REVIEW OF ELECTRIC UTILITY
2002 TEN-YEAR SITE PLANS

FLORIDA PUBLIC SERVICE COMMISSION

Division of Economic Regulation

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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.

TABLE 1. *CRITERIA FOR REVIEW OF TEN-YEAR SITE PLANS*

REQUIREMENT	COMMISSION ACTION
Review the need for electrical power in the area to be served	Reviewed load forecasts, demand-side management (DSM) assumptions, and reliability criteria.
Review possible alternatives to the proposed Plan	Reviewed DSM assumptions, fuel forecasts, and sensitivities to the base-case expansion plan.
Review anticipated environmental impact of proposed power plant sites	Solicited comments from DEP regarding environmental impact and compliance. Comments are summarized herein.
Consider views of local and state agencies on water and growth management issues	Solicited comments from DCA, water management districts, and regional planning councils. Comments are summarized herein.
Determine consistency of Plan with the State Comprehensive Plan	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 herein.
Review Plan for information on energy availability and consumption	Reviewed load forecast data and methodologies used to arrive at load and energy forecasts.

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. Utilities whose existing generating capacity is below 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.

1.2 PURPOSE

The *Ten-Year Site Plan* gives state and local agencies advance notice of proposed power plants and transmission facilities. 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 finding or determination 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 or Transmission Line Siting Act certification proceedings. This fact underscores the purpose of the *Ten-Year Site Plan* as an advance 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 16, 2002 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*. All comments are summarized in Section 4.0 of this review and are available upon request.

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 statewide reserve margins range from 24% to 27% during summer peak seasons, and from 27% to 31% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings.

2.2 SUMMARY OF RESOURCE ADDITIONS

Figure 1, shown below, and Tables 2 and 3, shown on the next two pages, summarize the aggregate plans for the State of Florida's utilities. These illustrations show the current and future resource mix, total planned capacity additions by type, and the next identified generating unit planned by each reporting utility.

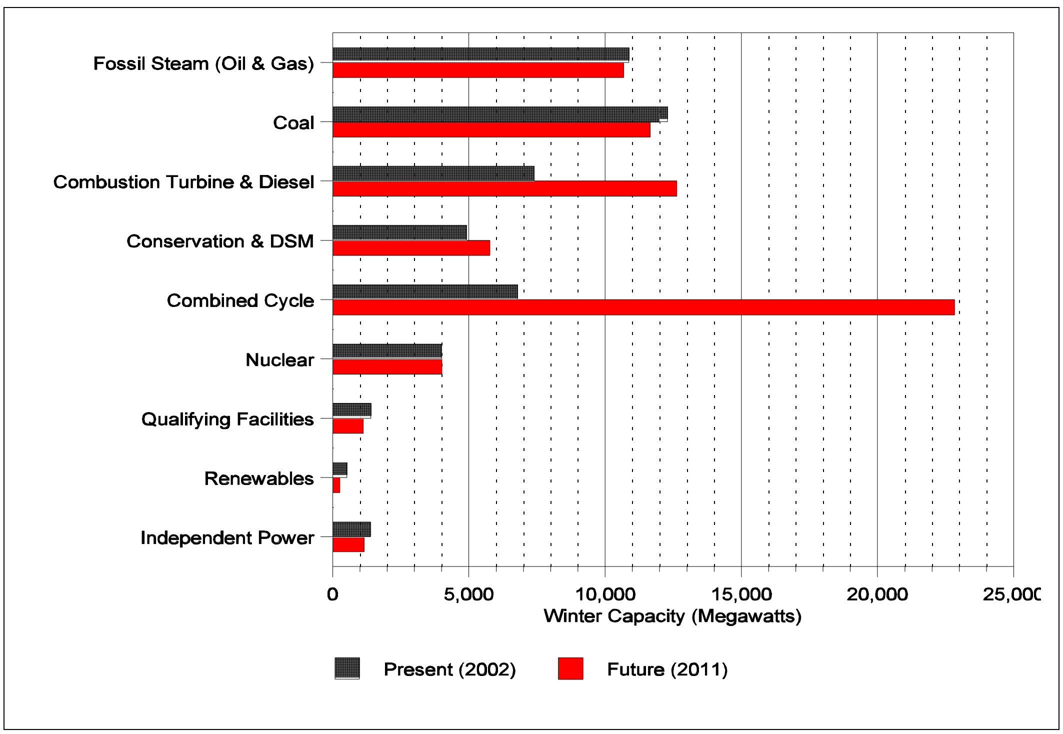

Figure 1. ***STATE OF FLORIDA – ELECTRIC UTILITY RESOURCE MIX BY PLANT TYPE / PRESENT AND FUTURE***

TABLE 2. *STATE OF FLORIDA – CAPACITY FROM NEW GENERATING UNITS, CAPACITY CHANGES AT EXISTING SITES, AND GENERATING UNIT RETIREMENTS (2002-2011)*	
	WINTER CAPACITY (MW)
CAPACITY FROM NEW GENERATING UNITS - planned by electric utilities	
Combined Cycle	11,333
Combustion Turbine	4,844
Coal	250
TOTAL	**16,427**
CAPACITY CHANGES AT EXISTING SITES - repowering, fuel conversion, return from cold standby	
Combined Cycle	4,699
Combustion Turbine	446
Coal	-895
Oil and Gas Fossil Steam	60
TOTAL	**4,310**
GENERATING UNIT RETIREMENTS - planned by electric utilities	
Combustion Turbine	-60
Oil and Gas Fossil Steam	-196
TOTAL	**-256**
TOTAL NET ELECTRIC UTILITY ADDITIONS	**20,481**

EXPIRATION OF NON-UTILITY GENERATOR CONTRACTS (for firm capacity)	
Cogeneration [1]	-559
Independent Power Producers [2]	-242
TOTAL NET CHANGES TO NON-UTILITY GENERATION	**-801**

TOTAL NET FIRM CAPACITY ADDITIONS	**19,680**

[1] Sixteen firm capacity contracts (559 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 2006. At that time, the capacity becomes uncommitted (merchant) capacity. OUC has a new purchased power contract, with the merchant portion of Stanton Energy Center Unit A, set to start in 2003.

TABLE 3. *REPORTING UTILITIES – NEXT IDENTIFIED GENERATING UNIT*				
UTILITY	GENERATING UNIT	UNIT TYPE	WINTER CAPACITY MW)	IN-SERVICE DATE
Florida Power Corporation (FPC)	Hines Unit 3	CC	582	11/2005
Florida Power & Light Company (FPL)	Ft. Myers Units 13-14	CT	362	5/2003
Gulf Power Company (Gulf)	Smith Unit 4	CT	157	6/2008
Tampa Electric Company (TECO)	Bayside Unit 1 [3]	CC	1045	5/2003
Florida Municipal Power Agency (FMPA)	Stanton Unit A [4]	CC	22	10/2003
Gainesville Regional Utilities (GRU)	*none planned*	---	---	---
JEA	Brandy Branch Unit 4 [5]	HRSG	191	6/2004
Kissimmee Utility Authority (KUA)	Stanton Unit A [4]	CC	22	10/2003
City of Lakeland (LAK)	McIntosh Unit 5 [6]	HRSG	120	4/2002
Orlando Utilities Commission (OUC)	Stanton Unit A [4]	CT	181	10/2003
City of Tallahassee (TAL)	*unknown (2 units)*	CT	100	5/2005
Seminole Electric Cooperative (SEC)	Payne Creek Unit 2	CT	182	6/2003

[3] Conversion of **Gannon Unit 5**, formerly a coal-fired generating unit, to combined cycle operation.

[4] **Stanton Unit A** is a 585 MW CC unit jointly owned by FMPA, KUA, OUC, and Southern Company-Florida, LLC.

[5] Two 191 MW CT units are currently in operation. A 191 MW heat recovery steam generator is planned to be added in June, 2004 to these two CT units, creating a 573 MW combined cycle unit.

[6] A 268 MW CT unit is currently in operation. A 120 MW heat recovery steam generator was added in April, 2002, creating a 388 MW combined cycle unit.

3.0 REVIEW & ANALYSIS - STATE PERSPECTIVE

3.1 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 members 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 *2002 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 *2002 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.

3.2 ELECTRIC UTILITY RESTRUCTURING

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

Energy Policy Act of 1992 (EPAct)

In 1992, Congress enacted EPAct. EPAct authorized the Federal Energy Regulatory Commission (FERC) to order utilities to transmit, over their own transmission lines, power from wholesale entities. 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.

FERC Order Nos. 888 and 889

In 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 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 (FLOASIS) in November, 1996.

FERC Order No. 2000

In December, 1999, FERC issued Order No. 2000, which required all public utilities that own, operate, or control interstate transmission facilities to propose to participate in a ***regional transmission organization (RTO)***. 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.

GridFlorida

In October, 2000, Peninsular Florida's three major utilities – FPC, FPL, and TECO – filed a joint RTO proposal, known as ***GridFlorida***, with the FERC. In June, 2001, the GridFlorida utilities separately petitioned the Commission to determine the prudence of the formation of, and participation in, GridFlorida. In December, 2001, the Commission found that the utilities were prudent in proactively forming GridFlorida. However, the companies were ordered to file with the Commission a modified RTO proposal that used an ISO structure in which each utility maintains ownership of its transmission facilities.

As a result of the Commission's decision, the GridFlorida utilities filed a modified joint proposal with the Commission in March, 2002. On September 3, 2002, the Commission issued Order No. PSC-02-1199-PAA-EI specifically approving the structure and governance aspects, the planning and operations aspects, and certain aspects of the rate design and pricing protocols of the proposed ISO. Proposed changes to the market design of GridFlorida were to be considered at a hearing to be held in October, 2002. On October 3, 2002, the Florida Office of Public Counsel (OPC) filed a notice of administrative appeal of Order No. PSC-02-1199-PAA-EI to the Florida Supreme Court. The Florida Rules of Appellate Procedure provide that the timely filing of a notice of appeal shall automatically operate as a stay pending review when the state, any public officer in an official capacity, board, commission or other body seeks review. Therefore, on October 28, 2002, the Commission issued Order No. PSC-02-1475-PCO-EI abating further proceedings regarding GridFlorida pending disposition of OPC's appeal of the Commission's order.

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 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, the foundation for load and energy forecasts, include energy usage patterns, number of customers, economic, demographic, weather data, and appliance-specific saturation and energy consumption characteristics. The Commission reviewed these data sources for 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 the impact of conservation programs or other events not already quantified. The Commission reviewed any adjustments for reasonableness.

3.3.2 EVALUATION OF HISTORICAL FORECAST ACCURACY

For each reporting utility, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period from 1997-2001. This review compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, actual 2001 energy sales were compared to the projected 2001 forecasts made in 1996, 1997, and 1998. 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 2 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 utility 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 2, 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.

