165	7,574	276	528	8,378	56.3%
1990	9,019	227	180	7,774	294	545	8,612	55.1%
1991	9,128	233	191	7,861	296	547	8,704	56.8%
1992	9,291	239	202	8,161	299	389	8,849	54.9%
1993	9,537	247	216	8,192	317	565	9,074	54.3%
1994	9,443	254	222	8,164	316	487	8,967	56.8%
1995	9,942	263	227	8,534	336	582	9,452	52.7%
1996	10,167	273	232	8,794	347	521	9,662	55.9%
1997	10,410	282	241	8,938	342	607	9,887	55.3%
1998	10,947	294	251	9,401	356	645	10,402	55.1%
1999	11,232	314	261	9,662	350	645	10,657	55.9%
2000	11,647	334	272	10,013	361	668	11,041	57.1%
2001	11,891	353	276	10,213	369	682	11,263	57.6%
2002	12,119	371	280	10,396	378	694	11,468	57.8%
2003	12,330	388	284	10,566	386	706	11,658	58.4%
2004	12,544	406	288	10,739	393	718	11,850	58.6%
2005	12,769	422	292	10,926	399	730	12,056	58.6%
2006	12,991	438	296	11,108	406	743	12,257	58.7%
2007	13,220	452	300	11,300	412	756	12,468	58.7%
2008	13,431	466	304	11,475	418	768	12,661	58.6%
CAAG								
89-98	2.5%	3.2%	4.8%	2.4%	2.9%	2.2%	2.4%	-0.2%
98-03	2.4%	5.7%	2.5%	2.4%	1.6%	1.8%	2.3%	1.1%
98-08	2.1%	4.7%	1.9%	2.0%	1.6%	1.8%	2.0%	0.6%

NOTE: Wholesale and total columns include contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA).

GULF POWER COMPANY

TABLE B-16
History and Forecast of Winter Peak Demand - MW
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Conservation	Net Firm Demand
88-89	1,762	56	1,706	0	0	113	0	95	1,554
89-90	2,038	57	1,980	0	0	120	0	97	1,821
90-91	1,649	50	1,600	0	0	126	0	98	1,425
91-92	1,772	60	1,712	0	0	132	0	99	1,541
92-93	1,820	61	1,759	0	0	140	0	100	1,579
93-94	2,055	72	1,983	0	0	145	0	101	1,809
94-95	1,993	71	1,922	0	0	150	0	102	1,740
95-96	2,404	82	2,322	0	0	157	0	103	2,144
96-97	2,208	80	2,127	0	0	163	0	105	1,939
97-98	1,974	61	1,913	0	0	175	0	107	1,692
98-99	2,390	76	2,314	28	0	209	0	109	2,071
99-00	2,461	77	2,384	28	0	244	0	112	2,105
00-01	2,511	78	2,433	28	0	278	0	113	2,121
01-02	2,558	80	2,478	28	0	310	0	114	2,135
02-03	2,595	81	2,513	28	0	341	0	115	2,139
03-04	2,643	83	2,560	28	0	373	0	116	2,154
04-05	2,694	84	2,610	28	0	399	0	117	2,178
05-06	2,743	85	2,658	28	0	425	0	118	2,200
06-07	2,796	87	2,709	28	0	448	0	119	2,229
07-08	2,848	88	2,760	24	0	470	0	120	2,258
CAAG									
89-98	1.3%	1.0%	1.3%	100.0%	0.0%	5.0%	0.0%	1.3%	0.9%
98-03	5.6%	5.8%	5.6%	0.0%	0.0%	14.3%	0.0%	1.4%	4.8%
98-08	3.7%	3.7%	3.7%	-1.7%	0.0%	10.4%	0.0%	1.2%	2.9%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)
NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-15

History and Forecast of Summer Peak Demand - MW

Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Conservation	Net Firm Demand
1989	1,858	60	1,799	0	0	79	0	81	1,698
1990	1,954	69	1,885	0	0	81	0	87	1,785
1991	1,923	64	1,860	0	0	83	0	92	1,748
1992	2,018	71	1,947	0	0	86	0	97	1,836
1993	2,096	76	2,021	0	0	88	0	102	1,906
1994	1,999	72	1,927	0	0	92	0	104	1,803
1995	2,265	82	2,183	0	0	96	0	122	2,048
1996	2,196	79	2,118	0	0	100	0	127	1,969
1997	2,284	75	2,208	0	0	107	0	137	2,040
1998	2,425	82	2,342	16	0	118	0	137	2,154
1999	2,460	76	2,385	29	0	144	0	142	2,175
2000	2,521	77	2,445	29	0	169	0	145	2,207
2001	2,574	78	2,496	29	0	193	0	147	2,234
2002	2,630	80	2,549	29	0	216	0	149	2,265
2003	2,668	81	2,587	29	0	238	0	150	2,280
2004	2,722	83	2,639	29	0	260	0	152	2,309
2005	2,780	84	2,696	29	0	279	0	154	2,347
2006	2,836	85	2,751	29	0	298	0	155	2,383
2007	2,896	87	2,809	29	0	314	0	157	2,425
2008	2,955	88	2,867	25	0	330	0	159	2,466
CAAG									
89-98	3.0%	3.6%	3.0%	100.0%	0.0%	4.6%	0.0%	6.0%	2.7%
98-03	1.9%	-0.2%	2.0%	12.7%	0.0%	15.1%	0.0%	1.9%	1.1%
98-08	2.0%	0.7%	2.0%	4.5%	0.0%	10.8%	0.0%	1.5%	1.4%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-14
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWH	(3) Utility Use & Losses GWH	(4) Net Energy for Load GWH	(5) Other Customers (Average No.)	(6) Total No. of Customers
1989	276	528	8,378	63	283,830
1990	294	545	8,612	68	289,400
1991	296	547	8,704	68	294,095
1992	299	389	8,849	74	301,719
1993	317	565	9,074	79	310,419
1994	316	487	8,967	93	318,578
1995	336	582	9,452	119	325,119
1996	347	521	9,662	157	330,571
1997	342	607	9,887	215	340,944
1998	356	645	10,402	262	350,447
1999	350	645	10,657	322	359,699
2000	361	668	11,041	352	368,870
2001	369	682	11,263	371	376,132
2002	378	694	11,468	382	382,906
2003	386	706	11,658	391	389,685
2004	393	718	11,850	400	396,496
2005	399	730	12,056	409	403,249
2006	406	743	12,257	418	410,009
2007	412	756	12,468	427	416,817
2008	418	768	12,661	436	423,605
CAAG					
89-98	2.9%	2.2%	2.4%	17.1%	2.4%
98-03	1.6%	1.8%	2.3%	8.3%	2.1%
98-08	1.6%	1.8%	2.0%	5.2%	1.9%

Note: Sales for Resale and Net Energy for Load include contracted energy allocated to certain customers by Southeastern Power Administration (SEPA).

