

REVIEW OF ELECTRIC UTILITY 2001 TEN-YEAR SITE PLANS

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FLORIDA PUBLIC SERVICE COMMISSION

Division of Safety and Electric Reliability

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1.0 INTRODUCTION

1.1 STATUTORY AUTHORITY

Section 186.801, Florida Statutes, requires that all major generating electric utilities in Florida submit a *Ten-Year Site Plan* to the Florida Public Service Commission (Commission) for review. Each *Ten-Year Site Plan* contains projections of the utility's electric power needs for the next ten years and the general location of proposed power plant sites and major transmission facilities.

In accordance with Section 186.801, Florida Statutes, the Commission performs a preliminary study of each *Ten-Year Site Plan* and must determine whether it is "**suitable**" or "**unsuitable**." The Commission considers the comments of local and state planning agencies regarding various issues of concern. Upon completion and approval, the *Ten-Year Site Plan* review is forwarded to the Florida Department of Environmental Protection (DEP). Section 186.801, Florida Statutes, specifies the criteria to be used by the Commission in its review. These criteria are summarized in Table 1.

To fulfill the requirements of Section 186.801, Florida Statutes, the Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code. Rule 25-22.071, Florida Administrative Code, requires the *Ten-Year Site Plan* to be submitted annually by April 1. However, utilities whose existing generating capacity is less than 250 megawatts (MW) are exempt from this requirement unless the utility plans to build a new generating unit larger than 75 MW.

The *Ten-Year Site Plan* review contained herein also fulfills an additional statutory requirement. Section 377.703(e), Florida Statutes, requires the Commission to analyze and provide natural gas and electricity forecasts for analysis by the Florida Department of Community Affairs (DCA). The Commission forwards its *Ten-Year Site Plan* review to DCA to satisfy this statutory requirement.

TABLE 1. SECTION 186.801, FLORIDA STATUTES – CRITERIA FOR REVIEW OF TEN-YEAR SITE PLANS	
REQUIREMENT	COMMISSION ACTION TAKEN TO COMPLY WITH REQUIREMENT
<i>Review the need for electrical power in the area to be served</i>	Reviewed load forecasts, demand-side management (DSM) assumptions, and reliability criteria.
<i>Review possible alternatives to the proposed Plan</i>	Reviewed DSM assumptions, fuel forecasts, and sensitivities to the base-case expansion plan.
<i>Review anticipated environmental impact of proposed power plant sites</i>	Solicited comments from DEP regarding environmental impact and compliance. Comments are summarized in Section 4.0 of this review.
<i>Consider views of local and state agencies regarding water and growth management issues</i>	Solicited comments from the Department of Community Affairs (DCA), water management districts, and regional planning councils. Comments are summarized in Section 4.0 of this review.
<i>Determine consistency of Plan with the State Comprehensive Plan</i>	Evaluated energy-related aspects of the Comprehensive Plan. Reviewed comments provided by DCA and by regional and local planning agencies on growth management and Comprehensive Plan issues. Comments are summarized in Section 4.0 of this review.
<i>Review Plan for information on energy availability and consumption</i>	Reviewed load forecast data and methodologies used to arrive at load and energy forecasts.

1.2 PURPOSE

The purpose of a *Ten-Year Site Plan* is to give state and local agencies advance notice of proposed power plants and transmission facilities. Therefore, the *Ten-Year Site Plan* is not intended to be a binding plan of action on electric utilities. As such, the Commission's classification of a utility's *Ten-Year Site Plan* as **suitable** or **unsuitable** also has no binding effect on the utility. Such a classification does not constitute a determination or finding in subsequent docketed matters before the Commission. If a utility's *Ten-Year Site Plan* raises a concern requiring Commission action, such action is formally undertaken after a public hearing.

Because the *Ten-Year Site Plan* is a planning document containing tentative data, it may not contain sufficient information to allow regional planning councils, water management districts, and other review agencies to fully assess site-specific issues within their jurisdictions. Such detailed data, based on in-depth environmental assessments, are provided by the utility when seeking local permits for a project or, if required, during Power Plant Siting Act (PPSA) or Transmission Line Siting Act (TLSA) certification proceedings. This fact underscores the purpose of the *Ten-Year Site Plan* as an early notification process rather than a binding plan of action.

1.3 PUBLIC INVOLVEMENT

Pursuant to the State of Florida's policy of "government in the sunshine," all Commission workshops and hearings are open to the public. Members of the public may directly participate in any Commission proceeding.

The Commission held a public workshop on August 13, 2001 to solicit public comments on the *Ten-Year Site Plans*. Prior to the workshop, state, local, and regional government agencies submitted written comments on the *Ten-Year Site Plans*. DCA submitted its comments on December 17, 2001. All comments are summarized in Section 4.0 of this review and are available upon request.

1.4 FLORIDA RELIABILITY COORDINATING COUNCIL

A region of the North American Electric Reliability Council, the Florida Reliability Coordinating Council (FRCC) has a formal reliability assessment process to annually review and assess existing and potential issues. FRCC member utilities exchange information in planning and operating areas related to the reliability of the bulk power supply, and review activities within the FRCC region relating to reliability. The FRCC has a reliability assessment group that decides which planning and operating studies will be performed to address these issues.

The FRCC annually publishes two documents which address the reliability of Peninsular Florida's electric grid. The **2001 Regional Load and Resource Plan** contains aggregate data on demand and energy, capacity and reserves, and proposed new unit additions for the FRCC region as well as statewide. The **2001 Reliability Assessment** is an aggregate study of the future reliability of Peninsular Florida's electric grid. The Commission used both FRCC documents to supplement its review of the *Ten-Year Site Plans* filed by the utilities.

2.0 EXECUTIVE SUMMARY

2.1 SUITABILITY

The Commission has reviewed *Ten-Year Site Plans* filed by twelve(12) reporting utilities and two (2) merchant plant companies. The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are **suitable** for planning purposes. Forecasted reserve margins for Peninsular Florida range from 20% to 23% during summer peak seasons, and from 23% to 26% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings.

2.2 CRITICAL CONCERNS

The Commission has identified two areas of concern which may impact the reliability and cost-effectiveness of the *Ten-Year Site Plans*. These concerns are discussed in detail in Section 3.1 of this review but are summarized below.

2.2.1 ABSENCE OF PROPOSED MERCHANT PLANTS IN FRCC'S 2001 REGIONAL LOAD AND RESOURCE PLAN

The Commission is concerned that the FRCC's **2001 Regional Load and Resource Plan** does not contain complete information on all generating units proposed over the ten-year planning horizon. The document does not include several proposed combustion turbine (CT) "merchant" plants which have received DEP air permits or are under review. The Commission believes that the FRCC is responsible for documenting **all** proposed generating units which impact the reliability of the state's electric system.

Because CT units do not produce any steam capacity, they do not require certification under the Power Plant Siting Act. Therefore, CT units can be constructed once the Department of Environmental Protection (DEP) issues all environmental permits. While not contributing to Peninsular Florida's reserve margin unless firm capacity is sold to utilities, merchant plants may enhance reliability by increasing operating reserves and may cause decreases in wholesale rates.

2.2.2 AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

Reserve margins for some Florida utilities, primarily Florida Power Corporation and Tampa Electric Company, are made up largely of non-firm resources such as load management and interruptible service. Residential customers can give just thirty days' notice to leave a utility's load management program. Customer flight from this program can cause sudden near-term reliability problems. However, **this appears to be a near-term concern**. Florida's utilities forecasted a slight decrease in their reliance on non-firm resources over the planning horizon, thus indicating a greater reliance on supply-side resources (generation and firm capacity purchases) in future years.

2.3 SUMMARY OF RESOURCE ADDITIONS

Tables 2-4 and Figures 1-4, on pages 9 through 12, summarize the aggregate plans for the State of Florida's utilities. These illustrations show the total planned resource additions by type, current and future resource mix, and planned major generating units and transmission lines.

TABLE 2. STATE OF FLORIDA – CAPACITY FROM NEW GENERATING UNITS, CAPACITY CHANGES AT EXISTING SITES, AND GENERATING UNIT RETIREMENTS (2001 - 2010)

	WINTER CAPACITY (MW)
CAPACITY FROM NEW GENERATING UNITS - planned by electric utilities	
Combined Cycle	9,406
Combustion Turbine	3,986
Coal	288
TOTAL	13,680
CAPACITY CHANGES AT EXISTING SITES - repowering, fuel conversion, return from cold standby	
Combined Cycle	2,521
Combustion Turbine	52
Coal	-581
Oil and Gas Fossil Steam	-403
TOTAL	1,589
GENERATING UNIT RETIREMENTS - planned by electric utilities	
Combustion Turbine	-314
Oil and Gas Fossil Steam	-826
TOTAL	-1,140
TOTAL NET ELECTRIC UTILITY ADDITIONS	14,129
EXPIRATION OF NON-UTILITY GENERATOR CONTRACTS (for firm capacity)	
Cogeneration ¹	-376
Independent Power Producers ²	-593
TOTAL NET CHANGES TO NON-UTILITY GENERATION	-969
TOTAL NET CAPACITY ADDITIONS	13,160

¹ Nine firm capacity contracts (376 MW total) are set to terminate over the next ten years. As these contracts expire, the capacity becomes uncommitted (merchant) capacity.

² OUC's purchased power contracts with Reliant - Indian River Units 1-3 are set to expire by 2004. At that time, the capacity becomes uncommitted (merchant) capacity.

Figure 1. STATE OF FLORIDA – RESOURCE PLAN / SUMMER

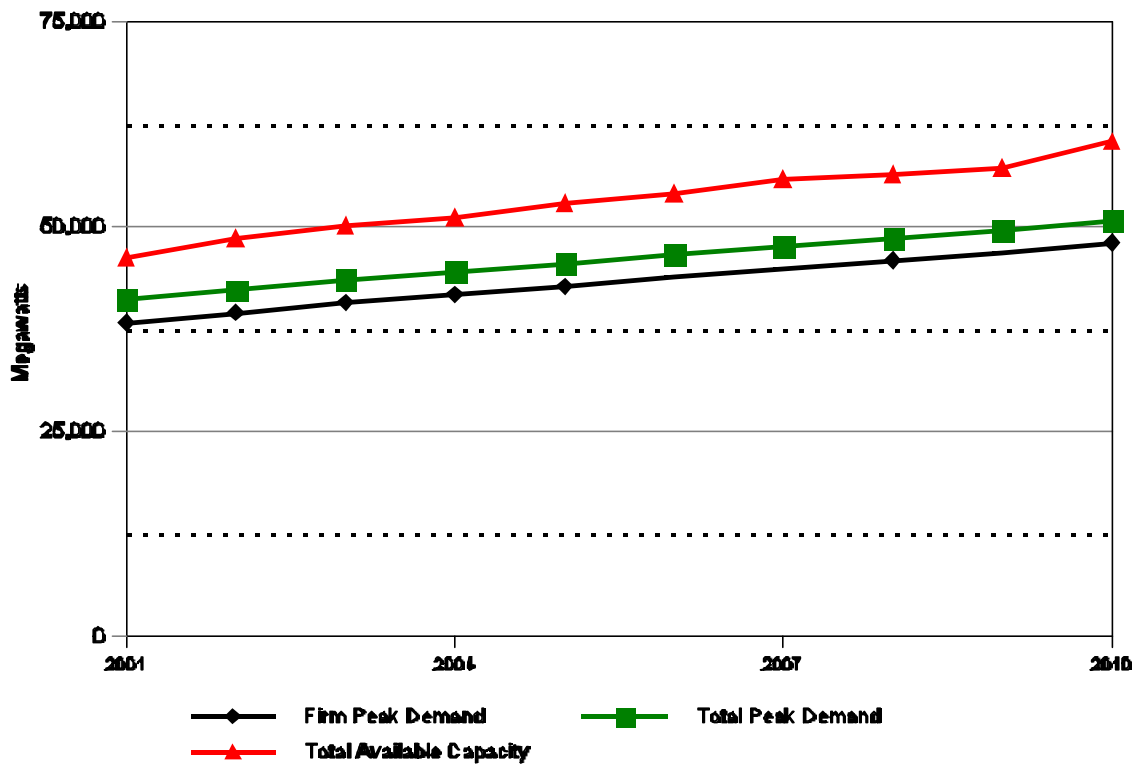


Figure 2. STATE OF FLORIDA – RESOURCE PLAN / WINTER

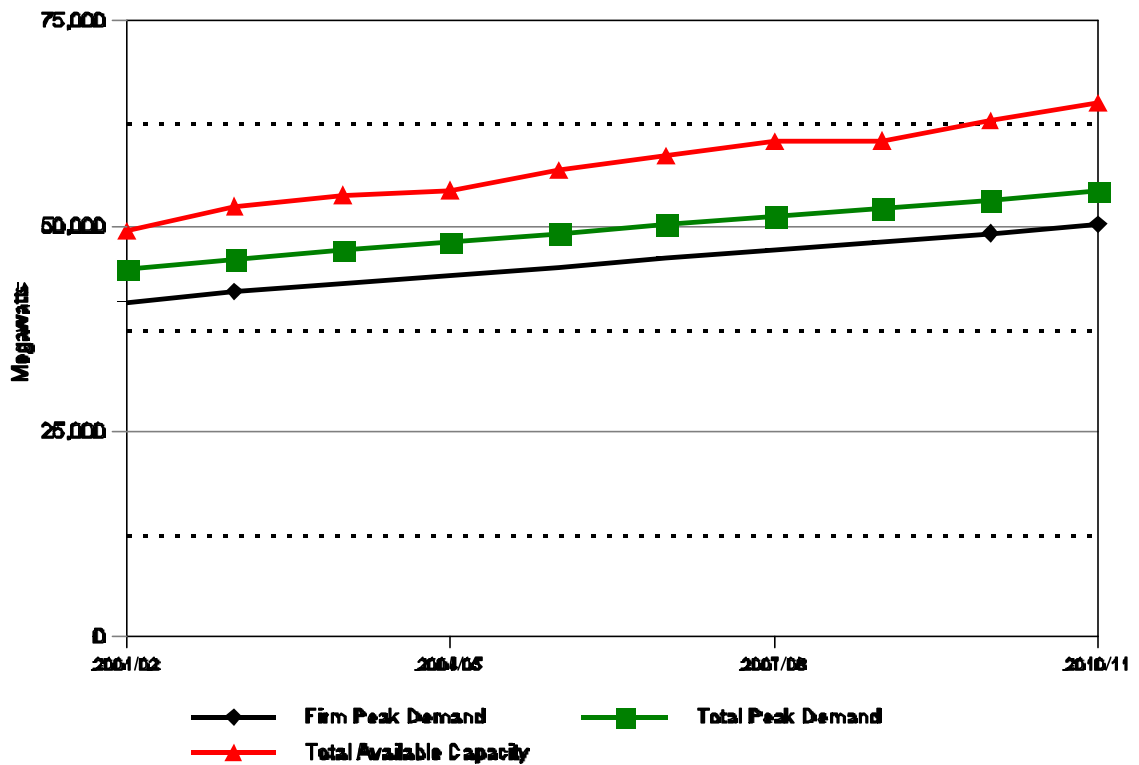


Figure 3. STATE OF FLORIDA – ELECTRIC UTILITY RESOURCE MIX BY PLANT TYPE / PRESENT AND FUTURE

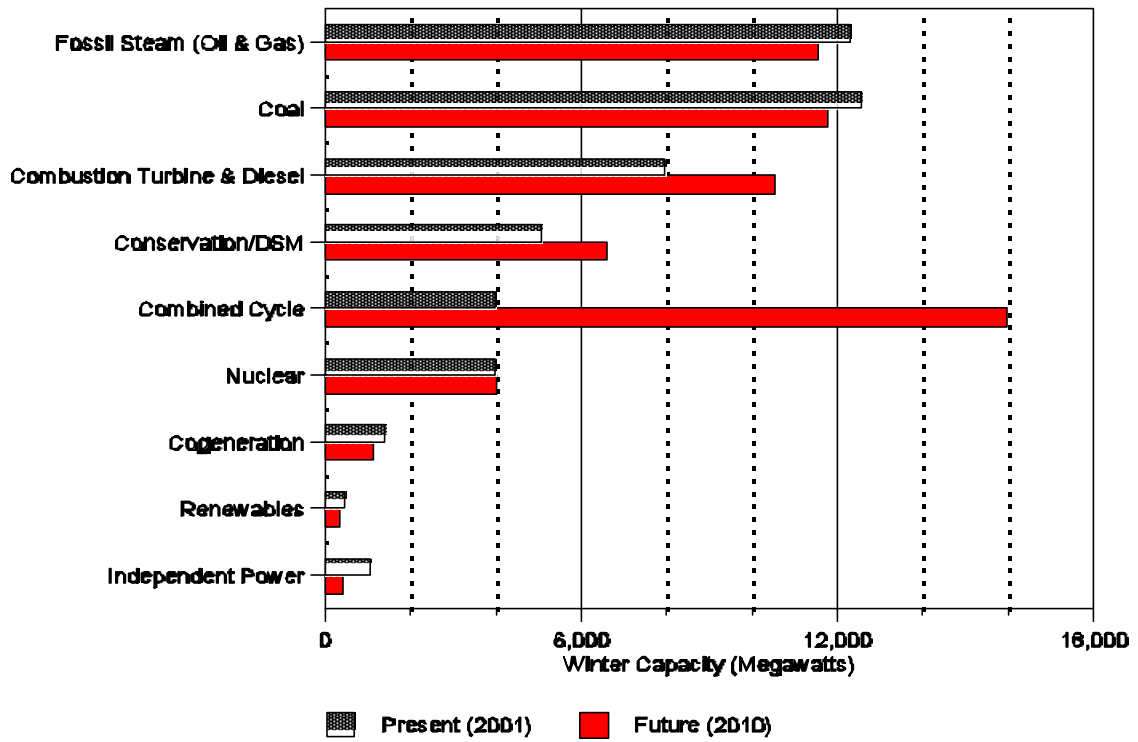


Figure 4. PROPOSED MAJOR GENERATING UNITS AND TRANSMISSION LINES (2001 - 2010)

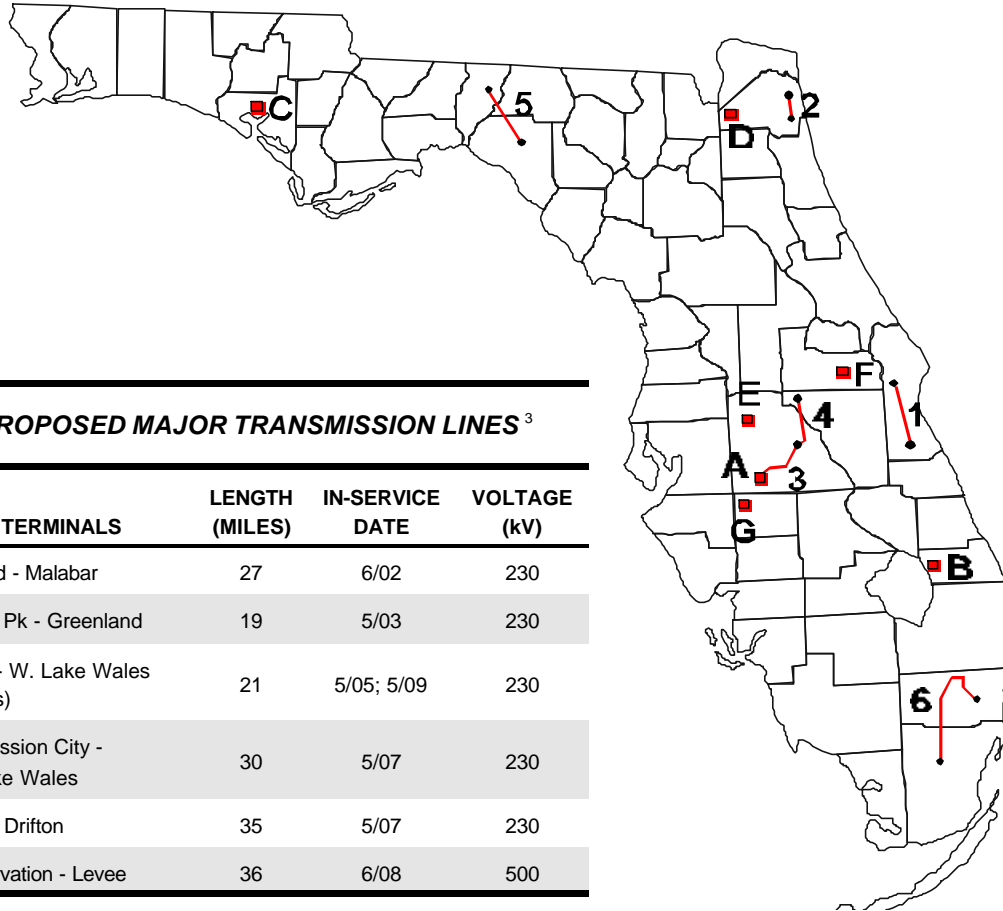


TABLE 3. PROPOSED MAJOR TRANSMISSION LINES³

UTILITY	TERMINALS	LENGTH (MILES)	IN-SERVICE DATE	VOLTAGE (kV)
1	FPL Brevard - Malabar	27	6/02	230
2	JEA Center Pk - Greenland	19	5/03	230
3	FPC Hines - W. Lake Wales (2 lines)	21	5/05; 5/09	230
4	FPC Intercession City - W. Lake Wales	30	5/07	230
5	FPC Perry - Drifton	35	5/07	230
6	FPL Conservation - Levee	36	6/08	500

TABLE 4. PROPOSED MAJOR GENERATING UNITS⁴

UTILITY	UNIT / SITE	TYPE	IN-SERVICE DATE	CAPACITY (MW)
A	FPC Hines 2-5	CC	11/03; 11/05; 11/07; 11/09	567 each
B	FPL Martin 5 & 6	CC	1/05; 1/06	429 each
C	Gulf Smith 3	CC	1/02	532
D	JEA Brandy Branch 4	CC	6/03	573
E	LAK McIntosh 4 & 5	coal (4); HRSG (5)	6/02 6/05	288 120
F	OUC Stanton 3 (w/ KUA, FMFA)	CC	10/03	585
G	SEC Payne Creek Unit 1	CC	1/02	440
	Calpine Osprey	CC	1/04	350

³ All proposed lines are exempt from the requirements of the Transmission Line Siting Act (TLSA) for one of three reasons: (1) the utility already owned the right-of-way prior to enactment of the TLSA in 1983; (2) the line is proposed to be located in existing right-of-way; or, (3) the line is not proposed to cross a county line.

