

**A Review of  
Florida Electric Utility  
2003 Ten-year Site Plans**

PREPARED BY THE

FLORIDA PUBLIC SERVICE COMMISSION  
Division of Economic Regulation

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# **EXECUTIVE SUMMARY**

## **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 state, regional, and local planning agencies regarding various issues of concern. A public Commission workshop was held on August 6, 2003 to enable utilities to present summaries of their *Ten-Year Site Plans* and to allow for public comment. Upon completion and approval of the *Ten-Year Site Plan* review, the report is forwarded to the Florida Department of Environmental Protection (DEP).

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. Electric utilities must file a *Ten-Year Site Plan* 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.

## **PURPOSE**

The *Ten-Year Site Plan* gives state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The *Ten-Year Site Plan* is not a binding plan of action on electric utilities. As such, the Commission's classification of a *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 docketed matters before the Commission. If a utility's *Ten-Year Site Plan* raises concerns that require Commission action, such action is formally undertaken after a public hearing.

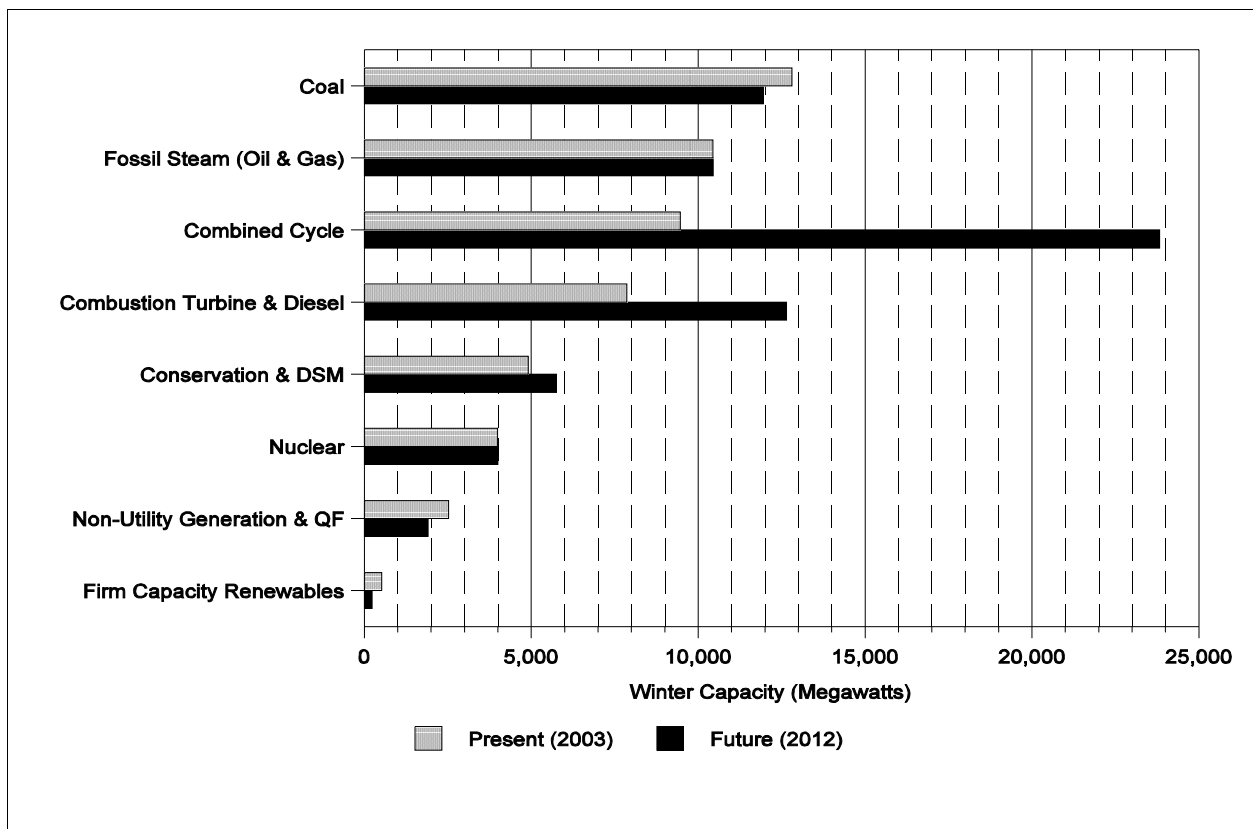
Because the *Ten-Year Site Plan* is a planning document containing tentative data, it may not contain sufficient information to allow regional planning councils, water management districts, and other review agencies to fully assess site-specific issues within their jurisdictions. Such detailed data, based on in-depth environmental assessments, are provided by the utility when seeking local permits or, if required, during Power Plant Siting Act or Transmission Line Siting Act certification proceedings.

## SUITABILITY

The Commission has reviewed *Ten-Year Site Plans* filed by eleven reporting utilities and one independent power producer (IPP). 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 23% to 26% during summer peak seasons, and from 26% to 30% during winter peak seasons. The Commission makes no determination on the suitability of the IPP filing.

## SUMMARY OF RESOURCE ADDITIONS

Figure 1, shown below, and Tables 1 and 2, 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 1. STATE OF FLORIDA – NET FIRM CAPACITY ADDITIONS BY FLORIDA’S ELECTRIC UTILITIES (2003-2012)**

	<b>WINTER CAPACITY (MW)</b>
<b>NET ELECTRIC UTILITY CAPACITY ADDITIONS</b>	
Combined Cycle - new generating units	11,457
Combined Cycle - repowerings, capacity changes at existing sites	2,908
Combustion Turbine - new generating units	4,806
Combustion Turbine - capacity changes at existing sites	19
Combustion Turbine - retirements	-41
Coal - new generating units	250
Coal - retirements	-1,107
Nuclear - capacity changes at existing sites	7
Oil and Gas Fossil Steam - capacity changes at existing sites	59
Oil and Gas Fossil Steam - retirements	-50
<b>TOTAL</b>	<b>18,308</b>
<b>NET CHANGES TO FIRM NON-UTILITY GENERATION</b>	
Expiration of Cogeneration contracts <sup>1</sup>	-569
Expiration of IPP contracts <sup>2</sup>	-322
<b>TOTAL</b>	<b>-891</b>
<b>TOTAL NET FIRM CAPACITY ADDITIONS</b>	<b>17,417</b>

<sup>1</sup> Sixteen firm capacity contracts (569 MW total) are set to terminate over the next ten years. As these contracts expire, the capacity becomes uncommitted (merchant) capacity.

<sup>2</sup> OUC's current purchased power contracts with Reliant - Indian River Units 1-3 are set to expire by October, 2007. At that time, the capacity becomes uncommitted (merchant) capacity. OUC has a new purchased power contract, which began in October, 2003, to buy additional capacity from Stanton Energy Center Unit A.

**Table 2. REPORTING UTILITIES – NEXT IDENTIFIED GENERATING UNIT**

UTILITY	GENERATING UNIT	UNIT TYPE	WINTER CAPACITY (MW)	IN-SERVICE DATE
Progress Energy Florida	Hines Unit 2	CC	582	12/2003
Florida Power & Light Company	Sanford Unit 4	CC	1036	6/2003
Gulf Power Company	<i>unknown</i> (2 units)	CT	332	6/2007
Tampa Electric Company	Bayside Unit 1 <sup>3</sup>	CC	779	5/2003
Florida Municipal Power Agency	Stanton Unit A <sup>4</sup>	CC	22	10/2003
Gainesville Regional Utilities	Deerhaven Unit 4	CT	81	5/2010
JEA	Brandy Branch Unit 4 <sup>5</sup>	HRSG	190	6/2005
City of Lakeland	<i>none planned</i>	---	---	---
Orlando Utilities Commission	Stanton Unit A <sup>4</sup>	CT	181	10/2003
City of Tallahassee	distributed generation	IC	48	5/2005
	<i>unsited</i>	CT	50	
Seminole Electric Cooperative	Payne Creek (5 units)	CT	320	12/2006

<sup>3</sup> Conversion of **Gannon Unit 5**, formerly a coal-fired generating unit, to gas-fired combined cycle operation.

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

<sup>5</sup> Two 191 MW CT units are currently in operation. A 190 MW heat recovery steam generator is planned to be added in June, 2005 to these two CT units, creating a 572 MW combined cycle unit.

## **REVIEW & ANALYSIS - STATE PERSPECTIVE**

## **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 *2003 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 *2003 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.

In addition to these activities, the FRCC has formed a Gas/Electricity Interdependency Task Force to determine the interdependency relationship between gas pipeline and electric system operations and planning. Through this task force, the FRCC hopes to identify any possible negative reliability impacts and, if necessary, recommend possible measures to mitigate such impacts and perform detailed analysis to determine precise mitigation measures. The Commission will continue to monitor the FRCC task force's activities.

### **AGE OF GENERATING UNITS**

The average age of existing generating capacity in the state, on a megawatt-weighted basis, is 22.3 years. As was previously shown in Table 1 on page 8, Florida's utilities plan to add over 18,300 MW of new generating units during the ten-year planning horizon, an amount that exceeds utility-owned generating unit additions over the past twenty years. As a result, the average age of Florida's generating units is expected to decrease over the next ten years. Table 3 shows the amount of existing generating capacity of Florida's utilities by age.

Table 4, on the next page, shows the average age of Florida's generating units, on a megawatt-weighted basis, by primary fuel type. The natural gas-fired generating fleet in Florida is the youngest of all unit types. During the ten-year

<b>Table 3. STATE OF FLORIDA – GENERATING UNIT CAPACITY BY AGE</b>	
<b>AGE OF UNITS</b>	<b>WINTER CAPACITY (MW)</b>
0 - 9 years	9,602
10 - 19 years	7,569
20 - 29 years	13,162
30 - 39 years	10,960
40 + years	2,997

planning horizon, nearly all proposed new generating unit additions are expected to be gas-fired. As a result, the average age of gas-fired units is expected to decrease over the next ten years while the average age of the remaining unit types is expected to increase.