GULF POWER COMPANY

TABLE B-13
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
		Average	Average KWH	Railroads	Highway	to Public	to Ultimate
		No. of	Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers	Per Customer	GWH	GWH	GWH	GWH
1989	2,095	229	9,147,029	0	16	0	7,574
1990	2,178	247	8,817,297	0	17	0	7,774
1991	2,117	260	8,143,878	0	16	0	7,861
1992	2,179	262	8,318,456	0	16	0	8,161
1993	2,030	268	7,574,388	0	16	0	8,192
1994	1,847	280	6,596,837	0	16	0	8,164
1995	1,795	276	6,502,731	0	16	0	8,534
1996	1,808	281	6,434,470	0	17	0	8,794
1997	1,903	277	6,870,216	0	17	0	8,938
1998	1,834	263	6,971,767	0	18	0	9,401
1999	1,938	285	6,801,516	0	18	0	9,662
2000	2,029	294	6,902,869	0	18	0	10,013
2001	2,076	297	6,989,061	0	19	0	10,213
2002	2,095	300	6,982,317	0	19	0	10,396
2003	2,093	303	6,907,883	0	19	0	10,566
2004	2,091	306	6,833,259	0	19	0	10,739
2005	2,087	309	6,753,665	0	19	0	10,926
2006	2,091	312	6,703,402	0	20	0	11,108
2007	2,094	315	6,648,572	0	20	0	11,300
2008	2,071	318	6,511,389	0	20	0	11,475
CAAG							
89-98	-1.5%	1.6%	-3.0%	0.0%	1.5%	0.0%	2.4%
98-03	2.7%	2.9%	-0.2%	0.0%	1.0%	0.0%	2.4%
98-08	1.2%	1.9%	-0.7%	0.0%	0.9%	0.0%	2.0%

GULF POWER COMPANY

TABLE B-12

History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population *	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
1989	662,784	2.65	3,294	250,038	13,173	2,169	33,500	64,761
1990	677,866	2.66	3,361	255,129	13,173	2,218	33,957	65,305
1991	689,901	2.66	3,455	259,395	13,320	2,273	34,372	66,120
1992	703,860	2.65	3,597	265,374	13,553	2,369	36,009	65,796
1993	726,046	2.67	3,713	271,594	13,671	2,433	38,477	63,242
1994	747,459	2.69	3,752	278,215	13,486	2,549	39,989	63,739
1995	760,195	2.68	4,014	283,717	14,148	2,708	41,007	66,043
1996	769,246	2.67	4,160	287,752	14,457	2,809	42,381	66,271
1997	791,009	2.67	4,119	296,497	13,894	2,898	43,955	65,928
1998	810,649	2.66	4,438	304,413	14,577	3,112	45,510	68,379
1999	830,557	2.66	4,558	312,479	14,587	3,147	46,614	67,512
2000	849,054	2.65	4,692	320,074	14,658	3,273	48,150	67,980
2001	863,541	2.65	4,772	326,118	14,632	3,346	49,347	67,812
2002	877,537	2.64	4,864	331,931	14,653	3,419	50,294	67,977
2003	891,566	2.64	4,958	337,784	14,677	3,496	51,208	68,275
2004	905,608	2.64	5,057	343,661	14,715	3,572	52,130	68,528
2005	919,427	2.63	5,170	349,473	14,793	3,650	53,059	68,793
2006	933,241	2.63	5,272	355,302	14,839	3,725	53,978	69,012
2007	947,114	2.62	5,382	361,172	14,901	3,805	54,904	69,295
2008	960,867	2.62	5,503	367,016	14,995	3,881	55,836	69,507
CAAG								
89-98	2.3%	0.1%	3.4%	2.2%	1.1%	4.1%	3.5%	0.6%
98-03	1.9%	-0.2%	2.2%	2.1%	0.1%	2.4%	2.4%	0.0%
98-08	1.7%	-0.2%	2.2%	1.9%	0.3%	2.2%	2.1%	0.2%

* Historical and projected figures include portions of Escambia, Santa Rosa, Okaloosa, Bay, Walton, Washington, Holmes, and Jackson counties served by Gulf Power Company.

TABLE B-4

HISTORICAL
TOTAL OTHER DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	0	0	10,512,611

1999 FORECAST
TOTAL OTHER DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	227,477
1999	0	0	209,356
2000	0	0	200,141
2001	0	0	197,388
2002	0	0	183,637
2003	0	0	193,860
2004	0	0	154,558
2005	0	0	100,691
2006	0	0	97,369
2007	0	0	96,452
2008	0	0	65,615

1999 FORECAST
TOTAL OTHER DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	10,740,088
1999	0	0	10,949,444
2000	0	0	11,149,585
2001	0	0	11,346,973
2002	0	0	11,530,611
2003	0	0	11,724,471
2004	0	0	11,879,029
2005	0	0	11,979,720
2006	0	0	12,077,089
2007	0	0	12,173,541
2008	0	0	12,239,156

TABLE B-5

HISTORICAL
TOTAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	213,772	262,789	513,626,118

1999 FORECAST
TOTAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	9,169	6,199	14,708,361
1999	8,542	6,693	13,636,079
2000	8,034	6,646	12,920,322
2001	6,710	6,539	9,374,828
2002	6,228	6,523	8,704,575
2003	6,237	6,533	8,733,912
2004	6,211	6,507	8,642,576
2005	6,211	6,507	8,587,647
2006	6,218	6,514	8,599,192
2007	6,228	6,524	8,618,452
2008	6,231	6,527	8,593,986

1999 FORECAST
TOTAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	222,941	268,989	528,334,480
1999	231,483	275,682	541,970,559
2000	239,517	282,328	554,890,880
2001	246,226	288,868	564,265,709
2002	252,453	295,390	572,970,285
2003	258,689	301,922	581,704,198
2004	264,901	308,430	590,346,775
2005	271,112	314,935	598,934,422
2006	277,329	321,449	607,533,614
2007	283,557	327,973	616,152,067
2008	289,787	334,500	624,746,053

TABLE B-6

HISTORICAL
RESIDENTIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	105,333	160,983	269,326,134

1999 FORECAST
RESIDENTIAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	7,273	5,968	8,941,405
1999	6,690	6,470	8,014,087
2000	6,182	6,423	7,307,545
2001	5,842	6,316	6,775,935
2002	5,360	6,300	6,119,433
2003	5,369	6,310	6,138,547
2004	5,343	6,284	6,086,513
2005	5,343	6,284	6,085,451
2006	5,350	6,291	6,100,318
2007	5,360	6,301	6,120,495
2008	5,363	6,304	6,126,866

1999 FORECAST
RESIDENTIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	112,606	166,952	278,267,540
1999	119,296	173,422	286,281,627
2000	125,478	179,845	293,589,171
2001	131,320	186,162	300,365,107
2002	136,679	192,462	306,484,539
2003	142,048	198,771	312,623,087
2004	147,392	205,056	318,709,600
2005	152,735	211,339	324,795,051
2006	158,085	217,630	330,895,369
2007	163,445	223,931	337,015,864
2008	168,808	230,235	343,142,730

TABLE B-7

HISTORICAL
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS
AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	108,439	101,806	233,787,373

1999 FORECAST
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	1,896	231	5,539,479
1999	1,852	223	5,412,636
2000	1,852	223	5,412,636
2001	868	223	2,401,505
2002	868	223	2,401,505
2003	868	223	2,401,505
2004	868	223	2,401,505
2005	868	223	2,401,505
2006	868	223	2,401,505
2007	868	223	2,401,505
2008	868	223	2,401,505

1999 FORECAST
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	110,335	102,037	239,326,852
1999	112,187	102,260	244,739,488
2000	114,039	102,483	250,152,124
2001	114,906	102,706	252,553,629
2002	115,774	102,928	254,955,135
2003	116,641	103,151	257,356,640
2004	117,509	103,374	259,758,146
2005	118,377	103,596	262,159,651
2006	119,244	103,819	264,561,156
2007	120,112	104,042	266,962,662
2008	120,979	104,265	269,364,167

TABLE B-8

HISTORICAL
OTHER EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	0	0	10,512,611

1999 FORECAST
OTHER EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	227,477
1999	0	0	209,356
2000	0	0	200,141
2001	0	0	197,388
2002	0	0	183,637
2003	0	0	193,860
2004	0	0	154,558
2005	0	0	100,691
2006	0	0	97,369
2007	0	0	96,452
2008	0	0	65,615

1999 FORECAST
OTHER EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	10,740,088
1999	0	0	10,949,444
2000	0	0	11,149,585
2001	0	0	11,346,973
2002	0	0	11,530,611
2003	0	0	11,724,471
2004	0	0	11,879,029
2005	0	0	11,979,720
2006	0	0	12,077,089
2007	0	0	12,173,541
2008	0	0	12,239,156

TABLE B-9

HISTORICAL
TOTAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	30,156	5,733	9,178,421