⁴ Hines 2, Smith 3, Brandy Branch 4, McIntosh 5, Stanton 3, Payne Creek 1, and Calpine Osprey have been certified under the Power Plant Siting Act (PPSA). All other generating units will require future certification under the PPSA.

3.0 REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

3.1 CRITICAL CONCERNS

The Commission has identified two primary areas of concern which may impact the reliability and cost-effectiveness of the *Ten-Year Site Plans*. These concerns, discussed below, are the **absence of proposed merchant plants in FRCC's 2001 Regional Load and Resource Plan** and the **amount of reserves provided by non-firm resources**.

3.1.1 ABSENCE OF PROPOSED MERCHANT PLANTS IN FRCC'S 2001 REGIONAL LOAD AND RESOURCE PLAN

The Commission is concerned that the FRCC's **2001 Regional Load and Resource Plan** does not contain complete information on all generating units proposed over the ten-year planning horizon. The document does not include approximately 8,000 MW of capacity from proposed "merchant" plants, which have no native load but sell wholesale power to load-serving entities. The Commission has compiled a list of these proposed merchant plants based on information provided by DEP. This list is located in Table 5 on the next page and is current as of the *Ten-Year Site Plan* Commission Workshop held on August 13, 2001. The Commission recognizes that a list of proposed merchant plants may change frequently, just as a list of proposed utility generating units may also change. The Commission believes that it is the FRCC's responsibility to document **all** proposed generating units which have an impact on the reliability of the state's electric system.

The Commission recognizes that CT merchant plants do not contribute to a traditional calculation of firm reserve margin. However, CT merchant plants may enhance reliability of Florida's electric grid by increasing the level of operating reserves and may place downward pressure on wholesale rates. In addition, utilities may contract with merchant plants in the future to replace or defer the construction of planned generating units. Therefore, so that the Commission can keep abreast of all proposed generating unit additions in the state which may enhance reliability, the Commission believes that the FRCC should include all proposed CT merchant plants in the **2001 Regional Load and Resource Plan** as potential sources of additional capacity.

TABLE 5. PROPOSED MERCHANT PLANTS

ENTITY / FACILITY NAME	# OF UNITS	LOCATION (COUNTY)	UNIT TYPE ⁵	CAPACITY (MW) ⁵	IN-SERVICE DATE	STATUS
Santa Rosa Energy Center	1	Santa Rosa	CC	241	2002	Air permit issued / under construction
Auburndale Peaker Project	2	Polk	CT	115	2002	Draft air permit issued / awaiting final approval
Enron / Ft. Pierce	1	St. Lucie	CT	196	2002	Awaiting local zoning permit
Enron / Midway	3	St. Lucie	CT	510	2002	Air permit issued
El Paso / Ips Avon Park	4	Hardee	CT	670	2002	Air permit issued / under construction
Enron / South Dade Energy Center	2	Dade	CT	366	2003	Awaiting local permits
Mirant / Peace River Station	3	Polk	CT	480	2003	
Dynegy / Palmetto Power Project	3	Osceola	CT	510	2003	Air permit issued
Enron / Deerfield Beach	3	Broward	CT	510	2003	Air permit issued
Enron / Pompano Beach	3	Broward	CT	510	2003	Awaiting local permits
Duke Energy Fort Pierce	8	St. Lucie	CT	640	2003	Air permit issued
Duke Energy Lake	8	Lake	CT	640	2003	Draft air permit issued / awaiting final approval
Mirant / Midway	4	St. Lucie	CT	640	2003	
El Paso / Broward	3	Broward	CC	175	2004	
El Paso / Belle Glade Energy Center	2	Palm Beach	CC	175	2004	
El Paso / Manatee	1	Manatee	CC	175	2004	
CPV Gulfcoast	1	Manatee	CC	245	2004	Air permit issued
CPV Pierce	1	Polk	CC	245	2004	Draft air permit issued / awaiting final approval
CPV Atlantic	1	St. Lucie	CC	245	2004	Air permit issued
Constellation / South Pond Energy Park	1	Hardee	CC	155	2005	Air permit applied for, not yet issued
Constellation / South Pond Energy Park	2	Hardee	CT	320	2005	Air permit applied for, not yet issued
Lake Worth Generation	1	Palm Beach	CC	205	?	Air permit issued
TOTAL				7,968		

⁵ The steam portion of these CC units will be less than 75 MW. Thus, these units are exempt from the requirements of the Power Plant Siting Act.

3.1.2 AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

For some Florida utilities, mainly Florida Power Corporation (FPC) and TECO, reserve margins consist largely of non-firm, non-generating resources such as load management and interruptible service. Because residential customers typically may give a utility just thirty days' notice to leave its load management program, customer flight from this program can cause sudden near-term reliability problems. Interruptible service customers typically must give utilities as much as five years' advance notice to switch to firm service.

The reliance on non-firm resources is primarily a winter season concern and appears to be near-term in nature. As shown in Figure 5, non-firm resources currently make up approximately 54% of Peninsular Florida's winter reserves. This percentage is forecasted to drop to just under 34% by winter, 2010/11. This indicates that Peninsular Florida's utilities plan to rely more on supply-side resources over the planning horizon.

TECO and FPC rely primarily on non-firm resources for reserves. Non-firm resources currently make up 87% of TECO's winter reserve margin, while 78% of FPC's winter reserves currently consist of non-firm resources. These percentages are forecasted to drop to 40% winter (TECO) and 55% winter (FPC) by winter, 2010/11 as new supply-side resources are added.

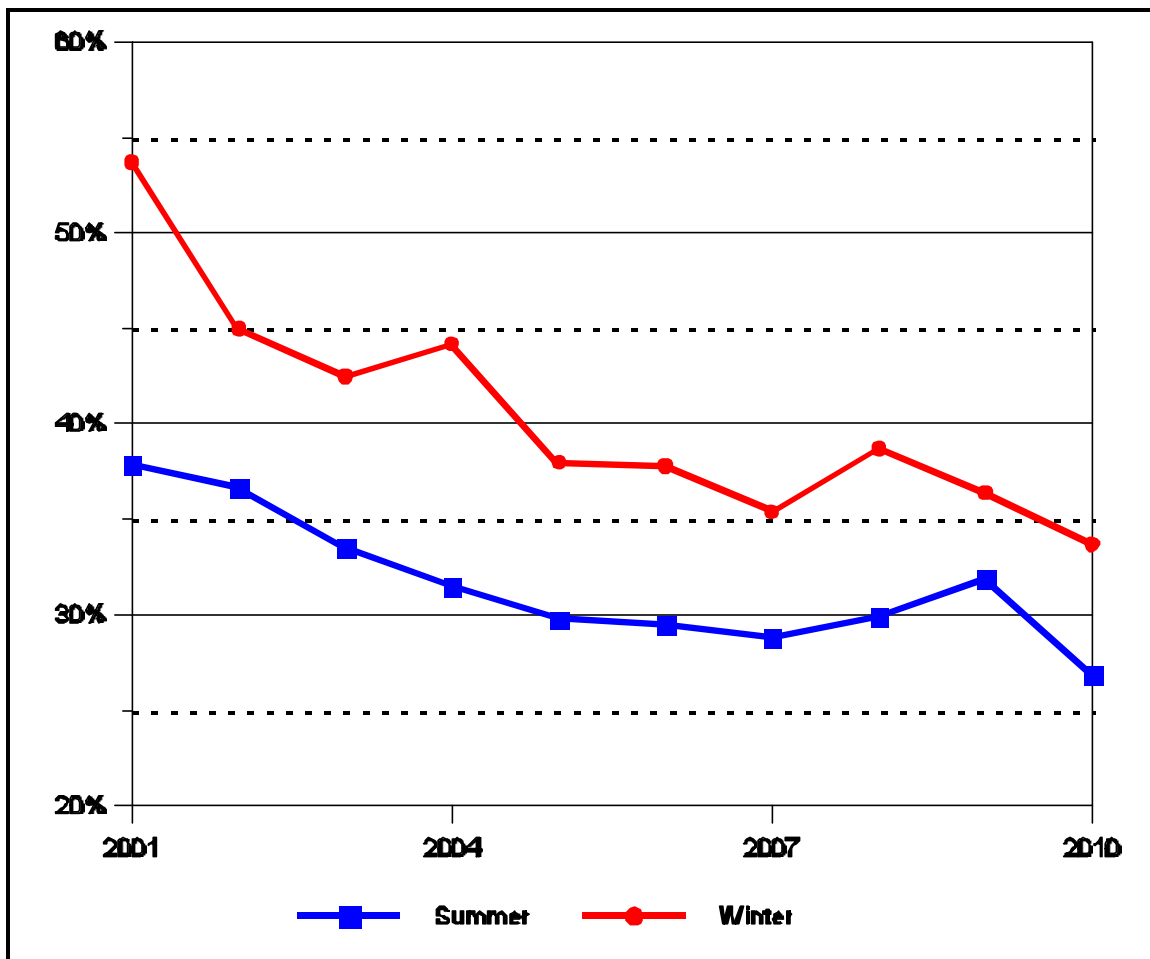


Figure 5. PENINSULAR FLORIDA – PERCENTAGE OF RESERVE MARGIN COMPRISED OF NON-FIRM LOAD

3.2 ELECTRIC UTILITY RESTRUCTURING

Several federal and state actions have encouraged a restructuring of the electric industry nationwide. These actions are discussed below.

In 1992, Congress enacted the **Energy Policy Act of 1992 (EPAct)**. The EPAct authorized the Federal Energy Regulatory Commission (FERC) to order utilities to transmit, over their own transmission lines, power from wholesale entities. The EPAct also requires that a utility refusing to provide wholesale transmission service must show good cause for such refusal. EPAct is considered to be the catalyst for current restructuring of the electric utility industry.

In April, 1996, FERC issued Order No. 888 which required that all transmission-owning public entities make their facilities available to all users in a fair, non-discriminatory manner. Open access transmission was facilitated by utilities through **functional unbundling**, a process by which the generation and transmission function within a single company are separated. FERC intended that Order No. 888 also encourage the development of **independent system operators (ISOs)** to manage the real-time actions of transmission systems.

In April, 1996, in response to concerns over the transparency of real-time information, FERC issued Order No. 889 which required the development of an **open-access same-time information system (OASIS)**. OASIS is an interactive database system designed to provide instantaneous information on the availability and price of transmission links between generation centers and load centers. The FRCC implemented Peninsular Florida's OASIS, known as FLOASIS, in November, 1996.

In December, 1999, FERC issued Order No. 2000, which encouraged the development of **regional transmission organizations (RTOs)**. In Order No. 2000, FERC concluded that RTOs would offer advantages over the present system because they will lead to enhanced regional reliability and speed the development of a competitive, wholesale electricity market. FERC also expects that RTOs will remove any potential for discriminatory transmission system access. On October 16, 2000, Peninsular Florida's three major utilities – FPC, FPL, and TECO – filed a joint **RTO** proposal, known as GridFlorida, with the FERC.

The Commission has opened separate dockets to investigate how the RTO proposal may impact the ratepayers of FPC, FPL, and TECO. Public hearings were held on October 3-5, 2001 in Docket Nos. 000824-EI (FPC), 001148-EI (FPL), and 010577-EI (TECO). On November 7, 2001, the Commission directed FPL, FPC and TECO to file, within 90 days, a plan to transfer control over their transmission power lines to an ISO. The Commission authorized the recovery of approximately \$9 million in start-up costs incurred with the development of GridFlorida to date.

Florida Energy 2020 Study Commission

Pursuant to Executive Order No. 2000-127, Governor Jeb Bush established the **Florida Energy 2020 Study Commission** (Study Commission) on May 3, 2000 to propose an energy plan and strategy for Florida. Consisting of 20 persons with various areas of expertise, the Study Commission has been meeting since September, 2000 to study the major issues affecting the future of the electric industry in the state. In accordance with the Governor's executive order, the Study Commission is to submit its report to the Senate, House of Representatives, and Governor by December, 2001.

3.3 LOAD FORECASTS

Electric utilities perform load forecasts to estimate future energy needs. From these estimates, utilities determine how much, and when, additional generating capacity may be needed. In evaluating a utility's forecast, the Commission uses three types of analyses. The first involves reviewing the load forecasting methodology to ensure that it uses reasonable models and assumptions. The second examines the historical forecast accuracy to determine whether or not the forecasting process has performed well in the past. The third compares forecasted values to historical growth patterns.

3.3.1 EVALUATION OF LOAD FORECASTING METHODOLOGY

Although each reporting utility has its own distinct forecasting process, there are four steps common in all forecast methodologies. These steps are discussed below.

Collection of Historical Data

Historical data is the foundation for utility load and energy forecasts. These data include energy usage patterns, number of customers, economic, demographic, and weather data for the utility's service territory, and appliance-specific saturation and energy consumption characteristics. The Commission reviewed these data sources for their timeliness, reliability and accuracy.

Derivation of Forecast Model Parameters

The parameters of a forecast model quantify the relationship between the economic and demographic data of a utility and the energy usage patterns of its customers. These parameters must be updated periodically to ensure that forecasts produced by the model reflect current consumption patterns.

Assembly of Forecast Assumptions

Forecast assumptions represent a utility's expectations of future economic, weather, technological, and demographic conditions in its service territory. In evaluating forecast assumptions, the Commission reviewed the sources for those assumptions, the consistency of those assumptions with other economic and demographic projections, and the validity of any adjustments made to those assumptions arising from known changes in a utility's service territory.

Calculation of Forecast

The load forecast is calculated by inputting forecast assumptions into the forecast model. The mathematical result may be adjusted to reflect the forecaster's professional judgement, or to reflect the impact of conservation programs or other events not already quantified. The Commission reviewed any adjustments made to utility forecasts for reasonableness.

NOTE: The load forecasts contained in the 2001 *Ten-Year Site Plans* were prepared in late 2000. The Commission's evaluation of the economic assumptions underlying these forecasts was based on the prevailing view of economic growth at the time the forecasts were made. Since that time, the rate of growth of the national and state economy has slowed significantly. Thus, there is an increased likelihood that the load forecasts contained in the 2001 *Ten-Year Site Plans* will overstate demand and energy growth over the ten-year planning horizon.

3.3.2 EVALUATION OF HISTORICAL FORECAST ACCURACY

Reviewing the past results of a load and energy forecasting methodology reveals whether that methodology has produced accurate forecasts. A pattern of over- or under-forecasting is indicative of past forecast error that could be carried forward into current forecasts.

For each reporting utility, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period from 1996-2000. This review compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, actual 2000 energy sales were compared to the projected 1999 forecasts made in 1995, 1996, and 1997. These differences, expressed as a percentage error rate, were used to calculate two measures of a utility's historical forecast accuracy. The first measure, **average absolute forecast error**, is an average of the percentage error rates calculated by ignoring the positive and negative signs that result when a forecast over- or under-estimates actual values. This calculation provides an overall measure of the accuracy of past utility forecasts. The second measure, **average forecast error**, is an average of the percentage error rates calculated without removing the positive and negative signs. This measure indicates a utility's tendency to over-forecast (positive values) or under-forecast (negative values).

The Commission evaluated the historical forecast accuracy of total retail energy sales for nine of the twelve reporting utilities. There were insufficient historical data to analyze the historical forecast accuracy of FMPA, KUA, and OUC. Figure 6 illustrates the historical forecast accuracy for the nine reporting utilities with sufficient historical data. A detailed discussion of the individual utility forecasts is included later in this review.

As a final check of the projections, the Commission compares the forecasts to historical growth patterns as well as past load forecasts. Unexpected changes in forecasted growth rates not explicitly accounted for in the forecast methodology may indicate that the load forecast does not properly reflect past consumer behavior, and the forecast likely is in error. As shown in Figure 6, all reporting utilities except FPC have a history of under-forecasting retail energy sales.

A detailed discussion of individual utility load forecasts is contained later in this review. In general, the load forecasting procedures used by the reporting utilities provide reliable forecasts of Florida's future energy needs.

