# A Review of Florida Electric Utility 2004 Ten-Year Site Plans


**PREPARED BY THE**

**FLORIDA PUBLIC SERVICE COMMISSION**
**Division of Economic Regulation**



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# INTRODUCTION

## *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. The Commission held a public workshop on September 20, 2004 to allow for public comment on the *Ten-Year Site Plans*. Upon completion and approval of the *Ten-Year Site Plan* review, the report is forwarded to the Florida Department of Environmental Protection (DEP) for use in subsequent power plant siting proceedings.

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 an annual *Ten-Year Site Plan* 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 unit larger than 75 MW within the ten-year planning period.

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 to DEP.

## *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 addressed at 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. Detailed data based on in-depth environmental assessments are provided by the utility 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.

## FLORIDA RELIABILITY COORDINATING COUNCIL

As a region of the North American Electric Reliability Council (NERC), the Florida Reliability Coordinating Council (FRCC) has a formal reliability assessment process to review and assess annually existing and projected generation resources. FRCC members exchange information in planning and operating areas related to the reliability of the bulk power supply within the FRCC region, comprising of Peninsular Florida. 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 that address the reliability of Peninsular Florida's electric grid. The *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 *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 formed a Gas/Electricity Interdependency Task Force in 2003 to determine the relationship between gas pipeline and electric system operations and planning. Through this task force, the FRCC will perform detailed analysis of reliability impacts and, where applicable, recommend mitigation measures. The Commission staff participates on the FRCC task force. The NERC also formed a Gas/Electricity Interdependency Task Force whose scope was almost identical to that of the FRCC task force. The NERC task force recently completed a study which concluded, in part, that gas pipeline reliability can substantially impact electric generation, and that electric system reliability can have an impact on gas pipeline operations. The FRCC continues to review the recommendations made by the NERC task force to determine where to specifically focus future analyses.

## SUMMARY OF RESOURCE ADDITIONS

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

***Figure 1. State of Florida – Electric Utility Resource Mix***

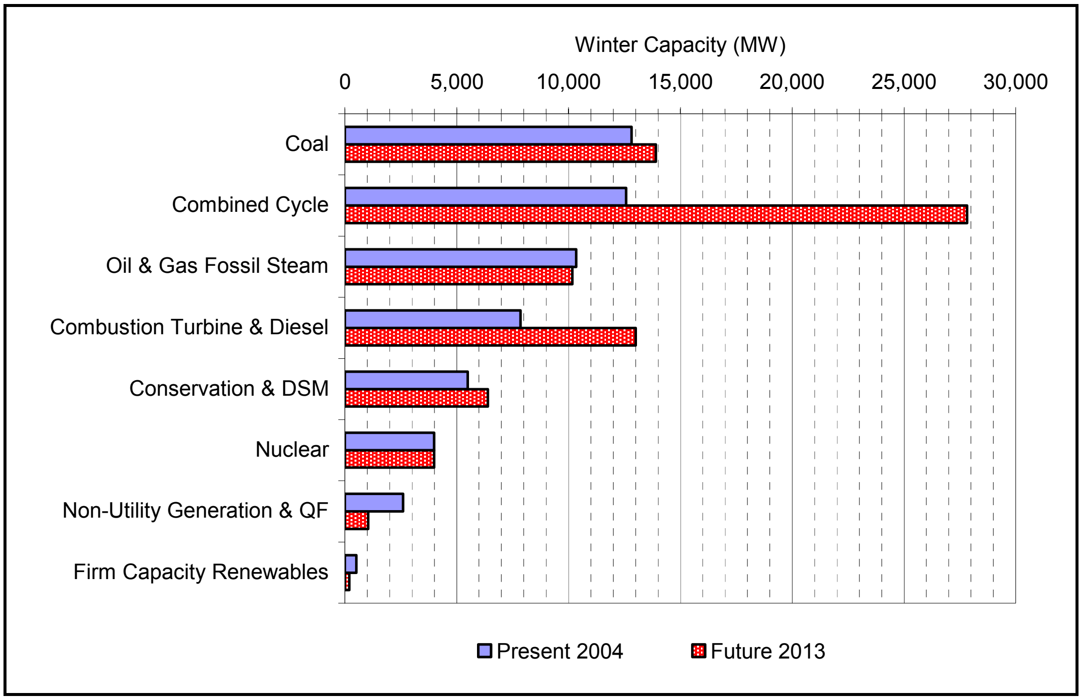


***Table 1. State of Florida – Net Capacity Additions By Florida's Electric Utilities***

| | | WINTER CAPACITY (MW) |
|---|---|---|
| Coal | Additions | 1,170 |
| | Reductions | -92 |
| Combined Cycle | Additions | 15,283 |
| | Reductions | -33 |
| Oil and Gas Fossil Steam | Additions | 4 |
| | Reductions | -173 |
| Combustion Turbine & Diesel | Additions | 5,547 |
| | Reductions | -406 |
| Nuclear | Additions | 0 |
| | Reductions | 0 |
| Non-Utility Generation & QF | Additions | 0 |
| | Reductions | -1,558 |
| Firm Capacity Renewables | Additions | 0 |
| | Reductions | -312 |
| Net Firm Capacity Interchange | Additions | 0 |
| | Reductions | -621 |
| TOTAL | Additions | 22,004 |
| | Reductions | -3,195 |
| NET CAPACITY ADDITIONS | | 18,809 |

***Table 2. Reporting Utilities – Proposed Generating Units Requiring Certification***

| UTILITY | GENERATING UNIT | WINTER CAPACITY (MW) | PROPOSED IN-SERVICE DATE |
|---|---|---|---|
| Seminole Electric Cooperative | Unsited CC[1] 1 | 182 | 12/2007 |
| Seminole Electric Cooperative | Unsited CC 2 | 182 | 12/2008 |
| Florida Power & Light Company | Corbett Unit 1 CC | 1,181 | 6/2009 |
| Progress Energy Florida | Hines Unit 5 CC | 536 | 12/2009 |
| Seminole Electric Cooperative | Unsited CC 3-5 | 546 | 12/2009 |
| Progress Energy Florida | Hines Unit 6 CC | 536 | 5/2010 |
| Seminole Electric Cooperative | Unsited CC 6 | 182 | 12/2010 |
| Gainesville Regional Utilities | Deerhaven Unit 3 CFB[2] | 220 | 5/2011 |
| Florida Power & Light Company | Unsited CC 1 | 1,181 | 6/2011 |
| JEA | Unsited CFB 1 | 250 | 6/2011 |
| Seminole Electric Cooperative | Unsited Coal 1 | 150 | 1/2012 |
| Progress Energy Florida | Unsited CC 1 | 536 | 5/2012 |
| Florida Power & Light Company | Unsited CC 2 | 1,181 | 6/2012 |
| JEA | Unsited CFB 2 | 250 | 1/2013 |
| Seminole Electric Cooperative | Unsited Coal 2-3 | 300 | 1/2013 |
| Tampa Electric Company | Unsited CC | 502 | 1/2013 |
| Progress Energy Florida | Unsited CC 2 | 536 | 12/2013 |
| Seminole Electric Cooperative | Unsited CC 7-9 | 546 | 12/2013 |
| | TOTAL | 8,997 | |

[1] Combined cycle generating unit.
[2] Circulating fluidized bed, coal-fired generating unit.

# AREAS OF CONCERN

## *IMPACT OF PLANS ON FUEL DIVERSITY*

In Florida, electric utilities generate electricity using several different types of fuels, including natural gas, coal, uranium, oil, biomass, and methane. When utilities produce electricity from a diverse variety of fuels, this action is viewed as beneficial because fuel diversity is associated with increased electric reliability and reduced production costs. For example, if a disruption were to occur in the supply of one fuel type, other fuel sources may be available for use in greater amounts to compensate for any differences in production needed to maintain the typical flow of electricity.