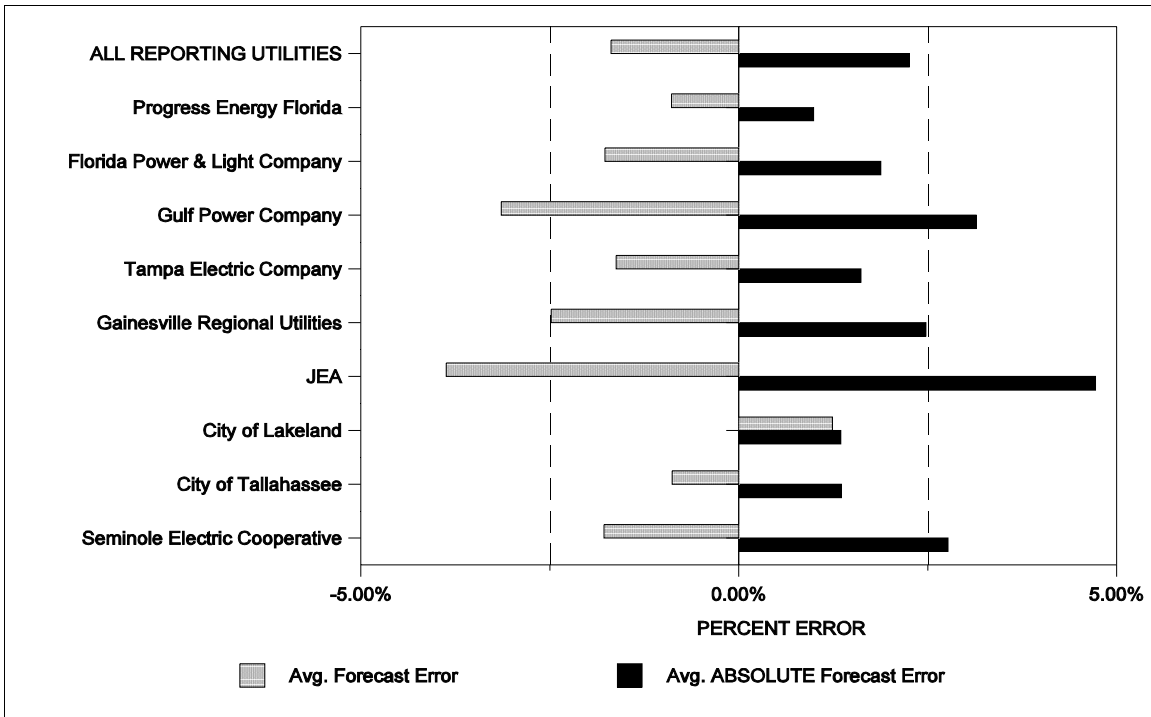
As generating units become older, they typically become more costly to operate relative to newer, more efficient units and, as a result, are dispatched less frequently. Electric utilities evaluate the retirement of older, less efficient units as part of a cost-effectiveness analysis that incorporates the repowering of existing units, the construction of new units, or the purchase of capacity from other sources. The end result of this analysis is the expansion plan contained in each utility's *Ten-Year Site Plan*.

<b>Table 4. STATE OF FLORIDA – AGE OF GENERATING UNITS BY FUEL TYPE</b>	
<b>UNIT (FUEL TYPE)</b>	<b>AVERAGE AGE (YEARS)</b>
Natural Gas	14.9
Coal	23.7
Nuclear	26.1
Oil (distillate and residual)	31.2
ALL UNIT TYPES	22.3

## **LOAD AND ENERGY FORECASTS**

Electric utilities perform load and energy forecasts to estimate how much, and when, additional generating capacity may be needed in the future. For each reporting utility, the Commission evaluated the historical forecast accuracy of total retail energy sales for a five-year period from 1998-2002. Actual energy sales for each year were compared to energy sales forecasts made three, four, and five years prior. For example, actual 2002 energy sales were compared to projected 2002 forecasts made in 1997, 1998, and 1999. These differences, expressed as a percentage error rate, were used to calculate two measures of a utility's historical forecast accuracy. **Average absolute forecast error** is an average of percentage error rates calculated by ignoring the positive and negative signs that result when a forecast over- or under-estimates actual values. This value provides an overall measure of the accuracy of past utility forecasts. **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 eleven reporting utilities. There were insufficient historical data to analyze the historical forecast accuracy of FMPA and OUC. Figure 2, on the next page, illustrates the historical forecast accuracy of total retail energy sales for the nine reporting utilities with sufficient historical data. All reporting utilities except PEF have a history of under-forecasting retail energy sales. A detailed discussion of the individual utility forecasts is included later in this review.



**Figure 2. TOTAL RETAIL ENERGY SALES (1998-2002) – HISTORICAL FORECAST ACCURACY**

## **DEMAND-SIDE MANAGEMENT**

**Demand-side management (DSM)** reduces customer peak demand and energy requirements, resulting in the deferral of need for new generating units. DSM programs have been available since 1980 as a result 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 set numeric DSM goals in 1999 and 2000, and the utilities continue to develop and implement DSM programs to meet these goals.

Florida's electric utilities have been successful in meeting the overall objectives of FEECA. As seen in Table 5, on the next page, it is estimated that utility conservation programs have reduced statewide summer peak demand by 4433 MW, winter peak demand by 5540 MW, and energy consumption by 4833 GWh. By 2012, DSM programs are forecasted to reduce summer peak demand by 5042 MW, winter peak demand by 6146 MW, and energy consumption by 6113 GWh. These DSM savings are also illustrated in Figures 3, 4, and 5 on the next two pages.

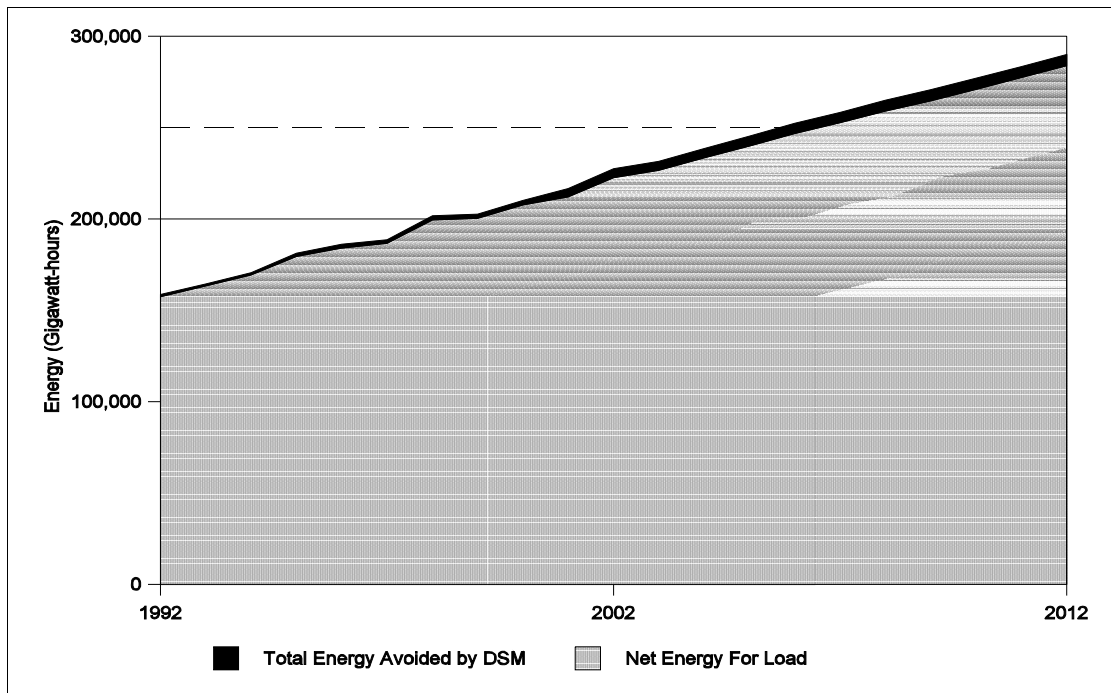
**Demand-side Management Goals**

The Commission set new numeric demand and energy DSM goals for FPL, PEF, Gulf, and TECO in 1999. These four utilities subsequently filed new DSM plans, which the Commission approved in 2000. The Commission set new DSM goals for Florida Public Utilities Company (FPUC) in 2000 and approved FPUC’s DSM Plan in 2001. The Commission set numeric goals of **zero** for JEA and OUC in 2000 because these two utilities could not identify any additional cost-effective DSM programs.

<b>Table 5. STATE OF FLORIDA – ESTIMATED SAVINGS FROM ELECTRIC UTILITY DSM PROGRAMS</b>		
	<b>2002</b>	<b>By 2012</b>
Summer Demand	4433 MW	5042 MW
Winter Demand	5540 MW	6146 MW
Annual Energy Consumption	4833 GWh	6113 GWh

**Energy Conservation Cost Recovery**

Florida’s investor-owned utilities have spent a substantial amount of money to implement DSM programs. Investor-owned utilities have the opportunity to 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 – IMPACT OF DSM ON NET ENERGY FOR LOAD**