1999 FORECAST
TOTAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	1,696	7,421	7,517,056
1999	21,947	29,999	16,717,295
2000	21,043	30,477	17,113,935
2001	19,233	27,962	13,613,825
2002	18,008	26,432	13,125,215
2003	17,638	25,875	13,022,430
2004	17,884	26,286	13,305,470
2005	14,111	20,879	11,273,560
2006	14,135	20,879	11,273,560
2007	11,489	16,998	9,730,260
2008	11,498	16,999	9,730,260

1999 FORECAST
TOTAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	31,852	13,154	16,695,477
1999	53,799	43,153	33,412,772
2000	74,842	73,630	50,526,707
2001	94,075	101,592	64,140,532
2002	112,083	128,024	77,265,747
2003	129,721	153,899	90,288,177
2004	147,605	180,185	103,593,647
2005	161,716	201,064	114,867,207
2006	175,851	221,943	126,140,767
2007	187,340	238,941	135,871,027
2008	198,838	255,940	145,601,287

TABLE B-10

HISTORICAL
RESIDENTIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	1,516	2,336	1,927,533

1999 FORECAST
RESIDENTIAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	3,649	5,543	2,814,366
1999	19,114	28,121	12,014,605
2000	19,410	28,599	12,411,245
2001	18,317	27,071	11,922,635
2002	17,225	25,542	11,434,025
2003	16,793	24,985	11,331,240
2004	17,026	25,396	11,614,280
2005	13,283	19,989	9,582,370
2006	13,283	19,989	9,582,370
2007	10,633	16,108	8,039,070
2008	10,632	16,109	8,039,070

1999 FORECAST
RESIDENTIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	5,165	7,879	4,741,899
1999	24,279	36,000	16,756,504
2000	43,689	64,599	29,167,749
2001	62,006	91,670	41,090,384
2002	79,231	117,212	52,524,409
2003	96,024	142,197	63,855,649
2004	113,050	167,593	75,469,929
2005	126,333	187,582	85,052,299
2006	139,616	207,571	94,634,669
2007	150,249	223,679	102,673,739
2008	160,881	239,788	110,712,809

TABLE B-11

HISTORICAL
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	28,641	3,397	7,250,888

1999 FORECAST
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	(1,954)	1,878	4,702,690
1999	2,833	1,878	4,702,690
2000	1,633	1,878	4,702,690
2001	916	891	1,691,190
2002	783	890	1,691,190
2003	845	890	1,691,190
2004	858	890	1,691,190
2005	828	890	1,691,190
2006	852	890	1,691,190
2007	856	890	1,691,190
2008	866	890	1,691,190

1999 FORECAST
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	26,687	5,275	11,953,578
1999	29,520	7,153	16,656,268
2000	31,153	9,031	21,358,958
2001	32,069	9,922	23,050,148
2002	32,852	10,812	24,741,338
2003	33,697	11,702	26,432,528
2004	34,555	12,592	28,123,718
2005	35,383	13,482	29,814,908
2006	36,235	14,372	31,506,098
2007	37,091	15,262	33,197,288
2008	37,957	16,152	34,888,478

B.1.5 RENEWABLE ENERGY

Gulf initiated implementation of a "Green Pricing" pilot program, *Solar for Schools,* to obtain funding for the installation of solar technologies in participating school facilities combined with energy conservation education of students. Initial solicitation began in September, 1996 and has resulted in participation of over 333 customers contributing $18,171 through December, 1998. A prototype installation at a local middle school has been completed and the experience gained at this site will be used to design future *Solar for Schools* installations.

District heating and cooling plants are an older fundamental application of large central station heating and cooling equipment for service to multiple premises in close proximity. These systems are typically located in college or school settings as well as some military bases and industrial plants.

Within Gulf's service area there exist a number of these systems which were appropriate or seemed appropriate at the time of their installation. Current day considerations for energy pricing, operating and maintenance expenses have resulted in many of these systems becoming uneconomical and decommissioned. Future installations of district heating and cooling plants of any consequence hinge primarily upon the opportunity for optimum application of this technology. The very dispersed construction of low rise buildings which are characteristic of the building demographics in Gulf Power's service area yield no significant opportunities for district heating and cooling that are economically viable on the planning horizon.

B.1.6 DATA SOURCES

The following data sources were utilized in the development of Gulf's projections:

1. Gulf Power Company historical billing data.
2. Gulf Power Company historical survey data.
3. Gulf Power Company historical load research data.
4. Historical weather data from NOAA and Weather Service Corp.
5. Historical data from the Florida Statistical Abstracts produced by the Bureau of Economic and Business Research, University of Florida.
6. Economic outlook including population projections, households, and other economic indicators from Regional Financial Associates. Data sources cited by RFA include the Bureau of Labor Statistics, Bureau of Economic Analysis, and the U.S. Bureau of Census.

B.1.7 DETAILED FORECAST RESULTS

The following Tables B-12 through B-17 provide the detailed forecast results.

GULF POWER COMPANY

TABLE B-12
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population *	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
1989	662,784	2.65	3,294	250,038	13,173	2,169	33,500	64,761
1990	677,866	2.66	3,361	255,129	13,173	2,218	33,957	65,305
1991	689,901	2.66	3,455	259,395	13,320	2,273	34,372	66,120
1992	703,860	2.65	3,597	265,374	13,553	2,369	36,009	65,796
1993	726,046	2.67	3,713	271,594	13,671	2,433	38,477	63,242
1994	747,459	2.69	3,752	278,215	13,486	2,549	39,989	63,739
1995	760,195	2.68	4,014	283,717	14,148	2,708	41,007	66,043
1996	769,246	2.67	4,160	287,752	14,457	2,809	42,381	66,271
1997	791,009	2.67	4,119	296,497	13,894	2,898	43,955	65,928
1998	810,649	2.66	4,438	304,413	14,577	3,112	45,510	68,379
1999	830,557	2.66	4,558	312,479	14,587	3,147	46,614	67,512
2000	849,054	2.65	4,692	320,074	14,658	3,273	48,150	67,980
2001	863,541	2.65	4,772	326,118	14,632	3,346	49,347	67,812
2002	877,537	2.64	4,864	331,931	14,653	3,419	50,294	67,977
2003	891,566	2.64	4,958	337,784	14,677	3,496	51,208	68,275
2004	905,608	2.64	5,057	343,661	14,715	3,572	52,130	68,528
2005	919,427	2.63	5,170	349,473	14,793	3,650	53,059	68,793
2006	933,241	2.63	5,272	355,302	14,839	3,725	53,978	69,012
2007	947,114	2.62	5,382	361,172	14,901	3,805	54,904	69,295
2008	960,867	2.62	5,503	367,016	14,995	3,881	55,836	69,507
CAAG								
89-98	2.3%	0.1%	3.4%	2.2%	1.1%	4.1%	3.5%	0.6%
98-03	1.9%	-0.2%	2.2%	2.1%	0.1%	2.4%	2.4%	0.0%
98-08	1.7%	-0.2%	2.2%	1.9%	0.3%	2.2%	2.1%	0.2%

* Historical and projected figures include portions of Escambia, Santa Rosa, Okaloosa, Bay, Walton, Washington, Holmes, and Jackson counties served by Gulf Power Company.