If a utility has the choice of generating electricity from two plants that burn two different types of fuels because both fuels are readily available, it will often choose to burn the fuel type with the lowest cost to reduce its overall costs of production. In addition, many generating units in Florida have fuel-switching capability, meaning that a single generator is capable of burning multiple fuels. Overall, a utility's choice of which fuel to burn at any point in time is usually not solely a function of availability and cost. Utilities also seek to actively maintain or develop fuel diversity to ensure reliability and minimize costs in the long term.

The outlook for fuel diversity in Florida is somewhat uncertain at this time. The use of natural gas for electricity production has increased significantly over the past 10 years from 12.7% in 1993 to 32% in 2004. The FRCC's *Regional Load and Resource Plan* indicates that 51.4% of total statewide generation in 2013 is expected to come from natural gas, with a decline in the overall contribution of other fuel types, especially oil and coal.

Over the past several years, utilities across the nation and within Florida have selected natural gas-fired generation as the predominant source of new capacity. If this trend continues, natural gas usage will approach the levels of oil usage that Florida was experiencing just prior to the oil embargoes of the 1970's. Recent past experience has shown that natural gas prices can be volatile. Further, Florida's utilities project a wide range of prices for natural gas. These facts, coupled with the Florida utilities' historic under-forecasting of natural gas price and consumption, could further strain Florida's economy. In the 1970's, the Commission took action to encourage the utilities to diversify their fuel mix in an effort to mitigate volatile fuel prices. Based on current fuel mix and fuel price projections, Florida's utilities should explore the feasibility of adding solid fuel generation as part of future capacity additions.

One Florida utility, FPL, is currently seeking to address these fuel diversity issues by comparing natural gas-fired and coal-fired alternatives. The differences between the two technologies not only include forecasted fuel price differences between natural gas and coal, but also future emissions control technologies and requirements, as well as the capital costs and the feasibility of developing and constructing a coal-fired generating unit in Florida. FPL is expected to provide a report to the Commission by March 2005 that will include an evaluation of natural gas-fired versus coal-fired future generation. Three other electric utilities, JEA, Gainesville Regional Utilities, and Seminole Electric Cooperative, have included coal-fired generating units in their planned resource additions.

# REVIEW & ANALYSIS – STATEWIDE PERSPECTIVE

## *LOAD & ENERGY FORECAST*

Electric utilities perform load and energy forecasts to estimate the amount and timing of future capacity needs. 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. For the nine utilities with sufficient historical data, the Commission compared actual energy sales for each year between 1999 and 2003 to energy sales forecasts made three, four, and five years prior. For example, actual 2003 energy sales were compared to projected 2003 forecasts made in 1998, 1999, and 2000. These differences were used to calculate two measures of a utility's historical forecast accuracy: average forecast error and average absolute forecast error. Average forecast error is an average of the percentage error rates that indicates a utility's tendency to over-forecast (positive values) or under-forecast (negative values). Average absolute forecast error is an average of percentage error rates that ignores the resulting positive and negative signs. This value provides an overall measure of the accuracy of past utility forecasts.

Table 3 illustrates the historical forecast accuracy of total retail energy sales for the nine reporting utilities with sufficient historical data. A detailed discussion of the individual utility forecasts is included starting on page 26.

***Table 3. Total Retail Energy Sales – Historical Forecast Accuracy***

| UTILITY | AVERAGE FORECAST ERROR (%) | AVERAGE ABSOLUTE FORECAST ERROR (%) |
|---|---|---|
| Progress Energy Florida | -0.52 | 0.62 |
| Florida Power & Light Company | -1.13 | 1.24 |
| Gulf Power Company | -1.77 | 2.07 |
| Tampa Electric Company | -0.76 | 0.76 |
| Gainesville Regional Utilities | -1.42 | 1.42 |
| JEA | -1.95 | 2.79 |
| City of Lakeland | 1.48 | 1.48 |
| City of Tallahassee | 0.33 | 0.55 |
| Seminole Electric Cooperative | -0.72 | 1.71 |
| AVERAGE FOR ALL REPORTING UTILITIES | -0.72 | 1.40 |

## *DEMAND-SIDE MANAGEMENT*

Demand-side management (DSM) reduces customer peak demand and energy requirements, resulting in the deferral of need for new generating units. Utility-sponsored 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 conservation goals in 2004, 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 shown in Table 4, it is estimated that utility conservation programs have reduced statewide summer peak demand by 4588 MW, winter peak demand by 5491 MW, and energy consumption by 5132 GWh. By 2013, DSM programs are forecasted to reduce summer peak demand by 5165 MW, winter peak demand by 6393 MW, and energy consumption by 6618 GWh. Figures 2, 3, and 4, on the next two pages, illustrate the impact of DSM savings on summer peak demand, winter peak demand, and energy consumption.

***Table 4. State of Florida – Estimated Cumulative Savings From Electric Utility DSM Programs***

| DSM Savings | 2003 | By 2013 |
|---|---|---|
| Summer Peak Demand | 4588 MW | 5165 MW |
| Winter Peak Demand | 5491 MW | 6393 MW |
| Annual Energy Consumption | 5132 GWh | 6618 GWh |

***Numeric Conservation Goals and DSM Plans***

FEECA requires that all investor-owned utilities, and any municipal or cooperative utility with annual energy sales of at least 2,000 GWh as of July 1, 1993 meet numeric conservation goals set by the Commission. Seven Florida utilities are subject to this requirement: PEF, FPL, Gulf, TECO, Florida Public Utilities Company (FPUC), JEA, and OUC. The Commission set new numeric demand and energy goals for these seven utilities in July 2004. In general, the new numeric goals were lower than the previous goals set by the Commission in 1999 for two primary reasons: DSM programs have reached a saturation in participation levels; and, DSM program cost-effectiveness continues to decline due to the relatively lower cost of new generating units.

PEF, FPUC, JEA, and OUC filed new DSM plans as part of their numeric conservation goals filings. These four DSM plans were approved by the Commission in July 2004. FPL, Gulf, and TECO are scheduled to file their DSM plans for Commission approval by the end of 2004.