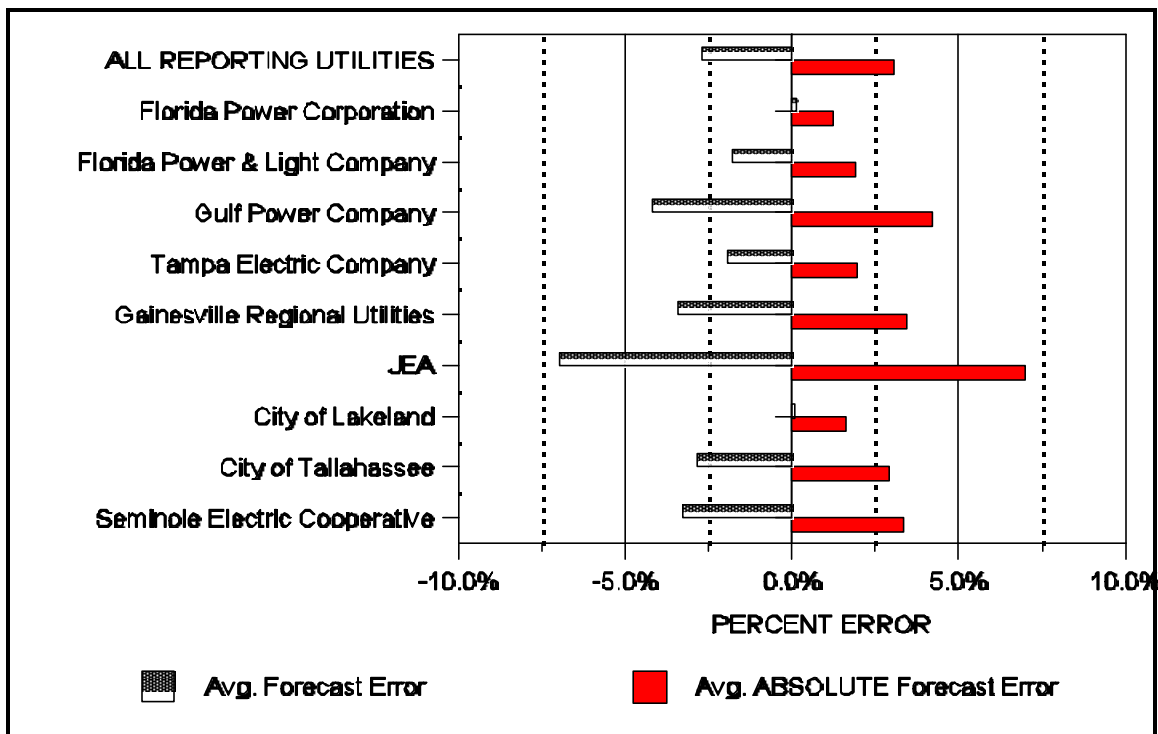


Figure 6. TOTAL RETAIL ENERGY SALES – HISTORICAL FORECAST ACCURACY

3.4 DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) reduces customer peak demand and energy requirements, and defers the construction of new generating units. DSM programs have been offered since 1980 as a result of the Florida Legislature's enactment of the **Florida Energy Efficiency and Conservation Act (FEECA)**. The Commission's broad-based authority over electric utility conservation measures and programs is embodied in Rules 25-17.001 through 25-17.015, Florida Administrative Code.

FEECA emphasizes reducing the growth rate of weather-sensitive peak demand, reducing and controlling the growth rate of electricity consumption, and reducing the consumption of expensive resources such as petroleum fuels. To meet these objectives, the Commission has set DSM goals, and the utilities have developed and implemented DSM programs designed to meet these goals. The DSM programs developed by Florida's electric utilities can be generally grouped into two types: **dispatchable** (e.g., load management, interruptible service), which are controlled by the utility; and **non-dispatchable** (e.g., attic insulation, energy-efficient lighting), which are permanent measures installed in a dwelling.

3.4.1 ESTIMATED IMPACT OF DSM ON DEMAND AND ENERGY CONSUMPTION

Florida's electric utilities have been successful in meeting the overall objectives of FEECA. As seen in Table 6, utility conservation programs have reduced statewide summer peak demand by an estimated 3761 MW, winter peak demand by 5451 MW, and energy consumption by 2595 GWh. By 2010, DSM programs are forecasted to reduce aggregate summer peak demand by 4568 MW, winter peak demand by 6474 MW, and energy consumption by 4543 GWh. These DSM savings are also illustrated in Figures 8, 9, and 10 on the next two pages.

TABLE 6. ESTIMATED SAVINGS FROM FLORIDA UTILITIES' DSM PROGRAMS		
	To Date	By 2010
Summer Peak Demand	3761 MW	4568 MW
Winter Peak Demand	5451 MW	6474 MW
Energy Consumption	2595 GWh	4543 GWh

3.4.2 CHANGES TO FEECA

When FEECA was enacted in 1980, every electric utility in the state was subject to its requirements. After its first revision in 1989, FEECA applied only to twelve electric utilities whose annual energy sales exceeded 500 GWh. Those twelve utilities provided approximately 94% of all electricity consumed in Florida. When FEECA was revised again in 1996, the minimum sales threshold was increased to 2000 GWh. As a result, FEECA's requirements now apply only to the five investor-owned utilities and two municipal utilities, JEA and OUC. These utilities generate approximately 87% of all electricity consumed in Florida.

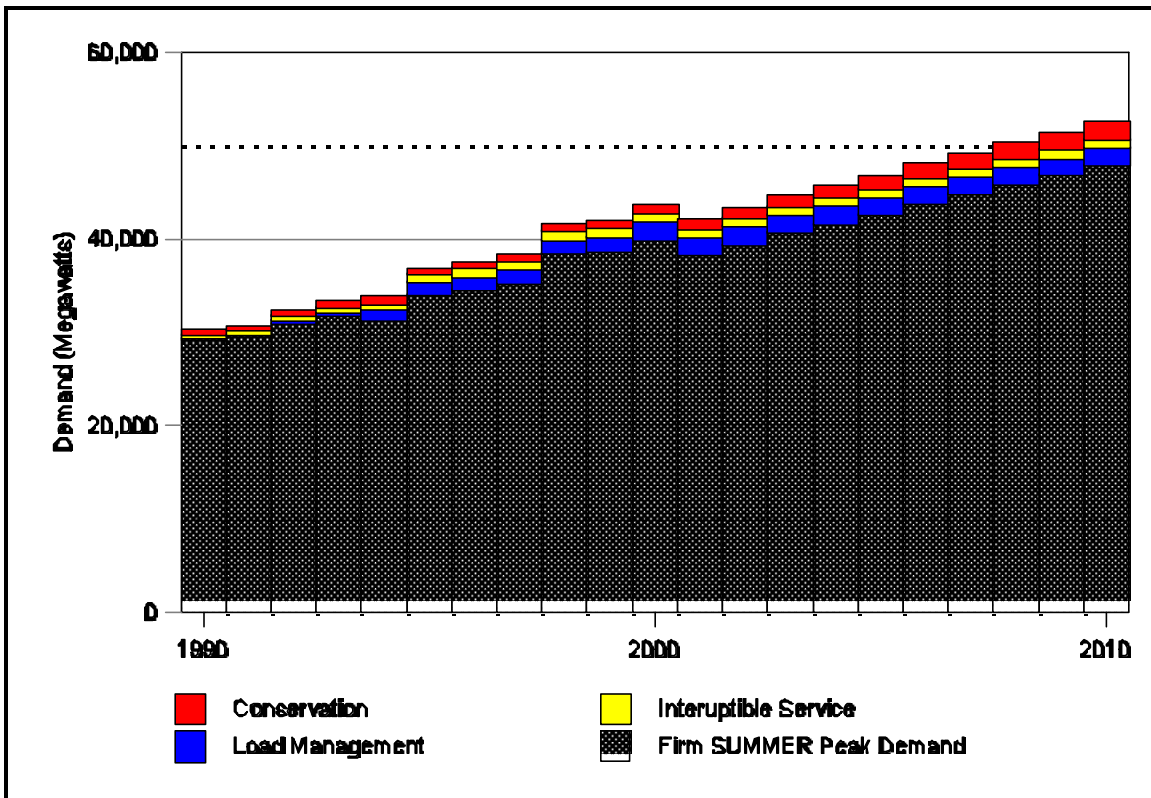


Figure 7. STATE OF FLORIDA – ESTIMATED IMPACT OF DSM ON SUMMER PEAK DEMAND / HISTORY AND FORECAST

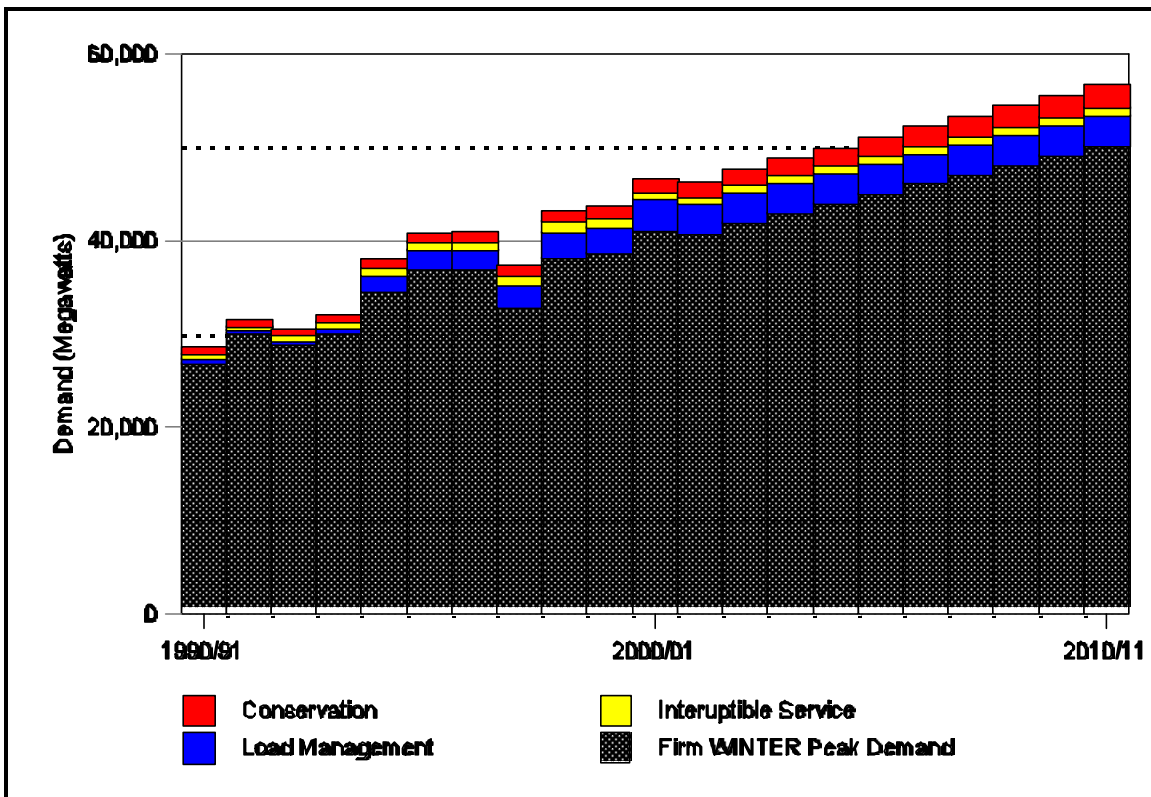


Figure 8. STATE OF FLORIDA – ESTIMATED IMPACT OF DSM ON WINTER PEAK DEMAND / HISTORY AND FORECAST

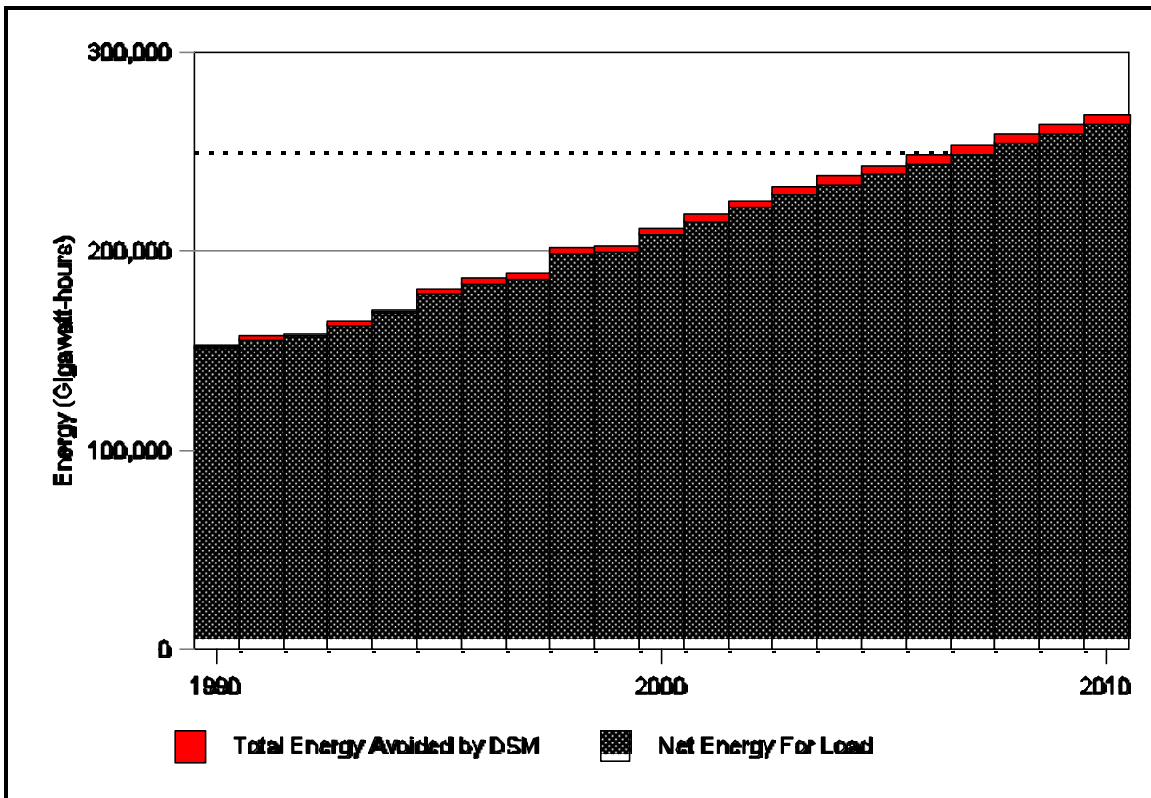


Figure 9. STATE OF FLORIDA – ESTIMATED IMPACT OF DSM ON NET ENERGY FOR LOAD / HISTORY AND FORECAST

3.4.3 DEMAND-SIDE MANAGEMENT GOALS

The Commission set new numeric demand and energy DSM goals for FPL, FPC, Gulf, and TECO in August, 1999. These four utilities subsequently filed new DSM plans to meet their goals. The Commission approved all four DSM plans in April, 2000. The Commission set new numeric demand and energy DSM goals for Florida Public Utilities Company (FPUC) in April, 2000. FPUC's DSM Plan was approved in October, 2001. The Commission set numeric goals of **zero** for JEA and OUC in April, 2000 because these two utilities could not identify any additional cost-effective DSM programs to offer.

3.4.4 ENERGY CONSERVATION COST RECOVERY CLAUSE

Florida's investor-owned utilities have spent a vast amount of money to implement DSM programs. This money has been collected from utility ratepayers through the Energy Conservation Cost Recovery Clause (ECCR). The ECCR clause allows investor-owned utilities to recover, on an annual basis, prudently incurred expenses associated with the implementation of Commission-approved DSM programs.

Since 1981, Florida's investor-owned utilities have collected over \$3.2 billion through the ECCR clause. As shown in Figure 10, annual DSM expenditures increased substantially between 1990 and 1996 due primarily to the expansion of FPL's and FPC's load management programs. However, total DSM expenditures have decreased slightly since 1996 due to DSM program saturation and to declining DSM cost-effectiveness caused by the lower cost of new combined cycle and combustion turbine units.

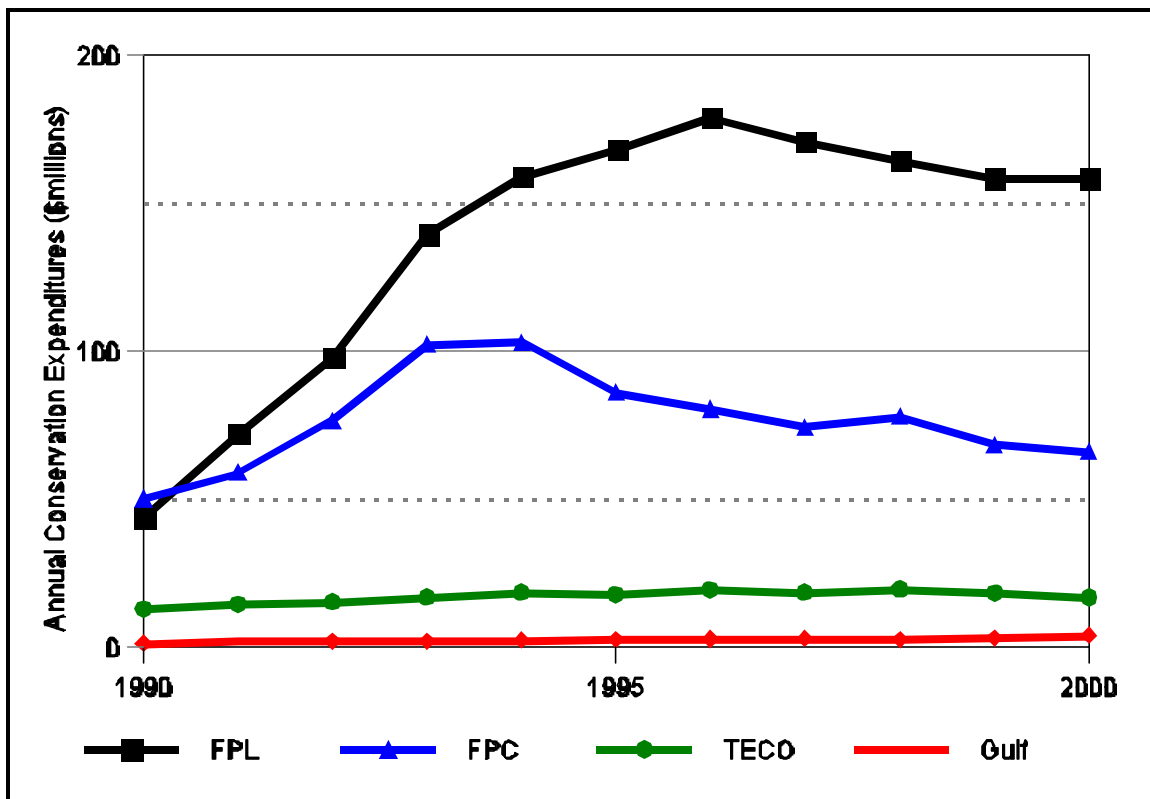


Figure 10. ENERGY CONSERVATION COST RECOVERY CLAUSE – EXPENSES

3.4.5 STATE COMPREHENSIVE PLAN

Energy conservation is a component of the State Comprehensive Plan. Section 187.201(12)(a), Florida Statutes, contains the State Comprehensive Plan's goal concerning energy as stated below:

"Florida shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors, while at the same time promoting an increased use of renewable energy resources."

To meet this goal, the State of Florida has implemented policies to reduce per-capita energy consumption through the development and application of end-use efficiency alternatives, renewable energy resources, efficient building code standards, and by informing the public of energy conservation measures. The Commission set DSM goals and approved DSM plans for electric utilities, and continues to work with the Department of Community Affairs (DCA) to ensure a building code that promotes energy-efficient, cost-effective new construction. These activities have the effect of promoting end-use efficiency and reducing per-capita energy consumption from what it otherwise would have been. These activities will continue in the future.

However, in spite of the Commission's efforts, residential per-capita energy consumption has consistently risen over the past ten years, and is expected to continue to increase each year over the planning horizon. Past and projected increases may also be attributed to the following factors: the nominal cost of electricity has remained relatively stable for over a decade; natural gas, used by many residents nationwide for heating, water heating, and cooking, is relatively unavailable in parts of Florida; the average home size has increased over time; and, many more electricity-consuming appliances exist in the home today than in past years.

Figure 11 illustrates historical and forecasted per-capita energy consumption for the state. As shown, per-capita energy consumption is expected to increase at a lesser rate in the future than in the past due largely to the replacement of older household appliances with newer, more energy-efficient models. However, this year's forecasted per-capita energy consumption for the planning horizon is an average of 3.4% higher than forecasts made last year for a comparable period.