GULF POWER COMPANY

TABLE B-13

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
Year	GWH	Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Highway Lighting GWH	to Public Authorities GWH	to Ultimate Consumers GWH
1989	2,095	229	9,147,029	0	16	0	7,574
1990	2,178	247	8,817,297	0	17	0	7,774
1991	2,117	260	8,143,878	0	16	0	7,861
1992	2,179	262	8,318,456	0	16	0	8,161
1993	2,030	268	7,574,388	0	16	0	8,192
1994	1,847	280	6,596,837	0	16	0	8,164
1995	1,795	276	6,502,731	0	16	0	8,534
1996	1,808	281	6,434,470	0	17	0	8,794
1997	1,903	277	6,870,216	0	17	0	8,938
1998	1,834	263	6,971,767	0	18	0	9,401
1999	1,938	285	6,801,516	0	18	0	9,662
2000	2,029	294	6,902,869	0	18	0	10,013
2001	2,076	297	6,989,061	0	19	0	10,213
2002	2,095	300	6,982,317	0	19	0	10,396
2003	2,093	303	6,907,883	0	19	0	10,566
2004	2,091	306	6,833,259	0	19	0	10,739
2005	2,087	309	6,753,665	0	19	0	10,926
2006	2,091	312	6,703,402	0	20	0	11,108
2007	2,094	315	6,648,572	0	20	0	11,300
2008	2,071	318	6,511,389	0	20	0	11,475
CAAG							
89-98	-1.5%	1.6%	-3.0%	0.0%	1.5%	0.0%	2.4%
98-03	2.7%	2.9%	-0.2%	0.0%	1.0%	0.0%	2.4%
98-08	1.2%	1.9%	-0.7%	0.0%	0.9%	0.0%	2.0%

GULF POWER COMPANY

TABLE B-14

History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWH	(3) Utility Use & Losses GWH	(4) Net Energy for Load GWH	(5) Other Customers (Average No.)	(6) Total No. of Customers
1989	276	528	8,378	63	283,830
1990	294	545	8,612	68	289,400
1991	296	547	8,704	68	294,095
1992	299	389	8,849	74	301,719
1993	317	565	9,074	79	310,419
1994	316	487	8,967	93	318,578
1995	336	582	9,452	119	325,119
1996	347	521	9,662	157	330,571
1997	342	607	9,887	215	340,944
1998	356	645	10,402	262	350,447
1999	350	645	10,657	322	359,699
2000	361	668	11,041	352	368,870
2001	369	682	11,263	371	376,132
2002	378	694	11,468	382	382,906
2003	386	706	11,658	391	389,685
2004	393	718	11,850	400	396,496
2005	399	730	12,056	409	403,249
2006	406	743	12,257	418	410,009
2007	412	756	12,468	427	416,817
2008	418	768	12,661	436	423,605
CAAG					
89-98	2.9%	2.2%	2.4%	17.1%	2.4%
98-03	1.6%	1.8%	2.3%	8.3%	2.1%
98-08	1.6%	1.8%	2.0%	5.2%	1.9%

Note: Sales for Resale and Net Energy for Load include contracted energy allocated to certain customers by Southeastern Power Administration (SEPA).

GULF POWER COMPANY

TABLE B-15

History and Forecast of Summer Peak Demand - MW
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Conservation	Net Firm Demand
1989	1,858	60	1,799	0	0	79	0	81	1,698
1990	1,954	69	1,885	0	0	81	0	87	1,785
1991	1,923	64	1,860	0	0	83	0	92	1,748
1992	2,018	71	1,947	0	0	86	0	97	1,836
1993	2,096	76	2,021	0	0	88	0	102	1,906
1994	1,999	72	1,927	0	0	92	0	104	1,803
1995	2,265	82	2,183	0	0	96	0	122	2,048
1996	2,196	79	2,118	0	0	100	0	127	1,969
1997	2,284	75	2,208	0	0	107	0	137	2,040
1998	2,425	82	2,342	16	0	118	0	137	2,154
1999	2,460	76	2,385	29	0	144	0	142	2,175
2000	2,521	77	2,445	29	0	169	0	145	2,207
2001	2,574	78	2,496	29	0	193	0	147	2,234
2002	2,630	80	2,549	29	0	216	0	149	2,265
2003	2,668	81	2,587	29	0	238	0	150	2,280
2004	2,722	83	2,639	29	0	260	0	152	2,309
2005	2,780	84	2,696	29	0	279	0	154	2,347
2006	2,836	85	2,751	29	0	298	0	155	2,383
2007	2,896	87	2,809	29	0	314	0	157	2,425
2008	2,955	88	2,867	25	0	330	0	159	2,466
CAAG									
89-98	3.0%	3.6%	3.0%	100.0%	0.0%	4.6%	0.0%	6.0%	2.7%
98-03	1.9%	-0.2%	2.0%	12.7%	0.0%	15.1%	0.0%	1.9%	1.1%
98-08	2.0%	0.7%	2.0%	4.5%	0.0%	10.8%	0.0%	1.5%	1.4%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-16
History and Forecast of Winter Peak Demand - MW
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Conservation	(10) Net Firm Demand
88-89	1,762	56	1,706	0	0	113	0	95	1,554
89-90	2,038	57	1,980	0	0	120	0	97	1,821
90-91	1,649	50	1,600	0	0	126	0	98	1,425
91-92	1,772	60	1,712	0	0	132	0	99	1,541
92-93	1,820	61	1,759	0	0	140	0	100	1,579
93-94	2,055	72	1,983	0	0	145	0	101	1,809
94-95	1,993	71	1,922	0	0	150	0	102	1,740
95-96	2,404	82	2,322	0	0	157	0	103	2,144
96-97	2,208	80	2,127	0	0	163	0	105	1,939
97-98	1,974	61	1,913	0	0	175	0	107	1,692
98-99	2,390	76	2,314	28	0	209	0	109	2,071
99-00	2,461	77	2,384	28	0	244	0	112	2,105
00-01	2,511	78	2,433	28	0	278	0	113	2,121
01-02	2,558	80	2,478	28	0	310	0	114	2,135
02-03	2,595	81	2,513	28	0	341	0	115	2,139
03-04	2,643	83	2,560	28	0	373	0	116	2,154
04-05	2,694	84	2,610	28	0	399	0	117	2,178
05-06	2,743	85	2,658	28	0	425	0	118	2,200
06-07	2,796	87	2,709	28	0	448	0	119	2,229
07-08	2,848	88	2,760	24	0	470	0	120	2,258
CAAG									
89-98	1.3%	1.0%	1.3%	100.0%	0.0%	5.0%	0.0%	1.3%	0.9%
98-03	5.6%	5.8%	5.6%	0.0%	0.0%	14.3%	0.0%	1.4%	4.8%
98-08	3.7%	3.7%	3.7%	-1.7%	0.0%	10.4%	0.0%	1.2%	2.9%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-17
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1989	8,763	221	165	7,574	276	528	8,378	56.3%
1990	9,019	227	180	7,774	294	545	8,612	55.1%
1991	9,128	233	191	7,861	296	547	8,704	56.8%
1992	9,291	239	202	8,161	299	389	8,849	54.9%
1993	9,537	247	216	8,192	317	565	9,074	54.3%
1994	9,443	254	222	8,164	316	487	8,967	56.8%
1995	9,942	263	227	8,534	336	582	9,452	52.7%
1996	10,167	273	232	8,794	347	521	9,662	55.9%
1997	10,410	282	241	8,938	342	607	9,887	55.3%
1998	10,947	294	251	9,401	356	645	10,402	55.1%
1999	11,232	314	261	9,662	350	645	10,657	55.9%
2000	11,647	334	272	10,013	361	668	11,041	57.1%
2001	11,891	353	276	10,213	369	682	11,263	57.6%
2002	12,119	371	280	10,396	378	694	11,468	57.8%
2003	12,330	388	284	10,566	386	706	11,658	58.4%
2004	12,544	406	288	10,739	393	718	11,850	58.6%
2005	12,769	422	292	10,926	399	730	12,056	58.6%
2006	12,991	438	296	11,108	406	743	12,257	58.7%
2007	13,220	452	300	11,300	412	756	12,468	58.7%
2008	13,431	466	304	11,475	418	768	12,661	58.6%
CAAG								
89-98	2.5%	3.2%	4.8%	2.4%	2.9%	2.2%	2.4%	-0.2%
98-03	2.4%	5.7%	2.5%	2.4%	1.6%	1.8%	2.3%	1.1%
98-08	2.1%	4.7%	1.9%	2.0%	1.6%	1.8%	2.0%	0.6%

NOTE: Wholesale and total columns include contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA).

C. Technology Screening Process

TECHNOLOGY SCREENING PROCESS

Preparation of the Southern electric system (SES) Integrated Resource Plan (IRP) requires the identification of a manageable number of generating unit alternatives to be evaluated in the generation mix analysis. For each candidate technology, inputs must be developed for the option's conceptual capital cost, design configuration, reliability data, and operation and maintenance costs. It is important to note that the information developed is not site-specific and is intended to be representative of average cost and performance data for a "generic" site.