***Figure 2. State of Florida – Impact of DSM on Summer Peak Demand***

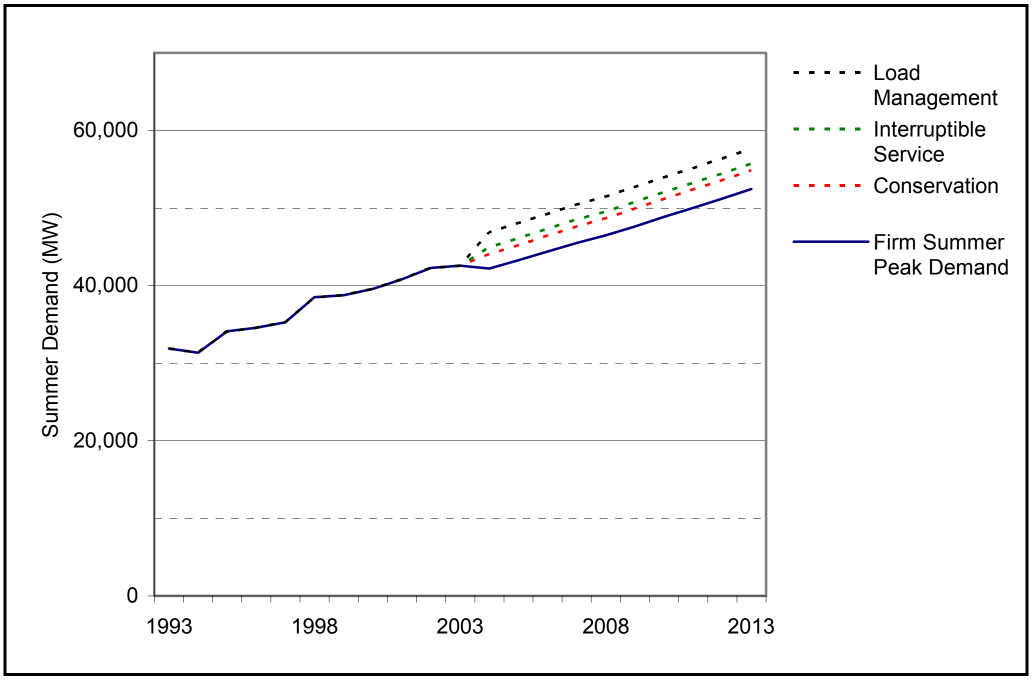



***Figure 3. State of Florida – Impact of DSM on Winter Peak Demand***

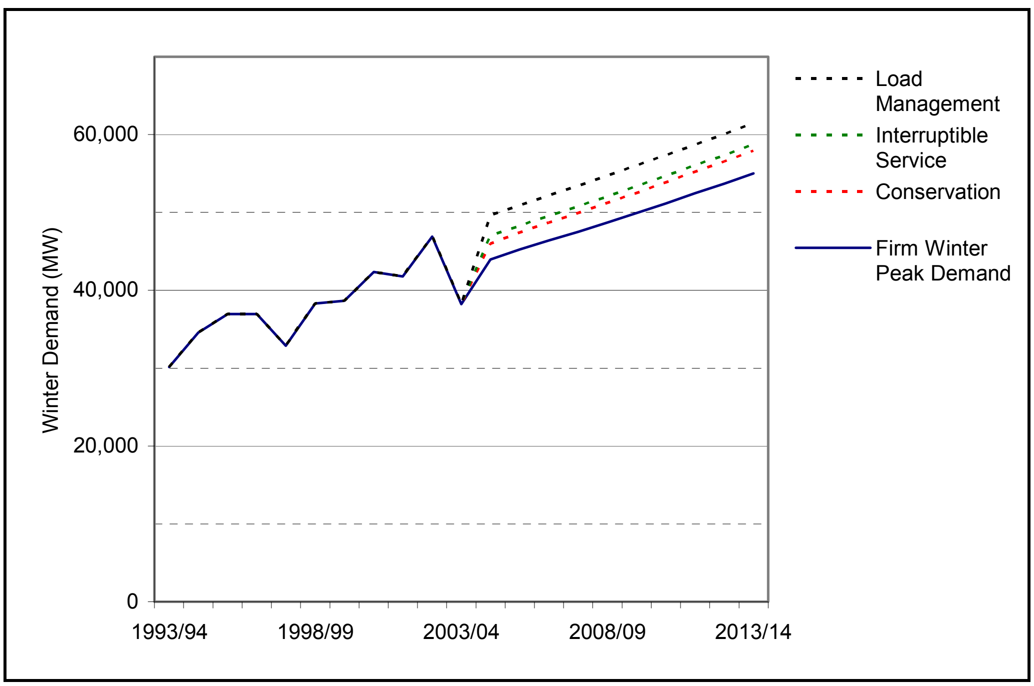
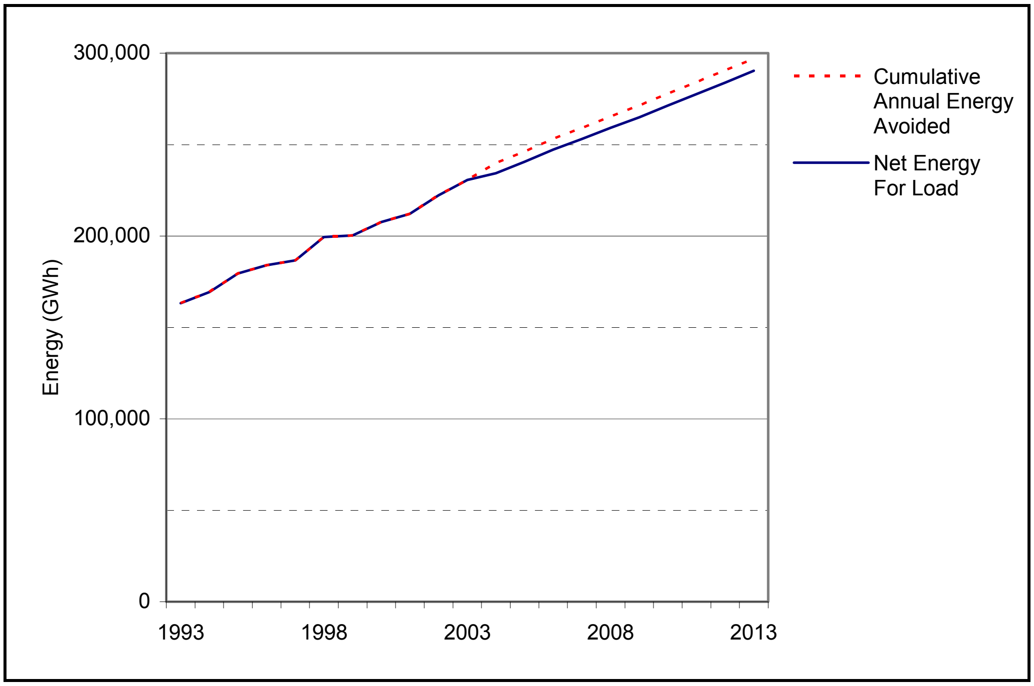


***Figure 4. State of Florida – Impact of DSM on Net Energy for Load***




***Energy Conservation Cost Recovery***

Investor-owned utilities may be able 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 generating units.

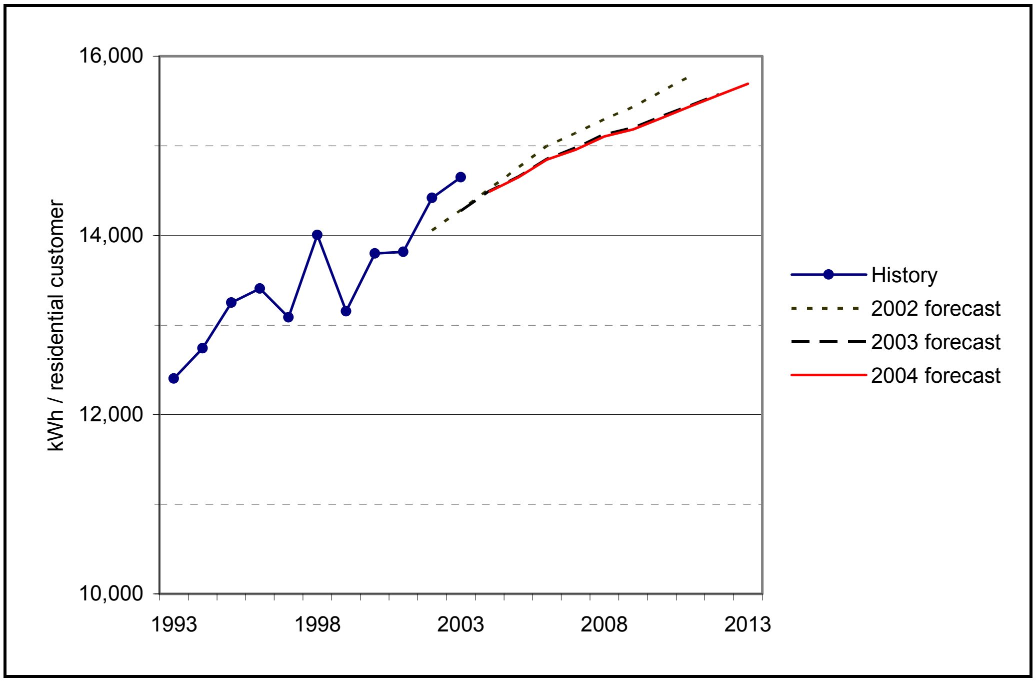
***State Comprehensive Plan***

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 has set numeric conservation goals and has approved DSM plans for electric utilities, and continues to work with the Florida Department of Community Affairs (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.