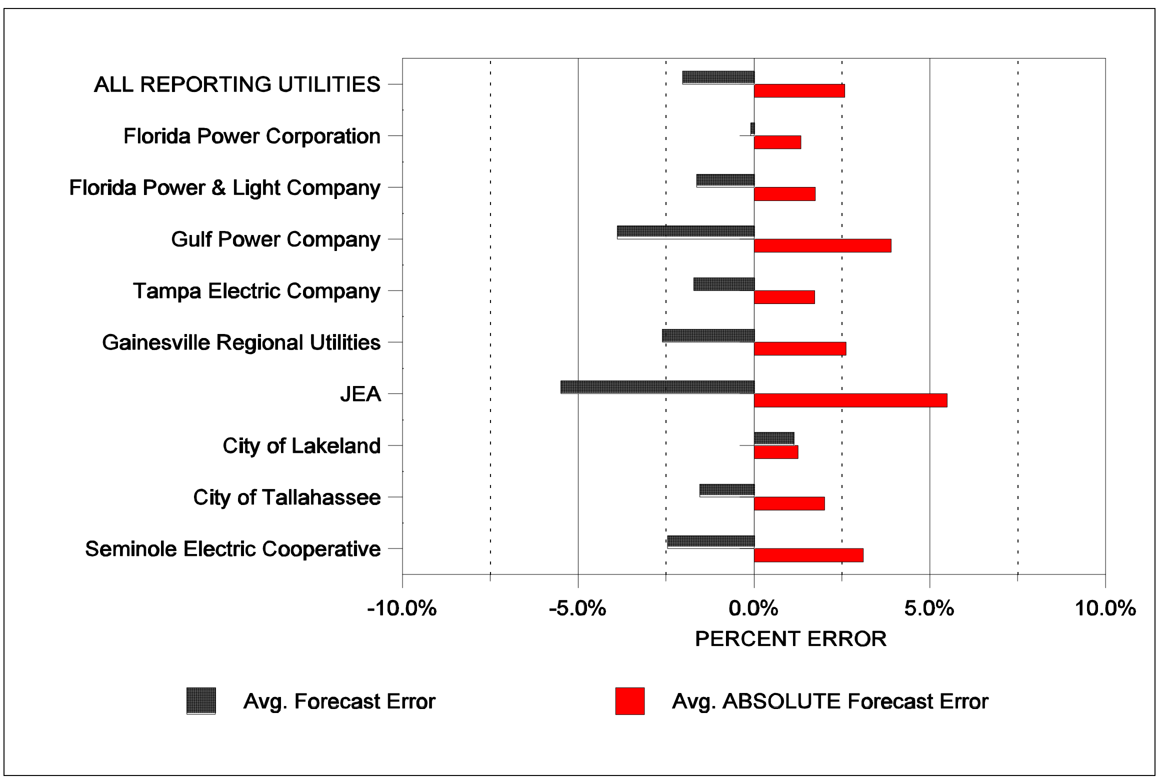

Figure 2. ***TOTAL RETAIL ENERGY SALES (1997-2001) – HISTORICAL FORECAST ACCURACY***

3.4 DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) reduces customer peak demand and energy requirements, which, in turn, 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.

Florida's electric utilities have been successful in meeting the overall objectives of FEECA. As seen in Table 4, it is estimated that utility conservation programs have reduced statewide summer peak demand by 3481 MW, winter peak demand by 4914 MW, and energy consumption by 1950 GWh. By 2011, DSM programs are forecasted to reduce summer peak demand by 4073 MW, winter peak demand by 5760 MW, and energy consumption by 3566 GWh. These DSM savings are also illustrated in Figures 3, 4, and 5 on the next two pages.

TABLE 4. *ESTIMATED SAVINGS FROM FLORIDA UTILITY DSM PROGRAMS*

	2002	**By 2011**
Summer Peak Demand	3481 MW	4073 MW
Winter Peak Demand	4914 MW	5760 MW
Energy Consumption	1950 GWh	3566 GWh

3.4.1 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, which the Commission approved in April, 2000. The Commission set new DSM goals for Florida Public Utilities Company (FPUC) in April, 2000 and approved FPUC's DSM Plan 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.

3.4.2 ENERGY CONSERVATION COST RECOVERY CLAUSE

Florida's investor-owned utilities have spent a vast amount of money to implement DSM programs. Investor-owned utilities recover prudently incurred expenditures associated with Commission-approved DSM programs through the Energy Conservation Cost Recovery Clause

(ECCR). Since 1981, Florida's investor-owned utilities have collected over $3.4 billion through the ECCR clause. Annual ECCR expenditures have remained fairly stable over the past five years due to DSM program saturation and to declining DSM cost-effectiveness caused by the lower cost of new generation.

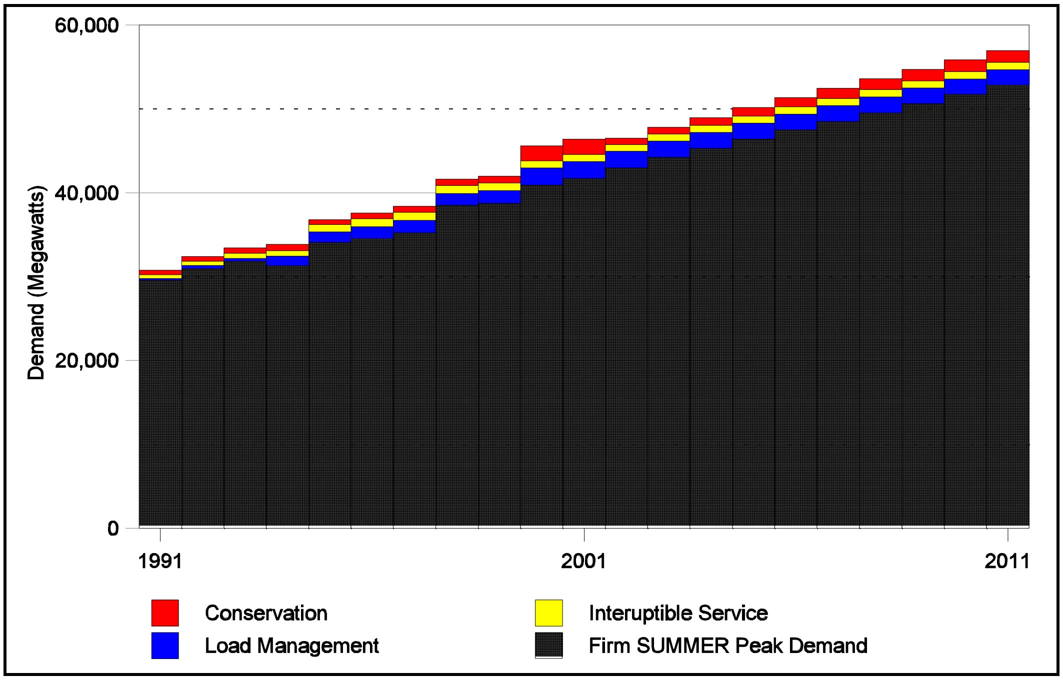

Figure 3. ***STATE OF FLORIDA - ESTIMATED IMPACT OF DSM ON SUMMER PEAK DEMAND / HISTORY AND FORECAST***

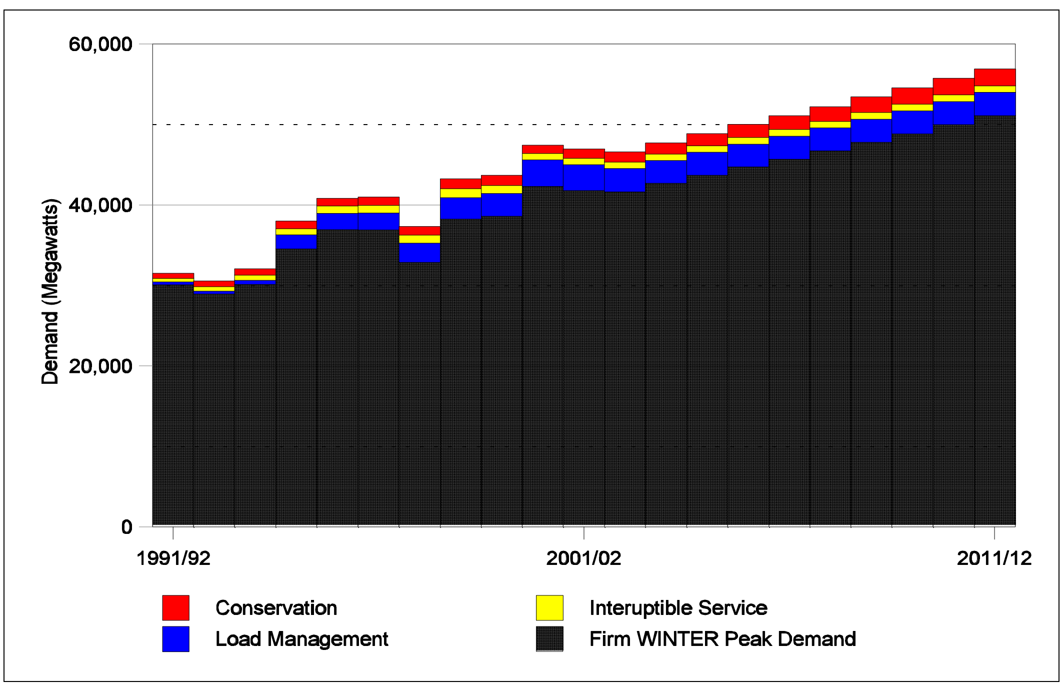

Figure 4. ***STATE OF FLORIDA – ESTIMATED IMPACT OF DSM ON WINTER PEAK DEMAND / HISTORY AND FORECAST***

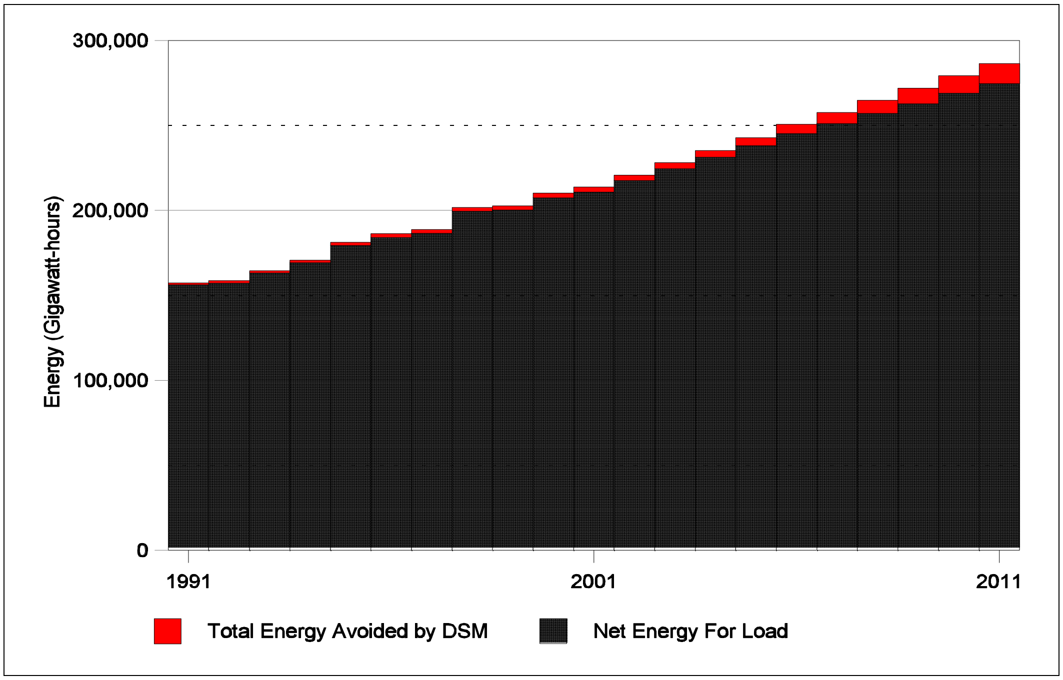

Figure 5. ***STATE OF FLORIDA – ESTIMATED IMPACT OF DSM ON NET ENERGY FOR LOAD / HISTORY AND FORECAST***

3.4.3 *STATE COMPREHENSIVE PLAN*

Energy conservation is a component of the State Comprehensive Plan. Section 187.201(12)(a), Florida Statutes, states that "*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 DCA to ensure a building code that promotes energy-efficient, cost-effective new construction. These activities promote end-use efficiency and reducing per-capita energy consumption from what it otherwise would have been.