The technology screening begins with a preliminary review of both mature and emerging technologies to identify those that are potentially suitable for installation on the SES during the planning horizon. Three technologies which had been evaluated in prior years were deleted from the list developed for the 1998 IRP. These were the intermediate load cycling coal fired, intermediate load compressed air energy storage (CAES), and peaking compressed air energy storage technologies. However, three new technologies were added, including inlet cooled combined cycle using ATS, air blown integrated gasification combined cycle (IGCC), and the topping pressurized circulating fluidized bed (PCFB). The following technologies were included for consideration in the screening process:

1. Base Load Pulverized Coal
1. Base Load Integrated Gasification Combined Cycle (IGCC)
3. Base Load Pressurized Fluidized-Bed Combustion (PCFB)
4. Base Load Combined Cycle, 'F' - Technology
5. Base Load Combined Cycle, 'G' - Technology
6. Intermediate Load Low Heat Rate 'G' Type CT
7. Peaking Combustion Turbine (3-Unit and 6-Unit Sites)
8. Pumped Storage Hydro (PSH)
9. Inlet Cooled Combined Cycle With ATS Technology

In addition to a general plant description and major performance assumptions, the following information was developed for each technology under consideration:

- Heat Rate and Output
- Capital Cost
- Fixed and Variable O&M Cost
- Capital Expenditures for Maintenance
- Emissions Estimates
- Plant Life
- Maintenance Time
- Equivalent Forced Outage Rate (EFOR)
- Performance Degradation
- Project Schedule
- Cash flow Table

Certain information regarding project schedule, performance degradation, emissions, EFOR and cash flow was not available for all of the technologies.

There are four categories of cost estimates. These include very conceptual, conceptual, budgetary and definitive. Below is a definition of each cost category:

Very Conceptual - The cost is as conceptual as the technology. As these technologies are developed, the costs will become more refined.

Conceptual - The technology is being developed. However, the first units have not been produced. Estimates are supplied by researchers, vendors, and governmental agencies. As these technologies are developed, the costs will become more refined.

Budgetary - This is a mature technology. There are actual costs of existing plants. The vendors offer market driven pricing and/or Southern Company Services has developed cost models.

Definitive - None of the cost information used in the technology screening process is definitive. Definitive estimates are within 5% of the final cost and are based on specific site and owner requirements. Definitive estimates are based on definitive scopes.

The cost models developed for matur‹
prior years are reviewed for consistency
information from ongoing projects. All ‹
dollars are based on values as of Januar
escalation factor of 2% was applied for
technologies, except that the base load
not escalated and IGCC was escalated at
cycle and simple cycle cost models were
and updated given the probability that t
would be chosen for near term capacity a
budgetary estimates were obtained from t
lowest cost was incorporated in the cost
contingency was held to 2.5% for major e
the balance of plant to reflect the actı
estimate. In case of coal technologies
held to 5% for major equipment and 10%
plant.

All cost models were separated intc
Procurement and Construction (EPC), site
costs. EPC cost is equivalent in scope t
contractor would quote for the project.
the design engineering, procurement of
equipment, and the contractor's scope.
land, site preparation, water treatment
and site related engineering. Owner's
and construction management, startup, a

Project schedules were developed for the new additions. Schedules for the remaining technologies were reviewed, but were not changed from the prior year. It should be noted that actual project schedules would vary based on the unique requirements of the project. Construction spending curves were expressed in percentages instead of dollar amounts to allow the flexibility to use either the EPC cost or total plant cost. Non-recoverable turbine degradation in output and heat rate was included for each technology in the technology documentation.

The nine listed technologies were reviewed and screened for reasonableness to select the final candidate technologies to be included in the generation mix process. Some technologies are eliminated when they are evaluated on an economic bus-bar analysis. The bus-bar evaluation estimates the relative cost per kilowatt-hour for the various alternatives at varying capacity factors. After this screening was completed, the following three technologies were retained as candidates for the generation mix analysis: (1) nominal 670 MW pulverized coal unit, (2) nominal 500 MW F-class combined cycle unit, and (3) simple cycle combustion turbine unit. More detailed information on these three candidate technologies is provided below.

PULVERIZED COAL
NOMINAL 670 MW

I. GENERAL DESCRIPTION OF THE PLANT

The major systems in the unit are based on a coal fired drum boiler operating at 2,400 psig, 1,000 deg. F. main steam temperature with a reheat temperature of 1,000 deg. F., driving a 3,600 rpm turbine-generator. Steam is condensed using circulating water that is cooled by hyperbolic natural draft cooling towers. The condensate/feedwater system utilizes four LP, three HP and one deaerating feedwater heater. A wet limestone scrubber with forced oxidation, designed for 95 % removal, is utilized for S02 reduction. Advanced low NOx burners as well as a selective catalytic reduction system, designed for 80% removal, are utilized for NOx control. A dry ash handling system is utilized for fly ash. Bottom ash is handled using hydrobins, a settling tank, and a clarifier. Both fly ash and bottom ash are either trucked away to landfill or sold.

State of Technology

This is a mature technology and currently available.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

		Net Heat Rate (Based on HHV) Btu/kWh	Net Unit Output kW
a.	Peaking Condition (kW) (DB = 95° F; WB = 76° F)		
	Rated	9,455	661,205
b.	Annual Average (kW) (DB = 64.4° F; WB = 58° F)		
	Rated	9,289	672,961
	75%	9,481	506,015
	50%	9,800	341,545

Basis for Heat Rate Data:

- ABB Turbine - Generator
- 8 Feedwater Heaters
- Wet Limestone Scrubber with Forced Oxidation
- Selective Catalytic Reduction System
- 2,400 psig/1,000° F/1,000° F Cycle
- 1 % Make-up and Blow-down
- Average System Weather Conditions Calculated Based on Wet and Dry Bulb Temperature Near Macon, GA.

III. PLANT COSTS

(with 5% contingency on major equipment and 10% on balance of plant)	Per Kilowatt *	Total
EPC	$ 840	$555,412,000
Site	$ 39	$ 25,725,000
Owner's	$ 53	$ 34,940,000

Scope of supply on the output side extends through the switchyard to the first breaker and disconnect. Plant costs are overnight costs as of 1/1/97. This is a budget grade estimate.

* Based on the peaking rating

IV.	FIXED 0 & M COSTS (Based on the Peaking Rating)	
	$/kW-Yr	9.92
	Total	$ 6,560,000
V.	VARIABLE 0 & M COSTS (Based on the Annual Average Rating and a 65% Capacity Factor)	
	Mills/KWH	1.65
	- Total -	$6,335,000
VI.	PLANT LIFE (yrs)	45
VII.	MAINTENANCE TIME (weeks/yr)	4
VIII.	EQUIVALENT FORCED OUTAGE RATE	6.5
IX.	EXPENDITURE DATA AVAILABLE?	Yes
X.	PROJECT SCHEDULE AVAILABLE?	Yes
XI.	EXPECTED PLANT DEGRADATION -OUTPUT	2.04%
	HEAT RATE	2.04%
XII.	CAPITAL EXPENDITURE FOR MAINTENANCE ($/kW-yr)	0.47

COMBINED CYCLE -'F'
NOMINAL 500 MW

I. GENERAL DESCRIPTION OF THE PLANT

The base load combined cycle unit is a nominally rated 500 MW plant based on a power cycle utilizing two (2) nominal 170 MW advanced design industrial combustion turbine-generators with evaporative coolers, two natural circulation triple pressure heat recovery steam generators (HRSGs) with reheat sections and integral deaerators, a single condensing reheat steam turbine, a steam condenser with a mechanical draft cooling tower system for condenser cooling and associated support systems. The combustion turbines will be housed in an individual weather-proofed outdoor enclosure which includes insulation for sound attenuation and thermal protection.