Despite these 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; average home size has increased over time; and, homes contain many more electricity-consuming appliances than in past years.

Figure 5 illustrates historical and forecasted residential per-capita energy consumption. Statewide, per-capita energy consumption usage increased at an average of 1.6% per year over the past ten years and is forecasted to grow at an average of 0.9% per year over the planning horizon. The 2004 forecast of per-capita residential energy consumption is nearly identical to the forecast made last year, but is slightly lower than the forecast made two years ago, for a comparable period.

***Figure 5. State of Florida – Energy Consumption Per Residential Customer***



## *RELIABILITY CRITERIA*

Reliability criteria enable utilities to determine when additional future resources are required. The primary reliability criterion used by most utilities, reserve margin, indicates the amount of capacity that exceeds firm peak demand. Reserve margin is usually expressed as a percentage exceeding firm peak demand. Reserve margin is comprised of demand-side (non-firm) resources and supply-side (capacity) resources. 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.

Because of reserve margin's limitations, some utilities also use a probabilistic reliability criterion such as loss of load probability (LOLP), expressed in days per year. The typical LOLP planning criterion 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. 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.

The reliability criteria used by each reporting utility are shown in Table 5.

***Table 5. Reliability Criteria***

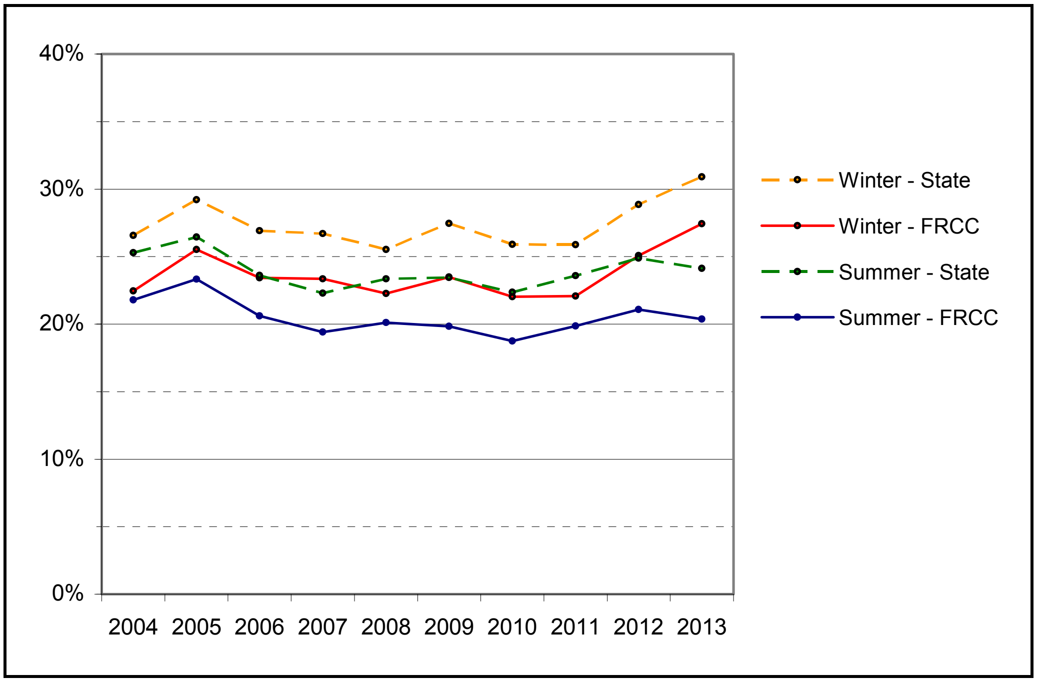
| UTILITY | RESERVE MARGIN | | LOLP (days/year) | EUE/NEL (%) |
|---|---|---|---|---|
| | SUM | WIN | | |
| Progress Energy Florida | 20% | 20% | 0.1 | --- |
| Florida Power & Light Company | 20% | 20% | 0.1 | --- |
| Gulf Power Company | 13.5%[3] | --- | --- | --- |
| Tampa Electric Company | 20% | 20% | --- | --- |
| Florida Municipal Power Agency | 18% | --- | --- | --- |
| Gainesville Regional Utilities | 15% | 15% | --- | --- |
| JEA | 15% | 15% | --- | --- |
| City of Lakeland | 20% | 22% | --- | --- |
| Orlando Utilities Commission | 15% | 15% | --- | --- |
| City of Tallahassee | 17% | --- | --- | --- |
| Seminole Electric Cooperative | 15% | 15% | --- | 1% |

[3] Near-term (1-3 years) criterion. Long-term criterion (2007 and beyond) is 15%.

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, reserve margin continues to be the primary criterion driving a utility's capacity needs. In the late 1990's, the Commission was increasingly concerned with the declining reserve margins forecasted by Florida's utilities and the impact of such declines on reliability. In response to these concerns, PEF, FPL, and TECO agreed to adopt a 20% reserve margin planning criterion starting in Summer, 2004.

Figure 6 shows the forecasted summer and winter reserve margin over the next ten years for Peninsular Florida's utilities.

***Figure 6. Forecasted Reserve Margin***




***Proposed New Independent Power Producer (IPP) Capacity***

In its *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 would not be 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.

## *FUEL PRICE FORECAST*

Fuel price is a primary factor affecting the type of generating unit added by an electric utility. The reporting utilities produced base-case fuel price forecasts for most fuels, and 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 6, on the next page, shows the forecasted annual average growth rate in price for each fuel, as forecasted by the reporting utilities and by the EIA for the 2004-2007 and 2007-2013 time periods.

Most Florida utilities generally expect prices to stay flat – or even fall from current levels -- during the first three years, then increase at a moderate rate during the 2007-2013 time period. However, as global economic activity increases, the demand for all fuels across the globe, especially China and India, will push world market prices higher. EIA reported that demand for fuel in developing Asian economies will grow twice as fast over the planning horizon compared with the United States and other industrialized nations. The utilities' *Ten-Year Site Plans* do not contemplate the impact of significant fuel price increases on siting decisions. To the extent appropriate and necessary, utilities should monitor how changes in the world market price for each fuel impacts its siting decisions.

Table 6 reflects a wide disparity in the utilities' expectations of future fuel prices, particularly natural gas. Utilities that have forecasted a price decline over the next three years believe that current elevated prices are a temporary aberration, and will soon return to their historical levels. The Commission does not discount the possibility that recent fuel price increases reflect the ever-increasing tension between increased global demand for all types of fuel and stagnant production levels. If a utility continues to forecast short-term fuel price declines, the utility should be fully prepared to substantiate its fuel price forecast and its underlying assumptions.

***Coal***

The average delivered cost of coal to electric utilities in 2003 increased to $25.29 per ton, up $0.55 per ton from 2002. Through 2013, EIA forecasts that delivered coal prices will increase at a rate of 2.4% per year during the first three years, then by 2.6% per year for the remaining seven years. From 2004 through 2007, Florida's utilities forecast changes in coal prices ranging from -7.9% to 5.3% per year. For the remainder of the planning horizon, coal prices may change at rates ranging from -0.5% to 3.9% per year.