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 over the planning horizon. Past and projected increases may be attributed to the following factors: the nominal cost of electricity has remained relatively stable for well 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 6 illustrates historical and forecasted residential per-capita energy consumption for the state. Per-capita energy consumption increased at an average annual growth rate (AAGR) of 1.5% over the past ten years. For the planning horizon, per-capita energy consumption is forecasted to grow at an AAGR of 1.3%. However, this year's forecasted per-capita energy consumption for the planning horizon is higher than forecasts made each of the past two years for a comparable period.

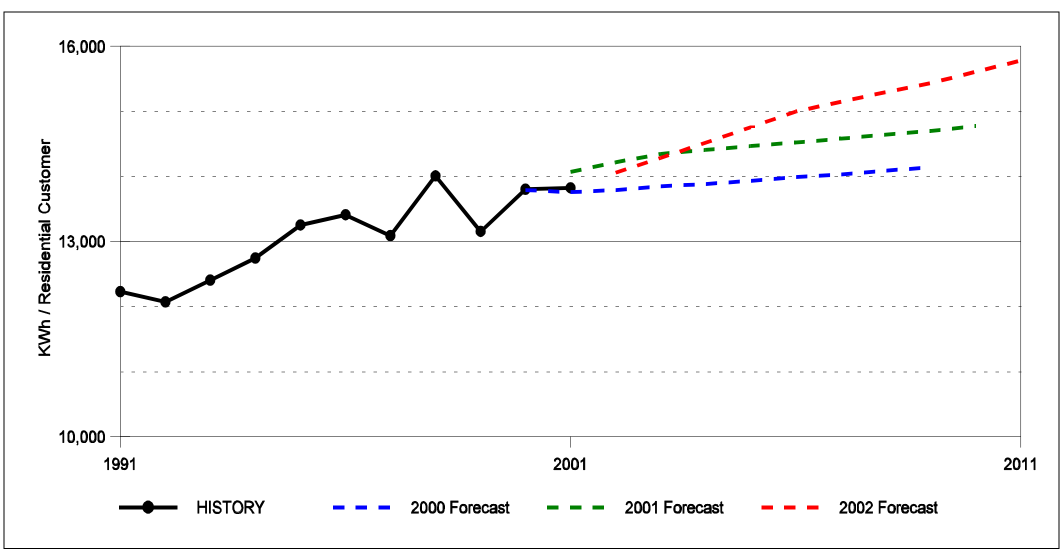

Figure 6. ***STATE OF FLORIDA – ENERGY CONSUMPTION PER RESIDENTIAL CUSTOMER / HISTORY AND FORECAST***

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 1.95 billion cubic feet per day (Bcf/day). In May, 2002, the Gulfstream Natural Gas System went into service with a pipeline capacity of 1.1 Bcf/day. As shown in Figure 7, over 80% of the existing pipeline capacity is used for electricity generation, both by utilities and non-utility generators.

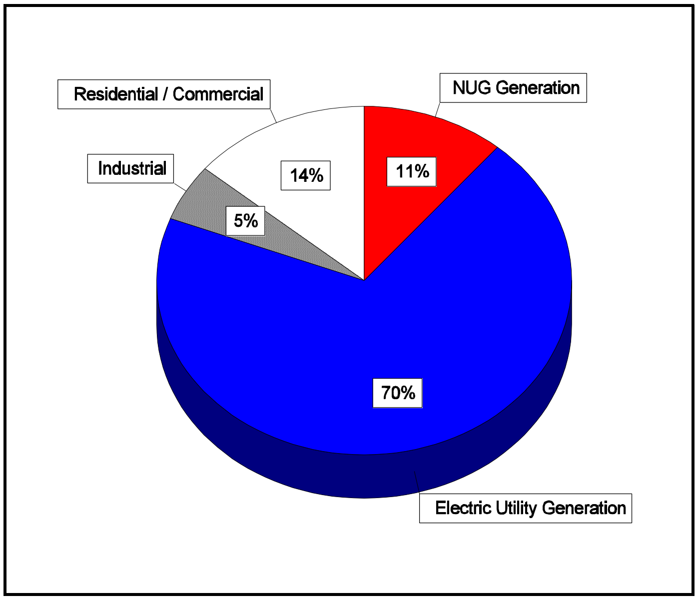

Figure 7. ***NATURAL GAS USAGE BY END-USER – 2001***

Electric utilities forecast a significant (125%) increase in natural gas requirements over the next ten years. As a result, it is estimated that an additional 0.41 Bcf/day of pipeline capacity will be required by 2011.

3.5.1 PROPOSED PIPELINE PROJECTS

FGT

FGT is implementing the third and fourth stages of its Phase V expansion project. These final stage of Phase V are expected to add 0.13 Bcf/day, increasing FGT's total system capacity to 2.08 Bcf/day. All stages of Phase V are expected to be completed in mid-2003.

FGT has also planned to implement a Phase VI expansion project. FGT applied for Federal Energy Regulatory Commission (FERC) approval in November, 2001. Phase VI will add 33.3 miles of new pipeline and an additional 18,600 horsepower of compression. Completion of Phase VI is expected to increase system pipeline capacity by 0.12 Bcf/day, bringing FGT's total capacity to 2.2 Bcf/day upon completion. Construction of Phase VI is expected to begin late in 2002 with an projected in-service date of November, 2003.

Gulfstream

Owned by Duke Energy and Williams, Gulfstream Natural Gas (Gulfstream), Florida's second major interstate pipeline, has placed in service Phase I of its two-phase natural gas transmission system. Phase I, with a capacity of 1.1 Bcf/day, crosses the Gulf of Mexico between Pascagoula, Mississippi and Manatee County, Florida with more than 430 miles of 36 inch pipe. The pipeline then extends across Manatee, Hardee, Polk, and Osceola counties. A planned Phase II expansion would extend the pipeline east to Fort Pierce and south to Palm Beach County. The 173-mile Phase II expansion has an anticipated in-service date of June, 2003.

Seafarer

On May 21, 2002, El Paso Corporation announced an open season for the Seafarer Pipeline System. As proposed, this pipeline will transport reliquified natural gas (LNG) from El Paso Global's proposed LNG terminal on Grand Bahama Island to Palm Beach County. The pipeline is then projected to extend westward, delivering natural gas at an interconnection with FGT and at a delivery point in Martin County. The 26-inch pipeline is expected to have a delivery capacity of up to 0.7 Bcf/day and is expected to be in service in late 2005.

Calypso

Calypso Pipeline, LLC, a subsidiary of Enron Global LNG, applied for FERC approval in July, 2001 to construct a new pipeline from a proposed LNG plant on Grand Bahama Island to an interconnection point on FGT's system in Broward County. Subsequently, the pipeline became part of the Enron bankruptcy proceedings and has since been purchased by Tractabel North American, Inc. The 24-inch pipeline is expected to have a delivery capacity of up to 0.832 Bcf/day. Construction could begin in late 2003 with an anticipated in-service date in 2006.

AES

AES Ocean Express, LLC submitted an application to Minerals Management Service in February, 2002, for the construction of a 54.3-mile 24-inch pipeline and a two million barrel LNG import and storage facility on Ocean Cay. The pipeline will originate in Ocean Cay and come ashore east of Dania, Florida. The proposed pipeline is designed to transport up to 0.842 Bcf/day. As proposed, the pipeline would interconnect with the FGT system and with an FPL gas line that serves the Lauderdale Plant. The Ocean Express project has an anticipated in-service date of March, 2005.

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 5.

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.

Reserve margin estimates system reliability only at the single peak hour of the summer or winter season. As a result, reserve margin cannot capture the impact of random events on system reliability throughout the year. Generating unit forced outages can adversely affect system reliability during off-peak months when many units are out of service for maintenance.

TABLE 5. *RELIABILITY CRITERIA FOR REPORTING UTILITIES*

UTILITY	RESERVE MARGIN	LOLP (days/yr)	EUE/NEL (%)
Florida Power Corporation	15% Summer/Winter [7]	0.1	---
Florida Power & Light Company	15% Summer/Winter [7]	0.1	---
Gulf Power Company	13.5% Summer [8]	---	---
Tampa Electric Company	15% Summer/Winter [7, 9]	---	---
Florida Municipal Power Agency	18% Summer / 15% Winter	---	---
Gainesville Regional Utilities	15% Summer/Winter	---	---
JEA	15% Summer/Winter	---	---
Kissimmee Utility Authority	15% Summer/Winter	---	---
City of Lakeland	20% Summer / 22% Winter	---	---
Orlando Utilities Commission	15% Summer/Winter	---	---
City of Tallahassee	17% Summer	---	---
Seminole Electric Cooperative	15% Summer/Winter	---	1%

[7] FPC, FPL, and TECO will increase their reserve margin criterion to 20% effective Summer, 2004.

[8] Gulf's reserve margin criterion increases to 15% starting in the fourth year of the planning horizon (in this case, 2005).

[9] TECO has adopted a 7% summer supply-side reserve margin component effective Summer, 2004.

Probabilistic Criteria

Because of the limitations of reserve margin, some 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 measure 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 8 and 9, 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% each year during the planning horizon.