State of Technology

This technology is currently available.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/KWH	Net Unit Output kW
a. Peaking Condition (kW) (DB = 95° F; WB = 76° F)		
Rated	7,178	521,000

b. Annual Average (kW)
(DB = 64.4° F; WB = 58° F)

Rated	6,860	517,000

Basis for Heat Rate Data:

- (2) GE 7FA's with reheat steam turbine 1,815 psig/1,050° F/1,050° F
- Average annual based on dry low NOx control to 9 ppm
- Evaporative cooler in use at 95° F
- 4.5" inlet / 12.0" exhaust loss on CT (at 64° F. design point)
- 2.0% station service
- 304 ft. site elevation
- Natural gas fuel (assume natural gas compressor not required)
- Corresponding relative humidities are 67% at 64 degrees F. dry bulb and 43% at 95 degrees F. dry bulb temperatures
- Peak rating based on 2/1 steam to fuel injection ratio for power augmentation

III. TOTAL PLANT COST

1 UNIT:

	Per Kilowatt *	Total
EPC	$ 338	$176,211,000
Site	$ 19	$9,682,000
Owner's	$ 11	$5,987,000

2 UNITS:

EPC	$ 325	$338,352,000
Site	$ 17	$18,088,000
Owner's	$ 11	$11,513,000

Capital cost for gas pipeline is not included. Scope of supply on the output side extends through the switchyard to the first breaker and disconnect. The plant costs are overnight costs as of 1/1/97. This is a budget grade estimate.

* Based on the peaking rating

IV. FIXED O & M COSTS
(Based on the Peaking Rating)

1 UNIT:	$/kW-Yr	3.66
	Total	$1,908,000
2 UNITS:	$/kW-Yr	2.46
	Total	$2,561,000

V. VARIABLE O & M COSTS
(Based on the Annual Average Rating and a 65% Capacity Factor)

1 UNIT:	Mills/KWH	1.68
	Total	$4,934,000
2 UNITS:	Mills/KWH	1.56
	Total	$9,209,000

VI. PLANT LIFE (yrs)	40
VII. MAINTENANCE TIME (weeks/yr)	3.0
VIII. EQUIV. FORCED OUTAGE RATE	3.44%
IX. EXPENDITURE DATA AVAILABLE?	Yes

X.	PROJECT SCHEDULE AVAILABLE?	Yes
XI.	EXPECTED PLANT DEGRADATION -OUTPUT HEAT RATE	5.89% 2.64%
XII.	CAPITAL EXPENDITURE FOR MAINTENANCE (S/kW-yr)	1.15

SIMPLE CYCLE COMBUSTION TURBINE
NOMINAL 350 MW

I. GENERAL DESCRIEPTION OF THE PLANT

The combustion turbine plant model consists of current generation state-of-the-art, heavy duty industrial Westinghouse 501D5A nominal 120 MW units with evaporative cooler. These units utilize firing temperatures in the range of 1,950°-2,200° F. Extensive factory modularization of systems and components results in low costs for peaking applications. The plant utilizes natural gas as the primary fuel with No. 2 distillate as the back-up fuel. NOx is controlled to 25 ppm on the primary fuel through the use of water injection. The simple cycle combustion turbine plant design is based on siting three (3) nominal 120 MW simple cycle combustion turbines at one plant site.

State of Technology

This peaking plant will utilize mature technology that is commercially available at the present time.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/KWH	Net Unit Output kW
Peaking Condition (kW) (DB = 95 Deg. F; WP = 76 Deg. F)		
Maximum Load:	11,728	364,770

Basis for Heat Rate Data:

- Natural Gas Fuel
- 95° F Dry Bulb Ambient Temperature
- 43% Relative Humidity
- Altitude is 304 Feet Above Sea Level
- Water Injection to Meet 25 ppm NOx For Natural Gas
- 4.5" Inlet Pressure Loss
- 5" Exhaust Pressure Loss
- Performance at Base Combustor Firing Temperature
- Evaporative Cooler with 85% Effectiveness

III. TOTAL PLANT COST
(with 2.5% CT contingency and 10% for balance of plant)

	Per Kilowatt	Total
One site with three (3) Nominal 120 MW CTs		
EPC Cost	198	$ 72,330,000
Site Cost	13	$ 4,674,000
Owner's Cost	11	$ 3,860,000

Capital cost for gas pipeline is not included. Scope of supply on the output side extends to the high side of the generator step-up transformer. Plant costs are overnight costs as of 1/1/97. This is a budgetary grade estimate.

IV. FIXED O & M COSTS
(Based on the Peaking Rating)

$/kW-Yr	2.64
Total	$ 962,000

V. VARIABLE O & M COSTS
(Based on the Peaking Rating and 300 hrs/year)

Mills/KWH	2.68
Total	$ 293,000

VI. PLANT LIFE (yrs)	40
VII. MAINTENANCE TIME (weeks/yr)	2.6
VIII. EQUIV. FORCED OUTAGE RATE (For periods of demand only)	3.0%
IX. EXPENDITURE DATA AVAILABLE?	Yes
X. PROJECT SCHEDULE AVAILABLE?	Yes
XI. AMBIENT TEMP. VS. CT OUTPUT AVAILABLE?	Yes
XII. EXPECTED PLANT DEGRADATION - OUTPUT	3.13%
HEAT RATE	1.85%
XIII. CAPITAL EXPENDITURE FOR MAINTENANCE ($/KW-YR)	0.30

D. The Existing Smith
Generation Site

LANSING SMITH GENERATING PLANT

The existing Lansing Smith Generating Plant is located on Alligator Bayou, which lies between North and West Bays north of Panama City in Bay County, Florida. The plant site consists of a total of 1,340 acres, of which only 400 acres are currently in utility use. This site has been used as an electric generation facility since June of 1965. When this site was originally purchased, it was intended to support eight coal-fired steam turbine/generating units, but because of changing conditions, only two fossil steam units and a combustion turbine are currently in service.

Smith Unit No. 1, a coal-fired steam unit with a net generating capability of 162,000 kilowatts, went into service in June, 1965. This unit is comprised of a Combustion Engineering boiler and a Westinghouse 3,600 rpm turbine/generator set. The boiler generates steam with a main steam pressure of 1,800 psig and a superheat/reheat steam temperature of 1,000/1,000 degrees Fahrenheit. Smith Unit No. 1 uses once-through salt water for its condenser cooling and a Buell Envirotech hot-side precipitator for particulate removal. This unit is a Clean Air Act (CAA) Phase II affected unit and currently burns a 1% domestic coal.

Smith Unit No. 2, a coal-fired steam unit with a net generating capability of 192,600 kilowatts, went into service in June, 1967. This unit is comprised of a

Combustion Engineering boiler and a Westinghouse 3,600 rpm turbine/generator set. The boiler generates steam with a main steam pressure of 1,800 psig and a superheat/reheat steam temperature of 1,000/1,000 degrees Fahrenheit. Smith Unit No. 2 uses once-through salt water for its condenser cooling and a Buell Envirotech hot-side precipitator for particulate removal. This unit is a CAA Phase II affected unit and currently burns a 1% domestic coal and has low-NOx burners to reduce nitrous-oxide emissions.

Smith Unit A is a Pratt & Whitney, aero-derivative combustion turbine with a net capability of 31,600 kilowatts and went into service in May of 1971. This combustion turbine unit is fueled with No. 2 fuel oil with a storage capacity of 750,000 gallons. Smith Unit A is used exclusively for peaking type service and is the only Gulf Power Company unit that is black-start capable.

The coal for Units No. 1 and No. 2 is brought into the plant by barge and unloaded by a derrick crane located on the Alligator Bayou canal. The coal stockpile at the plant typically maintains a level of approximately 30 days of combined unit nameplate ratings. Currently, there are no natural gas facilities available at the plant for generating unit consumption.

Electrically, the power generated by the plant's units is transmitted to the load centers via three 115 KV and four 230 kV transmission lines. The installation of Gulf's planned 540 MW combined cycle unit will not necessitate any transmission system upgrades or new facilities.

Because of the site's original plan to have eight fossil steam units, there are many suitable acres for future unit expansion such as that currently planned by Gulf with its installation of Smith Unit 3. The undeveloped land on this site is mostly planted with pine trees.