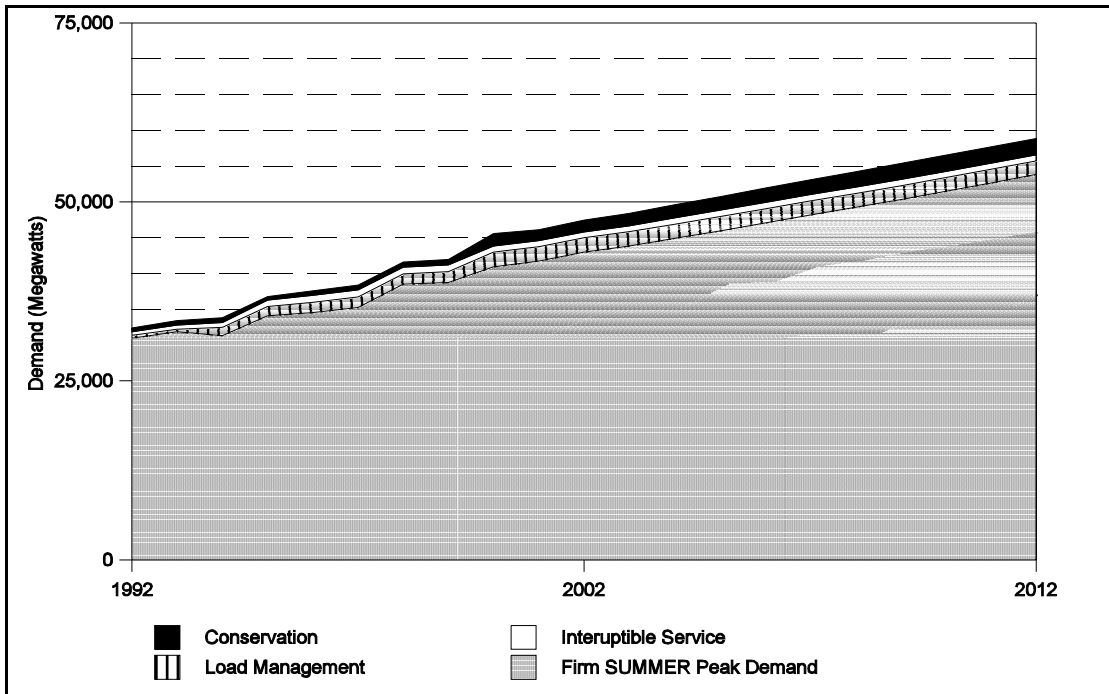


Figure 4. STATE OF FLORIDA - IMPACT OF DSM ON SUMMER PEAK DEMAND

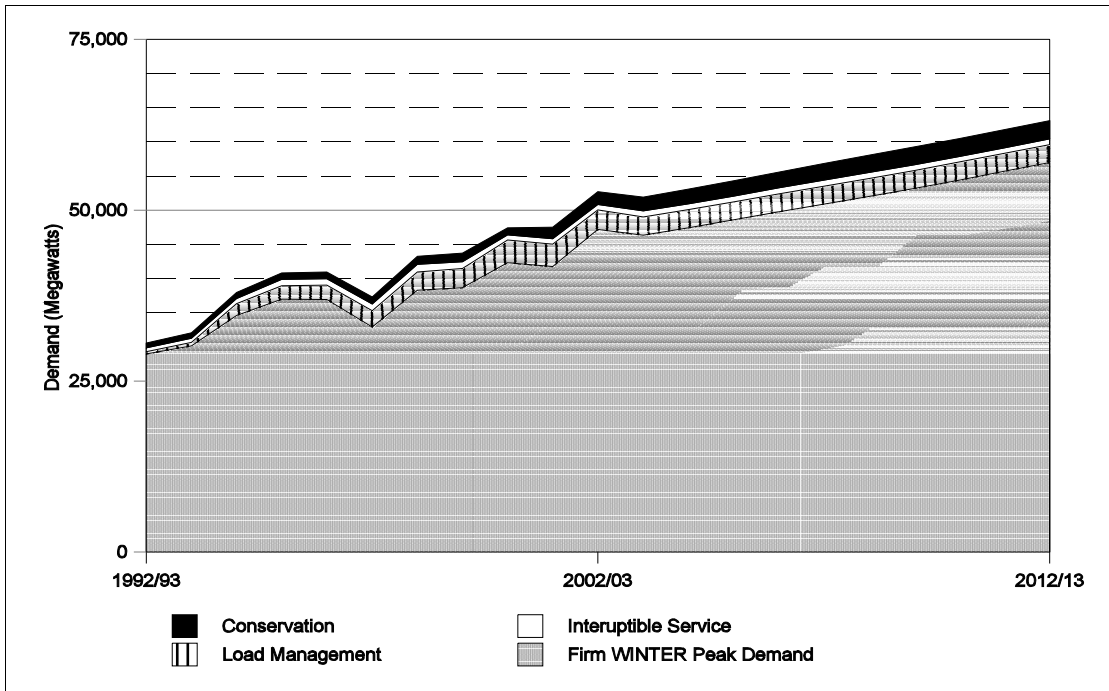


Figure 5. STATE OF FLORIDA - IMPACT OF DSM ON WINTER PEAK DEMAND

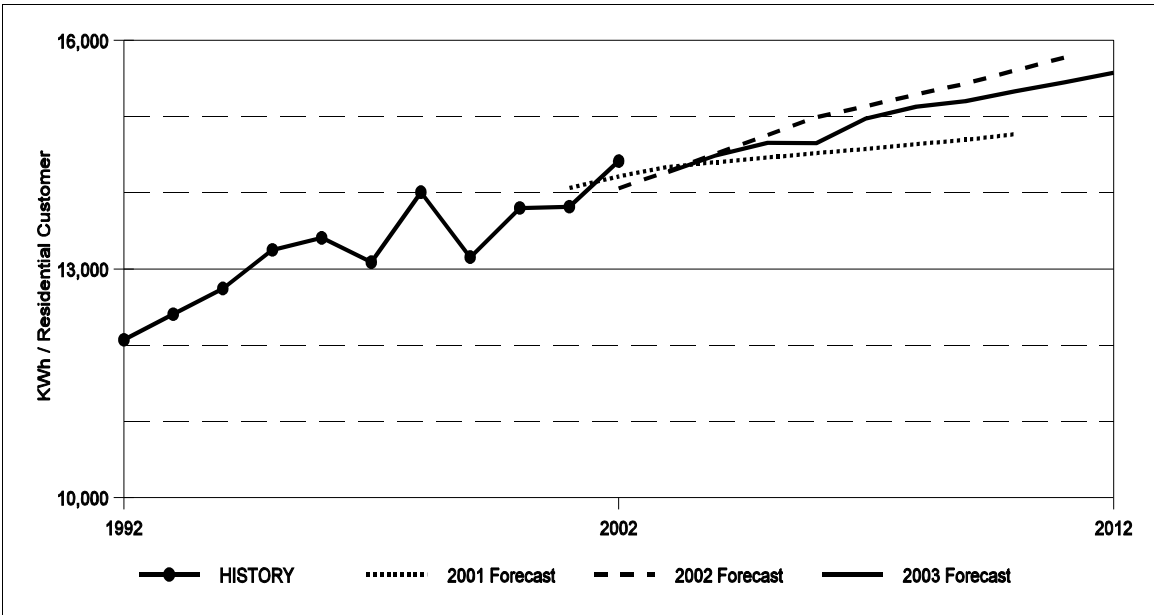


**State Comprehensive Plan**

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, and efficient building code standards. 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 increases may be attributed to the following factors: 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, on the next page, illustrates historical and forecasted residential per-capita energy usage for the state. Per-capita energy usage increased at an average of 1.7% per year over the past ten years, and is forecasted to grow at an average of 1.0% per year over the planning horizon. This year’s forecasted per-capita energy usage for the planning horizon is lower than the forecast made last year, but is higher than the forecast made two years ago, for a comparable period.



**Figure 6. STATE OF FLORIDA – ENERGY USAGE PER RESIDENTIAL CUSTOMER**

## RELIABILITY CRITERIA

Reliability criteria decide the timing of planned resource additions. To determine when additional future resources are required, utilities generally use two types of reliability criteria: **deterministic** (reserve margin) and **probabilistic** (loss of load probability or expected unserved energy). The reliability criteria used by each reporting utility are shown in Table 6.

<b>Table 6. REPORTING UTILITIES – RELIABILITY CRITERIA</b>			
UTILITY	RESERVE MARGIN	LOLP (days/yr)	EUE/NEL (%)
Progress Energy Florida	15% Summer/Winter <sup>6</sup>	0.1	---
Florida Power & Light Company	15% Summer/Winter <sup>6</sup>	0.1	---
Gulf Power Company	13.5% Summer <sup>7</sup>	---	---
Tampa Electric Company	15% Summer/Winter <sup>6, 8</sup>	---	---
Florida Municipal Power Agency	18% Summer	---	---
Gainesville Regional Utilities	15% Summer/Winter	---	---
JEA	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%

### **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. Beginning in 2004, TECO will also use 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 reliability during off-peak months when many units are out of service for maintenance.

<sup>6</sup> Reserve margin criterion increases to 20% effective Summer, 2004.

<sup>7</sup> Reserve margin criterion increases to 15% starting in the fourth year of the planning horizon (in this case, 2006).

<sup>8</sup> A 7% summer supply-side reserve margin component will be added 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 account for unit failures, unit maintenance, and assistance 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.

### ***Role of Reliability Criteria in Planning***

FRCC studies currently show that a 15% reserve margin correlates to LOLP values that are well below 0.1 days per year. These low LOLP values are the result of two factors: high unit availabilities and low forced outage rates typical of new, efficient new generating units; and, enhanced maintenance practices on older generating units. As a result of these factors, reserve margin continues to be the primary criterion driving a utility's capacity needs.

Figure 8, on the next page, shows the forecasted summer and winter reserve margin over the next ten years for Peninsular Florida's utilities. Peninsular Florida's reserve margins are expected to meet or exceed 20% each year during the planning horizon except for summer, 2011, where the reserve margin is forecasted to be 19%. Figure 9, also on the next page, shows forecasted reserve margins for the State of Florida. Statewide reserve margins are expected to be well over 20% throughout the planning horizon.

### ***Planned New Independent Power Producer Capacity in Florida***

In its *2003 Regional Load and Resource Plan*, the FRCC compiled a list of existing, planned, and prospective IPP plant additions. Currently, there are 18 IPP units in the state with a total winter capacity of approximately 4,350 MW. Approximately 3,150 MW of existing capacity is currently under contract with electric utilities. Last year's *Regional Load and Resource Plan* identified proposals for 53 additional IPP units totaling nearly 8,100 MW of winter capacity. However, as the Commission stated last year in its review, many of these proposed IPP units were not built. At this time, 16 new IPP units, with a combined winter capacity of approximately 2,660 MW, are now proposed in the planning horizon. Only 350 MW of the proposed IPP capacity is currently under contract. All proposed IPP units are scheduled to enter service by March, 2006.

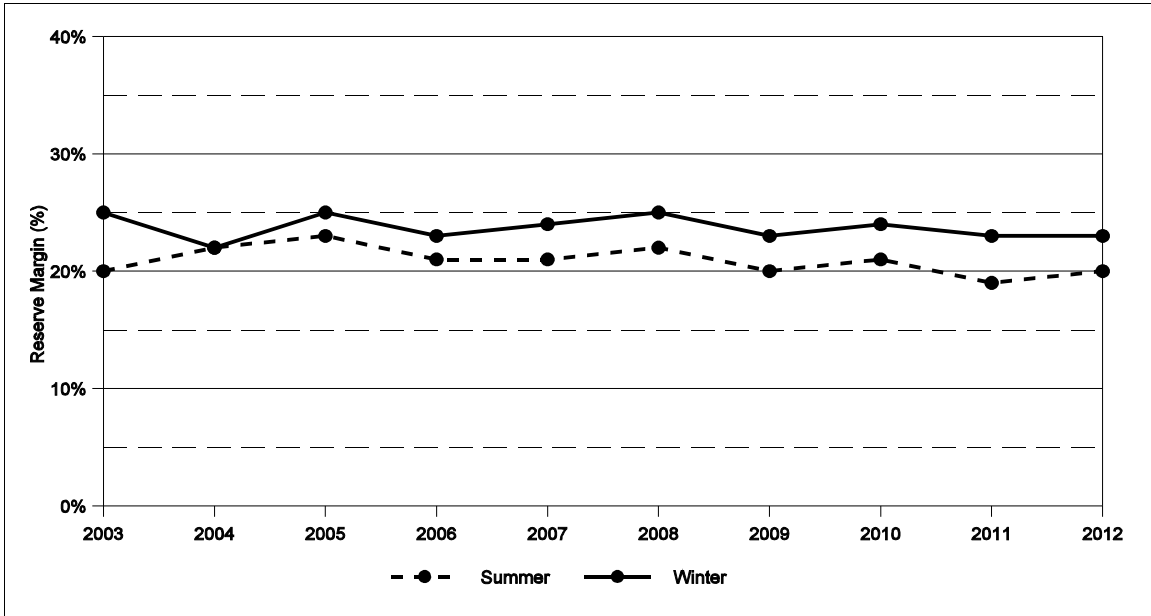


Figure 8. *PENINSULAR FLORIDA – FORECASTED RESERVE MARGIN*

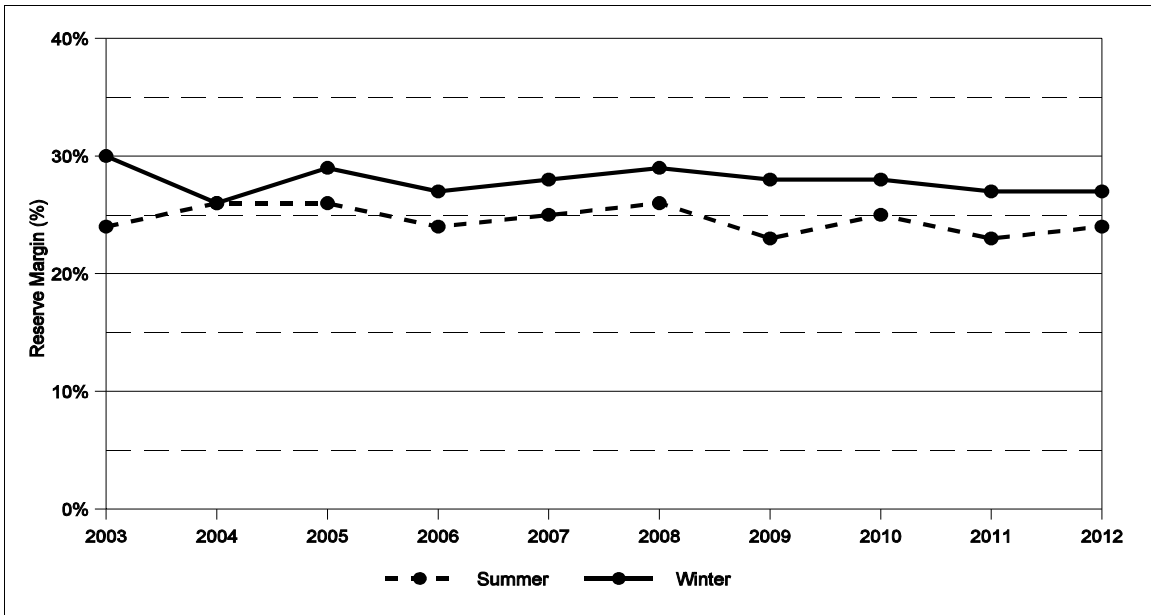


Figure 9. *STATE OF FLORIDA – FORECASTED RESERVE MARGIN*

## FUEL FORECASTS

Florida's electric utilities consider several strategic factors – fuel availability, generation 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, while some utilities also produced high- and low-price sensitivities.