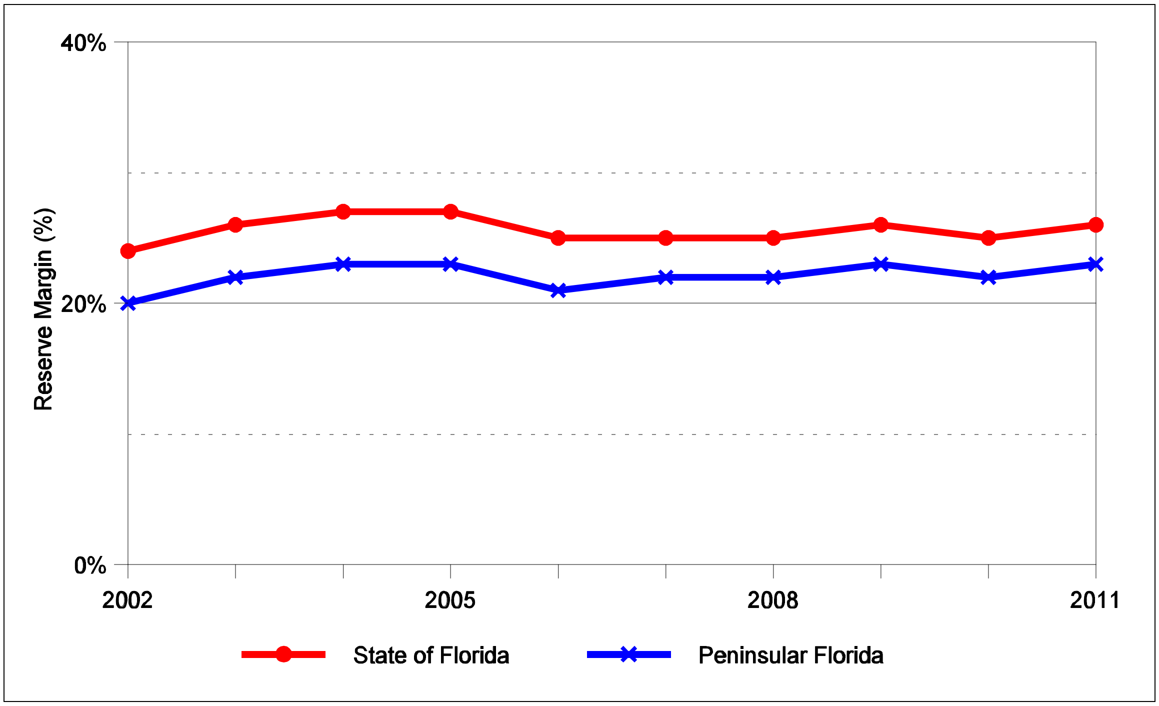

Figure 8. ***FORECASTED SUMMER RESERVE MARGIN***

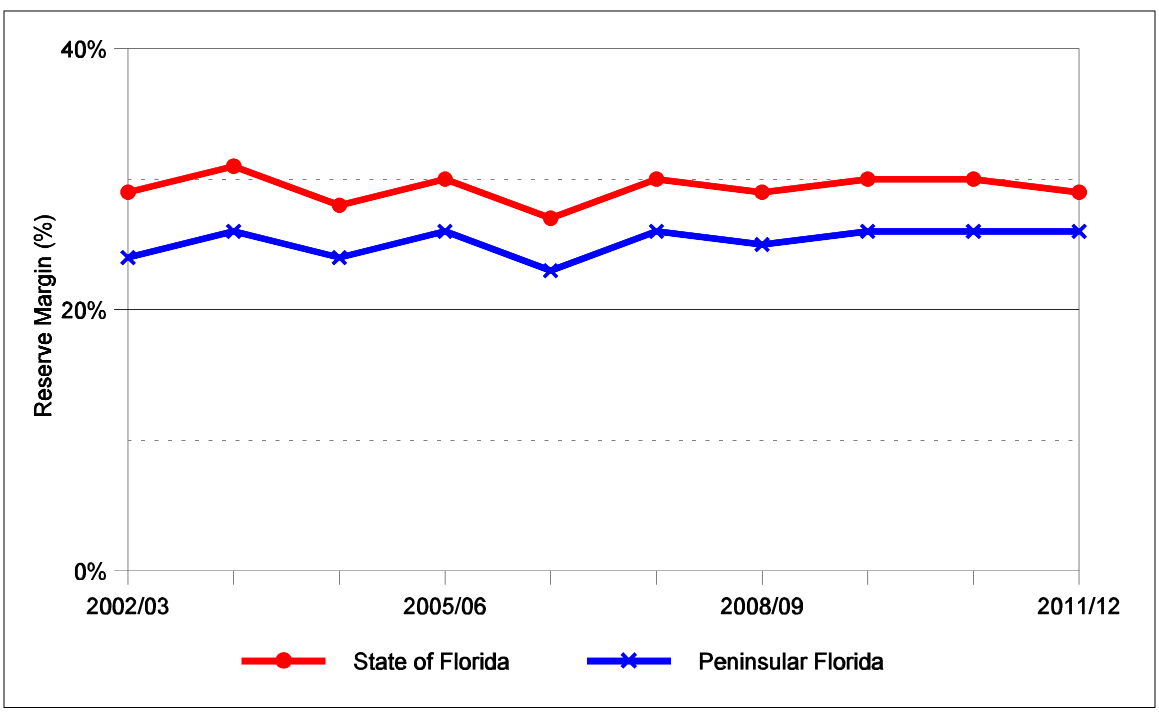

Figure 9. ***FORECASTED WINTER RESERVE MARGIN***

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)

In 1999, the Commission approved an agreement by FPC, FPL, and TECO to adopt a 20% reserve margin planning criterion starting in Summer, 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 are forecasting reserves that meet or exceed 20% in most years of the planning horizon.

Planned New Merchant Plant Capacity in Florida

There has been considerable interest in constructing merchant plants in Florida. Most of these planned and prospective units are natural gas-fired combustion turbine or combined cycle generators. Merchant plant owners may sell electricity in Florida's wholesale market. However, 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.

During periods of capacity shortages, merchant plants may enhance the reliability of Peninsular Florida's grid without putting retail ratepayers at risk for the cost 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, merchant plant owners bear the costs rather than retail customers.

Several companies have announced plans to build merchant plants in Florida by 2005. The FRCC compiled a list of planned and prospective merchant plant additions in its *2002 Regional Load and Resource Plan*. Fifteen of these units, totaling just over 2,500 MW of winter capacity, entered commercial service in 2002. Approximately 1,500 MW of this capacity is currently under contract with utilities. Fifty-three additional merchant plants, totaling nearly 8,100 MW of winter capacity, have been proposed. The Commission has determined that if all available, uncommitted merchant plant capacity was sold on a firm basis to Peninsular Florida's load-serving utilities, Peninsular Florida reserve margins could potentially increase from 26% to 45% by Winter, 2005/06. 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 availability, fuel mix, and environmental compliance – prior to selecting a supply-side resource. However, fuel price is 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.

The Commission has compared each utility's fuel price forecast to an outside source, the U.S. Energy Information Administration (EIA). EIA's comprehensive fuel price forecasts fall within a reasonable range of forecasts provided by the other outside sources. Table 6, 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.

3.7.1 COAL

The average U.S. delivered cost of coal in 2001 increased to $24.68 per ton, up $0.40 per ton from 2000. The demand for coal increased in early 2001, as crude oil prices doubled and natural gas prices quadrupled from previous levels. The increase in coal demand, combined with a relatively stable supply, caused coal prices to increase. Through 2011, EIA forecasts that delivered coal prices will increase at a rate of around 1.5% per year. Florida's utilities forecast changes in coal prices ranging from -2.9% to +4.0% per year during the planning horizon.

3.7.2 NATURAL GAS

The average cost of natural gas for electric utilities nationwide in 2001 was $4.52/MMBtu, up 3% from 2000. Several factors influence short-term natural gas prices: gas availability, storage levels, short-term fluctuations in residual and distillate oil prices, and weather implications. Through 2011, EIA forecasts that long-term natural gas prices will increase at approximately 6.0% per year. Florida's utilities forecast changes in natural gas prices ranging from 0.5% to 5.2% 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 such high levels that natural gas-fired generation may become more costly than generation from other fuel types. At the end of 2000, EIA estimated that U.S. proven natural gas reserves were approximately 177.4 trillion cubic feet (Tcf), a significant (6%) 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. Proven natural gas reserves in the Gulf of Mexico region were approximately 82.3 Tcf, a 3% increase from year-earlier estimates. EIA also estimated natural gas production in this region at approximately 11.7 Tcf in 2000.

TABLE 6. *FUEL PRICE FORECAST – AVERAGE ANNUAL GROWTH RATE (2002-2011)*					
UTILITY	COAL	NATURAL GAS	RESIDUAL OIL	DISTILLATE OIL	NUCLEAR
EIA	1.5%	6.0%	3.1%	2.7%	N/A
Florida Power Corporation	-0.2%	4.1%	1.4%	1.4%	-0.4%
Florida Power & Light Company	1.0%	2.0%	-0.1%	0.5%	1.2%
Gulf Power Company	-2.9%	1.0%	N/A	1.2%	N/A
Tampa Electric Company	0.6%	0.7%	1.9%	2.8%	N/A
Florida Municipal Power Agency	1.3%	3.2%	5.2%	5.2%	2.4%
Gainesville Regional Utilities	0.5%	4.6%	4.6%	3.5%	4.1%
JEA	-0.3%	5.2%	3.1%	2.4%	N/A
Kissimmee Utility Authority	0.6%	3.1%	5.1%	4.0%	2.5%
City of Lakeland	2.6%	3.7%	2.5%	6.5%	N/A
Orlando Utilities Commission	4.0%	1.9%	1.7%	0.8%	2.6%
City of Tallahassee	1.6%	0.5%	0.3%	0.7%	N/A
Seminole Electric Cooperative	0.7%	0.7%	2.9%	4.6%	1.9%

3.7.3 OIL

Residual (#6) Oil

EIA reports that the average U.S. delivered cost of residual oil in 2001 was $3.55/MMBtu, down from $4.01/MMBtu in 2000. Through 2011, EIA anticipates that long-term residual oil prices will increase at around 3.1% per year. Florida's utilities forecast changes in residual oil prices ranging from -0.1% to +5.2% per year during the planning horizon.

Distillate (#2) Oil

EIA reports that the average U.S. delivered cost of distillate oil in 2001 was $6.93/MMBtu, down from $7.55/MMBtu in 2000. Through 2011, EIA anticipates that long-term distillate oil prices will increase at around 2.7% per year. Florida's utilities forecast changes in distillate oil prices ranging from 0.5% to 6.5% per year during the planning horizon.

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.

3.8 GENERATION SELECTION

Florida's utilities provide electricity from several types of generating units. Prior to the early 1970's, plants in Florida were fueled primarily by oil. While oil-fired generation still provides just under 17% of Florida's energy 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 10 illustrates historic 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. Nearly all gas-fired capacity is expected to come from efficient combined cycle and combustion turbine units. Oil-fired generation is projected to decline, although SEC has twelve oil-fired peaking units in its *Ten-Year Site Plan*. Coal-fired generation is not considered a viable option for most Florida utilities because of high construction costs and environmental constraints, although JEA has a coal-fired unit in its *Ten-Year Site Plan*. 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.

3.8.1 NATURAL GAS

Florida's utilities project a substantial increase in natural gas-fired generation over the next ten years, from approximately 19% to 50% of all energy generated. The increase is due to the forecasted net addition of approximately 18,650 MW of gas-fired capacity, in the form of new combined cycle and combustion turbine units, unit repowerings, and fuel conversions. Natural gas consumption forecasts do not include usage from proposed new merchant plants.

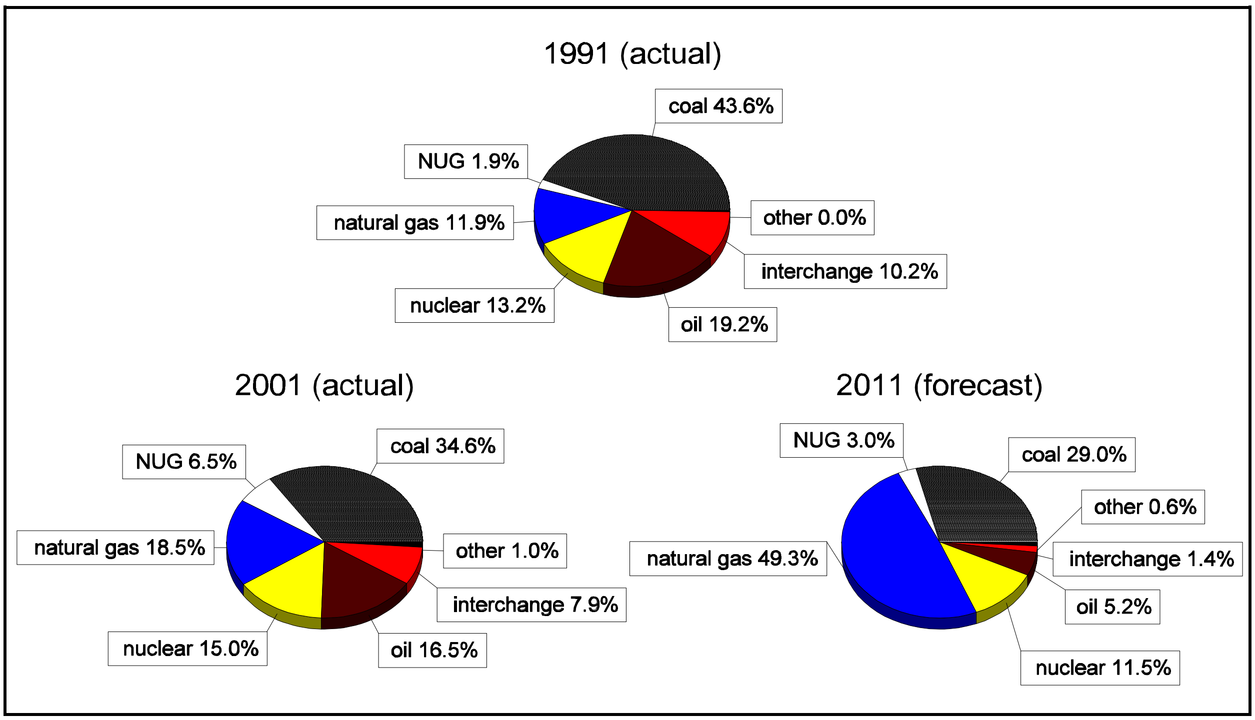

Figure 10. ***ENERGY GENERATION BY FUEL TYPE / HISTORY AND FORECAST***

3.8.2 OIL

Oil-fired generation decreased substantially during the 1980's in response to rising oil prices in the 1970's. However, oil is still used by many utilities in peaking combustion turbine units, both as a primary and a secondary fuel. Oil-fired capacity is forecasted to increase by approximately 2,350 MW due primarily to SEC's plan to build twelve 182 MW oil-fired combustion turbine units. Because it is expected that these units will be peaking generators, they are not expected to significantly increase the amount of oil-fired energy generated statewide. In fact, over the next ten years, oil-fired energy is expected to decrease from a current level of approximately 17% down to approximately 5% of statewide energy production.