In 2003, nationwide coal consumption by electric utilities increased by 27 million tons to a record 1,004 million tons. Electric utilities drove coal consumption to its record level as relatively higher priced natural gas-fired generation was displaced by coal-fired generation. In Florida, electric utilities decreased their coal consumption by 1.3 million tons to 24.4 million tons compared with 2002 levels.

***Table 6. Fuel Price Forecast – Average Annual Growth Rate (2004-2007 and 2007-2013)***

| UTILITY | COAL | | RESIDUAL OIL | | DISTILLATE OIL | | NATURAL GAS | | NUCLEAR | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2004-07 | 2007-13 | 2004-07 | 2007-13 | 2004-07 | 2007-13 | 2004-07 | 2007-13 | 2004-07 | 2007-13 |
| EIA | 2.4% | 2.6% | 2.7% | 3.2% | 1.3% | 2.5% | 3.8% | 5.1% | NA | NA |
| Progress Energy Florida | 1.1% | 1.6% | -3.7% | 2.6% | -4.6% | 2.5% | -7.4% | 0.8% | -1.2% | 1.7% |
| Florida Power & Light Company | 1.4% | 0.4% | -3.2% | 3.1% | -1.9% | 3.0% | -0.9% | 2.2% | 0.6% | 0.5% |
| Gulf Power Company | -2.6% | -0.5% | -5.6% | -1.4% | -3.0% | -0.6% | -5.9% | -1.2% | NA | NA |
| Tampa Electric Company | 1.6% | 1.7% | -4.1% | -0.2% | -5.9% | 0.8% | 1.6% | 0.0% | NA | NA |
| Florida Municipal Power Agency | 2.5% | 1.9% | 3.2% | 3.5% | 2.9% | 3.1% | -6.7% | 4.3% | 2.6% | 2.3% |
| Gainesville Regional Utilities | -7.9% | 1.8% | -0.7% | 3.1% | 0.6% | 2.7% | 1.6% | 4.1% | -1.0% | 1.3% |
| JEA | 0.1% | 2.3% | 1.4% | 2.7% | 1.2% | 2.5% | -4.2% | 1.8% | NA | NA |
| City of Lakeland | 5.3% | 3.9% | -0.1% | 4.0% | 3.6% | 3.2% | 2.1% | 3.9% | NA | NA |
| Orlando Utilities Commission | 2.6% | 3.7% | -1.8% | 1.7% | -2.1% | 1.9% | -1.7% | 0.8% | 2.4% | 2.5% |
| City of Tallahassee | -4.4% | -0.4% | -1.4% | 3.1% | -5.5% | 4.9% | -4.2% | 0.8% | NA | NA |
| Seminole Electric Cooperative | 1.2% | 1.2% | -3.1% | 3.5% | 4.4% | 3.4% | -2.4% | 3.2% | -2.8% | 1.2% |

The Commission examined the forecast error for coal prices for each investor-owned utility from 2000 through 2003. After comparing each utility's forecast and actual prices for coal, FPL and PEF consistently and substantially under-forecasted their coal prices by as much as 45% during this period. TECO also under-forecasted its coal prices during this period; however, the average forecast error was by less than 10%. Gulf consistently and substantially over-forecasted its coal prices during this period by as much as 20%.

Through 2013, EIA expects electric utility coal consumption to increase to 1,174 million tons, representing an average increase of 1.6% per year. In Florida, electric utilities expect to increase their coal consumption by 0.7% annually to 26.1 million tons.

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

EIA reports that the average U.S. delivered cost of residual oil was $29.40/barrel in 2003, up from $23.90/barrel in 2002. Through 2013, EIA forecasts that delivered residual oil prices will increase at a rate of 2.7% per year during the first three years, then by 3.2% per year for the remaining seven years. From 2004 through 2007, Florida's utilities forecast changes in residual oil prices ranging from -5.6% to 3.2% per year. For the remainder of the planning horizon, residual oil prices may change at rates ranging from -1.4% to 4.0% per year.

In 2003, nationwide residual oil consumption increased by 26.3 million barrels to 281.8 million barrels compared with 2002 levels. In Florida, electric utilities increased their residual oil consumption by 3.9 million barrels to 45.5 million barrels compared with 2002 levels.

The Commission examined the forecast error for residual oil prices for PEF, FPL, and TECO from 2000 through 2003. Gulf was not examined because it does not burn a significant amount of residual oil. After comparing each utility's forecast and actual prices for residual oil, the Commission determined that FPL, PEF, and TECO consistently and substantially under-forecasted their residual prices by as much as 95% during this period.

Through 2013, EIA expects residual oil consumption to increase to 272.3 million barrels, representing an average decrease of 0.3% per year. In Florida, electric utilities expect to decrease their residual oil consumption by 7.6% annually to 20.7 million barrels.

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

EIA reports that the average U.S. delivered cost of distillate oil was $39.14/barrel in 2003, up from $30.95/barrel in 2002. Through 2013, EIA forecasts that delivered distillate oil prices will increase at a rate of 1.3% per year during the first three years, then by 2.5% per year for the remaining seven years. From 2004 through 2007, Florida's utilities forecast changes in distillate oil prices ranging from -5.9% to 4.4% per year. For the remainder of the planning horizon, distillate oil prices may change at rates ranging from -0.6% to 4.9% per year.

In 2003, nationwide distillate oil consumption increased by 55.2 million barrels to 1,433.4 million barrels compared with 2002 levels. In Florida, electric utilities decreased their distillate oil consumption by 600,000 barrels to 2.3 million barrels compared with 2002 levels.

The Commission examined the forecast error for distillate oil prices for PEF, FPL, and TECO from 2000 through 2003. Gulf was not examined because it does not burn a significant amount of distillate oil. After comparing each utility's forecast and actual prices for distillate oil, the Commission determined that FPL, PEF, and TECO consistently and substantially under-forecasted their distillate oil prices by as much as 93% during this period.

Through 2013, EIA expects distillate oil consumption to increase to 1,721.3 million barrels, representing an average increase of 1.8% per year. In Florida, electric utilities expect to increase their distillate oil consumption by 8.4% annually to 5.1 million barrels.

***Natural Gas***

The average cost of natural gas for electric utilities nationwide was $5.55/MMBtu in 2003, up over 50 per cent from 2002 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 2013, EIA forecasts that delivered natural gas prices will increase at a rate of 3.8% per year during the first three years, then by 5.1% per year for the remaining seven years. From 2004 through 2007, Florida's utilities forecast changes in natural gas prices ranging from -7.4% to 2.1% per year. For the remainder of the planning horizon, natural gas prices may change at rates ranging from -1.2% to 4.3% per year.

In 2003, nationwide natural gas consumption by electric utilities decreased by 743 billion cubic feet (Bcf) to 4.929 trillion cubic feet (Tcf). In Florida, electric utilities increased their natural gas consumption by 9.8 Bcf to 455 Bcf compared with 2002 levels.

The Commission examined the forecast error for natural gas prices for each investor-owned utility from 2000 through 2003. After comparing each utility's forecast and actual prices for natural gas, the Commission determined that FPL, PEF, and TECO consistently and substantially under-forecasted their natural gas prices by as much as 111% during this period. Although Gulf did not consistently over-forecast or under-forecast natural gas prices during this period, Gulf does experience both substantial positive (115%) and negative (-36%) errors for its natural gas price forecasts.