Each utility's fuel price forecast was compared to data from the U.S. Energy Information Administration (EIA). EIA's comprehensive fuel price forecasts fall within a reasonable range of forecasts provided by other outside sources. Table 7 shows the forecasted annual average growth rate in price for each fuel, as forecasted by the reporting utilities and by the EIA.

<b>Table 7. REPORTING UTILITIES – FUEL PRICE FORECAST – AVERAGE ANNUAL GROWTH RATE (2003-2012)</b>					
UTILITY	COAL	RESIDUAL OIL	DISTILLATE OIL	NATURAL GAS	NUCLEAR
EIA	2.0%	2.4%	2.5%	2.3%	NA
Progress Energy Florida	1.1%	-5.0%	-3.1%	-3.7%	1.1%
Florida Power & Light Company	1.2%	-0.7%	0.1%	-5.5%	1.2%
Gulf Power Company	2.3%	-2.6%	-2.0%	-3.9%	NA
Tampa Electric Company	0.8%	0.0%	-3.4%	0.1%	NA
Florida Municipal Power Agency	1.3%	3.0%	2.9%	2.7%	2.3%
Gainesville Regional Utilities	1.2%	2.0%	4.0%	3.9%	-0.2%
JEA	1.4%	1.3%	1.3%	-2.3%	NA
City of Lakeland	1.0%	-0.9%	-1.4%	-0.2%	NA
Orlando Utilities Commission	4.8%	1.5%	NA	1.0%	2.5%
City of Tallahassee	1.6%	1.6%	1.1%	-0.8%	NA
Seminole Electric Cooperative	1.2%	3.1%	1.9%	1.8%	0.9%

### Coal

The average U.S. delivered cost of coal in 2002 increased to \$24.84 per ton, up \$0.16 per ton from 2001. Through 2012, EIA forecasts that delivered coal prices will increase at a rate of 2.0% per year. Florida's utilities forecast changes in coal prices ranging from 0.8% to 4.8% per year during the planning horizon.

In 2002, nationwide coal consumption increased by 11 million short tons to 1,072 million short tons. However, this consumption level remained well below 2000 consumption levels. Domestic coal production fell 3.0%, to 1,094 million tons, in 2002 due to several factors, including: reduced demand for coal among all coal consumers due to a slowing economy; and,

milder than normal weather nationwide. Through 2012, EIA expects domestic coal production to increase to 1,256 million tons, representing an average increase of 1.4% per year. During this same period, EIA expects net coal exports to fall to 12 million tons, thus reducing the amount of coal available for domestic consumption to 1,244 million tons.

### ***Residual (#6) Oil***

EIA reports that the average U.S. delivered cost of residual oil was \$3.63/MMBtu in 2002, up slightly from \$3.55/MMBtu in 2001. Through 2012, EIA anticipates that long-term residual oil prices will increase at around 2.4% per year. Florida's utilities forecast changes in residual oil prices ranging from -5.0% to +3.1% per year during the planning horizon.

### ***Distillate (#2) Oil***

EIA reports that the average U.S. delivered cost of distillate oil was \$5.00/MMBtu in 2002, down from \$6.93/MMBtu in 2001. Through 2012, EIA anticipates that long-term distillate oil prices will increase at around 2.5% per year. Florida's utilities forecast changes in distillate oil prices ranging from -3.4% to +4.0% per year during the planning horizon.

### ***Natural Gas***

The average cost of natural gas for electric utilities nationwide was \$3.77/MMBtu in 2002, down over 18% from 2001 levels. 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 2012, EIA forecasts that long-term natural gas prices will increase at approximately 2.3% per year. Florida's utilities forecast changes in natural gas prices ranging from -5.5% to +3.9% per year during the planning horizon.

EIA estimated that U.S. proven natural gas reserves at the end of 2001 were 183.5 trillion cubic feet (Tcf), a 3.4% increase from prior-year levels. EIA reported that natural gas consumption by all sectors in 2002 was 22.5 Tcf, a 1.3% increase over 2001 levels.

### ***Nuclear***

EIA assumes that nationwide nuclear capacity will stay nearly at current levels during the planning horizon, as the retirement of some nuclear units is expected to be offset by capacity increases at the remaining units. Both FPL and PEF expect their nuclear units to operate throughout the planning horizon.

Spent nuclear fuel disposal is a primary concern for electric utilities nationwide. The U.S. Department of Energy (DOE) has been collecting a 0.1 ¢/kWh fee on nuclear generation to finance the management and disposal of spent nuclear fuel. Nationwide, ratepayers pay nearly \$600 million per year into the DOE's Nuclear Waste Fund. FPL and PEF 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 more on-site spent fuel storage capacity. If DOE removal of spent nuclear fuel does not occur, it is estimated that 80% of the utilities' spent fuel pools will reach capacity by 2010.

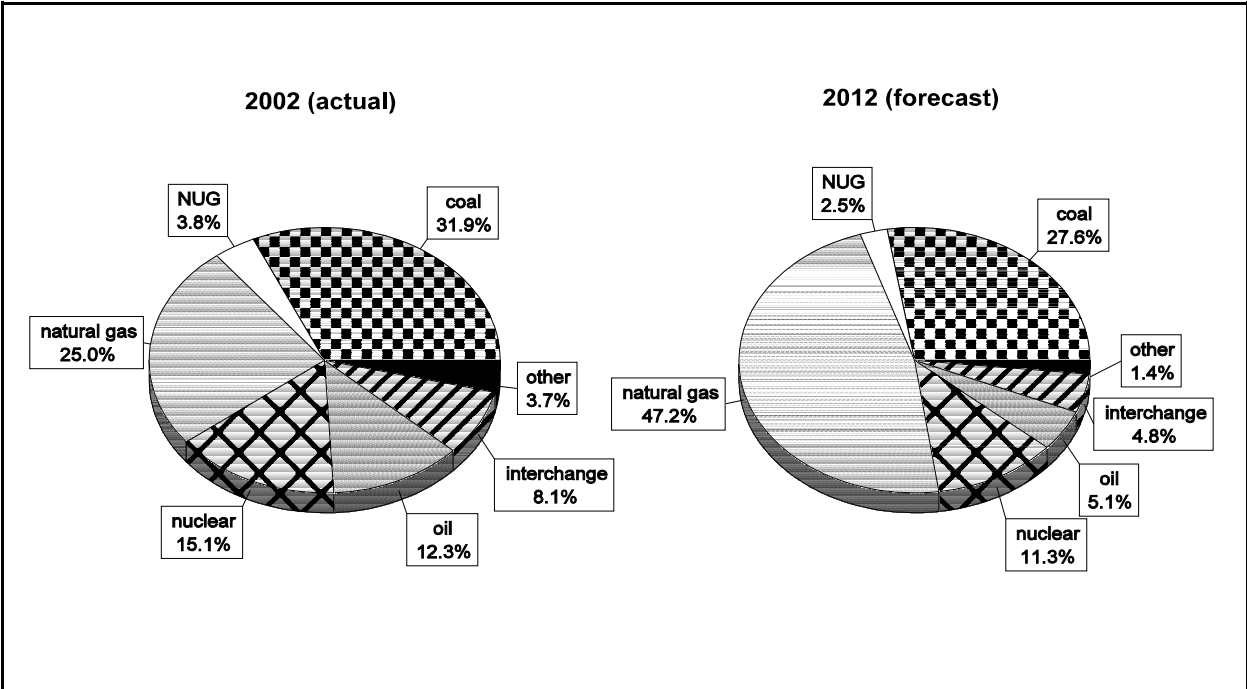
**GENERATION SELECTION**

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 approximately 12.3% 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 current 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, primarily from new, efficient combined cycle and combustion turbine units. Oil-fired generation is projected to decline. At this time, utility analyses indicate that additional nuclear power plants are not a viable option, primarily because of high construction costs and uncertainty over spent fuel disposal. Although coal-fired power plants have not been a viable option in recent years because of high construction costs and environmental constraints, utilities are now reconsidering coal plants as future generation resources due to recent high natural gas prices. For the past three years, JEA has included a coal-fired unit in its *Ten-Year Site Plan*.

**Natural Gas**

Florida's utilities project a substantial increase in natural gas-fired generation over the next ten years, from a current level of 25.0% up to 47.2% of statewide energy production. The increase is due to the forecasted addition of over 19,000 MW of gas-fired capacity, in the form of new combined cycle and combustion turbine units, as well as unit repowerings. Natural gas consumption forecasts do not include usage from proposed new IPP generating units.



**Figure 10. STATE OF FLORIDA – ENERGY GENERATION BY FUEL TYPE**

## ***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. Over the next ten years, oil-fired energy is expected to decrease from 12.3% to 5.1% of statewide energy production.

## ***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 857 MW, coal-fired energy is expected to decrease from 31.9% to 27.6% of statewide energy production over the next ten years.

## ***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 slowly decrease from 8% to 4.8% of statewide energy consumption over the next ten years. 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.

## ***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 Florida's utilities is expected to decrease from 3.9% to 2.6% of statewide energy consumption during the planning horizon. The forecasted decrease is due to the expiration of approximately 570 MW of firm cogeneration contracts and 320 MW of firm capacity contracts with independent power producers. However, these generators will remain in place once their contracts expire, and the owners of these facilities may sign new purchased power contracts with utilities at that time.



### **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. Electric utilities and non-utility generators produce renewable energy in Florida. Non-utility producers of renewable energy use some of their output on-site, selling the remainder to electric utilities either under firm contracts or on an as-available basis.

Hydroelectric units at two utility-owned 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 approximately 465 MW of firm capacity to Florida's utilities that is fired by municipal solid waste, wood and wood waste, and waste heat.

## **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 and have received Siting Board certification, but have yet to be placed into commercial service.

### **Progress Energy Florida – Hines Unit 2**

In December, 2000, the Commission granted PEF's petition to build a 582 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 December, 2003 in-service date.

#### ***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, 2005 in-service date, will be fitted to two 191 MW combustion turbine units currently in service, forming a 573 MW combined cycle unit. Brandy Branch Unit 4 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 April, 2004. Subject to contract re-opener 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.

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

In November, 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. Both Martin Unit 8 and Manatee Unit 3 were certified under the Power Plant Siting Act in April, 2003.

#### ***Progress Energy Florida – Hines Unit 3***

In February, 2003, the Commission granted PEF's petition to build a 582 MW gas-fired combined cycle unit at the existing Hines site in Polk County. Hines Unit 3 has an anticipated December, 2005 in-service date. Hines Unit 3 was certified under the Power Plant Siting Act in September, 2003.