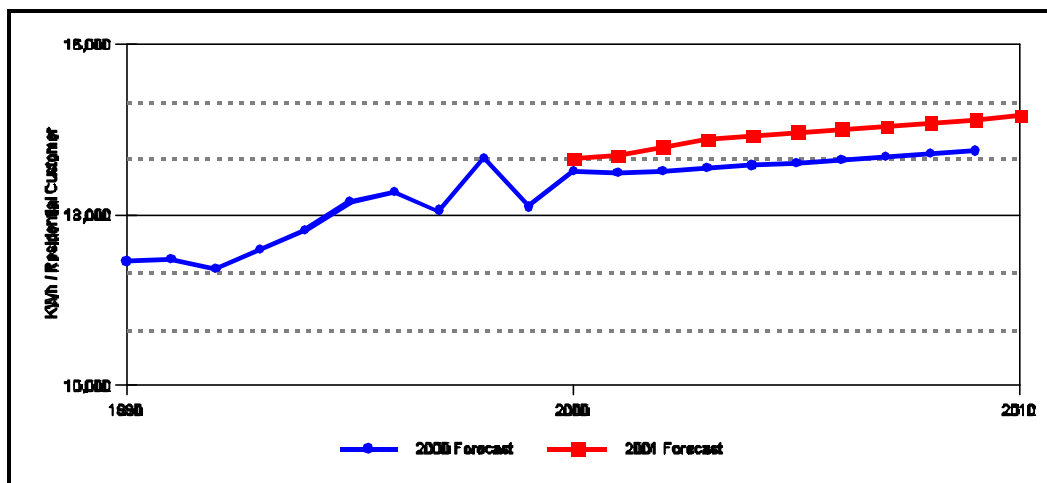


Figure 11. STATE OF FLORIDA – ENERGY CONSUMPTION PER RESIDENTIAL CUSTOMER / HISTORY AND FORECAST

3.5 NATURAL GAS AVAILABILITY

For over 40 years, Florida has relied primarily on a single gas transportation pipeline company, Florida Gas Transmission (FGT), to supply natural gas to electric utilities, industrial customers, and local distribution companies. FGT currently has a system pipeline capacity of around 1.7 billion cubic feet per day (Bcf/day). As shown in Figure 12, nearly 80% of the existing pipeline capacity is used for electricity generation, both by utilities and non-utility generators.

Electric utilities forecast a substantial (179%) increase in natural gas requirements over the next ten years. Much of this increase (84%) is forecasted to occur by 2005. As a result, it is estimated that an additional 1.1 Bcf/day of pipeline capacity may be required in the state by 2010.

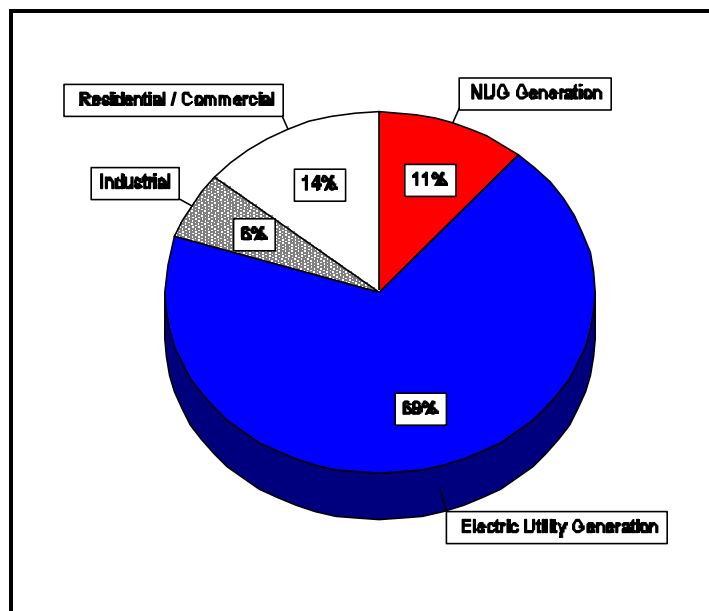


Figure 12. **NATURAL GAS CONSUMPTION BY END-USER -- 2000**

3.5.1 PROPOSED PIPELINE PROJECTS

To meet the forecasted growing demand for gas-fired electricity generation, gas transportation companies have recently completed, or are currently building, a number of new projects to bring needed capacity into the state. These include new construction as well as pipeline expansion projects.

FGT Phase IV

On May 1, 2001, FGT completed its Phase IV Expansion project. The project, consisting of compression upgrade and 134 miles of new pipeline, increased FGT's delivery capacity from 1.7 Bcf/day to 1.727 Bcf/day.

Gulfstream

The largest pipeline currently under construction is the \$1.6 billion Gulfstream project, which received FERC approval on February 22, 2001. This project was originally proposed by The Coastal Corporation and was later acquired by subsidiaries of Duke Energy and Williams. The 753-mile pipeline project originates offshore near the Mississippi-Alabama border, extends across the Gulf of Mexico, and comes ashore near Port Manatee, Florida. The pipeline project will continue across central and south Florida, terminating in Palm Beach County. Once completed, the Gulfstream system will have a delivery capacity of approximately 1.2 Bcf/day. Construction on the project began on June 1, 2001 and is expected to take approximately one year.

FGT Phase V

FGT's proposed Phase V expansion project received FERC approval on July 27, 2001. The \$450 million project involves construction of 166 miles of new pipeline and addition of compressor stations in Mississippi, Alabama, and Florida. FGT expects to complete this expansion by May, 2003. Upon

completion of Phase V, FGT's system pipeline capacity will be over 2.0 Bcf/day. This capacity is sufficient to meet anticipated demand for 2003 but not the forecasted need of 2.80 Bcf/day for 2010.

Calypso

Calypso Pipeline, LLC, a subsidiary of the Enron Corporation, applied for FERC approval on July 20, 2001 for a proposed pipeline project. The \$132 million project consists of a 42-mile pipeline originating offshore between southern Florida and the Bahamas, coming onshore in Broward County and connecting with FGT's existing Lauderdale lateral. Calypso will connect offshore with a new 54-mile non-jurisdictional pipeline terminating in Freeport, Grand Bahama Island. The project is expected to have a delivery capacity of 0.832 Bcf/day and is projected to be placed into service in October, 2004. Calypso believes that its location and connection with FGT will enable FGT to supply the increased needs of its electric utility customers in south Florida.

With the completion of these expansion and construction projects, the Commission expects that Florida will have adequate natural gas delivery capacity available to supply projected natural gas needs. As electric utilities revise their generation expansion plans, the timing of unit additions may change and, therefore, the timing of additional demand for natural gas delivery capacity may also change. However, the forecasted amount of delivery capacity needed in future years is presumed to accurate.

3.6 RELIABILITY REQUIREMENTS

3.6.1 RELIABILITY CRITERIA

Utilities plan resource additions to meet peak demand plus allow for planned maintenance and forced outages of generating units, as well as variation from base-case weather or forecasting assumptions. To determine when additional future resources are required, utilities generally use two types of reliability criteria: **deterministic** and **probabilistic**. The reliability criteria used by each reporting utility are shown in Table 7.

Deterministic Criteria

Most utilities use a deterministic reliability criterion. The primary criterion, **reserve margin**, is the amount of capacity that exceeds firm peak demand. This value may be expressed in megawatts or as a percentage exceeding firm peak demand. Reserve margin is comprised of demand-side (non-firm) resources and supply-side (capacity) resources. TECO also uses a **supply-side reserve margin** component which indicates the amount of firm capacity resources that exceed firm peak demand.

However, reserve margin measures system reliability only at the single peak hour of the summer or winter season. As a result, reserve margin cannot measure the impact of random events on system reliability throughout the year. Forced outages of generating units can adversely affect system reliability during off-peak months, when many units are out of service for maintenance.

TABLE 7. RELIABILITY CRITERIA FOR REPORTING UTILITIES			
UTILITY	RESERVE MARGIN	LOLP	EUE/NEL
Florida Power Corporation (FPC)	15% Summer/Winter ⁶	0.1	---
Florida Power & Light Company (FPL)	15% Summer/Winter ⁶	0.1	---
Gulf Power Company (Gulf)	13.5% Summer ⁷	---	---
Tampa Electric Company (TECO)	15% Summer/Winter ⁶ (7% supply-side Summer) ⁸	---	---
Florida Municipal Power Agency (FMPA)	18% Summer / 15% Winter	---	---
Gainesville Regional Utilities (GRU)	15% Summer/Winter	---	---
JEA	15% Summer/Winter	---	---
Kissimmee Utility Authority (KUA)	15% Summer/Winter	---	---
City of Lakeland (LAK)	20% Summer / 22% Winter	---	---
Orlando Utilities Commission (OUC)	15% Summer/Winter	---	---
City of Tallahassee (TAL)	17% Summer	---	---
Seminole Electric Cooperative (SEC)	15% Summer/Winter	---	---

⁶Pursuant to the stipulation in Docket No. 981890-EU, FPC, FPL, and TECO have agreed to increase their reserve margin planning criterion to 20% starting in Summer, 2004.

⁷Gulf's reserve margin planning criterion increases to 15% starting in the fourth year of the planning horizon (in this case, 2004).

⁸TECO's 7% summer supply-side reserve margin component becomes effective in Summer, 2004.

Probabilistic Criteria

Because of the limitations of reserve margin, many utilities also use probabilistic reliability criteria. The most common one is **loss of load probability (LOLP)**, expressed in days per year. The typical LOLP criterion used for planning purposes is 0.1 days per year. This means that, on average, a utility will likely be unable to meet its daily firm peak load on one day in ten years. The LOLP criterion allows a utility to calculate and incorporate its ability to import power from neighboring utilities. However, LOLP does not account for the magnitude of a forecasted capacity shortfall.

A second probabilistic method, **expected unserved energy (EUE)**, accounts for both the probability *and* magnitude of a forecasted energy shortfall. EUE is normally measured as a ratio of expected unserved energy to net energy for load (EUE/NEL), and the typical criterion is 1% EUE/NEL. This means that, on average, a utility will likely be unable to serve 1% of its annual net energy requirements in a given year.

3.6.2 ROLE OF RELIABILITY CRITERIA IN PLANNING

Once reliability criteria are established, utilities apply their load forecast to existing system resources. Reliability concerns arise if a utility's reserve margin falls below established criteria or the LOLP exceeds one day in ten years. In those instances, the utility must build or purchase additional capacity (supply-side options) or reduce peak load through additional cost-effective conservation programs (demand-side options). An integrated resource plan is developed by combining supply-side and demand-side options to satisfy the utility's reliability criteria in a cost-effective manner. This underscores the fact that reliability criteria decide the **timing** of planned resource additions.

As recently as ten years ago, a 15% reserve margin in Peninsular Florida was approximately equivalent to an LOLP of 0.1 days per year. FRCC studies currently show that a 15% reserve margin correlates to LOLP values substantially lower than 0.1 days per year. These LOLP values are believed to result from the high unit availability and low forced outage rates resulting from better maintenance practices on older generating units. Therefore, reserve margin has become the primary criterion driving the need for additional capacity.

Figures 13 and 14, on the next page, show the forecasted summer and winter reserve margin over the next ten years, for the State of Florida and for Peninsular Florida's utilities. Both figures show the expectation that Peninsular Florida's summer and winter reserve margins will meet or exceed 20% during the planning horizon.

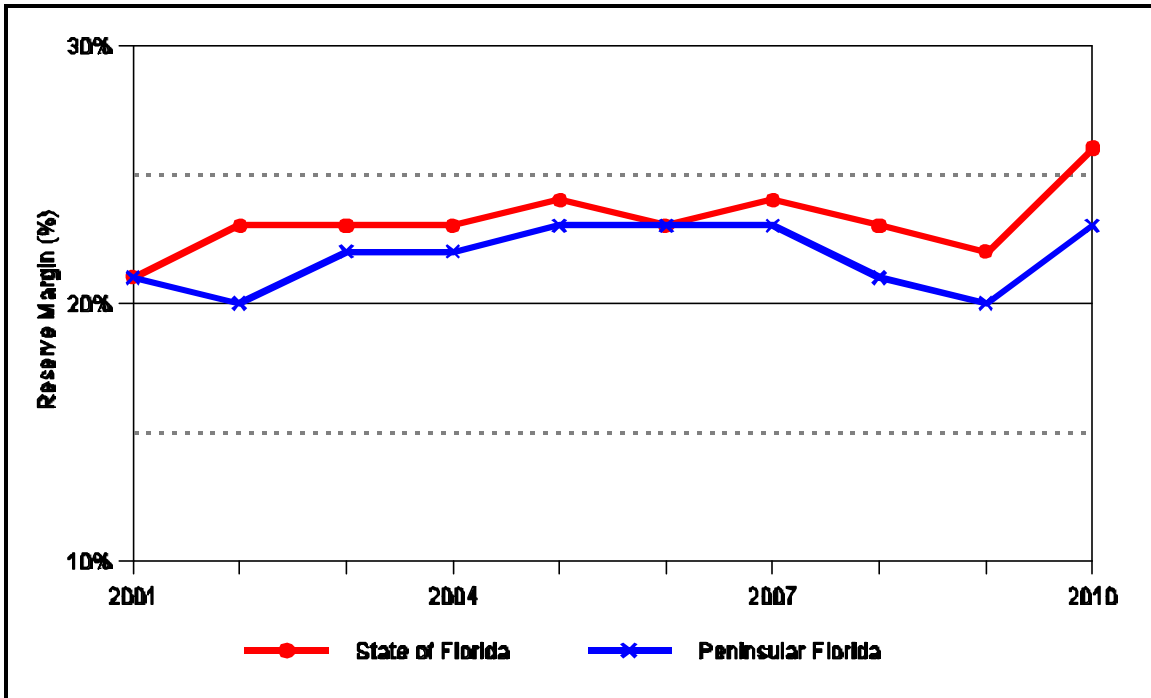


Figure 13. FORECASTED SUMMER RESERVE MARGIN

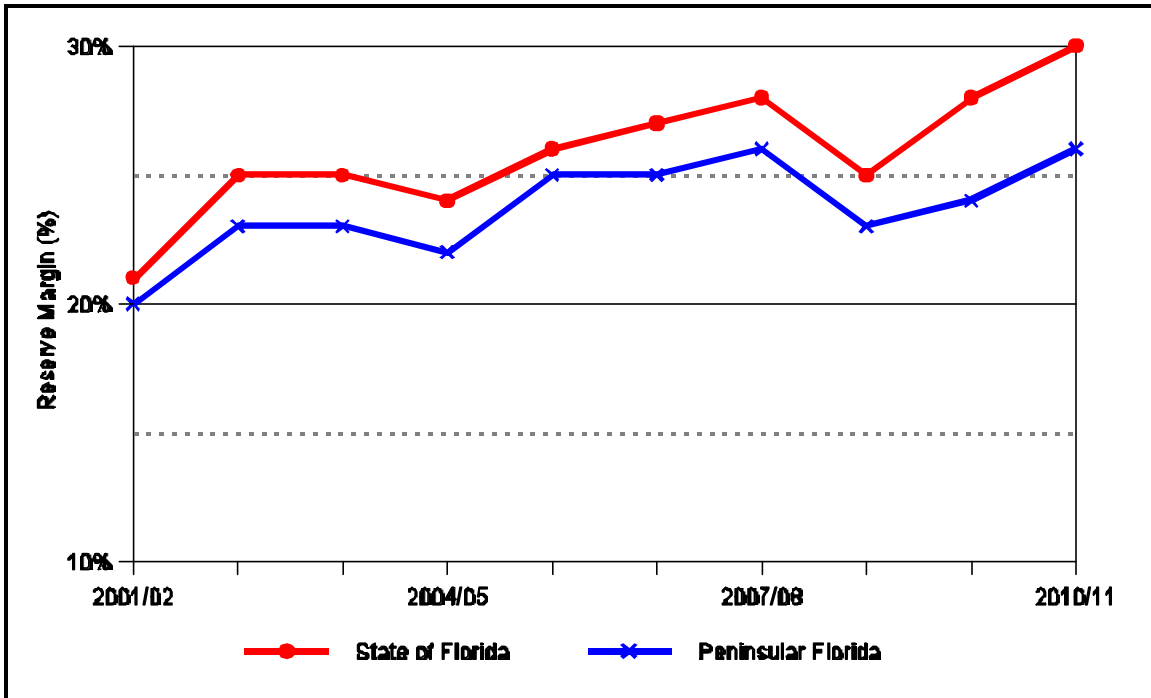


Figure 14. FORECASTED WINTER RESERVE MARGIN

3.6.3 COMMISSION ACTIONS AFFECTING RELIABILITY

In the late 1990's, the Commission became increasingly concerned with the declining reserve margins forecasted by Florida's utilities and the impact of such declines on reliability. However, much of the Commission's concerns on reliability have been mitigated by two actions:

Reserve Margin Agreement (FPC, FPL, and TECO)

The Commission opened Docket No. 981890-EU to investigate the adequacy of reserve margins for Peninsular Florida's utilities. All generating utilities in Peninsular Florida were part of the investigation. Gulf was not investigated because its service territory is not contained in Peninsular Florida.

The Commission concluded its reserve margin investigation when, on November 30, 1999, it approved an agreement by FPC, FPL, and TECO to adopt a 20% reserve margin planning criterion starting in the summer of 2004. The agreement does not extend to municipal and cooperative electric utilities, who can therefore carry their current level of reserves. However, since FPC, FPL, and TECO make up approximately 75% of Peninsular Florida's generation, all municipal and cooperative utilities could carry exactly the FRCC minimum 15% reserve margin and the weighted average reserve margin for Peninsular Florida would still be nearly 19%. It should be noted that Florida's municipal and cooperative utilities typically have reserves exceeding 20% in most years.

Announcement of New Merchant Plant Capacity in Florida.

There is considerable interest in constructing merchant plants in Florida. Most merchant plant developers plan to build natural gas-fired combustion turbine or combined cycle generators. Recent technological improvements, combined with the low price of natural gas, results in low production costs for these types of generators, giving merchant plant owners an opportunity to sell electricity in the wholesale market.

Unless specific contracts exist, Florida's load-serving utilities have no obligation to purchase electricity from merchant plants. Likewise, merchant plants have no obligation to sell electricity to Florida's load-serving utilities absent a contract. As a practical matter, most sales from in-state merchant plants will likely stay in-state because of transmission line constraints on the Southern Company-FRCC interface and the low marginal cost of coal-fired electricity in the Southern Company region.

During periods of capacity shortages, merchant plants may enhance the reliability of Peninsular Florida's grid without putting retail ratepayers at risk for the costs of the facility. When a merchant plant is unavailable due to planned or forced outages, or is uneconomical to operate due to high fuel costs, the merchant plant's owners bear the costs rather than retail customers.

Several companies have announced plans to construct combined cycle and combustion turbine merchant plants in Florida over the next five years. Approximately 60 of these units, totaling around 8,000 MW of capacity, have either received their air permit from DEP or have applied for one. It is estimated that 14 of these units, totaling approximately 2,200 MW, will be gas-fired combined cycle generators which normally would require certification under the Power Plant Siting Act. However, the owners of these units will limit their steam-fired capacity output to below 75 MW.

As noted previously, the FRCC did not include any merchant plant additions in its **2001 Regional Load and Resource Plan**. The Commission has compiled a list of proposed merchant plants; this list is shown previously in Table 5 on page 14. If these merchant plant developers were to sign firm capacity contracts to sell all of their output to load-serving utilities, Peninsular Florida summer reserve margins could potentially increase from 23% to 43% by summer, 2005. However, it is more likely that some proposed merchant plants will either not be built or will defer planned utility generating units if purchased power contracts are signed.

3.7 FUEL FORECASTS

Florida's electric utilities consider several strategic factors such as fuel mix, fuel availability, and environmental compliance prior to selecting a supply-side resource. However, fuel prices are the primary factor affecting the **type** of generating unit added. The reporting utilities produced base-case fuel price forecasts for most fuels. Some utilities produced high- and low-price sensitivities.