Through 2013, EIA expects electric utility natural gas consumption to increase to 7.248 Tcf, representing an average increase of 3.9% per year. In Florida, electric utilities expect to increase their natural gas consumption by 8.8% annually to 1.061 Tcf.

EIA estimated that U.S. proven year-end 2002 natural gas reserves were 186.9 Tcf, a 1.9% increase from prior-year levels. EIA reported that natural gas consumption by all sectors in 2003 was 22.0 Tcf, a 4.6% decrease over 2002 levels.

***Nuclear***

EIA assumes that nationwide nuclear capacity will increase slightly 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.

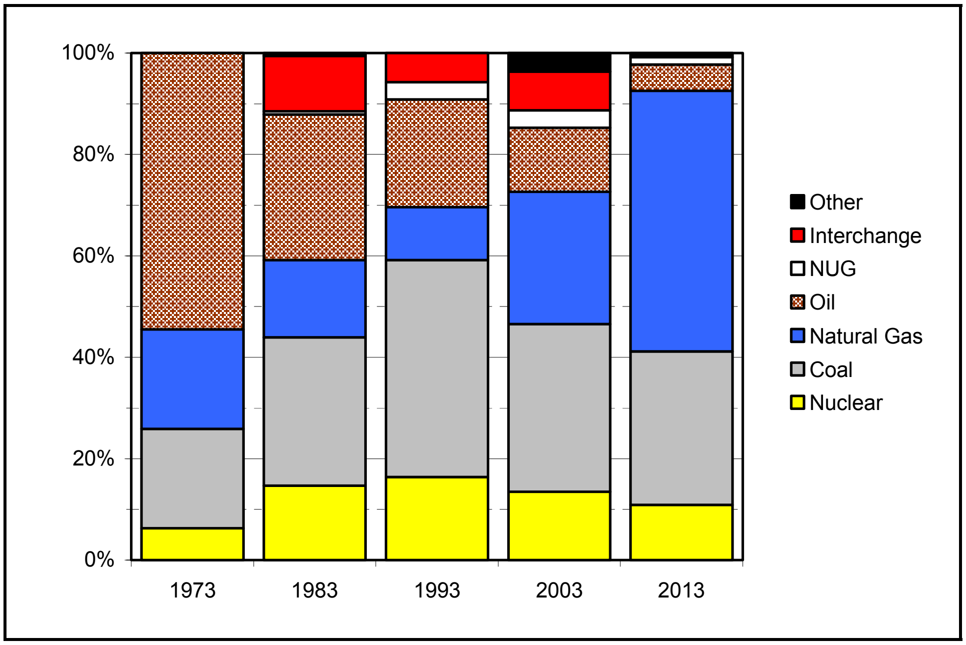
## GENERATING UNIT SELECTION

In addition to traditional economic analyses, Florida's electric utilities consider several strategic factors, such as fuel availability, generation mix, and environmental compliance, prior to selecting a supply-side resource. For example, limited gas supplies, potential restrictions in pipeline capability, and erratic natural gas fuel costs could hinder future development of gas-fired generating units. Coal-fired generation consumes more water than a comparable sized gas-fired unit, a concern in Florida where water supplies may have an uncertain future. There also is a relative shortage of coal-capable sites, that provide the needed land area as well as access to coal delivery. Uncertainty over future changes to environmental requirements could discourage coal unit construction.

In the 1970's, oil consumption in the United States rose while domestic oil production declined. In 1973, at the time of the foreign oil embargo, oil prices tripled almost overnight. Oil-fired plants comprised 55% of the State's electricity generation mix at that time. These plants were adversely affected by oil price increases, and Florida's utilities began to look to other types of fuel to meet growing demand. Initially, this resulted in a movement in Florida towards coal and "coal by wire" from newly constructed coal generation and the construction of new transmission lines to the Southern Company.

Looking towards the future, Florida's utilities forecast a continued decline in reliance on oil-fired generation. However, utilities forecast a substantial increase in natural gas-fired generation, from 26% to over 50% of total energy consumed, during the planning horizon. 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. With the state's reliance on natural gas approaching the levels of its reliance on oil in the 70's, Florida's utilities should once again evaluate the benefits of maintaining a diversified fuel mix. As emerging research and development in coal-fired generation reduces high capital costs, emissions, permitting lead times, and investment risk, coal could again play a critical role in electric power generation in Florida. Figure 7, on the next page, illustrates the past, current, and future energy generation mix by fuel type for Florida's electric utilities.

***Figure 7. State of Florida – Generation Mix By Fuel Type*[4]**



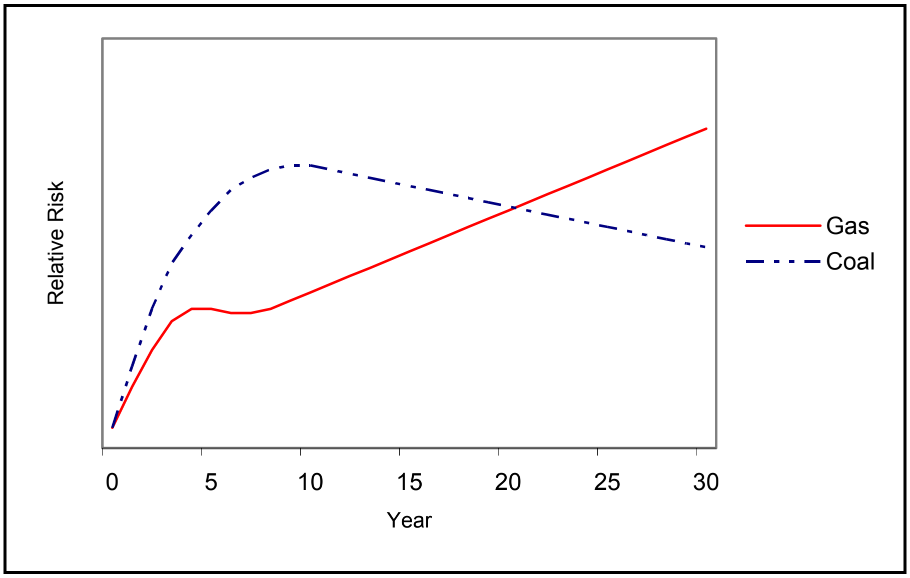

***Economics***

Gas fired generating units are typically a more cost-effective alternative to coal-fired units despite recent sharp rises in natural gas prices. A major reason is that the newer gas-fired combined cycle (CC) units achieve extremely high fuel efficiencies, with heat rates near 7,600 BTU/KWh versus 10,000 BTU/KWh for new coal-fired units. Further, gas-fired CC units have lower installed capital costs of approximately $500/KW versus $1500/KW for coal, making these units cheaper to construct. Finally, new CC units offer a more speedy solution to meet rising demand. New CC units can be permitted and constructed in three years versus the seven years required for coal-fired units. Given these advantages, gas-fired capacity is projected to comprise 93% of all planned generating capacity additions nationwide over the next ten years.

A key factor affecting the decision to build gas-fired or coal-fired capacity is the number of years required for a coal plant to become cost-effective. Having higher upfront construction costs, coal-fired plants result in higher customer risk associated with uncertainty over fuel cost differential. As the commodity price difference between the two fuels widens, the breakeven period decreases. In other words, as the cost of natural gas rises faster than the cost of coal, the number of years required for fuel savings to outweigh the higher upfront cost of coal-fired generation decreases. A representation of the costs of new coal-fired and gas-fired generating units is shown in Figure 8 on the next page.

[4] Other fuel types include petroleum coke and coal gasification.