3.8.3 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. While coal-fired capacity in the state is forecasted to decrease by only 645 MW, coal-fired energy is expected to decrease from a current level of 35% down to approximately 29% of statewide energy production over the next ten years.

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 around 3600 MW over the Southern Company-Florida interconnection. Approximately 2500 MW of the interface is currently reserved for firm sales and for delivery of capacity from generating units owned by Florida utilities located in Southern Company's region. Approximately 1100 MW remains available for non-firm, economy transactions.

Florida's utilities predict that the level of interchange energy purchases will remain steady, at approximately 5% of all energy consumed in Florida until 2010. At that time, interchange purchases are forecasted to sharply decrease to just over 1.4% by 2012. The forecasted decrease is due primarily to the increased amount of natural gas generation expected to enter service in the state at that time. 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 may remain available 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 6.5% to 3.0% of total energy consumed, during the planning horizon. The forecasted decrease is due to the expiration of approximately 550 MW of firm NUG contracts. However, these generators will remain in place once their contracts expire, and the owners of these NUGs may sign new purchased power contracts with utilities at that time.

3.8.6 OTHER SOURCES OF GENERATION

Coal Gasification

Coal gasification technology appears to provide utilities the flexibility to meet potential environmental restrictions and address concerns with the high initial capital investment, if the combined cycle portion of the facility is constructed first. If the price of oil and natural gas increase substantially above the price of coal, potential savings from coal gasification might justify additional capital investment. As a result, for power plant siting purposes, it is important to consider whether a site can support coal gasification. No Florida utility currently plans to build a new coal gasification plant.

Renewables

In Florida, renewable energy comes primarily from ***hydroelectric***, ***landfill gas***, and ***waste-to-energy*** sources. Because of relatively high capital and operating costs, renewable energy sources do not account for a large portion of Florida's electricity generation.

Hydroelectric units at two existing sites supply 50 MW of renewable capacity. However, hydroelectric generation accounts for less than 0.1% of 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.

Landfill gas is used by OUC to supplement coal-fired generation. Landfill gas is also used by JEA in a 3 MW facility.

Refuse-derived fuel is used by LAK to supplement some of its coal-fired generation. In addition, non-utility generators sell around 450 MW of municipal solid waste-fired capacity to Florida's utilities.

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 service.

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 site in Polk County. Certified under the Power Plant Siting Act in September, 2001, Hines Unit 2 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. In February, 2001, Panda appealed the Commission's approval to the Florida Supreme Court. The Supreme Court affirmed the Commission's decision in an order dated February 25, 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, 2004 in-service date, will be fitted to two 191 MW combustion turbine units currently in service, forming a 573 MW combined cycle unit. The unit was certified under the Power Plant Siting Act in March, 2002.

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 October, 2003. Subject to contract reopener provisions, SEC may purchase up to the full output of the unit through May, 2020. The Osprey Unit was certified under the Power Plant Siting Act in June, 2001.

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. Stanton Unit A has an anticipated October, 2003 in-service date. This unit was certified under the Power Plant Siting Act in September, 2001.

Florida Power & Light Company – Martin Unit 8 and Manatee Unit 3

On November 19, 2002, the Commission granted FPL's petition for approval to construct Martin Unit 8 and Manatee Unit 3. Martin Unit 8 is a 835 MW combined cycle expansion project at the existing Martin plant site in Martin County. Martin Units 8A and 8B, two 181 MW combustion turbine units, currently operate at the site. The Martin Unit 8 expansion project will add two identical combustion turbine units, four heat recovery steam generators, and a steam turbine. When completed, Martin Unit 8 will supply 1,197 MW of winter capacity. Manatee Unit 3 is a new 1,197 MW combined cycle unit at the existing Manatee site in Manatee County. Manatee Unit 3 will be identical to the completed Martin Unit 8 expansion project. Both units have an anticipated in-service date of June, 2005. FPL is awaiting a final certification decision from the Power Plant Siting Board.

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 likely require certification under the Power Plant Siting Act prior to construction. These proposed units are summarized below:

FMPA – Unsited combined cycle unit

FMPA has proposed to build a new 200 MW gas-fired combined cycle unit at a yet-to-be determined site. The proposed unit has a tentative in-service date of June, 2007.

Florida Power Corporation – Hines Units 3, 4, 5, and 6

FPC has proposed to add four new 550 MW, gas-fired combined cycle units at the existing Hines plant site in Polk County. Hines Units 3-6 are currently scheduled to be placed into commercial service in November of 2005, 2007, 2009, and 2010, respectively. The Commission is currently reviewing FPC's petition for approval to construct Hines Unit 3, with a hearing scheduled for December 3-4, 2002.

Florida Power & Light Company – Four Unsited combined cycle units

FPL has proposed to add four new 1,197 MW gas-fired combined cycle units at yet-to-be determined sites. These four units are currently scheduled to be placed into commercial service in June of 2007, 2009, 2010, and 2011, respectively. These units are identical to Martin Unit 8 and Manatee Unit 3, whose need was approved by the Commission on November 19, 2002..

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 June, 2008.

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 June, 2010.

4.0 REVIEW & ANALYSIS - INDIVIDUAL UTILITIES

4.1 FLORIDA POWER CORPORATION (FPC)

4.1.1 GENERATION SELECTION

As seen in Table 7, FPC's system winter capacity is currently 9,865 MW. Of this total, 8,574 MW comes from FPC-owned generation. Firm interchange purchases account for 473 MW, while the remaining 818 MW comes from non-utility generators.

FPC plans to add two 582 MW and three 550 MW gas-fired combined cycle units at the **Hines** site in 2003, 2005, 2007, 2009, and 2010, respectively. Two new 184 MW combustion turbine units are proposed for the **Intercession City** site in 2004 and 2008. FPC plans to retire three fossil steam units with a total generating capacity of 146 MW at the **Suwannee** site. Additionally, FPC expects to lose approximately 160 MW due to the expiration of five cogeneration contracts. Firm capacity imports are forecasted to decrease by 60 MW in 2011.

TABLE 7. *FPC – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	782	0
Coal	2341	0
Firm Imports	473	-60
Firm Exports	0	0
Firm Non-Utility Generation	818	-160
Combined Cycle	752	2814
Fossil Steam	1642	-146
Combustion Turbine	3057	380
TOTAL	9865	2828

4.1.2 RELIABILITY CRITERIA

FPC currently plans its utility system using dual reliability criteria of a 15% summer and winter peak reserve margin and a 0.1 days per year LOLP. FPC will increase its reserve margin criterion to 20% starting in Summer, 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. Detailed econometric models, by class of business, 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 peak demand will increase at an AAGR of 2.0% per year over the 2002-2011 planning horizon, which is below the actual 1992-2001 AAGR of 3.41%. Over the next ten years, summer peak demand is forecasted to increase at an AAGR of 1.85%. FPC assumes the termination of a short-term wholesale sales contract with SEC, thus accounting for most of the lower forecasted demand growth. In addition, forecasted retail sector growth is below the historical average due to slower population growth.

FPC's 1997-2001 retail sales forecasts have an absolute forecast error of 1.33%, which is considerably below the 2.57% average of the reporting utilities. Over the same period, FPC's retail sales forecasts have an average forecast error of -0.09%, reflecting a slight tendency to under-forecast.

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 DCA. In total, FPC's DSM programs are forecasted to reduce 2011/12 winter peak demand by 1611 MW (15.8%). Much of FPC's forecasted winter 2011/12 savings are attributed to non-dispatchable conservation programs (632MW), interruptible service tariffs (351 MW), and load management (628 MW). Due to decreased customer participation, residential load management savings are forecasted to drop by approximately 190 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 82% 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 during the winter peak season is expected to drop to 44% over the planning horizon.

4.1.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

East Central Florida Regional Planning Council – Proposed expansion at Intercession City site is desirable due to existence of infrastructure at the site.

Florida Department of Environmental Protection – Finds that FPC's *Ten-Year Site Plan* is adequate for planning purposes.

South Florida Water Management District – No adverse comments regarding the suitability of FPC's proposed plant sites.

Southwest Florida Water Management District – Has concerns with the number of proposed inland sites for plant expansion. Recommends that utilities consider the use of alternatives to ground water for cooling purposes, such as locating proposed plants on the coast to allow the use of seawater.

4.1.6 SUITABILITY

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

4.2 FLORIDA POWER & LIGHT COMPANY (FPL)

4.2.1 GENERATION SELECTION

As seen in Table 8, FPL's system winter capacity is currently 20,526 MW. Of this total, 17,730 MW comes from FPL-owned generation. Firm capacity purchases from Southern Company, JEA, and others account for another 1,910 MW, while purchases from non-utility generators comprise the remaining 886 MW.

FPL plans to add approximately 6,450 MW of supply-side resources during the planning horizon. FPL is nearing completion of the repowering projects at the existing **Ft. Myers** and **Sanford** sites. These unit repowerings are expected to add 2,277 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.

In June, 2001, FPL placed into service two 181 MW CT units at the **Martin** site. FPL plans to add 835 MW of additional capacity to these units by June 2005, resulting in a 1,197 MW CC unit known as **Martin Unit 8**. Also proposed by June, 2005 is **Manatee Unit 3**, a 1,197 MW CC unit also due to be placed into service in June, 2005. FPL also plans to add two 181 MW CT units at the **Ft. Myers** site by May, 2003, as well as four 1,197 MW CC units at yet-to-be determined sites in 2007, 2009, and 2010, and 2011, respectively. Firm capacity imports are expected to increase to near 2,700 MW by 2004, but decrease to 389 MW by 2011. FPL forecasts a loss of approximately 300 MW from non-utility generators during the planning horizon due to the expiration of four cogeneration contracts.