## **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 – Cane Island Unit 4***

FMPA has proposed to build a new 250 MW gas-fired combined cycle unit at the Cane Island site in Osceola County. The proposed unit has a tentative in-service date of June, 2007.

### ***Progress Energy Florida – Hines Units 4, 5, and 6***

PEF has proposed to add three new 540 MW gas-fired combined cycle units at the existing Hines plant site in Polk County. Hines Unit 4 through 6 are currently scheduled to be placed into commercial service in December of 2007, 2009 and 2011, respectively. On October 7, 2003, PEF released a Request for Proposals for alternatives to the proposed Hines Unit 4. Responses are due December 16, 2003, and a final decision is expected in the summer of 2004.

### ***Florida Power & Light Company – Turkey Point combined cycle unit; three unsited combined cycle units***

FPL has proposed to add four new 1,209 MW gas-fired combined cycle units. The first unit, at the Turkey Point site, is scheduled to enter commercial service in June, 2007. The other three identical combined cycle units are at yet-to-be determined sites and are currently scheduled for commercial service in June of 2008, 2010, and 2012, respectively. On August 25, 2003, FPL released a Request for Proposals for alternatives to the proposed Turkey Point CC unit. Responses were received on October 24, 2003, and a final decision is expected in May, 2004.

### ***SEC – Unsited combined cycle units***

SEC has proposed to build three new 182 MW gas-fired combined cycle units at a yet-to-be determined site. Two of the proposed units have a tentative in-service date of May, 2009 while the third unit is tentatively scheduled for November, 2009.

### ***JEA – Unsited combined cycle unit; Unsited coal unit***

JEA has proposed to build a new 352 MW gas-fired combined cycle unit at a yet-to-be determined site in Duval County. The proposed unit has a tentative in-service date of January, 2009. 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.

## **NATURAL GAS AVAILABILITY**

For over 40 years, Florida 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 2.2 billion cubic feet per day (Bcf/day). In May, 2002, the Gulfstream pipeline went into service with a pipeline capacity of 1.1 Bcf/day. As shown in Figure 11, over 83% of the existing pipeline capacity is used for electricity generation, both by utilities and non-utility generators.

Electric utilities forecast a significant (127%) increase in the need for natural gas over the next ten years. Based on this forecast and the forecasted requirements of the other sectors, total pipeline demand is estimated to average 3.48 Bcf/day by 2012. Peak demand could be higher. Given that the combined capacity of FGT and Gulfstream is 3.3 Bcf/day, it would appear that, at a minimum, an additional 0.18 Bcf/day of pipeline capacity would be needed to satisfy forecasted 2012 requirements. However, as the subscription levels of FGT and Gulfstream are not readily available, the timing of needed additional pipeline capacity may be earlier than 2012. For proposed electric generating units that do not have contracted pipeline capacity, their needs must be met either by remaining pipeline capacity, if any, or by new pipeline construction.

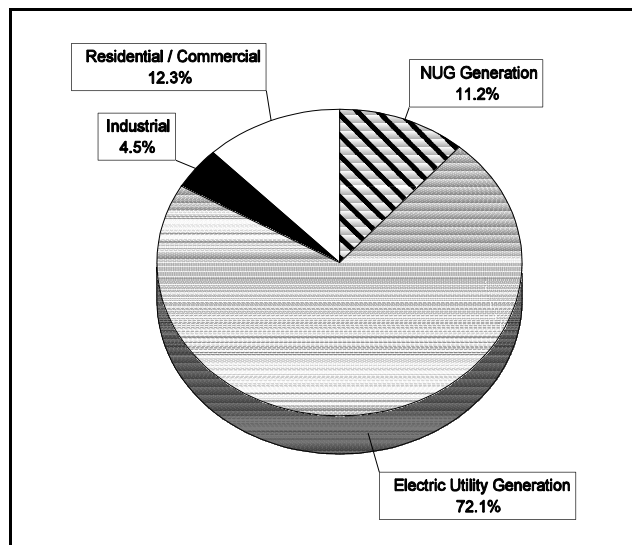
The Commission does not have the data necessary to calculate when specific pipeline capacity needs will occur. However, the Commission will continue discussions with the FRCC to compile the data and prepare the necessary analyses to determine the timing of pipeline capacity additions.

### **FGT**

FGT applied for FERC approval in November, 2001 to implement a Phase VI expansion project. Phase VI added 33.3 miles of new pipeline and an additional 18,600 horsepower of compression. Completed in November, 2003, the Phase VI expansion Phase VI increased system pipeline capacity by 0.12 Bcf/day, bringing FGT's total capacity to 2.2 Bcf/day.

### **Gulfstream**

Gulfstream placed Phase I of its two-phase natural gas transmission system into service in May, 2002. Phase I, with a capacity of 1.1 Bcf/day, crosses the Gulf of Mexico between



**Figure 11. NATURAL GAS CONSUMPTION BY END-USER – 2002**

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. Phase II, which was approved by the FERC as part of Gulfstream's original certificate application, would extend the pipeline east to Fort Pierce and south to Palm Beach County. On October 8, 2003, at Gulfstream's request, the FERC amended Gulfstream's original certificate to allow Phase II to be designated as two phases, Phase II and Phase III. Under the new classification, Phase II will consist of 105 miles of mainline facilities to Martin County. As projected, Phase II is expected to have an in-service date of May 1, 2005. Phase III would extend the system to Palm Beach County. While it is expected that there will be a period of time between the construction of Phase II and Phase III, both lines are expected to be in service by February, 2006.

### **Seafarer**

The proposed Seafarer Pipeline System, owned by the El Paso Corporation, 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. Seafarer plans to submit an application to the FERC in early 2004. The 26-inch pipeline, with a delivery capacity of up to 0.7 Bcf/day, is expected to be in service in early 2007.

### **Calypso**

Calypso Pipeline, LLC, a subsidiary of Enron Global LNG, applied for FERC approval in 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 Tractebel North American, Inc. May 1, 2003, the FERC issued a preliminary determination of non-environmental issues; on August 1, 2003, the FERC issued a draft environmental statement supporting Tractebel's proposed route. The 24-inch pipeline is expected to have a delivery capacity of up to 0.832 Bcf/day and is expected to be in service in 2007.

### **AES**

AES Ocean Express applied for FERC approval in February, 2002 to construct a 54.3-mile, 24-inch pipeline extending from the United States - Bahamas Exclusive Economic Zone boundary to a termination just west of the Ft. Lauderdale/Hollywood International Airport. The proposed pipeline is designed to transport up to 0.842 Bcf/day and would interconnect with the FGT system and with an FPL gas pipeline that serves the Lauderdale Plant. On April 10, 2003, the FERC issued a preliminary determination on non-environmental issues. On June 27, 2003, the FERC released a favorable draft environmental impact statement for AES. The Ocean Express project has an anticipated in-service date of March, 2006.

## **REVIEW & ANALYSIS - INDIVIDUAL UTILITIES**

## PROGRESS ENERGY FLORIDA (PEF)

### Generation Selection

As seen in Table 8, PEF's system winter capacity is currently 9,899 MW. Of this total, 8,586 MW comes from PEF-owned generation. Firm interchange purchases account for 474 MW, while the remaining 839 MW comes from non-utility generators.

PEF plans to add two 582 MW and three 540 MW gas-fired combined cycle units at the **Hines** site in 2003, 2005, 2007, 2009, and 2011, respectively. Three new 182 MW combustion turbine units are proposed for a yet-to-be determined site, one in 2004 and two in 2006. PEF expects to lose approximately 192 MW due to the expiration of cogeneration contracts. Firm capacity imports are forecasted to decrease by 61 MW during the planning horizon.

<b>Table 8. PEF – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Nuclear	782	7
Coal	2341	0
Firm Imports	474	-61
Firm Non-Utility Generation	839	-192
Combined Cycle	752	2784
Fossil Steam	1642	0
Combustion Turbine	3069	546
<b>TOTAL</b>	<b>9899</b>	<b>3084</b>

### Reliability Criteria

PEF has historically been a winter-peaking utility. PEF utilizes dual reliability criteria of a 15% summer and winter peak reserve margin and a 0.1 days per year LOLP. PEF's reserve margin criterion increases to 20% starting in Summer, 2004. Forecasted reserve margins, as shown in PEF's *Ten-Year Site Plan*, are expected to meet or exceed the reliability criteria in each year of the planning horizon.

### Load Forecast

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

Under base-case assumptions, PEF forecasts that winter peak demand will increase at

an average of 2.27% per year over the planning horizon, which is considerably less than the actual growth of 4.33% per year over the past ten years. Summer peak demand is forecasted to increase at an average of 2.54% per year over the planning horizon. PEF uses a projected population growth of 1.6% per year, published by the University of Florida's Bureau of Economic and Business Research.

PEF's 1998-2003 retail sales forecasts have an absolute forecast error of 0.99%, which is considerably less than the 2.26% average of the reporting utilities. Over the same period, PEF's retail sales forecasts have an average forecast error of -0.89%, reflecting a slight tendency to under-forecast.

### ***Demand-side Management***

The Commission set new DSM goals for PEF in 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. The Commission will set new DSM goals for PEF in 2004.

PEF's DSM Plan, approved by the Commission in 2000, consists of five residential and eight commercial/industrial DSM programs, as well as a research and development program. PEF also has a low income pilot program offered in conjunction with DCA. In total, PEF's DSM programs are forecasted to reduce winter 2011/12 peak demand by 1620 MW. These savings are attributed to non-dispatchable conservation programs (633 MW), interruptible service tariffs (354 MW), and load management (633 MW). Due to an expected decrease in customer participation, residential load management savings are forecasted to decrease during the planning horizon by 139 MW from current levels.

### ***State, Regional, and Local Agency Comments***

Central Florida Regional Planning Council - Cites limitations on water resources which could lead to curtailment of water available for electric generation. New ground water use permits cannot be assumed.

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 PEF's *Ten-Year Site Plan* is adequate for planning purposes.

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

Southwest Florida Water Management District – Cites PEF's efforts to minimize use of groundwater at Hines site. Planned unit additions may potentially be sited within the Southern Water Usage Caution Area. Recommends that process and cooling water needs be met from alternative sources to groundwater.

Tampa Bay Regional Planning Council - PEF's *Ten-Year Site Plan* complies with regional policies.



### **Suitability**

Forecasted reserve margins are expected to be at or above PEF'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 PEF's *Ten-Year Site Plan* as **suitable** for planning purposes.

## **FLORIDA POWER & LIGHT COMPANY (FPL)**

### **Generation Selection**

As seen in Table 9, on the next page, FPL's system winter capacity is currently 22,132 MW. Of this total, 18,780 MW currently comes from FPL-owned generation. FPL currently purchases 2,475 MW of firm capacity from Southern Company (929 MW), JEA (390 MW), and other entities (1156 MW), while purchases from non-utility generators comprise the remaining 877 MW.

FPL plans to add approximately 5,700 MW of supply-side resources during the planning horizon. Included in this total is the recently completed **Sanford** unit repowering project, which added 1,036 MW of winter generating capacity to FPL's system when it went into commercial service in October, 2003. FPL also recently completed construction on two 181 MW CT units at the **Ft. Myers** site in May, 2003. FPL has two 181 MW CT units currently in service at the **Martin** site. FPL recently received Commission approval 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**. At the same time, the Commission approved FPL's request to construct **Manatee Unit 3**, a 1,197 MW CC unit also due to be placed into service in June, 2005.