Although each utility has its own unique method for forecasting fuel prices, the reporting utilities generally perform the following steps:

- (1) Apply specific knowledge of contractual relationships with fuel vendors to reasonable assumptions of future events which the utility cannot control.
- (2) Perform forecast sensitivities by modifying base-case assumptions to test the utility's generation expansion plan under various economic and technical scenarios.
- (3) Compare utility fuel price forecasts to outside sources such as the U.S. Energy Information Administration (EIA).

The Commission has compared each utility's fuel price forecast with the respective EIA forecast. EIA's comprehensive fuel price forecasts fall within a reasonable range of forecasts provided by the other outside sources. Table 8, on the next page, shows the forecasted annual average growth rate (AAGR) in price for each fuel, as forecasted by the reporting utilities and by EIA.

Florida's investor-owned utilities forecast fuel prices to increase at a more moderate pace during the planning horizon than does EIA. EIA believes that prices for residual and oil, distillate oil, and, to some extent, natural gas, are correlated to the world price for crude oil. In 2000, the world price for crude oil doubled due to increased demand and stagnant supply. However, Florida's utilities anticipate that recent price increases were a short-term occurrence, and that market forces will push world oil prices down from recent heights. Prices for residual oil, distillate oil, and natural gas are expected to similarly decline.

The Commission also recognizes that each utility's fuel price forecast reflects assumptions made about relevant factors that affect fuel prices. The Commission encourages each utility to periodically review these assumptions so that they accurately reflect real-world conditions. If the utility's assumptions are no longer consistent with real-world conditions, the Commission would expect to see a corresponding change in the fuel price forecast.

3.7.1 COAL

The average U.S. delivered cost of coal in 2000 decreased to \$24.28 per ton, down \$0.44 per ton from 1999. EIA attributes this decrease to the expiration, renegotiation, and buyout of older high-priced coal contracts; improvements in efficiency in coal mining and transportation; and, excess coal mining capacity.

In early 2001, the demand for coal increased as crude oil prices doubled and natural gas prices quadrupled from previous levels. This increase in coal demand, combined with a relatively stable supply, placed upward pressure on coal prices. Through 2009, EIA forecasts that delivered coal prices will increase at a rate of around 0.7% per year.

TABLE 8. FUEL PRICE FORECAST -- AVERAGE ANNUAL GROWTH RATE (2001 - 2010)

UTILITY	COAL	RESIDUAL OIL	DISTILLATE OIL	NATURAL GAS	NUCLEAR
EIA	0.7%	6.5%	3.7%	3.6%	NA
Florida Power Corporation	0.0%	3.4%	3.4%	0.5%	1.8%
Florida Power & Light Company	NA	-2.4%	-0.5%	-1.6%	0.7%
Gulf Power Company	1.3%	NA	2.5%	0.0%	NA
Tampa Electric Company	1.8%	0.4%	0.9%	-0.3%	NA
Florida Municipal Power Agency	NA	NA	NA	NA	NA
Gainesville Regional Utilities	0.6%	2.5%	2.7%	-1.1%	4.1%
JEA	-0.4%	0.0%	5.6%	1.2%	NA
Kissimmee Utility Authority	1.4%	-0.5%	0.4%	-4.9%	2.6%
City of Lakeland	3.2%	7.1%	4.5%	4.7%	NA
Orlando Utilities Commission	1.2%	6.5%	4.0%	4.2%	2.6%
City of Tallahassee	1.5%	-0.2%	0.2%	0.9%	NA
Seminole Electric Cooperative	0.8%	-3.8%	-0.7%	3.6%	2.8%

3.7.2 PETROLEUM

Florida's utilities primarily consume three types of petroleum-derived products: **distillate**, or light (#2) oil; **residual**, or heavy (#6) oil; and **petroleum coke**. While distillate oil is typically burned in peaking units, utilities normally burn residual oil and petroleum coke in baseload and in cycling units.

Residual Oil

EIA reports that the average U.S. delivered cost of residual oil in 2000 was \$4.01/MMBtu, up considerably from \$2.49/MMBtu in 1999. Through 2009, EIA anticipates that long-term residual oil prices will increase at approximately 6.5% per year. Florida's utilities forecast changes in residual oil prices ranging from -2.4% to +7.1% per year during the planning horizon.

Distillate Oil

EIA reports that the average U.S. delivered cost of distillate oil in 2000 was \$7.57/MMBtu, up considerably from \$4.99/MMBtu in 1999. Through 2009, EIA anticipates that long-term distillate oil prices will increase at approximately 3.7% per year. Florida's utilities forecast changes in distillate oil prices ranging from -0.7% to +5.6% per year during the planning horizon.

Petroleum Coke

Utilities in Florida have increasingly begun to use petroleum coke as a viable boiler fuel. With the proper emission control technology, utilities can blend petroleum coke with coal to achieve fuel cost savings over the sole use of coal. The reporting utilities expect to increase annual petroleum coke consumption from about 685,000 to 3,156,000 tons per year during the planning horizon.

3.7.3 NATURAL GAS

The average cost of natural gas for electric utilities nationwide in 2000 was \$4.32/MMBtu, up over 65% over 1999 costs. Several factors influence short-term natural gas prices: gas availability, storage levels, short-term fluctuations in residual and distillate oil prices, and weather implications. Florida's utilities forecast changes in natural gas prices ranging from -4.9% to +4.7% per year during the planning horizon.

The Commission examined the status of proven natural gas reserves at both the national and regional level. If sufficient quantities of natural gas are not available, prices may rise to prohibitively expensive levels which may cause natural gas-fired generation to be more costly than other types of generation. At the end of 1999, EIA estimated that U.S. proven natural gas reserves were approximately 167.4 trillion cubic feet (Tcf), a slight (2.1%) increase over year-earlier estimates. However, most natural gas consumed in Florida originates either from the Gulf of Mexico or from states adjacent to this region. EIA estimated, at the end of 1999, that proven natural gas reserves in the Gulf of Mexico region were approximately 79.9 Tcf, a 1.8% increase from year-earlier estimates. EIA also estimated natural gas production in this region at approximately 11.7 Tcf in 1999.

3.7.4 NUCLEAR

EIA expects that energy generation from nuclear will decrease by 0.1% per year during the planning horizon. By the year 2015, EIA assumes that nationwide nuclear capacity will drop by 18% due to the expected retirement of several nuclear units. However, both FPL and FPC expect their nuclear units to operate throughout the planning horizon.

Spent nuclear fuel disposal is a primary concern to both FPL and FPC. The U.S. DOE has been collecting a 0.1 ¢/kWh fee on nuclear-fired generation to finance the management and disposal of spent nuclear fuel. Nationwide, ratepayers pay approximately \$600 million per year into the DOE's Nuclear Waste Fund. FPL and FPC ratepayers pay a combined total of nearly \$25 million per year into the fund. However, DOE has yet to begin accepting spent nuclear fuel, and utilities nationwide may incur significant costs to build additional on-site spent fuel storage capacity. If DOE removal of spent nuclear fuel from reactor sites does not occur, an estimated 80% of the utilities' spent fuel pools will reach capacity by 2010.

3.7.5 RENEWABLES

Renewable sources comprise four broad categories: **solar**, **wind**, **water**, and **biomass**. Through tax incentives, legal mandates, and technical assistance going back over 25 years, federal and state governments have attempted to increase the amount of electricity derived from renewable sources. Because of relatively high capital and operating costs, renewable energy has consistently accounted for only 0.2% of the state's total energy generation since 1980. In Florida, non-utility generators sell around 450 MW of renewable capacity, in the form of municipal solid waste-fired capacity, to the grid. Renewable energy is currently generated at four utility-owned sites:

- TAL's Corn Station generates 11 MW of hydroelectric capacity;
- LAK and OUC use refuse-derived fuel to supplement the coal-fired generation at McIntosh Unit 3;
- OUC can burn landfill methane gas in both of its Stanton coal units; and
- JEA burns landfill methane gas at its 3 MW Girvin facility.

3.8 GENERATION SELECTION

Florida's utilities supply electricity from many generating unit types. However, generating units in Florida were fueled primarily by oil prior to the early 1970's. While oil-fired generation still provides just under 18% of Florida's electricity at present, the oil embargoes of the 1970's forced utilities to turn more to domestic fuels such as coal, nuclear, and natural gas to generate electricity. Figure 15 illustrates the historical and forecasted energy generation mix by fuel type for Florida's electric utilities.

Over the next ten years, Florida's utilities forecast a substantial increase in natural gas-fired generation as the emphasis shifts away from oil-fired and coal-fired generating units. Nearly all gas-fired capacity is expected to come from efficient combined cycle and combustion turbine units. Coal-fired generation is not considered a viable option for most of Florida's electric utilities because of environmental constraints and high construction costs, although both JEA and LAK have proposed coal units in their *Ten-Year Site Plans*. Likewise, additional nuclear power plants are not considered a viable option in Florida's future primarily because of high construction costs and uncertainty over spent fuel disposal.

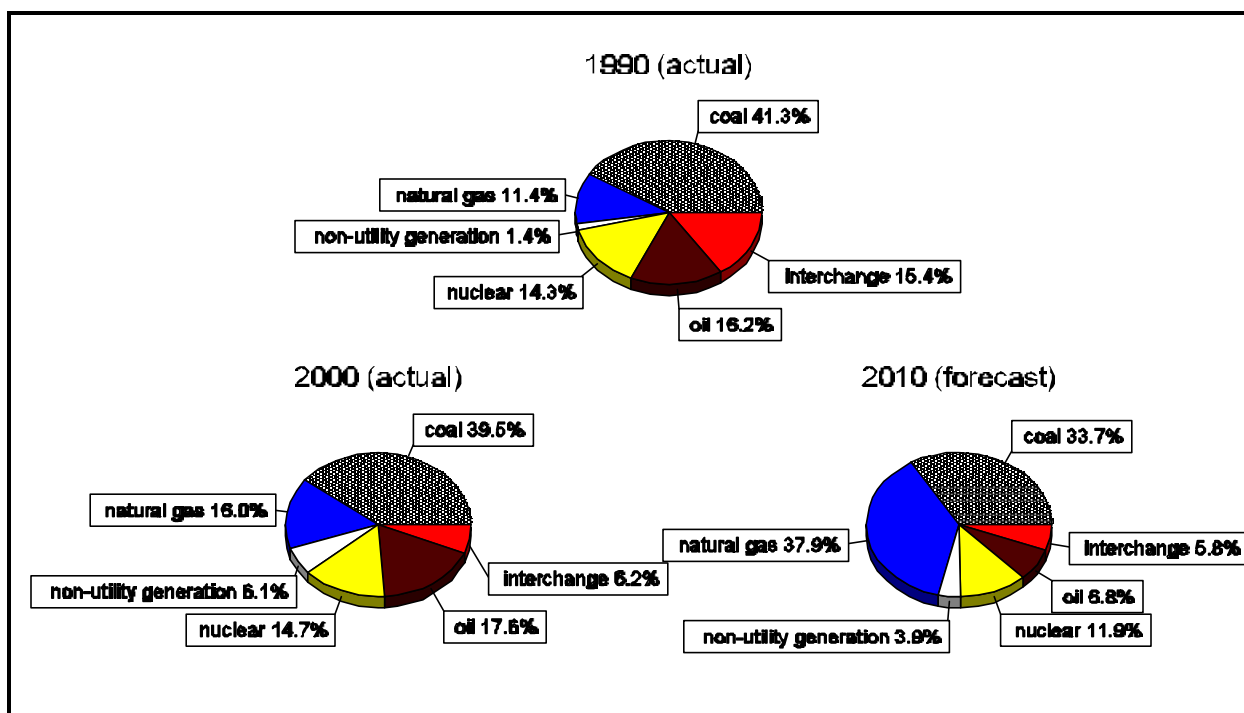


Figure 15. ENERGY GENERATION BY FUEL TYPE / HISTORY AND FORECAST

.8.1 NATURAL GAS

Florida's utilities project a substantial increase in natural gas-fired generation over the next ten years, from approximately 16% to 38% of all energy generated. The increase is due primarily to planned combined cycle and combustion turbine unit additions. In addition, all proposed unit repowerings and unit additions by non-utility generators are expected to use natural gas. Projections of increased natural gas consumption do not include the recently announced new merchant plants.

3.8.2 COAL

Coal generation increased substantially during the 1980's in response to the oil price increases of the 1970's. Coal plants have traditionally been justified based on low forecasts of coal prices relative to oil

or natural gas. However, coal plants are capital-intensive, and there are increased concerns surrounding the emissions of coal plants that may lead to stricter regulations that further increase capital investments at coal plants. As a result, Florida's utilities forecast that coal-fired energy will slowly decrease, from a current level of 39.5% down to approximately 34% of all energy produced over the next ten years.

3.8.3 COAL GASIFICATION

Coal gasification technology appears to provide utilities the flexibility to meet potential environmental restrictions and address concerns over the high initial capital investment, if the combined cycle portion of the facility is constructed first. If the differential between oil / natural gas and coal widens, the savings from coal gasification might justify additional capital investment at that time. As a result, for power plant siting purposes, it is important to consider whether a site can support coal gasification and all the implications to the local transportation infrastructure. No Florida utility currently plans to build a new coal gasification plant.

3.8.4 INTERCHANGE PURCHASES

Peninsular Florida's utilities continue to rely on capacity and energy purchases from out-of-state utilities. Interchange purchases are typically short-term purchases of excess capacity and energy between utilities. Florida can safely import approximately 3600 MW over the Southern Company-Florida interconnection. Of the total interface, approximately 2600 MW is currently reserved for firm sales, leaving approximately 1000 MW available for non-firm, economy transactions.

Florida's utilities forecast a slow decline in interchange power purchases over the planning horizon. Interchange purchases are forecasted to comprise 5.8% of all energy consumed in ten years, down slightly from a current level of 6.1%. The forecasted slight decrease is primarily because load growth in Southern Company's territory is expected to use much of the excess capacity and energy currently available for resale to Florida. While the amount of interchange power is projected to decrease, the transfer capability between Southern Company and Peninsular Florida is expected to remain at approximately 3600 MW. As a result, some capacity from Southern Company should remain for economy and emergency transactions.

3.8.5 PURCHASES FROM NON-UTILITY GENERATORS

Non-utility generators (NUGs) build and operate power plants to satisfy contractual requirements with retail-serving electric utilities. NUGs supply firm capacity to many of Florida's utilities under long-term and short-term purchased power contracts. NUGs do not serve retail customers.

The amount of NUG electricity purchased by Peninsular Florida's utilities is expected to decrease, from 6.2% to 3.9% of total energy consumed, during the planning horizon. The forecasted decrease is due to the expiration of around 970 MW of firm NUG contracts. However, these generators will remain once their contracts expire, and it is likely that the owners of these NUGs will sign new purchased power contracts with utilities.

3.8.6 HYDROELECTRIC

While existing hydroelectric generating units continue to make a minute contribution (less than 0.1%) to Peninsular Florida's generation mix, there are no planned new units due to the absence of a feasible location. Florida's flat terrain does not lend itself to hydroelectric power.

3.9 STATUS OF NEED DETERMINATIONS & SITE CERTIFICATIONS

The Commission has granted a Determination of Need for several generating units in recent years. Many of these units have gone on to receive certification under the Power Plant Siting Act (Sections 403.501 through 403.518, Florida Statutes) by Florida's Governor and Cabinet, acting as the Power Plant Siting Board.

The following summary describes those generating units that have received a Determination of Need from the Commission but have yet to be placed into commercial operation.

Seminole Electric Cooperative -- Payne Creek Generating Station Unit 1

The Commission granted SEC's need petition for a 440 MW combined cycle unit at the existing Hardee Power Station site in June, 1994. This unit was certified under the Power Plant Siting Act in August, 1995 and originally was to be in service by 1999. However, SEC deferred construction of the unit in order to purchase cost-effective firm capacity from FPC. The revised capacity of the unit is 574 MW, and the anticipated in-service date is January, 2002.

Gulf Power Company -- Smith Unit 3

In June, 1999, the Commission granted Gulf's petition for a 532 MW gas-fired combined cycle unit at the existing Lansing Smith site in Bay County. Smith Unit 3 was certified under the Power Plant Siting Act in July, 2000. Gulf began construction on the unit in November, 2000 to meet an in-service date of June, 2002.

City of Lakeland -- McIntosh Unit 5

In April, 1999, the Commission granted LAK's petition to build a 120 MW steam turbine portion of a 365 MW combined cycle unit at the McIntosh site in Polk County. The steam turbine portion of McIntosh Unit 5 was certified under the Power Plant Siting Act in June, 2000. Construction began immediately thereafter to meet an anticipated January, 2002 in-service date.

Florida Power Corporation -- Hines Unit 2

In December, 2000, the Commission granted FPC's petition to build a 567 MW gas-fired combined cycle unit at the existing Hines plant site in Polk County. This unit was certified under the Power Plant Siting Act in September, 2001. The unit has an anticipated November, 2003 in-service date.

Panda Energy International, Inc. (Panda) questioned whether FPC properly evaluated proposed bids offered as alternatives to Hines Unit 2. On February 5, 2001, Panda appealed the Commission's approval to the Florida Supreme Court. The Supreme Court's final decision is expected later this year. Construction on the unit is scheduled to start early in 2002.

JEA -- Brandy Branch Unit 4

In February, 2001, the Commission granted JEA's petition to add a 191 MW heat recovery steam generator (HRSG) at the new Brandy Branch site in Duval County. The HRSG, with an anticipated June, 2003 in-service date, will be fitted to two 191 MW combustion turbine units already placed into service in January, 2001, forming a 573 MW combined cycle unit. JEA is awaiting final certification from the Power Plant Siting Board.

Seminole Electric Cooperative / Calpine Construction Finance Company -- Calpine Osprey Unit

In April, 2001, the Commission granted a joint petition by SEC and Calpine to construct a 529 MW gas-fired combined cycle unit at a new site in Polk County. The unit will be owned by Calpine, who will sell 350 MW of firm capacity to SEC from June, 2004 through May, 2009. The expected in-service date of the unit is the second quarter of 2003. Subject to contract reopener provisions, SEC may purchase up to

the full output of the unit through May, 2020. SEC and Calpine are awaiting a final certification decision from the Power Plant Siting Board.

Orlando Utilities Commission / Kissimmee Utility Authority / Florida Municipal Power Agency/Southern Company-Florida, LLC – Stanton Unit A

In April, 2001, the Commission granted a joint petition by OUC, KUA, FMPA, and Southern-Florida to construct a 633 MW gas-fired combined cycle unit at the existing Stanton site in Orange County. This unit was certified under the Power Plant Siting Act in September, 2001. Construction began immediately thereafter to meet an anticipated October, 2003 in-service date.

3.10 PLANNED UTILITY-OWNED GENERATING UNITS REQUIRING CERTIFICATION

The *Ten-Year Site Plans* filed by the reporting utilities contain proposed generating units which will require certification under the Power Plant Siting Act prior to their construction. This section summarizes these proposed units. The general location of these sites can be found in Figure 5 on page 13.

Florida Power Corporation -- Hines Units 3, 4, and 5

FPC has proposed to add three new 596 MW, gas-fired combined cycle units at the existing Hines plant site in Polk County. Identical to the first two units at the site, Hines Units 3-5 are currently scheduled to be placed into commercial service in 2005, 2007, and 2009, respectively. All three proposed Hines units will require certification under the Power Plant Siting Act. A request for proposals to seek out alternatives to Unit 3 will be issued next year.

Florida Power & Light Company -- Martin Units 5 and 6; Midway Unit 1; five Unsited combined cycle units

FPL plans to add two new 596MW, gas-fired combined cycle units at the existing Martin plant site in Martin County. Martin Units 5 and 6 are currently scheduled to begin commercial service in June, 2005 and June, 2006, respectively. FPL also plans to add an identical unit at the new Midway site in St. Lucie County. Midway Unit 1 as an anticipated in-service date of June, 2005. All of these proposed units will require certification under the Power Plant Siting Act. A request for proposals to seek alternatives to Martin Unit 5 has been issued.