TABLE 8. *FPL – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	3013	0
Coal	926	0
Firm Imports	1910	-1521
Firm Non-Utility Generation	886	-291
Combined Cycle	3976	8262
Fossil Steam	7507	0
Combustion Turbine	2308	0
TOTAL	20526	6450

4.2.2 RELIABILITY CRITERIA

FPL currently plans its utility system using dual reliability criteria of a 15% summer and winter peak reserve margin and a 0.1 days per year LOLP. FPL will increase its summer and winter planning reserve margin to 20% starting in Summer, 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 long-term sales, net energy for load, and peak load forecasts as key inputs into the models used to develop an integrated resource plan. The primary drivers of its models are demographic trends, weather, economic conditions, and electricity price. The regression model for the residential energy sales forecast contains the real residential price of electricity, per-capita income, and cooling and heating degree days. The regression model for the commercial energy sales forecast contains Florida's commercial employment, the real commercial price of electricity, and cooling degree days. 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 peak demand will increase at an AAGR of 1.85% per year over the 2002-2011 planning horizon, which is considerably below the actual 1992-2001 AAGR of 3.29%. Over the next ten years, winter peak demand is forecasted to increase at an AAGR of 1.91%.

FPL's 1997-2001 retail sales forecasts have an absolute forecast error of 1.74%, which is below the 2.57% average of the reporting utilities. For the same five-year period, FPL's retail sales forecasts have an average forecast error of -1.63%, reflecting a tendency to under-forecast.

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. The Commission approved FPL's DSM Plan in April, 2000.

FPL currently offers six residential and eight commercial/industrial DSM programs to its customers. These programs are forecast to reduce peak demand by 1,955 MW by 2011/12 winter, representing approximately 10.3% of FPL's total winter peak demand at that time. These programs are also projected to reduce FPL's system annual energy usage by 1,092 GWh (0.9%) by 2011.

4.2.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

East Central Florida Regional Planning Council – Recommends that FPL seek alternatives to ground water for future plant additions at the Sanford site. Anticipates reduction in emissions from repowered Sanford units.

Florida Department of Environmental Protection – Finds that FPL's *Ten-Year Site Plan* is adequate for planning purposes.

Manatee County – Provided general comments on Manatee Unit 3 and an associated transmission line.

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 – No adverse comments regarding the suitability of FPL's proposed plant sites.

Southwest Florida Water Management District – Has concerns with the number of proposed inland sites for plant expansion. Recommends that utilities consider the use of alternatives to ground water for cooling purposes, such as locating proposed plants on the coast to allow the use of seawater.

St. Johns Water Management District – No increase in ground water consumption expected at Sanford or Cape Canaveral sites. Recommend alternatives to ground water for cooling purposes at Cape Canaveral site if future expansion occurs there.

Treasure Coast Regional Planning Council – 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* complies with regional policies.

Volusia County – Provided general comments on the Sanford site.

4.2.6 SUITABILITY

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

4.3 GULF POWER COMPANY (Gulf)

4.3.1 GENERATION SELECTION

As seen in Table 9, Gulf's system winter capacity is currently 2,383 MW. Gulf owns 2,262 MW of this capacity, purchases 321 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**. This gas-fired combined cycle unit was placed into commercial service in June, 2002. Gulf also plans to add a new 157 MW gas-fired combustion turbine unit at the Smith site in 2008. Firm imports are forecasted to drop to approximately 7 MW during the planning horizon, while firm exports are expected to drop to zero by 2011. Gulf also plans to retire a 40 MW combustion turbine at the Smith site in 2006. Finally, Gulf will also lose 19 MW in 2005 due to the expiration of its only cogeneration contract.

TABLE 9. *GULF – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	2159	0
Firm Imports	321	-314
Firm Exports	-219	219
Firm Non-Utility Generation	19	-19
Combined Cycle	0	574
Fossil Steam	48	0
Combustion Turbine	55	117
TOTAL	2383	577

4.3.2 RELIABILITY CRITERIA

Gulf is typically a summer peaking utility because the availability of natural gas (for heating) in its service territory reduces electric winter heating load. Southern Company currently uses a systemwide 13.5% reserve margin criterion for its near-term (3-year) criterion. Beyond three years (in this case, 2005), the reserve margin planning criterion is 15%.

Gulf's *Ten-Year Site Plan* identifies a summer capacity need in 2007 (30 MW) and 2009 (17 MW) to maintain its reserve margin criterion. 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 any capacity deficiencies that may occur on Gulf's system. Gulf expects to be a net purchaser of capacity from the Southern Company pool.

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. Gulf did not specifically identify its data sources, and low- and high-band forecast sensitivities were not performed.

Under base-case assumptions, Gulf forecasts that summer peak demand will increase at an AAGR of 1.1% per year over the 2002-2011 planning horizon, which is less than half of the actual 1992-2001 AAGR of 2.47%. Over the next ten years, winter peak demand is forecasted to increase at an AAGR of 0.9%, which is also less than half of the actual AAGR of 2.55%.

Gulf stated in 1997 that the stabilization of appliance saturation rates and appliance efficiencies are the main factors suppressing demand growth. Another factor believed to be the cause of suppressed demand growth is Gulf's conservation programs. Gulf's projected 1.7% average annual population growth for the 2001-2006 period mirrors the state's forecasted population growth rate. Gulf's average forecast error for retail sales decreased from -4.17% for the 1996-2000 period to -3.89% for the 1997-2001 period, reflecting a continued tendency to under-forecast.

4.3.4 DEMAND-SIDE MANAGEMENT

The Commission set new DSM goals for Gulf in August, 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. The Commission approved Gulf's DSM Plan 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 2011/12 winter peak demand by 532 MW (22.8%). Gulf currently receives only 28 MW of savings from its interruptible service tariff. Gulf does not have dispatchable load management on its system. As a result, only 28 MW (5.6%) of Gulf's 2001/02 winter reserves are comprised of non-firm resources.

4.3.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Environmental Protection – Finds 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.

4.3.6 SUITABILITY

The Commission notes that Gulf's 15% reserve margin criteria is forecasted to be violated for two summer seasons during the planning horizon. As it has in past years, Gulf indicates that it will continue to rely on capacity purchases from the Southern Company pool during times of need. 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, The Commission classifies Gulf's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

4.4 TAMPA ELECTRIC COMPANY (TECO)

4.4.1 GENERATION SELECTION

As seen in Table 10, TECO's system winter capacity is currently 4,361 MW. Of this total, 3,697 MW comes from TECO-owned generation. TECO currently purchases 749 MW of firm capacity from other utilities and 62 MW from non-utility generators. TECO also currently exports 147 MW of firm capacity to other utilities.

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

TECO plans to retire 168 MW of fossil steam capacity at the **Hookers Point** and **Dinner Lake** sites 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. TECO also expects to lose 41MW due to the expiration of two cogeneration contracts.

TABLE 10. *TECO – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	2882	-1150
Firm Imports	749	-300
Firm Exports	-147	147
Firm Non-Utility Generation	62	-41
Integrated Coal Gasified Combined Cycle	250	0
Combined Cycle	0	1842
Fossil Steam	168	-168
Combustion Turbine	397	1080
TOTAL	4361	1410

4.4.2 RELIABILITY CRITERIA

TECO has historically been primarily a summer-peaking utility. However, because winter peak demands are a primary concern to utilities in Florida, TECO currently uses a 15% summer and winter peak reserve margin as its reliability criterion.

TECO will increase its summer and winter planning reserve margin to 20% starting in Summer, 2004. A new subcomponent of TECO's future 20% reserve margin criterion is a 7% summer supply-side component. The supply-side component will require 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, 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 Hardee Power Station 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 Hardee Power Station at times when SEC does not exercise its capacity rights.

Because Hardee Power Station's output 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 Hardee Power Station 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 Hardee Power Station 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 Hardee Power Station's capacity and energy in past years, particularly during seasonal peaks.

The fact that both TECO and SEC include Hardee Power Station capacity in their respective reserve margins is not of critical concern at this time since statewide reserve margins are forecasted to exceed 20% throughout the planning horizon. However, staff will continue to monitor this issue since reserve margins may change in the future.

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 models are combined to develop a demand and energy projection. Phosphate demand and energy are forecasted separately and then added to the forecast. Projected demand and energy reductions from 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 created high- and low-case forecasts based on higher or lower expected growth in the number of customers, employment, and income.

Under base-case assumptions, TECO forecasts that summer peak demand will increase at an AAGR of 3.12% per year over the 2002-2011 planning horizon, which is comparable to the actual 1992-2001 AAGR of 3.06%. Over the next ten years, winter peak demand is forecasted to increase at an AAGR of 4.35%.

TECO’s 1997-2001 retail sales forecasts have an absolute forecast error of 1.72, which is below the 2.57% average of the reporting utilities. For the same five-year period, TECO’s retail sales forecasts have an average forecast error of -1.72%, reflecting a tendency to under-forecast.

4.4.5 DEMAND-SIDE MANAGEMENT

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

TECO currently offers eleven DSM programs. Most of TECO’s forecasted demand savings are expected to come from non-dispatchable conservation programs (winter demand reduction estimated at 698 MW by 2011/12) and a dispatchable load management program (242 MW by 2011/12). While interruptible service is forecasted to continue during the planning horizon, its contribution to TECO's winter demand savings is forecasted to decrease to 151 MW during the planning horizon. In total, TECO's DSM programs are forecasted to reduce winter peak demand by approximately 1091 MW (24.1%) by 2011/12.

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 nearly 69% 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 Environmental Protection – Finds that TECO’s *Ten-Year Site Plan* is adequate for planning purposes.

Southwest Florida Water Management District – Has concerns with the number of proposed inland sites for plant expansion. Recommends that utilities consider the use of alternatives to ground water for cooling purposes, such as locating proposed plants on the coast to allow the use of seawater.

Tampa Bay Regional Planning Council – TECO’s *Ten-Year Site Plan* is consistent with regional policies. Proposed changes at Big Bend and Gannon (Bayside) 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. The Commission classifies TECO's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

4.5 FLORIDA MUNICIPAL POWER AGENCY (FMPA)

FMPA is an organization that jointly manages and operates the activities of 31 municipal electric utilities. FMPA added two new members, the City of Lake Worth (LWU) and the Kissimmee Utility Authority (KUA), in 2002. Fifteen member utilities, including LWU and KUA, currently comprise FMPA's **All-Requirements Project**, meaning that FMPA plans for, and supplies, 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 11, FMPA's **All-Requirements Project** currently has a winter system generating capacity of 1,317 MW. However, the combined generation of FMPA's members, currently 527 MW, is insufficient to meet aggregate load. To serve load that exceeds generation, FMPA currently purchases 790 MW of capacity from other utilities. FMPA has partial requirements contracts with FPC and FPL, who serve the load that exceeds FMPA's own generation and capacity purchases. FMPA's *Ten-Year Site Plan* includes the addition of LWU as an **All-Requirements Project** member but not KUA. KUA's membership will be reflected in FMPA's *Ten-Year Site Plan* for 2003.

FMPA plans to add 396 MW of capacity during the planning period. FMPA plans to add an 18 MW CT in Key West in 2005, a yet-to-be sited 200 MW CC unit in 2007, and a yet-to-be sited 165 MW CT unit in 2009. All other planned additions are expected to come from joint ownership shares in two new generating units: 125 MW from **Cane Island Unit 3**, a CC unit jointly owned with KUA that was placed into commercial service in January, 2002; and, 22 MW from **Stanton Unit A**, a 585 MW CC unit jointly owned with OUC, KUA, and Southern Company-Florida, LLC and scheduled to enter service in October, 2003. Firm imports are forecasted to decrease to 656 MW by 2012.