FPL also plans to add four 1,200 MW class CC units: one at the **Turkey Point** site in 2007, and three at yet-to-be determined sites in 2008, 2010, and 2012, respectively. On August 25, 2003, FPL released a Request for Proposals for alternatives to the proposed Turkey Point CC unit. Responses are due on October 24, 2003, and a final decision is expected in 2004.

FPL forecasts a loss of 282 MW from non-utility generators during the planning horizon due to the expiration of cogeneration contracts. Firm capacity imports are expected to decrease to 1,319 MW 2012, although FPL includes in this total a 929 MW firm capacity contract with Southern Company that is set to expire in 2010. In its *Ten-Year Site Plan*, FPL discusses its ongoing actions to extend this contract or to find replacement capacity prior to 2010.

### **Reliability Criteria**

FPL has traditionally been a summer-peaking utility because winter temperatures have been relatively mild in recent years. However, FPL forecasts that winter peak demand will be higher than summer peak during the planning horizon. As a result, FPL utilizes a dual reliability criteria of a 15% summer and winter peak reserve margin and a 0.1 days per year LOLP. FPL's reserve margin criterion increases to 20% starting in Summer, 2004.

Forecasted reserve margins, as shown in FPL's *Ten-Year Site Plan*, are expected to meet or exceed the reliability criteria in each year of the planning horizon. If the 929 MW firm

capacity contract with Southern Company is removed from FPL's reserve margin calculation after 2010, when the contract is set to expire, winter reserve margins are still expected to exceed 20% throughout the remainder of the planning horizon. However, summer reserve margins are expected to be 18.9% in 2010, 15.9% in 2011, and 18.3% in 2012.

<b>Table 9. FPL – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Nuclear	3013	0
Coal	926	0
Firm Imports	2475	-1156
Firm Non-Utility Generation	877	-282
Combined Cycle	5118	7075
Fossil Steam	7036	59
Combustion Turbine	2687	3
<b>TOTAL</b>	<b>22132</b>	<b>5699</b>

**Load Forecast**

FPL develops its sales, net energy for load, and peak load forecasts as key inputs into its integrated resource plan. The primary drivers of these forecasts are demographic trends, weather, economic conditions, and electricity price. 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 average of 2.22% per year over the planning horizon, which is higher than the actual growth of 1.95% per year over the past ten years. Winter peak demand is forecasted to increase at an average of 1.95% per year over the planning horizon, which is considerably less than the actual growth of 5.07% per year seen during the past ten years.

FPL's 1998-2002 retail sales forecasts have an absolute forecast error of 1.88%, which is less than the 2.26% average of the reporting utilities. Over the same period, FPL's retail sales forecasts have an average forecast error of -1.77%, reflecting a tendency to under-forecast.

**Demand-side Management**

The Commission set new DSM goals for FPL in 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 will set new DSM

goals for FPL in 2004.

FPL currently offers six residential and eight commercial/industrial DSM programs as part of a DSM Plan that was approved by the Commission in 2000. FPL also has a research and development program to study potential DSM applications. The majority of FPL's demand savings result from residential and commercial load management programs. FPL's DSM programs are forecast to reduce winter 2012/13 peak demand by 1,873 MW and 2012 system annual energy usage by 911 GWh.

FPL has a green energy project, in which customers pay additional money to purchase energy generated from renewable resources. FPL also has a photovoltaic research project.

### ***State, Regional, and Local Agency Comments***

East Central Florida Regional Planning Council – Cites water resource and quality issues as reason for coordination with county and regional water agencies. Anticipates reduction in emissions from repowered Sanford units.

Florida Department of Environmental Protection – States that FPL's *Ten-Year Site Plan* appears to be suitable, but is concerned that the combined cycle unit scheduled for 2007 is unsited. Notes FPL plans for two 230 kV transmission lines in 2004 although no siting applications have been filed or exemptions obtained.

Lee County – Finds that FPL's *Ten-Year Site Plan* is suitable.

Manatee County – Provided general comments on Manatee Unit 3. Is concerned with FPL's inclusion of the Manatee site as a preferred site for future units.

Miami-Dade County - Provides comments on FPL's designation of the Turkey Point site as a potential site for future units.

South Florida Regional Planning Council – Concerned that future expansion in Miami-Dade County could adversely impact water quality in Biscayne Bay.

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 – Describes water consumption issues at Manatee site. States that water resource constraints may pose significant permitting challenges in parts of the district.

St. Johns Water Management District – Designation of Cape Canaveral as a potential site not expected to have adverse effects on water quality or wildlife.

Treasure Coast Regional Planning Council – Requests that FPL upgrade the efficiency and appearance of the Riviera site. Believes 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 – Has no comment on FPL's *Ten-Year Site Plan*.

### **Suitability**

Forecasted reserve margins are expected to meet or exceed FPL's 15% criterion for each seasonal peak through Summer, 2004. If the 929 MW firm capacity contract with Southern Company is removed from FPL's reserve margin calculation after 2010, the new 20% reserve margin criterion is forecasted to be met during all winter seasons but violated in the summers of 2010, 2011, and 2012. In its *Ten-Year Site Plan*, FPL discusses its ongoing actions to extend this contract or find replacement capacity prior to 2010. Therefore, the Commission classifies FPL's *Ten-Year Site Plan* as **suitable** for planning purposes.

### **GULF POWER COMPANY (Gulf)**

#### **Generation Selection**

As seen in Table 10, Gulf's system winter capacity is currently 2,679 MW. Gulf owns 2,844 MW of installed capacity and currently purchases 27 MW of firm capacity via interchange and 19 MW from a non-utility generator. Gulf exports 211 MW of firm capacity to other utilities..

Gulf plans to add approximately 300 MW during the planning horizon. Two new 166 MW gas-fired combustion turbine units are planned for a yet-to-be determined site in 2007. 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 expects the new **Smith Unit 3** to have unit deratings totaling 28 MW between the present time and 2006. Gulf plans unit retirements at the **Crist** site (83 MW total) and the **Scholz** site (92 MW total). Gulf forecasts the loss of 19 MW in 2005 due to the expiration of its only firm cogeneration contract.

<b>Table 10. GULF – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Coal	2122	-92
Firm Imports	27	-20
Firm Exports	-211	211
Firm Non-Utility Generation	19	-19
Combined Cycle	584	-28
Fossil Steam	83	-83
Combustion Turbine	55	332
TOTAL	2679	301

#### **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% summer reserve margin criterion for its near-term (3-year) criterion. Beyond three years (in this case, 2006), the reserve margin planning criterion is 15%.

Gulf's *Ten-Year Site Plan* indicates that the summer reserve margin criterion will be violated in 2005 (78 MW deficiency), 2006 (74 MW), 2009 (29 MW), and 2012 (46 MW). Gulf's *Ten-Year Site Plan* discusses at length the company's ability to rely on firm interchange from other Southern Company members to meet potential capacity deficiencies that may occur on Gulf's system. Over the planning horizon, Gulf expects to be a net purchaser of capacity from the Southern Company pool.

### ***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 adequately identifies its data sources. However, low- and high-band forecast sensitivities were not performed.

Under base-case assumptions, Gulf forecasts that summer peak demand will increase at an average of 0.51% per year over the planning horizon, which is considerably less than the actual growth of 3.23% per year over the past ten years. Winter peak demand is forecasted to increase at an average of 1.09% per year over the planning horizon, which is less than one-third of the actual growth of 3.70% per year seen during the past ten years.

One factor suppressing forecasted demand growth is Gulf's conservation programs. Another factor may be Gulf's projection of population growth, which averages 1.5% per year over the planning horizon and is slightly less than the 1.6% forecasted statewide by the University of Florida. However, Gulf's average forecast error for retail sales has continued to decrease over the past two years, from -4.17% for the 1996-2000 period to -3.14% for the 1998-2003 period.

### ***Demand-side Management***

The Commission set new DSM goals for Gulf in 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 will set new DSM goals for Gulf in 2004.

Gulf currently offers seven DSM programs and four types of audits as part of a DSM Plan that was approved by the Commission in 2000. Most forecasted demand savings are from the Good Cents Home program, the Advanced Energy Management program (a customer-controlled demand control program in which customers can reduce electricity consumption in response to pricing signals), and an interruptible service tariff. Gulf does not have dispatchable load management on its system. Gulf's DSM programs are expected to reduce winter 2011/12 peak demand by 554 MW, summer 2012 peak demand by 478 MW, and 2012 system annual

energy usage by 905 GWh.

Gulf has a green pricing program which funds two types of renewables projects. Solar for Schools has promoted the installation of solar technologies in school facilities since 1996. EarthCents promotes the installation of small photovoltaic generating facilities.

### **State, Regional, and Local Agency Comments**

Florida Department of Environmental Protection – States that Gulf's *Ten-Year Site Plan* appears to be suitable, but is concerned with the Shoal River greenfield site because any generator located there would likely have to be a zero-discharge facility.

West Florida Regional Planning Council – Gulf's *Ten-Year Site Plan* is generally consistent with regional policies in the West Florida Strategic Regional Policy Plan.

### **Suitability**

The Commission notes that Gulf's 15% reserve margin criteria is forecasted to be violated for four 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.

## **TAMPA ELECTRIC COMPANY (TECO)**

### **Generation Selection**

As seen in Table 11, TECO's system winter capacity is currently 4,404 MW. Of this total, 3,611 MW comes from TECO-owned generation. TECO currently purchases 731 MW of firm capacity from other utilities and 62 MW from non-utility generators.

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. TECO plans to cease all coal operations at the **Gannon** site. Currently, units 1 through 4 are in long-term reserve shutdown status and will be retired by the end of 2004. Units 5 and 6 have been converted to use the steam output of seven new gas-fired combustion turbine units and seven heat recovery steam generators. The resulting facility will have two combined cycle units and be known as **Bayside** Power Station. **Bayside Unit 1** went into service in May of this year and has a winter capacity of 779 MW. **Bayside Unit 2** is expected to enter service in January, 2004 with a winter capacity of 1,022 MW. TECO's *Ten-Year Site Plan* also contains seven 180 MW gas-fired combustion turbine units, two at the **Bayside** site, three at the **Polk** site, and two at a yet-to-be determined location.

Firm capacity imports are forecasted to drop to 449 MW in 2003 and stay at that level for the remainder of the planning horizon. TECO also expects to lose 41 MW due to the expiration of two cogeneration contracts.

<b>Table 11. TECO – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Coal	2866	0
Firm Imports	731	-282
Firm Exports	0	0
Firm Non-Utility Generation	62	-41
Integrated Coal Gasified Combined Cycle	260	0
Combined Cycle	0	1801
Fossil Steam	0	0
Combustion Turbine	485	1080
<b>TOTAL</b>	<b>4404</b>	<b>2558</b>

### **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's reserve margin criterion increases 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. Forecasted reserve margins, as shown in TECO's *Ten-Year Site Plan*, are expected to meet or exceed TECO's reliability criteria in each year of the planning horizon.