FPL has also proposed to build five 596 MW gas-fired combined cycle units at yet-to-be determined sites. These units have planned in-service dates of 2007, 2009, and 2010 (three units), respectively. If FPL ultimately decides to build these units, they will require certification under the Power Plant Siting Act.

JEA – Unsited combined cycle unit; Unsited Coal Unit

JEA has proposed to build a new 352 MW gas-fired combined cycle unit at a yet-to-be determined site in Duval County. The proposed unit has a tentative in-service date of January, 2007. JEA has also proposed to build a 250 MW pulverized coal at a yet-to-be determined site in Duval County. This unit has a tentative in-service date of may, 2010. If these units are ultimately built, they will require certification under the Power Plant Siting Act.

City of Lakeland -- McIntosh Unit 4

LAK has proposed to construct a 288 MW pressurized fluidized bed coal unit at the existing McIntosh plant site in Polk County. This unit was formerly a candidate for funding from the U.S. Department of Energy's Clean Coal Technology Program. LAK plans to petition the Commission for a Determination of Need in the near future to meet a June, 2005 in-service date. This unit will require certification under the Power Plant Siting Act.

4.0 REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

4.1 FLORIDA POWER CORPORATION (FPC)

4.1.1 GENERATION SELECTION

As seen in Table 9, FPC's system winter capacity is currently 9,824 MW. Of this total, 8,574 MW comes from FPC-owned generation. Firm interchange purchases account for 469 MW, while the remaining 831 MW comes from non-utility generators. FPC currently exports 50 MW of firm capacity to other utilities.

FPC plans to add one 567 MW, and three 579 MW, gas-fired combined cycle units at the **Hines** site in 2003, 2005, 2007, and 2009, respectively. Planned for 2006 is a new 182 MW combustion turbine unit at the **DeBary** site. FPC plans to retire nine units with a total generating capacity of 392 MW. The following sites will be affected: **Higgins** (134 MW), **Suwannee** (146 MW), **Avon Park** (64 MW), **Turner** (32 MW), and **Rio Pinar** (16 MW). Additionally, FPC expects to lose approximately 175 MW due to the expiration of five cogeneration contracts. Current firm exports of 50 MW are forecasted to end by 2007.

TABLE 9. FPC – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	782	0
Coal	2341	0
Firm Imports	469	10
Firm Exports	-50	50
Firm Non-Utility Generation	831	-173
Combined Cycle	752	2304
Fossil Steam	1642	-146
Combustion Turbine	3057	-64
TOTAL	9824	1981

4.1.2 RELIABILITY CRITERIA

FPC currently plans resource additions on its system to meet a dual reliability criteria of 15% summer and winter peak reserve margin and a 0.1 days per year loss of load probability (LOLP). Pursuant to a stipulation reached in the Commission's reserve margin investigation (Docket No. 981890-EU), FPC has agreed to raise its reserve margin criterion to 20% starting in the summer of 2004. FPC currently plans to retain its LOLP planning criterion. FPC is a winter-peaking utility.

4.1.3 LOAD FORECAST

FPC identifies and justifies its load forecast methodology via its models, variables, data sources, assumptions, and informed judgements. The Commission believes that all of these factors have been accurately documented. A combination of short-term econometric models and an hourly and annual peak and energy end-use forecasting system provide a sound foundation for planning purposes. The variables used were obtained from reputable sources and are representative of a valid load forecast model.

Under base-case assumptions, FPC forecasts that winter firm demand will increase at an average annual growth rate (AAGR) of 1.24% per year over the next ten years, considerably below the actual 1991-2000 AAGR of 3.85%. For the 2001-2010 planning horizon, base-case summer firm demand is forecasted to grow at an AAGR of 1.33%. FPC assumes the loss of a short-term wholesale sales contract with Seminole Electric Cooperative, thus accounting for most of the slow forecasted demand growth. In addition, forecasted retail sector growth is below the historical average due to slower population growth, less rapid economic expansion, and improved appliance efficiencies. FPC has the lowest forecasted growth rate of all reporting utilities.

FPC's 1996-2000 retail sales forecasts have an absolute forecast error of 1.18%, considerably below the 3.02% average for the reporting utilities. Over the same period, FPC's retail sales forecasts have an average forecast error of 0.12%, which shows a history of slightly over-forecasting.

4.1.4 DEMAND-SIDE MANAGEMENT

The Commission set new DSM goals for FPC in August, 1999. These goals call for a cumulative reduction of 163 MW of summer peak demand, 426 MW of winter peak demand, and 204 GWh of energy consumption over the next ten years. FPC's DSM Plan was approved by the Commission in April, 2000.

FPC's DSM Plan consists of 14 programs -- five residential, eight commercial/industrial, and one research and development. FPC also has a low income pilot program offered in conjunction with the Department of Community Affairs. In total, FPC's DSM programs are forecasted to reduce 2010 winter peak demand by 1595 MW (15.8%). Much of FPC's winter, 2010 forecasted savings are attributed to non-dispatchable conservation programs (631MW), interruptible service tariffs (344 MW), and load management (620 MW). Due to decreased customer participation, residential load management savings are forecasted to drop by approximately 240 MW during the planning horizon.

However, non-firm resources such as interruptible service and load management make up a substantial part of FPC's reserve margin. Non-firm resources currently comprise approximately 78% of FPC's winter reserves. In recent years, the Commission has been concerned with the level of non-firm reserves carried by FPC. However, this appears to be primarily a winter problem and is expected to be short-term. FPC forecasts a considerable level of customer attrition from its load management program, and FPC's reliance on non-firm resources is expected to drop to 55% by winter, 2010 as new supply-side resources are added.

4.1.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA provided general comments on FPC's *Ten-Year Site Plan*. Stated that the Hines facility is consistent with applicable local land use and zoning ordinances.

Florida Department of Environmental Protection (DEP)

DEP found that FPC's *Ten-Year Site Plan* is adequate for planning purposes.

South Florida Water Management District

The District does not have any adverse comments regarding the suitability of FPC's proposed plant sites.

Southwest Florida Water Management District

The District has concerns with the number of proposed inland sites for plant expansion. The District recommends that the utilities consider coastal alternatives for plant expansion to take advantage of sea water for cooling purposes.

Tampa Bay Regional Planning Council

FPC's *Ten-Year Site Plan* is consistent with regional policies. The proposed combined cycle units at the Polk site will have a net positive effect on air and water quality in the region due to lower emissions and decrease cooling water requirements.

4.1.6 SUITABILITY

Forecasted reserve margins are expected to be at or above FPC's criterion of 15% for each seasonal peak through the summer of 2004, after which time forecasted reserve margins are expected to be at or above the new 20% criterion. FPC's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.2 FLORIDA POWER & LIGHT COMPANY (FPL)

4.2.1 GENERATION SELECTION

As seen in Table 10, FPL's system winter capacity is currently 19,955 MW. Of this total, 17,750 MW comes from FPL-owned generation. Firm capacity purchases from Southern Company and JEA account for another 1,319 MW of firm capacity, while purchases from non-utility generators comprises the remaining 886 MW.

FPL plans to add approximately 5,850 MW of supply-side resources during the planning horizon. A significant part of FPL's expansion plan is the repowering of existing **Ft. Myers** and **Sanford** generating units. FPL is constructing state-of-the-art combustion turbines to feed steam into the existing boilers, thus operating as combined cycle units. These unit repowerings alone are expected to add over 2,400 MW of winter generating capacity to FPL's system by May, 2003. These unit repowerings were exempt from the Power Plant Siting Act and have had no pre-approval from the Commission.

FPL placed into service, in June, 2001, two 181 MW CT units at the **Martin** site. Also proposed during the planning horizon are five 596 MW gas-fired combined cycle units: **Martin Unit 5** and **Midway Unit 1** in June, 2005; **Martin Unit 6** in June, 2006, and a yet-to-be sited unit in 2007 and 2009. Firm capacity imports are expected to increase by over 1,000 MW in 2002, but drop back to current levels by 2005. FPL forecasts a loss of approximately 200 MW from non-utility generators due to the expiration of four cogeneration contracts.

TABLE 10. FPL – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	3013	0
Coal	926	0
Firm Imports	1319	0
Firm Non-Utility Generation	886	-203
Combined Cycle	2528	5246
Fossil Steam	8432	-386
Combustion Turbine	2851	1192
TOTAL	19955	5849

4.2.2 RELIABILITY CRITERIA

Prior to 1998, FPL planned resource additions on its system to meet a dual reliability criteria of 15% summer peak reserve margin and a 0.1 days per year loss of load probability (LOLP). In 1998, FPL added a third reliability criterion, 15% winter peak reserve margin. Pursuant to a stipulation reached in the Commission's reserve margin investigation (Docket No. 981890-EU), FPL has agreed to raise its summer and winter planning reserve margin to 20% starting in the summer of 2004. FPL plans to retain its LOLP planning criterion.

FPL has traditionally been a summer-peaking utility because winter temperatures have been mild in recent years. However, FPL forecasts that winter peak demand will be higher than summer peak during the planning horizon.

4.2.3 LOAD FORECAST

FPL develops its residential load forecast with an integrated end-use/econometrics model. This method forecasts electricity sales in the residential sector simulating the energy usage of eleven major residential appliances plus residual electricity use. Following an analysis of appliance stock, prices, and other factors, electricity consumption is then aggregated across all households to generate a forecast for total residential sales. In addition, the model simulates appliance stock in new and existing homes by taking energy, weather, and conservation measures into consideration.

FPL adequately identifies and describes the models, variables, data sources, assumptions, and informed judgements used to generate its demand and energy forecasts. The Commission believes that these factors have been accurately documented and that FPL's data sources are credible.

Under base-case assumptions, FPL forecasts that summer firm demand will increase at an AAGR of 2.37%, considerably above the actual 1990-1999 AAGR of 1.04%. FPL's 2001 base-case summer peak demand forecast is higher than its 2000 forecast by an average of 1,175 MW over the forecast horizon. FPL attributes the rise of the telecommunications industry for 570MW of this increase. Other contributors include a larger customer base, continued economic growth, and an increasing stock of electricity-consuming appliances.

For the 2001-2010 planning horizon, FPL's base-case winter firm demand is forecasted to grow at an AAGR of 2.31%. FPL's 2001 base-case winter peak demand forecast is higher than its 2000 forecast by an average of 1,140 MW over the forecast horizon due to the same factors that affect summer peak demand.

FPL's 1995-1998 retail sales forecasts have an absolute percent error of 1.88%, which is lower than the 3.02% average for the reporting utilities. For the same five-year period, FPL's retail sales forecasts have an average forecast error of -1.77%, which reflects a history of under-forecasting.

4.2.4 DEMAND-SIDE MANAGEMENT

The Commission set new DSM goals for FPL in August, 1999. These goals call for a cumulative reduction of 765 MW of summer peak demand, 505 MW of winter peak demand, and 1,287 GWh of energy consumption over the next ten years. FPL's DSM Plan was approved by the Commission in April, 2000.

FPL currently offers six residential and eight commercial/industrial DSM programs to its customers. These programs are forecast to reduce winter peak demand by 2,345 MW by 2010, representing approximately 10.3% of FPL's total winter peak demand. These programs are also projected to reduce FPL's system annual energy usage by 1,210 GWh (1%) in 2010.

4.2.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA expressed general concerns with the ongoing repowering projects at Ft. Myers and Sanford, as well as proposed new generation at Martin. DCA also provided general comments on the future use of the Cape Canaveral, Riviera, and Port Everglades power plant sites and the Midway substation site.

Florida Department of Environmental Protection (DEP)

DEP found that FPL's *Ten-Year Site Plan* is adequate for planning purposes.

Lee County

FPL's *Ten-Year Site Plan* is consistent with the County's comprehensive plan. Expansion at existing sites, such as Ft. Myers, is consistent with the comprehensive plan.

Northeast Florida Regional Planning Council

No new plants or modifications to existing sites are expected in the Region. Therefore, no comments are offered on FPL's *Ten-Year Site Plan*.

Southwest Florida Regional Planning Council

Supports FPL's Ft. Myers repowering project because of improved air emissions, elimination of a tank farm, and elimination of barge traffic in adjacent waterways.

South Florida Water Management District

The District does not have any adverse comments regarding the suitability of FPL's proposed plant sites.

Southwest Florida Water Management District

The District has concerns with the number of proposed inland sites for plant expansion. The District recommends that the utilities consider coastal alternatives for plant expansion to take advantage of sea water for cooling purposes.

Treasure Coast Regional Planning Council

The Council has previously found that expansion at the Martin site does not conflict with regional policies. Agrees with FPL's identification of the Riviera site for possible future expansion because it is an existing site. Provided general comments on its belief that FPL and the State of Florida should develop new programs to reduce reliance on coal and other fossil fuels, increase conservation to offset the need for new plants, and increase reliance on photovoltaic systems to produce electricity.

Tampa Bay Regional Planning Council

FPL's *Ten-Year Site Plan* is consistent with regional policies.

4.2.6 SUITABILITY

Forecasted reserve margins are expected to meet or exceed FPL's 15% criterion for each seasonal peak through the summer of 2004. After that time forecasted reserve margins are expected to meet or exceed the new 20% criterion. FPL's *Ten-Year Site Plan* is ***suitable*** for planning purposes.

4.3 GULF POWER COMPANY (Gulf)

4.3.1 GENERATION SELECTION

As seen in Table 11, Gulf's system winter capacity is currently 2,379 MW. Gulf owns 2,259 MW of this capacity, purchases 320 MW of firm capacity via interchange, purchases 19 MW from a single non-utility generator, and exports 219 MW to other Southern Company members.

The primary unit addition in Gulf's *Ten-Year Site Plan* is the 574 MW **Smith Unit 3**, the first gas-fired combined cycle unit on Gulf's system. This unit is expected to be placed into commercial service in June, 2002. Gulf also plans to build a new 157 MW gas-fired combustion turbine unit at the Smith site. This unit is expected to be placed into service in June, 2005. Gulf expects to have a 60 MW ownership share of a generic combustion turbine unit to be located in Southern Company's territory. This unit is expected to be placed into commercial service in 2007. Firm imports are forecasted to drop to approximately 11 MW during the planning horizon, while firm exports are expected to drop to 210 MW during that time. Gulf also plans to retire a 40 MW combustion turbine at the Smith site in December, 2006. Finally, Gulf will also lose 19 MW due to the expiration of its only cogeneration contract.

TABLE 11. GULF – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	2122	0
Firm Imports	320	-309
Firm Exports	-219	9
Firm Non-Utility Generation	19	-19
Combined Cycle	0	574
Fossil Steam	83	0
Combustion Turbine	54	177
TOTAL	2379	432

4.3.2 RELIABILITY CRITERIA

Gulf is typically a summer peaking utility because natural gas (for heating) is readily available in its service territory. Southern Company currently uses a systemwide 13.5% reserve margin for its near-term (3-year) criterion. Beyond three years (in this case, 2004), the reserve margin planning criterion is 15%.

Nonetheless, Gulf forecasts that its planning criteria will be violated in the summer of 2001, 2004, 2008, and 2009. Gulf also expects to violate its planning criterion for the upcoming winter (2001/02). Gulf's *Ten-Year Site Plan* discusses at length the company's ability to rely on firm capacity interchange from other Southern Company members to meet capacity deficiencies on Gulf's system. As seen in Table 12 on the next page, the magnitude of Gulf's reserve deficiency is forecasted to grow to 75 MW by summer, 2010. This illustrates Gulf's expectation that it will be a net purchaser of capacity from the Southern Company pool.

Because Gulf's service territory is not located in Peninsular Florida, Gulf is not bound by the 20% reserve margin stipulation reached by FPC, FPL, and TECO in the Commission's reserve margin investigation (Docket No. 981890-EU).

TABLE 12. GULF – CAPACITY NEEDED TO ACHIEVE RESERVE MARGIN CRITERION				
SEASON (YEAR)		RESERVE MARGIN (%)		RESERVE DEFICIENCY (MW)
		FORECASTED	CRITERION	
SUMMER	2001	11.5%	13.5%	45
	2004	13.9%	15%	25
	2008	13.6%	15%	34
	2009	12.0%	15%	75
WINTER	2001/02	10.7%	13.5%	60

4.3.3 LOAD FORECAST

Gulf uses different methods to produce its short-term (0-2 years) and intermediate/long-term (3-25 years) forecasts. Short-term forecasts are based upon a variety of forecasting methods. Customer growth estimates are made using the aggregate of district projections performed by district personnel based on their contacts with sectors of the local economy and historical trends. Short-term energy sales forecasts are developed using multiple regression analyses. Gulf's intermediate- and long-term forecast models combine end-use and econometric methods such as the Residential End-Use Energy Planning System (REEPS) and the Commercial End-Use Model (COMMEND). Gulf did not specifically identify its data sources, and low- and high-band forecasts were not performed.

Gulf's base-case summer peak demand forecast for the next ten years shows an annual average growth rate (AAGR) of 1.22%, which is less than half of the 3.04% historical growth rate. The base-case winter peak demand over the forecast period is 1.13%, slightly more than half of the historical AAGR of 3.02%.

Gulf stated in 1997 that the stabilization of appliance saturation rates and appliance efficiencies are the main factors suppressing demand growth. Another factor suppressing demand growth is residential conservation programs. However, Gulf's projected 1.3% average annual population growth for the 2000-2005 period is substantially below the state's average annual growth rate of 1.7% per year. Underestimating population growth may contribute to Gulf underestimating retail sales growth. Gulf's average forecast error increased from -3.83% for the 1995-99 period to -4.17% for the 1996-2000 period.

4.3.4 DEMAND-SIDE MANAGEMENT

The Commission set new DSM goals for Gulf on August 17, 1999. These goals call for a cumulative reduction of 221 MW of summer peak demand, 235 MW of winter peak demand, and 143 GWh of energy consumption over the next ten years. Gulf's DSM Plan was approved by the Commission in April, 2000.

Most of Gulf's forecasted demand savings are expected to result from an interruptible service tariff, the Good Cents Home program, and the Advanced Energy Management program (a customer-controlled demand control program in which customers can reduce electricity consumption in response to pricing signals). All of Gulf's existing and new DSM programs are expected to reduce winter peak demand by an estimated 539 MW (19.2%). Gulf receives only 27 MW of savings from its interruptible service tariff. Gulf does not have dispatchable load management on its system. As a result, only 27 MW (8.6%) of Gulf's 2001 winter reserves are comprised of non-firm resources.

4.3.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA cannot comment on Gulf's proposed 60 MW combustion turbine unit planned for 2006 because no location is identified for this unit.

Florida Department of Environmental Protection (DEP)

DEP found that Gulf's *Ten-Year Site Plan* is adequate for planning purposes.

West Florida Regional Planning Council

Gulf's *Ten-Year Site Plan* does not conflict with regional policies in the West Florida Strategic Regional Policy Plan. However, the Council notes that additional air quality monitoring may be necessary in Bay County to determine whether the area becomes a "non-attainment" zone.

4.3.6 SUITABILITY

The Commission notes that Gulf expects to violate its short-term 13.5% / long-term 15% reserve margin criteria for four summer seasons and one winter season during the planning horizon. As it has in past years, Gulf indicates that it will continue to rely on capacity purchases from other the Southern Company pool during these times. It should be noted that Gulf's capacity deficiency is extremely small in magnitude in relation to the size of the Southern Company. For this reason, Gulf's *Ten-Year Site Plan* is ***suitable*** for planning purposes.

4.4 TAMPA ELECTRIC COMPANY (TECO)

4.4.1 GENERATION SELECTION

As seen in Table 13, TECO's system winter capacity is currently 4,099 MW. Of this total, 3,749 MW comes from TECO-owned generation. TECO currently purchases 604 MW of firm capacity from other utilities and 49 MW from non-utility generators. TECO also currently exports 299 MW of firm capacity to other utilities.