TABLE 11. *FMPA – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	75	0
Coal	245	0
Firm Imports	790	-134
Combined Cycle	60	347
Combustion Turbine	147	183
TOTAL	1317	396

4.5.2 *RELIABILITY CRITERIA*

FMPA has historically been a summer-peaking entity. As such, FMPA plans its system using a reliability criterion of 18% summer peak / 15% winter peak reserve margin. FMPA indicates that it will rely upon unspecified purchases of 35 MW in 2004, 20 MW in 2005, and 30 MW in 2006 to maintain its reserve margin criteria. In its *Ten-Year Site Plan*, FMPA states that it is currently negotiating contracts for purchased power expected to be supplied by resources within the FRCC region. Further, 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 retail sales data to enable the Commission to compare FMPA's forecast accuracy to other utilities.

For the 1992-2001 period, FMPA's base-case peak demand increased at an AAGR of 8.82% (summer) and 10.6% (winter) per year over the 2002-2011 planning horizon, primarily due to the addition of new member utilities. FMPA forecasts that summer peak demand will increase at an AAGR of 3.03% per year over the 2002-2011 planning horizon. Over the same period, winter peak demand is forecasted to increase at an AAGR of 2.97%.

4.5.4 *DEMAND-SIDE MANAGEMENT*

Member utilities individually promote their own conservation programs with assistance from FMPA. **All-Requirements Project** participants may choose from among seven conservation programs that have been evaluated to ensure cost effectiveness. These programs are forecasted to reduce the total 2011/12 winter load of FMPA's member utilities by 7 MW (0.5%).

4.5.5 *STATE, REGIONAL, AND LOCAL AGENCY COMMENTS*

Florida Department of Environmental Protection – Finds that FMPA's *Ten-Year Site Plan* is adequate for planning purposes.

Indian River County – FMPA's *Ten-Year Site Plan* is suitable for county land use 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 – Has concerns with the number of proposed inland sites for plant expansion. Recommends that utilities consider the use of alternatives to ground water for cooling purposes, such as locating proposed plants on the coast to allow the use of seawater.

4.5.6 SUITABILITY

As filed in its *Ten-Year Site Plan*, FMPA's forecasted reserve margins rely upon small amounts of unspecified purchases for 2004, 2005, and 2006. 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, the Commission classifies FMPA's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

4.6 GAINESVILLE REGIONAL UTILITIES (GRU)

4.6.1 GENERATION SELECTION

As seen in Table 12, GRU has a net winter system capacity of 536 MW. The units on GRU's system actually can supply 629 MW of winter generation. However, GRU currently exports 93 MW of firm capacity to other utilities. These exports are expected to drop to 3 MW in 2003 and zero by 2004. GRU does not plan to add any capacity, nor retire any existing units, during the planning horizon.

TABLE 12. *GRU – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	11	0
Coal	228	0
Firm Exports	-93	93
Combined Cycle	118	0
Fossil Steam	106	0
Combustion Turbine	166	0
TOTAL	536	93

4.6.2 RELIABILITY CRITERIA

GRU has historically been a summer-peaking utility. GRU plans its utility system using 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 demand and 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 AAGR of 2.06% per year over the 2002-2011 planning horizon, which is below the actual 1992-2001 AAGR of 3.25%. Over the next ten years, winter peak demand is forecasted to increase at an AAGR of 1.55%, which is also below the actual 1992-2001 AAGR of 2.87%.

GRU's 1997-2001 retail sales forecasts have an absolute forecast error of 2.61%, which is slightly above the 2.57% average of the reporting utilities. For the same five-year period, GRU's retail sales forecasts have an average forecast error of -2.61%, reflecting a tendency to under-forecast.

4.6.4 DEMAND-SIDE MANAGEMENT

GRU is no longer subject to the requirements of FEECA. However, GRU expects to continue offering conservation programs. GRU does not have any non-firm load. GRU offers energy audits, low income household weatherization and natural gas extension, promotion of natural gas in residential construction, natural gas displacement of electric space heating and water heating, promotion of solar 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 2011/12.

4.6.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Environmental Protection – Finds 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.

St. Johns River Water Management District – Commented on water consumption at existing GRU plant sites.

4.6.6 SUITABILITY

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

4.7 JEA

4.7.1 GENERATION SELECTION

As seen in Table 13, JEA has a winter system capacity of 2,910 MW. The units on JEA's system actually can supply 2,928 MW of winter generation. However, JEA is currently a net seller of capacity, exporting 445 MW while importing 427 MW.

JEA plans to add approximately 1,220 MW of winter capacity over the planning horizon. JEA plans to add a 191 MW heat recovery steam generator to two existing CT units at the **Brandy Branch** site. The resulting 573 MW CC unit is expected to enter service in June, 2004. JEA recently completed the repowering conversion of **Northside Unit 1** from gas/oil-fired steam to coal and the repowering of **Northside Unit 2**. Both units, with a combined capacity of 530 MW, entered service during 2002. JEA's *Ten-Year Site Plan* also includes a planned 352 MW CC unit in 2007, a 250 MW fluidized bed coal unit in 2010, and a 191 MW CT unit in 2011. All three units are planned for a yet-to-be-determined site.

JEA forecasts that firm exports will decrease to 383 MW by 2012, while firm purchases are expected to decrease to 70 MW by 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 13. *JEA – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	1221	780
Firm Exports	-445	62
Firm Imports	427	-357
Combined Cycle	0	543
Fossil Steam	505	0
Combustion Turbine	1202	191
TOTAL	2910	1219

4.7.2 RELIABILITY CRITERIA

JEA's peak demand has historically occurred nearly split between the summer and winter seasons. However, JEA forecasts that winter peak demand will exceed summer peak demand for each year of the planning horizon. Because of these seasonal variations, JEA uses a 15% summer and winter peak reserve margin as its reliability criterion.

4.7.3 LOAD FORECAST

JEA uses trend analysis of historical electric data to evaluate base, high, and low forecasts of demand, energy, and number of customers. Trend analysis does 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 – 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 four years show significant improvement over previous forecasting results.

Under base-case assumptions, JEA forecasts that winter peak demand will increase at an AAGR of 3.49% per year over the 2002-2011 planning horizon, which is below the actual 1992-2001 AAGR of 3.86%. Over the next ten years, summer peak demand is forecasted to increase at an AAGR of 3.52%, which is above the actual 1992-2001 AAGR of 3.13%.

JEA's 1997-2001 retail sales forecasts have an absolute forecast error of 5.49%, which is the highest among the reporting utilities and is considerably above the 2.57% average of the reporting utilities. For the same five-year period, JEA's retail sales forecasts have an average forecast error of -5.49%, reflecting a strong tendency to under-forecast.

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 153 MW by 2011/12.

In 2001, JEA developed a solar reimbursement program to encourage renewable technologies. Under the program, JEA reimburses customers for a portion of the installation cost of solar photovoltaic and solar hot water systems.

4.7.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

City of Jacksonville / Duval County – Finds that JEA's *Ten-Year Site Plan* is a suitable planning document.

Florida Department of Environmental Protection – Finds 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.

St. Johns River Water Management District – Stated that water consumption at the Northside plant may exceed permit limits.

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. The Commission classifies JEA's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

4.8 KISSIMMEE UTILITY AUTHORITY (KUA)

KUA became an **All-Requirements Project** member of FMPA in 2002. The information normally contained in KUA's *Ten-year Site Plan* will be incorporated into FMPA's *Ten-Year Site Plan* starting in 2003. As a result, KUA will no longer file a *Ten-Year Site Plan* with the Commission after this year. The following analysis describes KUA's stand-alone system as it existed when KUA's *Ten-year Site Plan* was filed in April, 2002.

4.8.1 GENERATION SELECTION

As seen in Table 14, KUA has a winter system capacity of 303 MW. Of this total, 185 MW comes from KUA-owned generation, while 118 MW comes from firm capacity purchases.

KUA's expansion plan reflects the addition of 133 MW of capacity from **Cane Island Unit 3**, which was placed into commercial service in January, 2002. This unit is jointly owned with FMPA. KUA also has a 22 MW ownership share in the proposed **Stanton Unit A**, a 585 MW CC unit due to be completed in October, 2003. This unit is jointly owned by OUC, KUA, FMPA, and Southern Company-Florida, LLC. KUA currently forecasts that its firm capacity purchases will decrease to 89 MW by 2012.

TABLE 14. *KUA – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	6	0
Coal	21	0
Firm Imports	118	-19
Combined Cycle	109	155
Combustion Turbine	49	0
TOTAL	303	136

4.8.2 RELIABILITY CRITERIA

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

KUA's *Ten-Year Site Plan* contains unspecified purchases in the summers of 2009 (13 MW), 2010 (28 MW), and 2011 (46 MW) to maintain its 15% reserve margin criterion. Reserve margin drops to 3.4% by 2011 w/o capacity additions. KUA acknowledges the deficiency in its *Ten-Year Site Plan* but relies only on unspecified capacity purchases to maintain its 15% reserve margin. KUA's future capacity deficiencies may be mitigated, however, now that KUA is a member of FMPA's **All-Requirements Project**.

4.8.3 LOAD FORECAST

KUA's forecast models measure changes in electricity usage per customer class as a function of factors such as temperature, income, and the real price of electricity. Population forecasts were obtained from the Bureau of Economic and Business Research, and normal weather conditions were assumed for the load forecast model. KUA did not identify its data sources and variables. Further, KUA has insufficient historical retail sales data to enable the Commission to compare KUA's forecast accuracy to other utilities.

Under base-case assumptions, KUA forecasts that summer peak demand will increase at an AAGR of 4.99% per year over the 2002-2011 planning horizon, which is above the actual 1992-2001 AAGR of 4.44%. Over the next ten years, winter peak demand is forecasted to increase at an AAGR of 4.08%, which is slightly below the actual 1992-2001 AAGR of 4.24%.

4.8.4 DEMAND-SIDE MANAGEMENT

KUA is no longer subject to the requirements of 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 2011/12.

4.8.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Environmental Protection – Finds that KUA's *Ten-Year Site Plan* is adequate for planning purposes.

South Florida Water Management District – No adverse comments regarding the suitability of KUA's proposed plant sites.

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. The forecasted capacity deficiencies are small and occur in the later years of the planning horizon. These future capacity deficiencies may be mitigated now that KUA is a member of FMPA's **All-Requirements Project**. 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 15, LAK has a winter system capacity of 791 MW. LAK owns 891 MW of generating units and exports 100 MW of firm capacity to FMPA.

LAK's expansion plans reflect the addition of a 120 MW heat recovery steam generator to an existing 268 MW CT unit at **McIntosh Unit 5**. The resulting 388 MW CC unit was completed in April, 2002. Twenty internal combustion units, totaling 50 MW of capacity, were added at the **Winston** peaking station site in April, 2002. Firm imports are expected to drop to zero by 2010.

TABLE 15. ***LAK – WINTER CAPACITY BY FUEL TYPE***

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Coal	205	0
Firm Imports	0	0
Firm Exports	-100	100
Combined Cycle	124	120
Fossil Steam	240	0
Combustion Turbine	322	50
TOTAL	791	270

4.9.2 RELIABILITY CRITERIA

LAK is a winter-peaking utility. LAK plans its utility system using a reliability criterion of 20% summer peak / 22% winter peak reserve margin.

4.9.3 LOAD FORECAST

LAK's load forecast methodology includes economic modeling and exponential smoothing. LAK makes short-term forecasts using time-series decomposition models. The long-term forecasts use service territory population, number of accounts, energy sales, net energy for load, and summer and winter 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 assumptions, LAK forecasts that winter peak demand will increase at an AAGR of 1.79% per year over the 2002-2011 planning horizon, which is below the actual 1992-2001 AAGR of 4.03%. Over the next ten years, summer peak demand is forecasted to increase at an AAGR of 2.22%, which is also below the actual 1992-2001 AAGR of 2.57%.