### **Treatment of Hardee Power Station**

Hardee Power Partners, Limited, a TECO Power Services Corporation, owns and operates the **Hardee Power Station**, a 449 MW facility consisting of a 269 MW combined cycle unit and two separate 90 MW combustion turbine units. 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 output 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 meet or exceed 20% throughout the planning horizon. The Commission will continue to monitor this issue since reserve margins may change in the future.

### ***Load Forecast***

TECO's retail customer demand and energy forecast is the result of six separate analyses: economic, customer, energy, peak demand, phosphate, and conservation programs. TECO's energy models are based on the Statistical Adjusted Engineering model, which specifies end-use variables such as heating, cooling, and base-use appliances. Phosphate demand and energy are forecasted separately and then added to the final forecast. Projected demand and energy reductions from conservation, load management, and cogeneration programs are subtracted from the forecast. TECO also performed high- and low-case sensitivities based on an explicit assumption of a  $\pm 0.5\%$  change in growth of employment, income, and number of customers.

Under base-case assumptions, TECO forecasts that summer peak demand will increase at an average of 3.07% per year over the planning horizon, which is slightly less than the actual growth of 3.23% per year over the past ten years. Winter peak demand is forecasted to increase at an average of 2.98% per year over the planning horizon, which is less than the actual growth of 3.60% seen during the past ten years.. TECO's projection of population growth, which averages 1.5% per year over the planning horizon, is slightly less than the 1.6% forecasted statewide by the University of Florida.

TECO's 1998-2002 retail sales forecasts have an absolute forecast error of 1.62%, which is less than the 2.26% average of the reporting utilities. Over the same period, TECO's retail sales forecasts have an average forecast error of -1.62%, reflecting a tendency to under-forecast.

### ***Demand-side Management***

The Commission set new DSM goals for TECO in 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 will set new DSM goals for TECO in 2004.

TECO currently offers eleven DSM programs as part of a DSM Plan that was approved by the Commission in 2000. Most of TECO's forecasted demand savings are expected to result from non-dispatchable conservation programs, a dispatchable load management program, and interruptible service. In total, TECO's DSM programs are forecasted to reduce winter 2011/12 peak demand by 1,178 MW, summer 2012 peak demand by 421 MW, and 2012 system annual energy usage by 607 GWh.



### **State, Regional, and Local Agency Comments**

Central Florida Regional Planning Council - Cites limitations on water resources which could lead to curtailment of water available for electric generation. New ground water use permits cannot be assumed.

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

Southwest Florida Water Management District – Concerned with the number of proposed plants located in the Southern Water Use Caution Area. States that water resource constraints may pose significant permitting challenges in parts of the district.

Tampa Bay Regional Planning Council – TECO's *Ten-Year Site Plan* is consistent with regional policies. Proposed changes at Gannon (Bayside) will have a net positive effect on air and water quality in the region due to the decreased use of coal.

### **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.

## **FLORIDA MUNICIPAL POWER AGENCY (FMPA)**

FMPA is an organization that jointly manages and operates the activities of 29 municipal electric utilities. Fifteen of these utilities currently comprise FMPA's **All-Requirements Project**, meaning that FMPA plans for, and supplies, all power requirements for these 15 members. Member cities not involved in the **All-Requirements Project** are responsible for planning their own generation needs.

### **Generation Selection**

As seen in Table 12, FMPA's **All-Requirements Project** currently has a winter system generating capacity of 1,711 MW. However, the combined generation of FMPA's members, currently 1,324 MW, is insufficient to meet aggregate load. To serve load that exceeds generation, FMPA currently purchases 387 MW of capacity from other utilities. FMPA has partial requirements contracts with PEF and FPL, who serve the load in their regions that exceeds FMPA's own generation and capacity purchases.

FMPA plans to add a net of 434 MW of capacity during the planning period. Current plans call for the addition of a 17 MW CT in Key West in 2006, a yet-to-be sited 250 MW CC unit in 2007, and a yet-to-be sited 165 MW CT unit in 2011. The remaining 124 MW of planned capacity will come from joint ownership in **Stanton Unit A**, a 585 MW CC unit jointly owned by FMPA, OUC, and Southern Company-Florida, LLC. This unit entered commercial service in October, 2003. Firm imports are forecasted to decrease to 265 MW by 2012.

<b>Table 12. FMPA – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Nuclear	82	0
Coal	220	0
Firm Imports	387	-122
Member-Owned Capacity	686	0
Combined Cycle	185	374
Combustion Turbine	151	182
<b>TOTAL</b>	<b>1711</b>	<b>434</b>

### **Reliability Criteria**

FMPA has historically been a summer-peaking entity. As such, FMPA plans its system using a reliability criterion of 18% summer reserve margin. FMPA's *Ten-Year Site Plan* indicates that the 18% summer reserve margin criterion will be violated in 2003 (17%) and 2004 (15%). FMPA's *Ten-Year Site Plan* did not identify any capacity resources to meet these projected reserve shortfalls. However, 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. No unspecified purchases are included among FMPA's future capacity resource additions.

### **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 has insufficient historical retail sales data to enable the Commission to compare FMPA's forecast accuracy to other utilities.

Over the past ten years, FMPA's base-case peak demand increased at an average of 8.71% (summer) and 10.5% (winter) per year, primarily due to the addition of new member utilities. Under base-case assumptions, FMPA forecasts that summer peak demand will increase at an average of 3.08% per year over the planning horizon. Over the same period, winter peak demand is forecasted to increase at an average of 2.5% per year.

### **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 2012/13 winter load of FMPA's member utilities by 15 MW.

### **State, Regional, and Local Agency Comments**

Central Florida Regional Planning Council - Cites limitations on water resources which could lead to curtailment of water available for electric generation. New ground water use permits cannot be assumed.

East Central Florida Regional Planning Council - The proposed Stanton Unit A does not conflict with regional policies.

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

Indian River County – Proposed transmission facility will require county approval.

Northeast Florida Regional Planning Council – No new plants or modifications to existing sites are expected in the Region.

South Florida Regional Planning Council - Discussed proposed CT unit in Key West.

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

Southwest Florida Water Management District – FMPA's *Ten-Year Site Plan* provided no information on potential water use at future plants. For any proposed plant located in the Southern Water Use Caution Area, water resource constraints may pose significant permitting challenges.

Treasure Coast Regional Planning Council - FMPA has no planned expansion in the region. However, the Council believes that FMPA 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.

### **Suitability**

As filed in its *Ten-Year Site Plan*, FMPA's forecasted reserve margins will fall slightly below the 18% planning criteria in the summers of 2003 and 2004. Otherwise, forecasted reserve margins are expected to meet or exceed FMPA's reserve margin criterion for each summer peak throughout the planning horizon. 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.

## **GAINESVILLE REGIONAL UTILITIES (GRU)**

### **Generation Selection**

As seen in Table 13, on the next page, GRU has a net winter system capacity of 629 MW. GRU currently does not purchase or sell any firm capacity. The only capacity addition in GRU's *Ten-Year Site Plan* is an 81 MW combustion turbine unit at the **Deerhaven** site in 2010.

<b>Table 13. GRU – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Nuclear	11	0
Coal	228	0
Combined Cycle	118	0
Fossil Steam	106	0
Combustion Turbine	166	81
<b>TOTAL</b>	<b>629</b>	<b>81</b>

### **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. Forecasted reserve margins, as shown in GRU's *Ten-Year Site Plan*, are expected to meet or exceed the reserve margin criterion in each year of the planning horizon.

### **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 average of 2.19% per year over the planning horizon, which is less than the actual growth of 2.76% per year over the past ten years. Winter peak demand is forecasted to increase at an average of 2.22% per year over the planning horizon, which is also less than the actual growth of 3.66% per year seen during the past ten years.

GRU's 1998-2002 retail sales forecasts have an absolute forecast error of 2.48%, which is higher than the 2.26% average of the reporting utilities. Over the same period, GRU's retail sales forecasts have an average forecast error of -2.48%, reflecting a tendency to under-forecast.

### **Demand-side Management**

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, and commercial lighting efficiency and maintenance services. These programs are expected to reduce GRU's total 2012/13 winter peak demand by 20 MW.

GRU is promoting the use of renewable energy by developing a 10 KW photovoltaic

project. Also planned are a green pricing program. Under the proposed green pricing program, energy produced at a local landfill may be packaged with other renewable sources and marketed to GRU's residential and commercial customers.

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

St. Johns River Water Management District – Commented that no increased demand for ground water is expected from the proposed Deerhaven CT unit.

### **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.

## **JEA**

### **Generation Selection**

As seen in Table 14, on the next page, JEA has a winter system capacity of 3,238 MW. The units on JEA's system actually can supply 3,476 MW of winter generation. However, JEA is currently a net seller of capacity, exporting 445 MW while importing 207 MW.

JEA plans approximately 900 MW of net winter capacity additions 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's *Ten-Year Site Plan* also includes a planned 352 MW CC unit in 2009, a 250 MW fluidized bed coal unit in 2010, and a 191 MW CT unit in 2012. All three units are planned for a yet-to-be-determined site.

JEA forecasts that firm exports will decrease to 383 MW by 2013, while firm purchases are expected to decrease to 70 MW by that time. Capacity purchases are made through a partnership known as The Energy Authority, which works on JEA's behalf as its power marketing group to buy and sell electricity as needed.

### **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.

JEA's *Ten-Year Site Plan* includes a 245 MW unspecified purchase of seasonal capacity for the winter of 2004/05. However, The Energy Authority will broker the purchase, and a signed contract is imminent for seasonal capacity from outside the FRCC region. Otherwise,

forecasted reserve margins, as shown in JEA's *Ten-Year Site Plan*, are expected to meet or exceed the 15% reserve margin criterion in each year of the planning horizon.

<b>Table 14. JEA – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Coal	1771	250
Firm Exports	-445	62
Firm Imports	207	-137
Combined Cycle	0	925
Fossil Steam	505	0
Combustion Turbine	1200	-191
<b>TOTAL</b>	<b>3238</b>	<b>909</b>

### **Load Forecast**

JEA's base-case forecast is derived from trend analysis based on weather-normalized historical electric data. Trend analysis methodology does not explicitly capture the impact of projected growth in personal income, population, and other variables related to electricity usage. JEA states that trend analysis has dramatically increased the accuracy of its forecasts. While forecast error rates have declined over the last five years, JEA's forecast error averages are still the highest of all reporting utilities. JEA's 1998-2003 retail sales forecasts have an absolute forecast error of 4.72%, which is considerably higher than the 2.26% average of the reporting utilities. Over the same period, JEA's retail sales forecasts have an average forecast error of -3.87%, reflecting a strong tendency to under-forecast.

Under base-case assumptions, JEA forecasts that winter peak demand will increase at an average of 3.15% per year over the planning horizon, which is less than the actual growth of 4.27% per year over the past ten years. Summer peak demand is forecasted to increase at an average of 2.56% per year over the planning horizon, which is less than the actual growth of 2.66% seen during the past ten years.

### **Demand-side Management**

The Commission set numeric goals of **zero** for JEA in 2000. However, JEA has continued 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 2012/13 winter peak demand by 201 MW.

JEA has a green power program to encourage the application of renewable energy technology. A component of the green power program is a solar reimbursement program, under

which JEA reimburses customers for a portion of the installation cost of solar photovoltaic and solar hot water systems. JEA has installed 170 KW of solar photovoltaic modules around Jacksonville. JEA forecasts demand reductions from this program of nearly 9 MW by 2007.