TECO's installed capacity is dominated by coal-fired generation. However, TECO's supply-side additions during the planning period are expected to consist solely of gas-fired generation. Five 180 MW gas-fired combustion turbine units are included in TECO's *Ten-Year Site Plan*, four at the **Polk** site and one at a yet-to-be determined location. Additionally, TECO plans to cease all coal operations at the **Gannon** site by the end of 2004. At that time, units 1 through 4 will be placed into long-term reserve shutdown status, causing a reduction of 526 MW. Units 5 and 6 will be fed the steam output of seven new gas-fired combustion turbine units and seven heat recovery steam generators. The resulting facility, renamed **Bayside Power Station**, will consist of two combined cycle units with a winter capacity of approximately 1842 MW. TECO expects to place the two Bayside units into service in 2003 and 2004, respectively.

TECO retired a 17 MW combustion turbine unit at the Gannon site in April of this past year. TECO also plans to retire all five units, totaling 189 MW, at the **Hookers Point** site in 2003. Firm capacity imports are forecasted to drop to 449 MW in 2003 and stay at that level for the remainder of the planning horizon. Exports are forecasted to drop to zero by 2003.

TABLE 13. TECO – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	2902	-1160
Firm Imports	604	-155
Firm Exports	-299	299
Firm Non-Utility Generation	45	15
Integrated Coal Gasified Combined Cycle	250	0
Combined Cycle	0	1842
Fossil Steam	189	-189
Combustion Turbine	408	883
TOTAL	4099	1535

4.4.2 RELIABILITY CRITERIA

TECO has been primarily a summer-peaking utility, as seven of the last ten annual peaks have occurred during the summer season. However, because winter peak demands are a primary concern to utilities in Florida, TECO currently uses a 15% winter peak reserve margin as its reliability criterion.

Pursuant to a stipulation reached in the Commission's reserve margin investigation (Docket No. 981890-EU), TECO has agreed to raise its reserve margin criterion to 20% starting in the summer of 2004. A new subcomponent of TECO's future 20% reserve margin criterion is a 7% summer supply-side

component. The supply-side component requires a minimum level of supply-side reserves while not limiting the contributions of non-firm resources. The Commission has not formally approved TECO's 7% summer supply-side reserve margin component.

4.4.3 TREATMENT OF HARDEE POWER STATION

Hardee Power Partners, Limited, a TECO Power Services Corporation, owns and operates the Hardee Power Station (HPS), a 362 MW facility consisting of a 269 MW combined cycle unit and a separate 93 MW combustion turbine unit. Seminole Electric Cooperative (SEC) has first priority use of HPS capacity as a reserve resource when its own generating units have capacity deratings or have forced or maintenance outages at its coal-fired generating station. TECO can purchase capacity and energy from HPS at times when SEC does not exercise its capacity rights.

Because HPS is shared by two utilities, there is particular interest in how each utility accounts for the capacity in their respective *Ten-Year Site Plan*. Currently, both TECO and SEC include HPS capacity in their reserve margin calculations. However, SEC has first call on this capacity for backup and emergency purposes. Since SEC can call on this capacity at any time during the year, including a seasonal peak, SEC's calculation of reserve margin properly accounts for HPS capacity.

However, in its *Ten-Year Site Plan*, TECO states that its reserve margin calculation assumes that no forced outages will occur at the time of system peak. TECO has historically purchased most of the capacity and energy generated by HPS in past years, particularly during seasonal peaks. The Commission is unsure whether TECO has properly estimated the number of hours and amount of capacity it expects to purchase from HPS based on historical use. The Commission has a commitment from TECO to resolve its HPS sharing arrangement with SEC when calculating individual reserve margins for the 2002 *Ten-Year Site Plan*.

Sufficient reserves currently exist in Peninsular Florida, and the FRCC's **2001 Regional Load and Resource Plan** shows that Peninsular Florida's utilities as a whole appear to be planning to have sufficient reserves over the next ten years. However, the Commission believes that if an extended or weather-related capacity shortfall were to occur, TECO will likely need to buy high-priced capacity and energy on the wholesale market.

4.4.4 LOAD FORECAST

TECO's retail demand and energy forecast is the result of five separate forecasting methods: **detailed end-use** model, **multiregression** model, **trend analysis**, **phosphate analysis**, and **conservation** programs. The detailed end-use model is the most comprehensive method. The first three forecasting methods are combined to develop a demand and energy projection. Phosphate demand and energy are forecasted separately and then combined into the final forecast. Projected demand and energy reductions from TECO's conservation, load management, and cogeneration programs are subtracted from the forecast. TECO's end-use methodology takes into account a wide range of forecast variables. TECO also constructed high- and low-case forecasts using explicit assumptions on higher or lower expected growth in the number of customers, employment, and income.

TECO's base-case summer peak demand is projected to increase at an average annual growth rate (AAGR) of 3.10%, which is higher than the summer historical growth rate of 2.90%. TECO's base-case winter peak demand is projected to increase at an AAGR of 2.94% considerably lower than the winter historical growth rate of 4.77%.

TECO's 1996-2000 retail sales forecasts have an absolute percent error of 1.91%, which is lower than the numeric average for the nine reporting utilities with sufficient historical data. For the same five-year period, TECO's retail sales forecasts have an average forecast error of -1.91%, which reflects a history of under-forecasting.

4.4.5 DEMAND-SIDE MANAGEMENT

The Commission set new DSM goals for TECO on August 17, 1999. These goals call for a cumulative reduction of 71 MW of summer peak demand, 123 MW of winter peak demand, and 189 GWh of energy consumption over the next ten years. TECO's DSM Plan was approved by the Commission in April, 2000.

TECO currently offers ten DSM programs. Most of TECO's forecasted demand savings are expected to come from non-dispatchable conservation programs (winter demand reduction estimated at 630 MW by 2010) and a dispatchable load management program (263 MW by 2010). While interruptible service is forecasted to continue during the planning horizon, its contribution to TECO's winter demand savings is forecasted to decrease from 188 MW to 166 MW during the planning horizon. In total, TECO's DSM programs are forecasted to reduce winter peak demand by approximately 1059 MW (20.0%) by 2010.

However, non-firm resources such as interruptible service and load management make up a substantial part of TECO's reserve margin. Non-firm resources currently make up around 87% of TECO's winter reserves. This is expected to be a short-term event, as TECO has adopted a 7% supply-side reserve margin criterion beginning in 2004.

4.4.6 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

Provided general comments on the Polk and Bayside (formerly Gannon) site. DCA cannot comment on the 150 MW combustion turbine unit proposed for 2010 because TECO does not give a location for this unit.

Florida Department of Environmental Protection (DEP)

DEP found that TECO's *Ten-Year Site Plan* is adequate for planning purposes.

Southwest Florida Water Management District

The District has concerns with the number of proposed inland sites for plant expansion. The District recommends that the utilities consider coastal alternatives for plant expansion to take advantage of sea water for cooling purposes.

Tampa Bay Regional Planning Council

TECO's *Ten-Year Site Plan* is consistent with regional policies. The proposed changes at Big Bend and Gannon will have a net positive effect on air and water quality in the region due to the decreased use of coal.

4.4.7 SUITABILITY

Reserve margins are expected to meet or exceed TECO's 15% reserve margin criterion for each peak through the summer of 2004. After that time, forecasted reserve margins are expected to meet or exceed the new dual 20% overall / 7% supply-side criteria. TECO's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.5 FLORIDA MUNICIPAL POWER AGENCY (FMPA)

FMPA is an organization that jointly manages and operates the activities of 29 municipal electric utilities. Thirteen member utilities currently comprise the All-Requirements Project, meaning that FMPA has committed to plan for, and supply, all power requirements for these members. Member cities not involved in the All-Requirements Project are responsible for planning their own generation and transmission needs.

4.5.1 GENERATION SELECTION

As seen in Table 14, FMPA's All-Requirements Project currently has a winter system generating capacity of 527 MW. However, the combined capacity of FMPA's members is insufficient to meet aggregate load. To serve load that exceeds generation, FMPA currently purchases over 800 MW of capacity from other utilities. FMPA has partial requirements contracts with FPC and FPL, who serve the amount of load that exceeds FMPA's own generation and capacity purchases.

FMPA plans to add 288 MW of generation during the planning period. All proposed capacity is expected to come from joint ownership shares in three new generating units:

- 125 MW from **Cane Island Unit 3**, a gas-fired combined cycle unit jointly owned with KUA. This unit was placed into commercial service in June, 2001.
- 63 MW from **Stanton Unit A**, a 585 MW gas-fired combined cycle unit jointly owned with OUC, KUA, and Southern Company-Florida, LLC. Certified under the Power Plant Siting Act in September, 2001, this unit is scheduled to be placed into service in 2003.
- 100 MW from **McIntosh Unit 4**, a fluidized bed coal unit jointly owned with LAK. This unit is scheduled to be placed into service in 2005.

TABLE 14. FMPA – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	75	0
Coal	245	0
Combined Cycle	60	288
Combustion Turbine	147	0
TOTAL	527	288

4.5.2 RELIABILITY CRITERIA

FMPA has historically been a summer-peaking utility. As such, FMPA plans resource additions on its system to meet a reserve margin criterion of 18% summer peak / 15% winter peak. FMPA's *Ten-Year Site Plan* indicates that its 18% summer criterion will be violated in every summer season except for 2002. Further, FMPA's winter criterion is expected to be violated for the last four winter seasons (2006/07 through 2009/10) of the planning horizon. FMPA's *Ten-Year Site Plan* did not identify any capacity resources to meet these projected reserve shortfalls. However, the Commission has been notified that FMPA has the option to purchase capacity and energy throughout the planning horizon under existing purchased power contracts. These contracts are expected to provide sufficient capacity to meet FMPA's current load forecast.

4.5.3 LOAD FORECAST

To estimate the energy needs for its All-Requirements Project members, FMPA uses econometric modeling and statistical analysis, incremental load analysis, and informed judgement. Some general economic and demographic assumptions are identified, but only one data source is identified. Applying generalized economic assumptions across all relevant member systems may not best represent the load characteristics for these geographically-dispersed municipalities. FMPA did not provide sensitivity analyses based upon varying economic and demographic assumptions, but rather high- and low-bandwidth cases based on different scenarios of events. Further, FMPA has insufficient historical forecast data to enable the Commission to compare FMPA's forecast accuracy to other utilities.

For the 1991-2000 period, FMPA's base-case summer peak demand increased at an average annual growth rate (AAGR) of 9.92%, due primarily to the addition of new member utilities. The projected AAGR for the next ten years is 3.08%. FMPA's base-case winter peak demand for the 1991-2000 period increased at an AAGR of 9.65%. For the ten year planning horizon, FMPA forecasts winter peak demand to increase at an AAGR of 3.13%.

4.5.4 DEMAND-SIDE MANAGEMENT

Member utilities individually promote their own conservation programs with assistance from FMPA. All-Requirements participants may choose from among seven conservation programs that have been evaluated to ensure cost effectiveness. These programs are forecasted to reduce the total 2010 winter load of FMPA's member utilities by 7 MW (0.5%).

4.5.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA participated in the site certification process for **Cane Island Unit 3** and **Stanton Unit A**. Therefore, no further comments are necessary.

Florida Department of Environmental Protection (DEP)

DEP found that FMPA's *Ten-Year Site Plan* is adequate for planning purposes.

Northeast Florida Regional Planning Council

No new plants or modifications to existing sites are expected in the Region.

Southwest Florida Water Management District

The District has concerns with the number of proposed inland sites for plant expansion. The District recommends that the utilities consider coastal alternatives for plant expansion to take advantage of sea water for cooling purposes.

4.5.6 SUITABILITY

As filed in its *Ten-Year Site Plan*, FMPA's forecasted reserve margins fall below the 18% summer reserve margin criterion in each summer season except 2002. Also, as filed, FMPA's 15% winter reserve margin criterion is forecasted to be violated each of the last four years of the planning horizon. However, FMPA has the option to continue purchasing capacity under existing contracts. These purchases are expected to meet FMPA's forecasted need for capacity and energy throughout the planning horizon. For this reason, FMPA's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.6 GAINESVILLE REGIONAL UTILITIES (GRU)

4.6.1 GENERATION SELECTION

As seen in Table 15, GRU has a winter system capacity of 468 MW. GRU's system actually has 511 MW of winter generation. However, GRU currently exports 43 MW of firm capacity to FMPA, although these exports are expected to drop to zero by 2004.

The only new capacity addition in GRU's *Ten-Year Site Plan* is the repowering of **J. R. Kelly Unit 8** as a 121 MW combined cycle unit. This unit was placed into service in April, 2001.

TABLE 15. GRU – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	11	0
Coal	228	0
Firm Exports	-43	43
Combined Cycle	0	121
Fossil Steam	106	0
Combustion Turbine	166	0
TOTAL	468	164

4.6.2 RELIABILITY CRITERIA

GRU has historically been a summer-peaking utility. GRU plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin.

4.6.3 LOAD FORECAST

GRU uses a series of linear multiple regression models to forecast energy consumption. GRU's historical data have been obtained from reputable sources, and GRU outlined the key assumptions of its forecast. The assumptions include normal weather conditions, prices adjusted for inflation, a 3% average annual inflation rate throughout the forecast, and declining real electricity prices.

Under base-case assumptions, GRU forecasts that summer peak demand will increase at an average annual growth rate (AAGR) of 2.35% , less than the 4.05% AAGR for the 1991-2000 period. GRU does not explain the reasons for the lower projected growth rate. Under base-case conditions, GRU forecasts that winter peak demand will increase at an AAGR of 1.77%.

GRU's 1996-2000 retail sales forecasts have an absolute percent error of 3.41%, higher than the numeric average for the nine reporting utilities with sufficient available historical data. For the same period, GRU's retail sales forecasts have an average forecast error of -3.41%, which reflects a history of under-forecasting.

4.6.4 DEMAND-SIDE MANAGEMENT

GRU is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). However, GRU expects to continue offering conservation programs. GRU does not have

any non-firm load. GRU offers energy audits, home fix-up programs, natural gas displacement of electric space heating and water heating, commercial lighting efficiency and maintenance services, and public information and education programs. These programs are expected to reduce GRU's winter peak demand by an estimated 18 MW (4.0%) by 2010.

4.6.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

Did not comment on GRU's *Ten-Year Site Plan* since no new generating units are proposed during the planning horizon.

Florida Department of Environmental Protection (DEP)

DEP found that GRU's *Ten-Year Site Plan* is adequate for planning purposes.

North Central Florida Regional Planning Council

Commented that GRU's *Ten-Year Site Plan* is consistent with the North Central Florida Strategic Regional Policy Plan.

4.6.6 SUITABILITY

Forecasted reserve margins are expected to substantially exceed GRU's 15% reserve margin criterion for each seasonal peak throughout the planning horizon. GRU's *Ten-Year Site Plan* is ***suitable*** for planning purposes.

4.7 JEA

4.7.1 GENERATION SELECTION

As seen in Table 16, JEA has a winter system capacity of 2,943 MW. Of this total, 2,828 MW comes from JEA-owned generation. JEA imports 560 MW of firm capacity via interchange but also exports 445 MW to other utilities.

JEA plans to add three new 191 MW combustion turbine (CT) units at the new **Brandy Branch** site. Two of these units went into commercial service in May, 2001; the third one is expected to be on-line in December, 2001. JEA plans to add a 191 MW heat recovery steam generator to two of these CT units, converting the block to a 573 MW combined cycle unit in June, 2004. JEA also plans to convert **Northside Unit 1** from gas/oil-fired steam to coal and repower **Northside Unit 2**, both in 2002. JEA's *Ten-Year Site Plan* also includes a planned 352 MW combined cycle unit in 2007 and a 250 MW fluidized bed coal unit in 2010. Both of these units are planned for a yet-to-be-determined site and, if ultimately built, will require certification under the Power Plant Siting Act.

In addition to adding new capacity, JEA also plans to retire 209 MW of fossil steam capacity at the **Southside** site by the end of 2001. JEA forecasts that firm exports will decrease to 383 MW by 2010, while firm purchases are expected to decrease to 207 MW during that time.

JEA's capacity purchases are made through a partnership with the Municipal Electric Authority of Georgia and the South Carolina Public Service Authority. This partnership, known as The Energy Authority, works on behalf of JEA as its power marketing group to meet purchased power needs.

TABLE 16. JEA – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	1221	518
Firm Exports	-445	62
Firm Imports	560	-353
Combined Cycle	0	925
Fossil Steam	976	-209
Combustion Turbine	631	191
TOTAL	2943	1134

4.7.2 RELIABILITY CRITERIA

Historically, JEA's peak demand has occurred nearly split between the summer and winter seasons. Because of these variations, JEA uses a 15% summer and winter peak reserve margin as its reliability criterion.

4.7.3 LOAD FORECAST

JEA uses trend analysis based on historical data to evaluate base, high, and low forecasts of demand, energy, and number of customers. All criteria are adjusted for JEA's assessment of the strength of the local economy. JEA's methodology splits the difference between a constant growth of 410 GWh per year and a constant growth rate of 3.4% per year. This methodology produces an increasing amount of

energy consumption but at a decreasing rate.

JEA's 1996-2000 retail sales forecasts have an absolute percent error of 6.96%, the highest among all of the state's reporting utilities and 3.91 percentage points over the statewide average of 3.02%. For the same period, JEA's retail sales forecasts have an average forecast error of -6.96%, which shows a strong tendency to under-forecast.

JEA's base-case winter peak demand forecast reflects an average annual growth rate (AAGR) of 2.56% over the planning horizon, which is lower than the historical winter peak AAGR of 4.45%. The base-case summer peak demand forecast shows an AAGR of 2.83%, which is lower than the historical summer peak AAGR of 3.44%.

JEA's method of trending historical data merely extends historical error into future time periods. Trend forecasts do not explicitly capture the impact of projected growth in personal income, population, and other variables related to electricity usage. Forecasts based upon multiple regression models include such variables. Trending techniques also ignore the detailed analyses of appliance use, efficiency, and saturation – all of which are the foundation of end-use models. Most of the state's large utilities, those with annual energy sales greater than 10,000 GWh, use end-use and econometric models simultaneously to generate load forecasts. However, JEA defends its use of trending methods because of lower cost and because good quality demographic data becomes available. It should be noted that JEA's trending results from the last three years show a significant improvement over previous forecasting results.

4.7.4 DEMAND-SIDE MANAGEMENT

The Commission set numeric goals of **zero** for JEA in April, 2000. JEA was unable to identify any cost-effective DSM programs to offer. However, JEA has agreed to continue its existing DSM programs including audits (required by FEECA), public information and education programs, and home fix-up programs. JEA does not currently have a load management program. Nearly all forecasted demand savings that can be documented are expected to come from JEA's interruptible tariffs, which are forecasted to reduce JEA's total winter peak demand by 189 MW by 2010.

4.7.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

City of Jacksonville / Duval County

States that JEA's *Ten-Year Site Plan* is suitable as a planning document.

Florida Department of Community Affairs (DCA)

Provided general land-use comments on JEA's **Northside** and **Brandy Branch** sites. Land use compatibility questions have not been settled for the new **Brandy Branch** units. DCA cannot comment on JEA's 295 MW combined cycle unit planned for 2007 because no location is identified for this unit.

Florida Department of Environmental Protection (DEP)

DEP found that JEA's *Ten-Year Site Plan* is adequate for planning purposes.

Northeast Florida Regional Planning Council

JEA's planned additions are generally consistent with regional policies.

4.7.6 SUITABILITY

Forecasted reserve margins are expected to meet or exceed JEA's 15% reserve margin criterion for each seasonal peak throughout the planning horizon. JEA's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.8 KISSIMMEE UTILITY AUTHORITY (KUA)

4.8.1 GENERATION SELECTION

As seen in Table 17, KUA has a winter system capacity of 284 MW. 176 MW of this total comes from KUA-owned generation, while 108 MW of firm capacity is purchased from other utilities.