LAK's 1997-2001 retail sales forecasts have an absolute forecast error of 1.24%, which is below the 2.57% average of the reporting utilities. For the same five-year period, LAK's retail sales forecasts have an average forecast error of 1.14%, reflecting a tendency to over-forecast.

4.9.4 DEMAND-SIDE MANAGEMENT

LAK is no longer subject to the requirements of 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 67 MW (8.2%) by 2011/12.

4.9.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Environmental Protection – Finds that LAK's *Ten-Year Site Plan* is adequate for planning purposes.

Southwest Florida Water Management District – Has concerns with the number of proposed inland sites for plant expansion. Recommends that utilities consider the use of alternatives to ground water for cooling purposes, such as locating proposed plants on the coast to allow the use of seawater.

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. The Commission classifies LAK's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

4.10 ORLANDO UTILITIES COMMISSION (OUC)

4.10.1 GENERATION SELECTION

As seen in Table 16, OUC has a winter system capacity of 1,385. Of this total, 1,092 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 300 MW of capacity to other utilities.

OUC's expansion plan reflects the addition of 181 MW of capacity from **Stanton Unit A** in October, 2003. OUC also plans to add two 175 MW CT units at the **Stanton** site, with in-service dates of 2006 and 2008, respectively. Firm imports are forecast to decrease to 231 MW, while exports are expected to decrease to zero, by 2012.

TABLE 16. *OUC – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	66	0
Coal	760	0
Firm Imports	593	-362
Firm Exports	-300	300
Combined Cycle	0	0
Combustion Turbine	266	531
TOTAL	1385	469

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.

OUC's *Ten-Year Site Plan* contains a 30 MW unspecified purchase in Summer, 2003. OUC's Summer, 2003 reserve margin is 13.6% without the unspecified purchase. OUC acknowledges the unspecified purchase in its *Ten-Year Site Plan*.

4.10.3 LOAD FORECAST

OUC uses linear regression sales forecast models because of the expense of updating and maintaining a detailed end-use database. OUC's methodology and assumptions may be appropriate; however, there are no data for the 1996-1998 period, and St. Cloud data were added only in 2001. Thus, there was insufficient data to measure the absolute forecast error of OUC's 1997-2001 retail sales forecasts.

Under base-case assumptions, OUC forecasts that summer peak demand will increase at an AAGR of 3.56% per year over the 2002-2011 planning horizon, which is slightly above the actual 1992-2001 AAGR of 3.50%. Over the next ten years, winter peak demand is forecasted to increase at an AAGR of 2.40%, which is much below the actual 1992-2001 AAGR of 7.74%.

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%) by 2011/12.

4.10.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

East Central Florida Regional Planning Council – Proposed units at Stanton site do not conflict with regional policies.

Florida Department of Environmental Protection – Finds that OUC's *Ten-Year Site Plan* is adequate for planning purposes.

St. Johns River Water Management District – Has no comments on proposed units at Stanton site.

4.10.6 SUITABILITY

As noted in its Ten-Year Site Plan, OUC expects to rely upon 30 MW of unspecified purchases for Summer, 2003. OUC's Summer, 2003 reserve margin is forecasted to be 13.6% without the unspecified purchases. Otherwise, forecasted reserve margins are expected to exceed OUC's 15% reserve margin criterion for each seasonal peak throughout the planning horizon. The Commission classifies OUC's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

4.11 CITY OF TALLAHASSEE (TAL)

4.11.1 GENERATION SELECTION

As seen in Table 17, TAL has a winter system capacity of 733 MW. Of this total, 699 MW comes from TAL's own system generation, while 34 MW comes from firm capacity purchases.

TAL's *Ten-Year Site Plan* shows the addition of two 50 MW combustion turbine units, in May, 2005, at a yet-to-be determined site. TAL also plans to add a total of 100 MW of CC capacity at a yet-to-be determined site between 2007 and 2010. Firm purchases are scheduled to drop to 11 by 2003 and staying at that level throughout the rest of the planning horizon. TAL plans to retire two CT units (20 MW total) at the **Purdom** site in 2008 and 2009, respectively. **Purdom Unit 7**, a 50 MW steam turbine unit, is also scheduled for retirement in 2011.

TABLE 17. *TAL – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Firm Imports	34	-23
Combined Cycle	262	100
Fossil Steam	366	-50
Hydroelectric	11	0
Combustion Turbine	60	80
TOTAL	733	107

4.11.2 RELIABILITY CRITERIA

TAL is primarily a summer-peaking utility. TAL plans its utility system using a reliability criterion of 17% reserve margin. TAL's *Ten-Year Site Plan* identifies a 14 MW unspecified purchase for Summer, 2004. Absent this unspecified purchase, TAL's Summer, 2004 reserve margin is 14.7%. In its *Ten-Year Site Plan*, TAL states that it is currently negotiating contracts for purchased power to meet its forecasted Summer, 2004 need. Further, the Commission has been notified that TAL has the option to extend an existing purchased power contract with Entergy. Either of these options are expected to provide sufficient capacity to meet TAL's current load forecast.

4.11.3 LOAD FORECAST

TAL uses a series of econometric-based linear regression forecasting models to develop its energy sales forecasts. These models rely upon an analysis of historical growth, usage patterns and population statistics. TAL lists data sources and tests its load forecast sensitivities for high- and low-growth cases.

Under base-case assumptions, TAL forecasts that summer peak demand will increase at an AAGR of 1.82% per year over the 2002-2011 planning horizon, which is below the actual 1992-

2001 AAGR of 3.26%. Over the next ten years, winter peak demand is forecasted to increase at an AAGR of 2.57%, which is above the actual 1992-2001 AAGR of 2.15%.

TAL's 1997-2001 retail sales forecasts have an absolute forecast error of 2.02%, which is below the 2.57% average of the reporting utilities. For the same five-year period, TAL's retail sales forecasts have an average forecast error of -1.54%, reflecting a tendency to under-forecast.

4.11.4 DEMAND-SIDE MANAGEMENT

TAL is no longer subject to the requirements of 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 28 MW (4.4%) by 2011/12.

4.11.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Environmental Protection – Expressed concern that TAL's *Ten-Year Site Plan* reflects a capacity shortfall in 2004.

4.11.6 SUITABILITY

Forecasted reserve margins are expected to fall below TAL's 17% reserve margin criterion in Summer, 2004 unless unspecified purchases are included. The forecasted capacity deficiency is small, and TAL may be able to continue purchasing capacity under an existing contract. This purchase is expected to meet TAL's forecasted need for capacity in Summer, 2004. For this reason, the Commission classifies TAL's 2002 *Ten-Year Site Plan* as ***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 does not serve any retail load. 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. Partial requirements providers (FPC, TECO, JEA, OUC, and GRU) serve all of SEC's load that exceeds specified capacity commitment levels.

4.12.1 GENERATION SELECTION

As seen in Table 18, SEC currently has a total winter generating capacity of 1,917 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 winter firm capacity from other utilities, 362 MW from Hardee Power Station, and 35 MW of cogeneration. 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 power purchases. The amount of partial requirements and full requirements purchases is currently 814 MW.

All of the approximately 2,184 MW of generating capacity proposed by SEC during the planning horizon is forecasted to be from CT units. Two 182 MW CT units are planned for the **Payne Creek** site in 2006. SEC's *Ten-Year Site Plan* also reflects plans for ten additional 182 MW CT units at a yet-to-be-determined site over the planning horizon. These units are planned to be placed into service as follows: one each in 2006, 2007, 2008, 2010, and 2011; and five units in 2009. SEC currently plans to use distillate oil to fuel all proposed CT units.

SEC's reliance on firm purchases is expected to decrease to 150 MW by 2012. However, the amount of partial requirements and full requirements capacity imports is forecasted to increase to 1,171 MW by that time.

TABLE 18. *SEC – WINTER CAPACITY BY FUEL TYPE*

UNIT TYPE	EXISTING CAPACITY (MW)	PROPOSED ADDITIONS (MW)
Nuclear	15	0
Coal	1330	0
Firm Imports	1016	-866
Partial Requirements Purchases	814	357
Firm Non-Utility Generation	397	-35
Combined Cycle	572	0
Combustion Turbine	0	2184
TOTAL	4144	1640

4.12.2 RELIABILITY CRITERIA

SEC expects to continue to be a winter-peaking utility primarily due to a forecasted increase in electric space-heating appliance saturation. SEC uses a dual reliability criteria of 15% summer and winter reserve margin and a 1% EUE/NEL ratio. Reserve margin is the primary criterion driving SEC's future resource needs.

4.12.3 TREATMENT OF HARDEE POWER STATION

Hardee Power Partners, Limited, a TECO Power Services Corporation, owns and operates the Hardee Power Station, a 362 MW facility consisting of a 269 MW combined cycle unit and a separate 93 MW combustion turbine unit. SEC has first priority use of Hardee Power Station 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 Hardee Power Station at times when SEC does not exercise its capacity rights.

Because Hardee Power Station's output 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 Hardee Power Station 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 Hardee Power Station 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 Hardee Power Station's capacity and energy in past years, particularly during seasonal peaks.

The fact that both TECO and SEC include Hardee Power Station capacity in their respective reserve margins is not of critical concern at this time since statewide reserve margins are forecasted to exceed 20% throughout the planning horizon. However, staff will continue to monitor this issue since reserve margins may change in the future.

4.12.4 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's load forecast and combined them to yield the final forecast. SEC provided detailed accounts of load forecasts based on economic, housing, appliance, weather and hourly load data. SEC provided high- and low-case load and energy forecast sensitivities.

Under base-case assumptions, SEC forecasts that winter peak demand will increase at an AAGR of 3.85% per year over the 2002-2011 planning horizon. While below the actual 1992-2001 AAGR of 4.46%, SEC's winter peak demand still has one of the highest forecasted growth rates in the state. Over the next ten years, summer peak demand is forecasted to increase at an AAGR of 3.77%, which is below the actual 1992-2001 AAGR of 5.00%.

SEC's 1997-2001 retail sales forecasts have an absolute forecast error of 3.11%, which is above the 2.57% average of the reporting utilities. For the same five-year period, SEC's retail sales forecasts have an average forecast error of -2.46%, reflecting a tendency to under-forecast.

4.12.5 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 reduce SEC's peak demand by approximately 144 MW. The remaining savings (104 MW) come from various interruptible service tariffs. The aggregate winter demand savings of SEC's members is forecasted to be 248 MW (4.8%) by 2011/12.

4.12.6 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Environmental Protection – Finds that SEC's *Ten-Year Site Plan* is adequate for planning purposes.

Southwest Florida Water Management District – Has concerns with the number of proposed inland sites for plant expansion. Recommends that utilities consider the use of alternatives to ground water for cooling purposes, such as locating proposed plants on the coast to allow the use of seawater.

4.12.7 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. The Commission classifies SEC's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

4.13 MERCHANT PLANT COMPANIES

Two merchant plant companies filed a Ten-Year Site Plan for 2002: Calpine Construction Finance Company (Calpine) and Oleander Power Project (Oleander).

Calpine filed a *Ten-Year Site Plan* which contained one gas-fired CT unit in Auburndale and five gas-fired CC units. When proposed by retail-serving utilities, CC 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. A third facility, the **Santa Rosa** unit, is expected to operate at a steam capacity under 75 MW, which would exempt the unit from requiring certification. 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 at a site in Brevard County. These units have received all required local permits and a DEP air permit. Four of the proposed units were placed into commercial operation in 2002. The in-service date of the fifth unit is unknown at this time.