E. Gulf Power's Request For Proposals

990325-EI

APPENDIX E

The Gulf Power Company Request for Proposals (RFP) follows and appears in its original state as issued.

August 21, 1998

Mr. Generic M. Respondent
The Company Name
The Company Address
City, State ZIPCODE

RE: Request for Proposals

Dear Mr. Respondent:

Gulf Power Company has determined that it will need additional firm capacity starting as early as the summer of 2002. The Company is seeking proposals for power supply from eligible Respondents to meet the Company's requirements for electric generation capacity as described in this Request For Proposal (RFP). Location, price, and reliability of the power offered will be major factors in the purchase decision. Creative supply side electric generation alternatives that provide exceptional value and economic benefits to Gulf Power and its customers will be appropriately considered in the proposal evaluations. The attached RFP document details the requirements and specifications that Respondents should meet and also outlines the information that should be provided in a proposal.

Respondents interested in submitting proposals under this solicitation should provide six completed copies and one original of the enclosed forms in both hardcopy and electronic format (3.5" floppy diskette). Any additional information that the Respondent deems necessary to evaluate the offer should be included along with the forms. All proposals must be received no later than 5:00 p.m., on Friday, October 16, 1998 at the following address:

Director, Bulk Power Supply, 15N-8181
Southern Company Services, Inc.
600 N. 18th Street
Birmingham, AL 35203
Phone: (404) 506-7250

Any portions of offers to be treated as confidential must be so identified.

Thank you for your interest in meeting the Company's power supply needs during this period.

Sincerely,

Garey C. Rozier
Director, Bulk Power Supply

REQUEST FOR PROPOSALS
August 21, 1998

Southern Company Services, Inc. (Southern), acting as agent for Gulf Power Company (The Company, or Gulf Power), issues this request for proposals (RFP) to acquire approximately 350-500 megawatts (MW) of supply-side resources beginning in the summer of 2002. The Company invites innovative proposals of various types of electric generation, including those representing base-load, intermediate, and peaking resources. Offers proposing new electric generating facilities located near Panama City, Florida will have a transmission cost advantage.

For purposes of this solicitation, the Company is interested in long term proposals lasting at least five years. In addition to "summer only" and "year round" offers, proposals reflecting various contract periods for the same resource will be considered. The Company is particularly interested in proposals that will offer exceptional value to the Company and its customers. Respondents are encouraged to be creative in crafting offers that will meet the Company's needs.

Proposals submitted pursuant to this solicitation will be considered and evaluated against each other and against any self-build options. Transmission and ancillary service studies will be conducted as appropriate to determine the total cost impacts. A short list will then be developed reflecting those Respondents whose proposals appear to demonstrate the most value (not necessarily the lowest price). Any Respondents so selected will be contacted for negotiations that may lead to a mutually-agreeable power purchase agreement. The Company naturally reserves the right to revise the capacity needs forecast at any point during the process or negotiations; any such change may reduce, eliminate, or increase the amount of power sought.

Respondents are asked to define the firmness of the capacity offered in their proposal in one of the following categories:

- Level A: "First Call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
- Level B: System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
- Level C: Capacity that is backed by the Respondent's purchase(s).
- Level D: "Financially firm" (replacement cost with no liquidated damages)
- Level E: No specified generation resources

To help defray the cost for performing the evaluation of each proposal, Respondents are required to submit a check for $8,000.00 for each proposal. Changes in the site, output, electrical characteristics (generator ratings), or technology changes (i.e. simple cycle, combined cycle, cogen, primary fuel) will require the submission of a separate proposal and payment of the fee. A change in financial terms is not considered a proposal change.

The Company reserves the right, without qualification and at its sole discretion, to reject any, all, or portions of the proposals received for any creditable reason or for failure to meet any criteria, and further reserves the right without qualification and at its sole discretion to decline to enter into a power purchase arrangement with any Respondent. Respondents should be aware, that the following (if submitted) will be classified as non-responsive and will not be considered or evaluated:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- proposals offering capacity and/or energy that is generated by facilities owned by the operating companies of the Southern Company;
- proposals involving resources that would result in increasing demand on resources owned by the operating companies of the Southern Company; or
- incomplete, or non-specific offers.

Those who submit proposals do so without recourse against the Southern Company or any of its affiliates or subsidiaries for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	August 21, 1998	
Proposals due	October 16, 1998	Proposals must be received or hand delivered to Southern's RFP Contact by 5:00 PM
Short-list determination	December 11, 1998	If applicable
Complete negotiations	March 1, 1999	If applicable
File contract(s) for certification with state public service commission	March 31, 1999	If applicable

The Company reserves the right to revise, suspend, or terminate this schedule at their sole discretion. Any changes to the schedule will be provided as appropriate.

RFP Contact

Proposals and questions should be submitted to Southern's RFP Contact:

Garey C. Rozier
Director, Bulk Power Supply, 15N-8181
Southern Company Services, Inc.
600 N. 18th Street
Birmingham, AL 35203
Phone: (404) 506-7250

Instructions for Completing Forms

1. All proposals should be submitted in the format shown in the RFP response form Attachment A. Additional information should be supplied (no particular format required) from the appropriate sections of Attachment B. Respondents should supply any additional information not included in these forms if such information may be needed for a thorough understanding and/or evaluation of the proposal.

2. Proposals must be signed by an officer of the Respondent.

3. A signed original and six (6) copies of the proposal forms and Respondent Questionnaire response should be submitted along with the electronic forms on a 3.5" floppy diskette. In the event of a discrepancy between the electronic forms and the hardcopy, the latter will be considered to be correct.

4. Prices and dollar figures quoted must be clearly stated as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.

5. Energy prices must be quoted as indicated in the forms as either $/MW-hour or as heat rates to be applied to the designated published fuel index. The fuel index preferred (but not required) is the Henry Hub, as published in *Gas Daily*. Fuel transportation costs and any adjustments for energy pricing must be included in all prices.

Confidentiality

The Company will take reasonable precautions and use reasonable efforts to protect any proprietary and/or confidential information contained in an offer provided that such information is clearly identified by the Respondent as proprietary and confidential on the page on which it appears. Such information may, however, be made available under applicable state and/or federal law to regulatory commission(s), their staff(s) or other governmental agencies having an interest in these matters. The Company reserves the right to release such information to agents or contractors for the purpose of evaluating the Respondent's proposals, but such agents or contractors will be required to observe the same care with respect to disclosure as Gulf Power and Southern. Under no circumstances will the Southern Company, its subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure before, during, or after the solicitation process.

Transmission Information and Requirements

1. If power is to be provided from resources outside the Southern control area, Respondents must provide a transmission map that shows the expected contract path(s) to be used to deliver power to the Southern Company transmission system. Additionally, the map should show any site-specific electric generation resource, together with a list of control areas to be crossed. For information concerning the

Southern Company transmission systems such as: availability data on specific transmission routes, existing constraints, and interconnection points, Respondents should contact:

John E. Lucas, Manager Transmission Services
Southern Company Services, Inc.
Post Office Box 2625
Birmingham, AL 35202

2. Respondents are responsible for paying all charges and/or costs for delivering power to the Southern Company transmission system. Respondents are to include in their quotes any and all such charges.

3. The costs of any transmission upgrades to the Southern Company transmission system associated with the proposal will be considered in the evaluation. The Company will conduct transmission impact studies, as appropriate, to determine these costs. It should be noted that proposals for new electric generating facilities located near Panama City, Florida will have a significant transmission cost advantage.

4. For new facilities, Respondents are responsible for all costs related to interconnection of the facility to the Southern Company transmission network. Respondents should include all costs associated with a generator step-up transformer and synchronization to the transmission network using a Respondent supplied generator breaker. Interface between the Respondent and the company will be the high side of the Respondent supplied generator step-up transformer.

Regulatory Provisions

1. It shall be the complete and sole responsibility of the Respondent to take all necessary actions to satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on Respondent by any federal, state, or local law concerning the generation, sale and/or delivery of the power. The Company will cooperate with the Respondent to provide information or such other assistance, as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise provide such information to the Company.