***Figure 8. Representative Cost Comparison of Coal-Fired and Gas-Fired Generating Units***




***Commission Actions to Encourage Solid Fuel Development***

In 1982, the Commission adopted an Oil Backout Cost Recovery mechanism to allow investor-owned utilities an opportunity to recover prudently incurred costs associated with generation and transmission projects that resulted in a decrease in oil consumption. The Commission's "Oil Backout" policy encouraged utilities to develop coal-fired generating units in Florida during the 1980's. Examples of such Oil Backout projects were the conversion of TECO's Gannon station to coal from oil and the 500 KV transmission lines connecting Florida to Georgia, that enabled Florida's utilities to purchase firm capacity and economy energy from coal-fired resources owned by the Southern Company.

***Department of Energy Actions to Encourage Solid Fuel Development***

The U.S. Department of Energy's Clean Coal Technology (CCT) Program encourages the development of advanced, more efficient, and environmentally responsible coal utilization options by providing funding to demonstrate new clean coal technologies. Through demonstration projects, the CCT Program intends to establish the commercial feasibility of promising advanced coal technologies. Tampa Electric Company's Polk Unit 1, an integrated coal gasification combined cycle (IGCC) unit, was built and placed into service in 1996 under the CCT Program. Orlando Utilities Commission and the Southern Company recently announced a joint deal to develop a CCT Program project at the Stanton site.

Coal gasification technology may provide utilities the flexibility to meet potential environmental restrictions and address concerns with the high initial capital investment. Coal gasification units have a lower heat rate and fewer emissions than a traditional coal-fired unit, and can be built in stages with the combined cycle portion of the plant being first constructed to operate on oil or natural gas. If oil and natural gas prices increase substantially above the price of coal, potential savings from coal gasification might justify additional capital investment to convert the unit to coal operation. As a result, for power plant siting purposes, it is important to consider whether a site can support coal gasification

***Future Actions***

According to the utilities' *Ten-Year Site Plans*, natural gas is forecasted to play an even more dominant role in electric power generation in Florida over the next ten years. To minimize price and supply volatility, electric power generation must rely on multiple fuel sources. As a result, Florida's utilities should evaluate potential sites for coal capability. To lessen the capital cost impact of building coal-fired units, utilities should look at the possibility of joint ownership of future coal units. Florida's municipal utilities have a successful history of sharing investment costs associated with coal units. Finally, utilities should investigate the possibility of receiving financial assistance through the DOE's CCT Program. As emerging research and development in coal-fired generation reduces high capital costs, emissions, permitting lead times, and investment risk, coal could again play a critical role in electric power generation in Florida.

One Florida utility, FPL, is currently seeking to address these fuel diversity issues by comparing natural gas-fired and coal-fired alternatives. The differences between the two technologies not only include forecasted fuel price differences between natural gas and coal, but also future emissions control technologies and requirements, as well as the capital costs and the feasibility of developing and constructing a coal-fired generating unit in Florida. FPL is expected to provide a report to the Commission by March 2005 that will include an evaluation of natural gas-fired versus coal-fired future generation.

***Natural Gas***

Florida's utilities project a substantial increase in natural gas-fired generation. Natural gas-fired generation, currently at 26% of statewide energy consumption, is expected to nearly double to 51% over the next ten years. Of the approximately 22,000 MW in gross capacity additions projected in the state over the planning horizon, nearly 20,400 MW is expected to come from gas-fired capacity, in the form of new CC and CT units. Natural gas consumption forecasts do not include usage from proposed new IPP generating units.

***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 CT units, both as a primary and a secondary fuel. Over the next ten years, oil-fired energy is expected to decrease from 13% to 5% 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 increase by approximately 1,100 MW, coal-fired energy is expected to decrease from 33% to 30% 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 forecast a slow decline in the level of interchange energy purchases over the next ten years, from 8% of statewide energy consumption to zero. The forecasted decrease is due primarily to the increase in natural gas generation expected in the state at that time. Further, FPL and PEF have long-term interchange contracts with Southern Company that are scheduled to expire in 2010. Both utilities recently sought Commission approval of new interchange contracts. If approved, the capacity and energy from the new contracts can be expected to maintain the current level of interchange energy entering Peninsular Florida from Southern Company.

The transfer capability between Southern Company and Peninsular Florida is expected to remain at approximately 3600 MW. As a result, some capacity and energy from Southern Company is expected to 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 sell firm capacity to many of Florida's utilities under long-term and short-term purchased power contracts. The amount of NUG electricity purchased by Florida's utilities is expected to decrease from 3.5% to 1.5% of statewide energy consumption during the planning horizon. The forecasted decrease is due to the expiration of 536 MW of firm cogeneration contracts and 1022 MW of firm capacity contracts with independent power producers. However, once their current contracts expire, these generators will remain in place and are expected to be available to provide capacity and energy under new purchased power contracts with utilities.

***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 energy 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, as Florida's flat terrain does not lend itself to hydroelectric power. Landfill gas provides a combined 5 MW of capacity to GRU and JEA. Non-utility generators sell approximately 450 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 & CERTIFICATIONS*

The Commission has granted a Determination of Need for several generating units and one transmission line in recent years. Many of these facilities have received certification under the Power Plant Siting Act (Sections 403.501 through 403.518, Florida Statutes) or the Transmission Line Siting Act (Sections 403.52 through 403.5365, Florida Statutes) by Florida's Governor and Cabinet. The following summary describes those facilities that have received a Determination of Need from the Commission but have yet to be placed into commercial service.

***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 Brandy Branch site in Duval County. The HRSG is being fitted to two existing 191 MW CT units to form a 573 MW CC unit. Brandy Branch Unit 4 was certified under the Power Plant Siting Act in March 2002 and is expected to enter service in June 2005.

***FPL -- 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, an 835 MW expansion project at the existing Martin plant site in Martin County, will result from the addition of two 181 MW CT units, four HRSGs, and a steam turbine to two existing 181 MW CT units. When completed, Martin Unit 8 will be a 1197 MW CC unit. Manatee Unit 3 is a new 1197 MW CC unit at the existing Manatee site in Manatee County. Both units will be identical when completed. Both units were certified under the Power Plant Siting Act in April 2003 and are expected to enter service in June 2005.

***PEF -- Hines Unit 3***

In February 2003, the Commission granted PEF's petition to build a 582 MW gas-fired CC unit at the existing Hines site in Polk County. Hines Unit 3 was certified under the Power Plant Siting Act in September 2003 and is expected to enter service in December 2005.

***FPL -- Collier-Orange River 230 kV line***

In April 2003, the Commission granted FPL's petition to build a 230 kV transmission line in a new corridor between two existing substations, Collier (in Collier County) and Orange River (in Lee County). The 54-mile line was certified under the Transmission Line Siting Act in June 2004 and is expected to enter service in June 2005.

***FPL – Turkey Point Unit 5***

In June 2004, the Commission granted FPL's petition to build a 1181 MW gas-fired CC unit at the existing Turkey Point site in Dade County. Turkey Point Unit 5 is expected to enter service in June 2007 and is awaiting certification under the Power Plant Siting Act.