**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.

**Suitability**

As noted in its *Ten-Year Site Plan*, JEA expects to rely upon 245 MW of unspecified capacity purchases for the winter of 2004/05. JEA’s reserve margin at that seasonal peak is forecasted to be 6.3% without the unspecified purchase. JEA has noted that a signed contract is imminent for seasonal capacity from outside the FRCC region. Otherwise, forecasted reserve margins are expected to 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.

**CITY OF LAKELAND (LAK)**

**Generation Selection**

As seen in Table 15, LAK has a winter system capacity of 939 MW. LAK owns 1,039 MW of generating units but exports 100 MW of firm capacity to FMPA. LAK does not plan to add any new generation during the planning horizon. The 100 MW capacity sale to FMPA is scheduled to end in 2010.

<b>Table 15. LAK – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Coal	205	0
Firm Exports	-100	100
Combined Cycle	489	0
Fossil Steam	243	0
Combustion Turbine	102	0
<b>TOTAL</b>	<b>939</b>	<b>100</b>

### **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. Forecasted reserve margins, as shown in LAK's *Ten-Year Site Plan*, are expected to exceed the reserve margin criterion in each year of the planning horizon.

### **Load Forecast**

LAK's load forecast methodology includes several regression models. The winter peak demand forecast model uses annual minimum temperatures and heating-degree days. The summer peak demand model uses annual maximum temperatures, temperature at time of summer peak, and Polk County population.

Under base-case assumptions, LAK forecasts that winter peak demand will increase at an average of 2.36% per year over the planning horizon, which is less than one-half of the actual growth of 5.06% over the past ten years. Summer peak demand is forecasted to increase at an average of 2.25% per year over the planning horizon, which is also less than the actual growth of 2.57% seen during the past ten years.

LAK's 1998-2002 retail sales forecasts have an absolute forecast error of 1.35%, which is less than the 2.26% average of the reporting utilities. Over the same period, LAK's retail sales forecasts have an average forecast error of 1.24%, reflecting a tendency to over-forecast.

### **Demand-side Management**

LAK offers two residential (load management and a loan program) and two commercial DSM programs (lighting and thermal energy storage), as well as an interruptible service tariff. These programs are expected to reduce LAK's 2012/13 winter peak demand by 63 MW. LAK is also involved in several solar program activities, including a solar street light program, a solar water heating project, residential and school photovoltaic systems, and a green pricing program.

### **State, Regional, and Local Agency Comments**

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

### **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.

## **ORLANDO UTILITIES COMMISSION (OUC)**

### **Generation Selection**

As seen in Table 16, on the next page, OUC has a winter system capacity of 1,756 MW. Of this total, 1,093 MW comes from OUC-owned generation. OUC currently purchases 879 MW of firm capacity and exports 216 MW of capacity to other utilities.



OUC's expansion plan reflects the addition of 181 MW of combined cycle capacity from **Stanton Unit A**, which entered commercial service in October, 2003. OUC also plans to add two 175 MW CT units at the **Stanton** site, with in-service dates of 2008 and 2011, respectively. Seven internal combustion units at the **St. Cloud** site, totaling 21 MW, are scheduled for retirement in 2004. Firm imports are forecast to decrease to 256 MW, while exports are expected to decrease to zero, by 2012.

<b>Table 16. OUC – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Nuclear	65	0
Coal	760	0
Firm Imports	879	-623
Firm Exports	-216	216
Combined Cycle	0	181
Combustion Turbine	268	329
<b>TOTAL</b>	<b>1756</b>	<b>103</b>

### **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. Forecasted reserve margins, as shown in OUC's *Ten-Year Site Plan*, are expected to exceed the reserve margin criterion in each year of the planning horizon.

### **Load Forecast**

OUC uses linear regression sales forecast models. OUC's energy models are based on the Statistical Adjusted Engineering model, which specifies end-use variables such as heating, cooling, and base-use appliances. OUC's methodology and assumptions are appropriate. There was insufficient data to measure the absolute forecast error of OUC's 1998-2002 retail sales forecasts.

Under base-case assumptions, OUC forecasts that summer peak demand will increase at an average of 0.1% per year over the planning horizon, which is much lower than the actual growth of 7.08% per year over the past ten years. The substantial difference is due to the addition of wholesale load in 2001, which is projected to decline to zero by 2007. Over the next ten years, winter peak demand is forecasted to increase at an average of 0.94%, which is much below the actual growth of 7.60% seen during the past ten years due to the changes in wholesale load.

### ***Demand-side Management***

The Commission set numeric goals of **zero** for OUC in 2000. However, continues to offer 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 2012/13 winter peak demand by 1 MW.

### ***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 comment on planned Stanton unit.

### ***Suitability***

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.

## ***CITY OF TALLAHASSEE (TAL)***

### ***Generation Selection***

As seen in Table 17 on the next page, TAL has a winter system capacity of 710 MW. Of this total, 699 MW comes from TAL's own system generation, while 11 MW comes from a firm capacity purchase.

TAL's *Ten-Year Site Plan* shows the addition, in May, 2005, of a 50 MW CT unit and 48 MW of distributed generation from eight quick-start turbines. The existing **Hopkins** site is the most likely location for this generation. TAL also plans to add a total of 100 MW of CC capacity at a yet-to-be determined site between 2009 and 2011. Firm purchases are scheduled to remain at 11 MW, and TAL plans to retire 70 MW at the **Purdum** site between 2008 and 2011.

### ***Reliability Criteria***

TAL is primarily a summer-peaking utility. TAL plans its utility system using a reliability criterion of 17% summer peak reserve margin. Forecasted reserve margins, as shown in TAL's *Ten-Year Site Plan*, are expected to exceed the reserve margin criterion in each year of the planning horizon.

### ***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 average of 1.65% per year over the planning horizon, which is lower than the actual growth of 2.63% per year over the past ten years. Winter peak demand is forecasted to increase at an average of 1.96% per year over the planning horizon, which is considerably lower than the actual growth of 3.63% per year seen during the past ten years.

TAL's 1998-2002 retail sales forecasts have an absolute forecast error of 1.63%, which is less than the 2.26% average of the reporting utilities. Over the same period, TAL's retail sales forecasts have an average forecast error of -0.88%, reflecting a slight tendency to under-forecast.

<b>Table 17. TAL – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Firm Imports	11	0
Combined Cycle	262	100
Fossil Steam	366	-50
Hydroelectric	11	0
Combustion Turbine	60	78
<b>TOTAL</b>	<b>710</b>	<b>128</b>

***Demand-side Management***

TAL offers five residential and five commercial DSM programs. These programs include loans and rebates, non-dispatchable conservation programs, public information and education programs, and home improvement programs. TAL does not have an interruptible service tariff or a load management program. TAL forecasts that its DSM programs will reduce the 2012/13 winter peak demand by 23 MW.

TAL promotes the use of renewable energy. TAL has an 11 MW hydroelectric generator on Lake Talquin. In addition, there are currently 28 KW of photovoltaic projects in TAL's service area, with plans for an additional 126 KW. TAL also promotes solar pool heating and solar water heating projects. TAL also has a green pricing program.

***State, Regional, and Local Agency Comments***

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

***Suitability***

Forecasted reserve margins are expected to exceed TAL's 17% reserve margin criterion for each seasonal peak throughout the planning horizon. The Commission classifies TAL's *Ten-Year Site Plan* as ***suitable*** for planning purposes.

**SEMINOLE ELECTRIC COOPERATIVE (SEC)**

SEC is a wholesale cooperative that provides full requirements capacity and energy to ten distribution system members. SEC relies on owned and purchased capacity resources to serve its member systems. SEC is obligated to serve all load up to specified capacity levels and provide adequate reserves. Partial requirements providers (PEF, TECO, JEA, OUC, and GRU) serve all of SEC’s load that exceeds specified capacity commitment levels.

**Generation Selection**

As seen in Table 18, SEC currently has a total system winter capacity of 4,428 MW. However, SEC’s generating capacity is 1,917 MW and, therefore, is insufficient to meet the aggregate load of SEC’s members. To serve load that exceeds generation, SEC purchases 1,294 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 PEF, 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 820 MW.

Although SEC plans to add over 2,130 MW of new generating capacity during the planning horizon, net system capacity is expected to increase by only 1,284 MW. SEC expects its reliance on firm purchases to decrease by 844 MW, and non-utility generation to decrease by 397 MW, during the planning horizon. The amount of partial requirements and full requirements capacity imports is forecasted to increase by 395 MW by that time.

Five 62 MW CT units are planned for the **Payne Creek** site in 2006. Seven additional 182 MW CT units are planned at yet-to-be-determined sites. These units are planned to be placed into service as follows: one each in 2006, 2007, 2010, 2011, and 2012; and three units in 2009. Also planned are three 182 MW CC units in 2009, also at a yet-to-be determined site.

<b>Table 18. SEC – WINTER CAPACITY BY FUEL TYPE</b>		
<b>UNIT TYPE</b>	<b>EXISTING CAPACITY (MW)</b>	<b>PROPOSED ADDITIONS (MW)</b>
Nuclear	15	0
Coal	1330	0
Firm Imports	1294	-844
Partial Requirements Purchases	820	395
Firm Non-Utility Generation	397	-397
Combined Cycle	572	546
Combustion Turbine	0	1584
<b>TOTAL</b>	<b>4428</b>	<b>1284</b>

### **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. Forecasted reserve margins, as shown in SEC's *Ten-Year Site Plan*, are expected to meet or exceed the reliability criteria in each year of the planning horizon.

### **Load Forecast**

SEC identifies and justifies its load forecast methodology with a thorough description of econometric and end-use models, variables, data sources, assumptions, and informed judgements. SEC analyzed each member cooperative's load forecast and combined them to yield the final forecast. 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 average of 3.77% per year over the planning horizon, which is less than the actual growth of 4.46% per year over the past ten years. Summer peak demand is forecasted to increase at an average of 3.64% per year over the planning horizon, which is less than the actual growth of 4.87% per year seen during the past ten years. SEC's peak demand forecasts exhibit the highest growth rates of all reporting utilities.

SEC's 1998-2002 retail sales forecasts have an absolute forecast error of 2.77%, which is above the 2.62% average of the reporting utilities. Over the same period, SEC's retail sales forecasts have an average forecast error of -1.78%, reflecting a tendency to under-forecast.

### **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 2012/13 demand savings of SEC's members is forecasted to be 248 MW.

### **State, Regional, and Local Agency Comments**

Central Florida Regional Planning Council - Cites limitations on water resources which could lead to curtailment of water available for electric generation. New ground water use permits cannot be assumed.

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

Southwest Florida Water Management District – SEC's *Ten-Year Site Plan* provided no information on potential water use at future plants. For any proposed plant located in the Southern Water Use Caution Area, water resource constraints may pose significant permitting challenges.

### ***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.

## ***INDEPENDENT POWER PRODUCERS***

One IPP, Calpine Construction Finance Company (Calpine), filed a *Ten-Year Site Plan* for 2003. Calpine's *Ten-Year Site Plan* contains four 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, Calpine's **Osprey** unit, a 578 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. A second facility, the Santa Rosa CC unit, entered service in May, 2003 with a steam-fired capacity of 74.5 MW, which exempts this unit from certification requirements. The status of a third facility, containing two CC units at the **Blue Heron** site, is uncertain at this time because there currently is not a contract to sell the output of these units to a retail-serving utility.