2. The Respondent shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale and/or delivery of power.

3. The proposal is subject to approval and/or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation (including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission).

4. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:

   > Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

5. The Company's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW to be located in the Panama City, Bay County, Florida area. For a more detailed description of this planned unit, refer to Attachment C.

Performance Assurances

The Company will rely, in part, on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement. Performance guarantees and financial credit assurances may also be required of the Respondents, subject to negotiation, at the Company's discretion.

Minimum Requirements for Proposals

Proposals that meet these requirements will be considered responsive to this RFP. Non-responsiveness is a basis for rejecting an offer in the Company's sole discretion.

1. All forms, including both hardcopy and electronic versions, must be properly completed and returned to the RFP Contact, Garey C. Rozier, no later than 5:00 p.m. on Friday, October 16, 1998. Late or incomplete offers may be rejected in the sole discretion of the Company. Offers must remain open until at least March 31, 1999.

2. Complete information is needed to facilitate a timely evaluation. Issues that the Respondent prefers to negotiate later may be identified in the response; however, the Respondent must provide all explicit data requested on the forms. The Company may, at is sole discretion and judgment, choose to reject non-specific offers from further consideration.

3. Capacity offered must be firm. Proposals must clearly identify the firmness of the resource by the levels outlined in Attachment B. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources may not be evaluated or considered.

4. Capacity offered will have the most value if fully dispatchable and available for first-call by the Southern Company system 24 hours per day and 7 days per week for the contracted period. Acceptable availability of the power when called for will be negotiated, with higher availability rates being preferred.

5. Proposal prices must include all costs that the Company will be expected to pay for the capacity and energy proposed. Attempts by the Respondent to increase prices will be grounds for rejection of the proposal.

6. No proposal less than 50 MW will be considered acceptable.

Proposal Evaluation

1. Proposals that are considered to be adequately responsive to the requirements of this RFP will be ranked and screened on price to eliminate those that are clearly not competitive before detailed modeling is performed. The majority of the evaluation will focus on price consideration. However, qualitative and non-price attributes will be considered in the overall screening process.

2. Proposals that pass the preliminary responsiveness screens will be further evaluated using appropriate production costing methods and models so that all reasonable cost impacts can be quantified.
   a.) Preference will be given to proposals that offer shorter unit commitment notification and greater dispatch flexibility.
   b.) Preference will be given to proposals that offer more contract flexibility features, such as call/put options, early-out provisions, and variable term pricing. The Respondent must separately identify any additional costs associated with these features.
   c.) It is the Respondent's responsibility to submit additional information related to the proposal if such information will materially improve the quality of its offer or the Company's understanding thereof.

3. An appropriate selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will be evaluated against each other and with any self-build options before the Company makes any commitments regarding the resource(s) to meet its identified needs.

4. The Company reserves the right to contact Respondents to request additional information on any aspect of any proposal.

Attachment A

Respondent's Company Name		
Maximum Capacity (MW)		
Minimum Capacity (MW)		
Proposal Start Month		
Proposal Start Year	2002	
Proposal End Month		
Proposal End Year		
Firmness Level		Enter Level A,B,C,D, or E (see RFP for Level descriptions)

Option Information if Applicable	
Option Premium Price ($/kW-month)	
Option Strike Price ($/kW-month)	
Option Strike Date	

Annual / Monthly	2002	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	2003	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	2004	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	2005	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	2006	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Attachment B
Respondent Questionnaire

All Respondents, as appropriate, must supply the following information:

1) Please provide documentation of your company's previous experience providing the proposed product.

2) Please provide the following financial and credit information for your company and for your parent company (if applicable):
   - Annual reports and Form 10-K for the past three years. If these documents are not available, then audited financial statements for the last three years will be accepted
   - Dunn and Bradstreet identification number
   - Credit rating of the Respondent's senior debt securities
   - Any additional documentation needed to allow the Company to determine the Respondent's financial strength and/or the strength of any corporate parents.

1) Present a detailed description of any security/credit instruments proposed by the Respondent to back its performance obligation.

2) Please describe whether or not this capacity has been offered in another RFP and under what conditions it would be released to serve this proposed sale.

3) Please describe the firmness category that best describes your offer and provide documentation that supports your ranking:
   Level A: "First call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
   Level B: System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
   Level C: Capacity that is backed by the Respondent's purchase(s).
   Level D: "Financially firm" (replacement cost with no liquidated damages)
   Level E: No specified generation resources

4) For a Level A proposal involving a specific unit, please provide the following information:
   A. Unit name, location, and schedule for construction (if applicable)
   B. Monthly Unit ratings
   C. Electrical Data as required in performing load flow and stability studies
   D. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation.)
   E. Fuel type and source (primary and secondary) and heat rate (applicable if pricing is not quoted as a firm energy price)
   F. Guaranteed availability
   G. Maximum and minimum operating level
   H. Minimum run time per dispatch call
   I. Minimum contract quantity (energy) per year (summer and winter)
   J. Minimum down time
   K. Start up time from cold start and from hot start

L. Will the unit qualify for quick start capability? (less than 10 minutes)
M. Start up costs from cold start and from hot start
N. Descriptions (including models and manufacturers) of all of the major components
O. A detailed description of the fuel and water supplies
P. A thorough description of anticipated environmental impact and compliance.

1) For a Level A, B, or C system sale and other sales, please provide the following information:
   A. A description of the system from which the power will be provided, including the name, location, peak hour load, the installed capacity, capacity mix and reserve projections (with and without the proposed capacity sale) during the proposal period.
   B. An explanation of any criteria under which the supply of system power might be curtailed or interrupted and the priority of this proposed transaction relative to all other supply commitments (existing and future) of the Respondent.
   C. For a Level A system sale, the proposed supply commitment is assumed to be at least as firm as the Respondent's service to its own native load. Please confirm this assumption. If this is not correct, please explain.
   D. For a Level B system sale, please provide evidence of capacity available above Respondent's existing load commitments. (i.e., Current IRP documentation)
   E. For a Level B or C system sale, please provide methodology by which the Respondent will ensure that sufficient capacity will be available to support the proposed sale.

1) Please describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the Southern Company transmission network. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.

2) Please describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.

3) Please explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the purchase after it has been scheduled.)

4) Please describe any dispatch notice or scheduling requirements for this offer.

5) Please describe any minimum requirement for the numbers of consecutive dispatch hours or a minimum energy take for the contract term?

6) Please describe any other limitations on the use or availability of the power.

Attachment C – Planned Unit Data

These following data represent generic technology assessment estimates which Gulf Power utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on the Company's existing Lansing T. Smith Electric Generating Plant property in Bay County, Florida.

2. Planned Size 532 MW

3. Commercial Operation of the facility is proposed to be June 1, 2002.

4. The primary fuel is natural gas. No secondary fuel source is anticipated.

5. The estimated total direct cost is $265,768,000 (installed 2002$).

6. The estimated annual levelized revenue requirement is $36,912,000 over 20 years.

7. The estimated annual value of deferral of this unit is $55.25/kW-yr (98$).

8. The estimated annual fixed O & M is $1,458,000(98$). The estimated variable O & M is $1.85/MWH(98$).

9. The estimated delivered fuel cost is $ 2.42/MMBtu (98$).

10. The following are estimates for:

Planned outage rate	5.8 %
Forced outage rate	3.2 %
Heat rate	6,527 Btu/KWH
Minimum load	284 MW
Ramp Rate	1 Hr. (Hot); 4 Hrs. (cold)

11. The estimated transmission interconnection costs associated with this unit are $ 15 million. This unit will also have an estimated $90 million dollars of gas lateral pipeline costs.

12. Air and water discharge permits will be required for this unit. It is the Company's plan to comply with all air and water quality standards of both the State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.062 % per year
General escalation:	3.062 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.68 %
	10 % preferred @ 7.73 %
	45 % equity @ 13.5 %