KUA's expansion plan reflects the addition of 133 MW of combined cycle capacity from **Cane Island Unit 3**, which was placed into commercial service in June, 2001. This unit is jointly owned with FMPA. KUA also has a 23 MW ownership share in the proposed **Stanton Unit A**, a 585 MW gas-fired combined cycle unit due to be completed in October, 2003. This unit, jointly owned by OUC, KUA, FMPA, and Southern Company-Florida, LLC, was certified under the Power Plant Siting Act in September, 2001. KUA currently forecasts that its firm capacity purchases will decrease to 89 MW by 2010.

TABLE 17. KUA – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	6	0
Coal	21	0
Firm Imports	108	-19
Combined Cycle	115	156
Combustion Turbine	34	0
TOTAL	284	137

4.8.2 RELIABILITY CRITERIA

KUA is primarily a summer-peaking utility. However, KUA plans its system to meet a reliability criterion of a 15% summer and winter peak reserve margin.

Nonetheless, KUA's 15% criterion is forecasted to be violated for the summers of 2008, 2009, and 2010 and the winter of 2009/10. The magnitude of these capacity deficiencies is small. KUA acknowledges the deficiency in its *Ten-Year Site Plan* but relies only on unspecified capacity purchases to maintain its 15% reserve margin.

4.8.3 LOAD FORECAST

KUA's econometric forecast models measure changes in electricity usage per customer class as a function of temperature, population, and income. Economic and population forecasts were obtained from the Bureau of Economic and Business Research, and normal weather conditions were assumed for the load forecast model. There is insufficient data to measure the absolute percent error of KUA's 1996-2000 retail sales forecasts. However, KUA's methodology and assumptions are appropriate.

KUA's base-case summer peak demand forecast reflects an average annual growth rate (AAGR) of 4.15%, higher than the historical AAGR of 4.77%. KUA's base-case winter peak demand forecast for 2000-2009 shows an AAGR of 4.17%, lower than the historical AAGR of 5.32%. KUA's base-case NEL forecast for the next ten years reflects an AAGR of 4.14%, lower than the historical growth rate of 5.17%.

4.8.4 DEMAND-SIDE MANAGEMENT

KUA is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). As a result, the Commission does not set numeric conservation goals for KUA. However, KUA plans to continue offering conservation programs such as energy audits and a residential load management program. The load management program is expected to reduce KUA's winter peak demand by an estimated 8 MW (2.2%) by 2010.

4.8.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA participated in the site certification process for **Cane Island Unit 3**. Therefore, no further comments are necessary.

Florida Department of Environmental Protection (DEP)

DEP found that KUA's *Ten-Year Site Plan* is adequate for planning purposes.

Southwest Florida Water Management District

The District has concerns with the number of proposed inland sites for plant expansion. The District recommends that the utilities consider coastal alternatives for plant expansion to take advantage of sea water for cooling purposes.

4.8.6 SUITABILITY

Forecasted reserve margins are expected to fall below KUA's 15% reserve margin criterion in the summers of 2008, 2009, and 2010, and the winter of 2009/2010. The forecasted capacity deficiencies are small and occur in the later years of the planning horizon. For this reason, KUA has ample time to select resources to meet its future needs. Therefore, KUA's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.9 CITY OF LAKELAND (LAK)

4.9.1 GENERATION SELECTION

As seen in Table 18, LAK has a winter system capacity of 704 MW. LAK owns 647 MW of generating units and imports 57 MW of firm capacity from other utilities.

LAK's expansion plans reflect the addition of a 120 MW heat recovery steam generator to **McIntosh Unit 5**. When placed into service in January, 2002, the total capacity of this combined cycle unit will be 365 MW. LAK also plans **McIntosh Unit 4**, a 188 MW fluidized bed coal unit with an in-service date of June, 2005.

LAK's plans also reflect the retirement of 74 MW of steam turbine capacity at the **Larsen** site. LAK's 57 MW of firm imports are expected to go to zero starting in 2002, and firm exports of 100 MW are forecasted to begin in 2002 and continue throughout the planning horizon.

TABLE 18. LAK – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	205	188
Firm Imports	57	0
Firm Exports	0	-100
Combined Cycle	124	388
Fossil Steam	264	-161
Combustion Turbine	54	0
TOTAL	704	315

4.9.2 RELIABILITY CRITERIA

LAK is a winter-peaking utility. For this reason, LAK now has a higher reserve margin criterion for winter peak. LAK recently increased its reserve margin criteria from 15% overall to 20% summer peak / 22% winter peak.

4.9.3 LOAD FORECAST

LAK's load forecast methodology includes several regression models measuring population, accounts, sales, net energy for load, and peak demand. LAK's load forecast is built from three data sources: Polk County population projections from the 1998 Bureau of Economic and Business Research forecast; the number of residential accounts in LAK's service area; and the results of LAK's 1994 Appliance Saturation Survey. The 1994 survey is dated and may not give appropriate results for the forecast. The Commission encourages use of the most recent possible data.

Under base case conditions, winter peak demand is projected to increase at an average annual growth rate (AAGR) of 1.77% over the next ten years, lower than the 4.06% AAGR for the 1991-2000 period. Summer peak demand is projected to increase at an AAGR of 2.45%, lower than the 2.97% AAGR for the 1991-2000 period. LAK does not specifically justify these lower growth rates, although its *Ten-Year Site Plan* notes that the projections include the effect of energy conservation programs.

LAK's 1996-2000 retail sales forecasts have an absolute percent error of 1.56%, lower than the

numeric average for the nine reporting utilities with sufficient available historical data. For the same period, LAK's retail sales forecasts have an average forecast error of 0.03%, which is the best among the reporting utilities.

4.9.4 DEMAND-SIDE MANAGEMENT

LAK is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). As a result, the Commission does not set numeric conservation goals for LAK. However, LAK plans to continue its research into other DSM technologies, including photovoltaic applications. Further, the utility plans to continue its existing conservation programs. In addition to interruptible service, LAK offers two residential programs (load management and a loan program) and three commercial programs (lighting, thermal energy storage, and high-pressure sodium outdoor lighting). These programs are expected to reduce LAK's winter peak demand by an estimated 69 MW (8.1%) by 2010.

4.9.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA provided general land-use comments on proposed new units at the **McIntosh** site.

Florida Department of Environmental Protection (DEP)

DEP found that LAK's *Ten-Year Site Plan* is adequate for planning purposes.

Southwest Florida Water Management District

The District has concerns with the number of proposed inland sites for plant expansion. The District recommends that the utilities consider coastal alternatives for plant expansion to take advantage of sea water for cooling purposes.

4.9.6 SUITABILITY

Forecasted reserve margins are expected to exceed LAK's 20% summer and 22% winter reserve margin criteria for each seasonal peak throughout the planning horizon. LAK's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.10 ORLANDO UTILITIES COMMISSION (OUC)

4.10.1 GENERATION SELECTION

As seen in Table 19, OUC has a winter system capacity of 1,323. Of this total, 1,071 MW comes from OUC-owned generation. OUC currently purchases 593 MW of firm capacity out of the **Indian River** fossil steam units purchased from OUC by **Reliant Energy** in 1999. OUC currently exports 341 MW of capacity to other utilities.

OUC's expansion plan reflects the addition of **Stanton Unit A**, a 585 MW gas-fired combined cycle unit, in October, 2003. This unit, jointly owned by OUC, KUA, FMPA, and Southern Company-Florida, LLC, was certified under the Power Plant Siting Act in September, 2001. This unit will be added to offset the gradual reduction, to zero, of the Reliant Energy firm purchase by the end of 2003. Also proposed are two 175 MW combustion turbine units at the Stanton site, with in-service dates of 2007 and 2008, respectively. Firm imports are forecasted to decrease to 336 MW by 2010, while firm exports to other utilities are expected to drop to 146 MW by 2010.

TABLE 19. OUC – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	65	0
Coal	759	0
Firm Imports	593	-257
Firm Exports	-341	195
Combined Cycle	0	585
Combustion Turbine	247	350
TOTAL	1323	873

4.10.2 RELIABILITY CRITERIA

OUC is primarily a summer-peaking utility. OUC plans its utility system using a reliability criterion of 15% summer and winter peak reserve margin.

4.10.3 LOAD FORECAST

OUC uses an end-use/econometric load forecasting methodology that has been enhanced to produce loads for each hour of the year in chronological order. OUC's methodology and assumptions are appropriate. There was insufficient data to measure the absolute percent error of OUC's 1996-2000 retail sales forecasts.

Under base case conditions, summer peak demand is projected to increase at an average annual growth rate (AAGR) of 2.55% over the forecast period, lower than the 3.11% AAGR actually experienced during the 1991-2000 period. Winter peak demand is forecast to increase at an AAGR of 2.68%, lower than the historical AAGR of 4.55%. OUC's base case net energy for load forecast for 2001-2010 shows a 2.55% AAGR, slightly higher than the 3.36% AAGR seen over the past ten years.

4.10.4 DEMAND-SIDE MANAGEMENT

The Commission set numeric goals of **zero** for OUC in April, 2000. OUC was unable to identify any cost-effective DSM programs to offer. However, OUC will continue its existing DSM programs including five residential conservation programs (audit, heat pump replacement, water heating, weatherization, home energy fix-up) and one commercial program (audit). OUC has an interruptible tariff but no load management program. Overall, OUC's conservation programs are expected to reduce winter peak demand by 32 MW (2.8%) in 2007.

4.10.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Consumer Affairs (DCA)

DCA provided general comments on the combustion units proposed for the **Stanton** site. DCA participated in the site certification process for **Stanton Unit A**. Therefore, no further comments are necessary on this unit.

Florida Department of Environmental Protection (DEP)

DEP found that OUC's *Ten-Year Site Plan* is adequate for planning purposes.

4.10.6 SUITABILITY

Forecasted reserve margins are expected to exceed OUC's 15% reserve margin criterion for each seasonal peak throughout the planning horizon. OUC's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.11 CITY OF TALLAHASSEE (TAL)

4.11.1 GENERATION SELECTION

As seen in Table 20, TAL has a winter system capacity of 620 MW. TAL actually owns 711 MW of generation, but sells 125 MW of capacity to other utilities. TAL currently purchases 34 MW of firm capacity, 25 MW from Entergy and 11 MW from FPC.

TAL's *Ten-Year Site Plan* shows the addition of two 50 MW combustion turbine units at a yet-to-be determined site. The Entergy firm capacity purchase is set to expire in 2002, leaving only the 11 MW FPC purchase throughout the planning horizon. Firm exports are currently expected to drop to zero in 2002. TAL plans to retire two CT units (10 MW total) at the Purdom site in 2008 and 2009, respectively.

TABLE 20. TAL – WINTER CAPACITY BY FUEL TYPE		
UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Firm Imports	34	-25
Firm Exports	-125	125
Combined Cycle	262	0
Fossil Steam	378	0
Hydroelectric	11	0
Combustion Turbine	60	90
TOTAL	620	190

4.11.2 RELIABILITY CRITERIA

TAL is primarily a summer-peaking utility. TAL plans resource additions on its system to meet a reliability criterion of 17% reserve margin. As a result of the Commission's reserve margin investigation in Docket No. 981890-EI, TAL may consider increasing its reserve margin criterion in the near future.

TAL's *Ten-Year Site Plan* reflects the inclusion of unspecified capacity purchases to maintain the existing 17% reserve margin criterion. Absent the inclusion of these unspecified purchases, TAL's existing 17% criterion would be violated for the summers of 2004, 2009, and 2010. The magnitude of these capacity deficiencies is small. TAL is currently conducting a comprehensive planning study to identify future resources to meet these small deficiencies.

4.11.3 LOAD FORECAST

TAL uses a series of econometric-based linear regression forecasting models to develop its energy forecasts. These models rely upon an analysis of the system's historical growth, usage patterns, and population statistics. TAL lists data sources and tests its load forecast sensitivities for high load growth and low load growth cases. However, one potentially significant forecasting assumption, customer income, was not listed.

Under base-case conditions, summer peak demand is projected to increase at an average annual growth rate (AAGR) of 2.18% over the forecast period, lower than the 3.26% AAGR actually experienced during the 1991-2000 period. Under base-case assumptions, TAL forecasts winter peak demand to increase at an AAGR of 2.32%, compared to a historical AAGR of 3.22%.

TAL's 1996-2000 retail sales forecasts have an absolute percent error of 2.87%, which is lower than the 3.02% numeric average for the nine reporting utilities with sufficient available historical data. For the same period, TAL's retail sales forecasts have an average forecast of -2.87%, which reflects a history of under-forecasting.

4.11.4 DEMAND-SIDE MANAGEMENT

TAL is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). As a result, the Commission does not set numeric conservation goals for TAL. However, TAL does not expect to reduce its current commitment to conservation. TAL offers five residential and five commercial programs. These programs include natural gas conversion, non-dispatchable conservation programs, public information and education programs, and home improvement programs. TAL does not have a load management program. TAL forecasts that its DSM programs will reduce winter peak demand by an estimated 35 MW (5.2%) by 2010.

4.11.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Consumer Affairs (DCA)

DCA provided general comments on TAL's proposed combustion turbine units.

Florida Department of Environmental Protection (DEP)

DEP found that TAL's *Ten-Year Site Plan* is adequate for planning purposes.

4.11.6 SUITABILITY

Forecasted reserve margins are expected to fall below TAL's 17% reserve margin criterion in the summers of 2004, 2009, and 2010 unless unspecified purchases are included. The forecasted capacity deficiencies are small and occur in the later years of the planning horizon. It should be noted that TAL has indicated that it is currently conducting a comprehensive planning study to identify future resources to meet these deficiencies. Therefore, TAL's 2001 *Ten-Year Site Plan* is **suitable** for planning purposes.

4.12 SEMINOLE ELECTRIC COOPERATIVE (SEC)

SEC is a wholesale cooperative that provides full requirements to ten distribution system members. SEC relies on owned and purchased capacity resources to meet the needs of its member systems. SEC is obligated to serve all load up to specified capacity commitment levels and provide adequate reserves. SEC's partial requirements providers (FPC, TECO, JEA, OUC, and GRU) serve all load above specified capacity commitment levels.

4.12.1 GENERATION SELECTION

As seen in Table 21, SEC currently has a total winter generating capacity of 1,345 MW. However, SEC's generating capacity is insufficient to meet the aggregate load of its members. To serve load that exceeds generation, SEC purchases 1,138 MW of capacity from other utilities. In addition, SEC has partial requirements and full requirements contracts with FPC, GRU, and TECO, who serve the amount of load that exceeds SEC's own generation and capacity purchases. The amount of partial requirements and full requirements purchases is currently 760 MW.

SEC plans to diversify its generation resources with the addition of the **Payne Creek Generating Station Unit 1**, a 574 MW combined cycle unit, in January, 2002. SEC's *Ten-Year Site Plan* also shows the planned addition of nine combustion turbine units over the planning horizon. Two of the CT units (364 MW total) are planned for the Payne Creek site in 2006, while the remaining seven CT units (1274 MW total) are planned for a yet-to-be-determined site between 2007 and 2010. SEC's reliance on firm purchases is expected to decrease to 547 MW during the planning horizon. However, the amount of partial requirements and full requirements capacity imports is forecasted to increase to 1,395 MW during this time.

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	15	0
Coal	1330	0
Firm Imports	1138	-591
Combined Cycle	0	574
Combustion Turbine	0	1638
TOTAL	2483	1621

4.12.2 RELIABILITY CRITERIA

SEC is a winter-peaking utility. SEC uses a dual reliability criteria of 15% summer and winter reserve margin and a 1% ratio of expected unserved energy (EUE) to net energy for load (NEL). Reserve margin is the primary criterion driving SEC's future resource needs.

4.12.3 LOAD FORECAST

SEC identifies and justifies its load forecast methodology with a thorough description of econometric and end-use models, variables, data sources, assumptions, and informed judgements. SEC

analyzed each member cooperative's load forecast and combined them to yield the final forecast results. SEC provided detailed accounts of load forecasts which are based on economic, housing, appliance, weather and hourly load data. SEC also provided a high and low growth rate forecast.

SEC expects to continue to be a winter-peaking utility primarily due to forecasted increases in electric space-heating appliance saturations. Under base case conditions, winter peak demand forecast is projected to increase at an average annual growth rate (AAGR) of 3.57% over the forecast period. While the winter peak demand forecast is lower than the 5.52% AAGR actually experienced during the 1991-2000 period, it is still one of the highest winter peak growth rates in the state. SEC's base-case summer peak demand is forecast to grow at an AAGR of 3.42%, lower than the historical AAGR of 5.12%.

SEC's 1996-2000 retail sales forecasts have an absolute percent error of 3.29%, with an average forecast error of -3.29%. These results reflect SEC's history of under-forecasting.

4.12.4 DEMAND-SIDE MANAGEMENT

Member utilities individually promote their own conservation programs with SEC's assistance. Given the power supply agreements that SEC has with its members, demand reduction resulting from conservation and load management programs does not affect the operation of SEC's generating units. However, conservation reduces the level of partial requirements purchases.

Some of SEC's member utilities have load management programs whose dispatch are coordinated by SEC. These programs provide approximately 144 MW, or half, of SEC's forecasted demand savings. The remaining savings (137 MW) come from various interruptible service tariffs. The aggregate winter demand savings of SEC's members is forecasted to be 281 MW (5.4%) by 2010.

4.12.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA provided general comments on unit additions proposed at the **Payne Creek** site. DCA cannot comment on several of the combustion turbine units in SEC's *Ten-Year Site Plan* because no location is given for these units.

Florida Department of Environmental Protection (DEP)

DEP found that SEC's *Ten-Year Site Plan* is adequate for planning purposes.

Northeast Florida Regional Planning Council

No new plants or modifications to existing sites are expected in the Region. Therefore, no comments are offered on SEC's *Ten-Year Site Plan*.

Southwest Florida Water Management District

The District has concerns with the number of proposed inland sites for plant expansion. The District recommends that the utilities consider coastal alternatives for plant expansion to take advantage of sea water for cooling purposes.

4.12.6 SUITABILITY

Forecasted reserve margins are expected to meet or exceed SEC's 15% reserve margin planning criterion for each seasonal peak throughout the planning horizon. SEC's *Ten-Year Site Plan* is **suitable** for planning purposes.

4.13 MERCHANT PLANT COMPANIES

Two merchant plant companies filed a Ten-Year Site Plan for 2001: Calpine Construction Finance Company (Calpine) and Oleander Power Project (Oleander).

Calpine filed a *Ten-Year Site Plan* which contained four gas-fired combined cycle units. When proposed by retail-serving utilities, combined cycle units require certification under the Power Plant Siting Act and, therefore, a determination of need from the Commission. However, the Commission has granted a determination of need for one of Calpine's proposed units. The **Osprey** unit, a 585 MW unit located in Polk County, was granted a determination of need from the Commission because SEC was a co-applicant and has contracted to buy the unit's output. The status of a second facility, the **Blue Heron** unit, is uncertain at this time because there currently is not a contract to sell the unit's output to a retail-serving utility. The location of two other units in Calpine's *Ten-Year Site Plan* is considered to be confidential by Calpine. The Commission has no information on these units except that Calpine plans for them to be gas-fired combined cycle units..

Oleander's *Ten-Year Site Plan* contains five identical 182 MW combustion turbine units proposed for a site in Brevard County. These units have received all required local permits and a DEP air permit. Four of the proposed units are currently under construction and are expected to be in commercial operation in June, 2002. Oleander plans to start construction on the fifth unit in early 2003 to meet an anticipated June, 2004 in-service date.

As shown previously in Table 5 on page 14, there are over 20 additional potential merchant plant sites on which DEP has either issued an air permit or is reviewing a permit request. None of these companies filed a *Ten-Year Site Plan*.