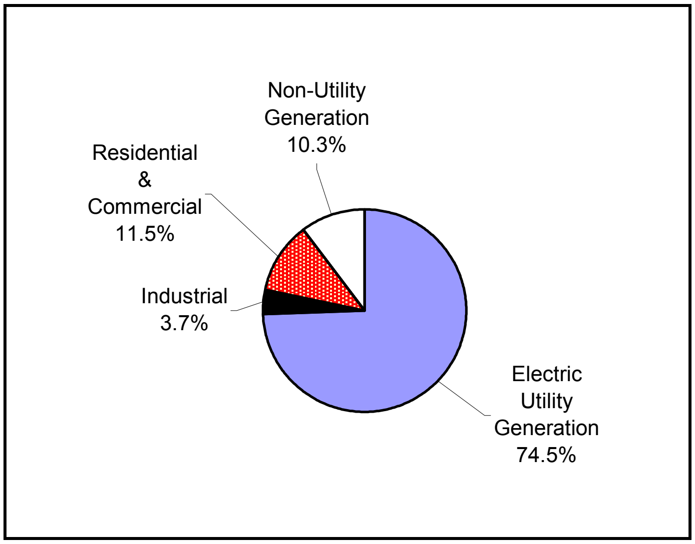
***PEF -- Hines Unit 4***

On November 3, 2004, the Commission granted PEF's petition to build a 517 MW gas-fired CC unit at the existing Hines site in Polk County. Hines Unit 4 has an anticipated December 2007 in-service date and is awaiting certification under the Power Plant Siting Act.

## NATURAL GAS PIPELINE ADEQUACY

Florida currently relies primarily on two gas pipeline companies, Florida Gas Transmission (FGT) and Gulfstream Natural Gas (Gulfstream), 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), while Gulfstream has a system pipeline capacity of 1.1 Bcf/day. A vast majority of the state's natural gas consumption (nearly 85%) is for electricity generation, both by utilities and non-utility generators. Figure 9 shows a breakdown of natural gas consumption by end-user.

***Figure 9. Natural Gas Consumption By End-User -- 2003***




Electric utility generation is forecasted to result in a significant (92%) increase in natural gas requirements over the next ten years. Increased dependency on natural gas could affect the reliability of electric utility generation supply in Florida. The primary threat to reliability comes from the possibility of natural gas supply disruption. The FRCC has formed a Gas/Electricity Interdependency Task Force to determine reliability impacts and to recommend mitigating measures should reliability risks arise. The NERC also has established a Gas/Electricity Interdependency Task Force whose scope was almost identical to that of the FRCC task force. The NERC task force completed a study in May 2004, concluding in part that gas pipeline reliability can substantially impact electric generation, and that electric system reliability can have an impact on gas pipeline operations. The FRCC continues to review the recommendations made by the NERC task force to determine where to specifically focus future analyses. The FRCC task force has recommended that the region has adequate pipeline capacity for reliability purposes for both current and future natural gas demand. However, the FRCC task force's conclusion assumes that the generating units that have the capability to burn oil will do so at times of peak demand. Therefore, economics may be the driving factor for any future gas pipeline expansions.

Based on the forecasted requirements of electric utilities and other sectors, the Commission estimates that total pipeline demand will increase to an average of 3.65 Bcf/day by 2013. Given the combined capacity of FGT and Gulfstream (3.3 Bcf/day), it would appear that, at a minimum, an additional 0.35 Bcf/day of pipeline capacity would be needed to satisfy forecasted 2013 requirements. However, this forecast is based on the average natural gas requirements and does not incorporate any additional capacity that may be needed during periods of peak demand. Providing an allowance for peak demand, the Commission estimates that incremental pipeline capacity requirements by 2013 could increase up to 0.82 Bcf/day. This forecast also does not reflect the potential impact of three potential liquefied natural gas (LNG) projects proposed by Calypso, Ocean Express, and Seafarer. If any one of these three proposed LNG pipeline projects are placed into service, the Commission expects that no additional pipeline capacity will be needed during the next ten years.

***FGT***

FGT operates 5,000 miles of pipeline nationwide, 3,300 miles of which are in Florida. In November 2003, FGT placed into service its Phase VI expansion facilities that consists of 33 miles of pipeline and 18,600 horsepower of compression. The Phase VI expansion 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 2002. Phase I, with a capacity of 1.1 Bcf/day, crosses the Gulf of Mexico between Pascagoula, Mississippi and Manatee County, Florida with more than 430 miles of 36-inch pipe. The pipeline then extends across Manatee, Hardee, Polk, and Osceola counties. Phase II, currently under construction, will extend the Phase I project to Martin County and is expected to enter service in December 2004.

***Calypso LNG***

The proposed Calypso pipeline, owned by Tractabel North American, Inc., will transport LNG from a proposed plant on Grand Bahamas Island to an interconnection point on FGT's system in Broward County. The proposed project has received approval from the FERC as well as Florida's Governor and Cabinet. The 24-inch pipeline is expected to have a delivery capacity of up to 0.832 Bcf/day and is expected to enter service in 2007. This project is awaiting approval from the Bahamian government.

***Ocean Express LNG***

The proposed AES Ocean Express pipeline is a 54.3-mile, 24-inch LNG pipeline extending from the United States - Bahamas Exclusive Economic Zone boundary to a termination near Ft. Lauderdale. 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. The Ocean Express project has received approval from the FERC as well as Florida's Governor and Cabinet. AES anticipates Ocean Express to be in-service by mid-2007. This project is awaiting approval from the Bahamian government.

***Seafarer LNG***

The proposed Seafarer pipeline, owned by the El Paso Corporation, will transport LNG from El Paso Global's proposed terminal on Grand Bahamas Island to Palm Beach County. The pipeline is then projected to extend westward, delivering natural gas at an interconnection with FGT. The 162-mile, 26-inch pipeline, with a delivery capacity of up to 0.7 Bcf/day, is expected to enter service in 2008. Seafarer's application is pending before the FERC.

# REVIEW & ANALYSIS – INDIVIDUAL UTILITY PLANS

## *PROGRESS ENERGY FLORIDA (PEF)*

***Load and Energy Forecast***

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

Under base-case assumptions, PEF forecasts that winter firm demand will increase at an average annual growth rate (AAGR) of 2.32% per year over the 2004/05-2013/14 planning horizon, considerably below the actual 1993/04-2002/03 AAGR of 5.86%. Over the next ten years, summer peak demand is forecasted to increase at an AAGR of 2.21%. PEF uses the University of Florida's Bureau of Economic and Business Research projected population growth rate of 1.7% per year over the period between 2004 and 2013.

PEF's 1999-2003 retail sales forecasts have an absolute forecast error of 0.62%, below the 1.40% average for the reporting utilities. Over the same period, PEF's retail sales forecasts have an average forecast error of -0.52%, reflecting a slight tendency to under-forecast.

***Demand-Side Management***

PEF is subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. The Commission set new numeric conservation goals for PEF in 2004. These goals call for a cumulative reduction of 128 MW of summer peak demand, 400 MW of winter peak demand, and 190 GWh of energy consumption over the next ten years. PEF's new numeric goals are slightly lower than the prior numeric demand and energy conservation goals set by the Commission in 1999. Revisions to the Florida State Energy Code will take effect in 2005, resulting in increases in minimum energy efficiency levels. These new requirements are expected to reduce potential demand and energy savings attributable to PEF's DSM programs. Additionally, PEF expects decreased participation in some of its DSM programs due to saturation.

PEF's new DSM Plan was also approved in 2004. PEF's DSM Plan contains five residential programs, seven commercial and industrial programs, a qualifying facility program, and a research and development program. All of these programs were part of PEF's most recent DSM Plan approved by the Commission in 2000. Ten of these programs remain unchanged from that time. The remaining four programs were minimally modified to ensure cost-effectiveness.

***Reliability Criteria***

PEF's primary reliability criterion is reserve margin, and PEF has historically been a winter-peaking utility. Effective Summer, 2004, PEF's summer and winter peak reserve margin criteria increased from 15% to 20%. PEF also utilizes an LOLP criterion of 0.1 days per year. 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.

***Fuel Forecast***

For the period 2004-2013, PEF provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated PEF's price forecasts against comparable EIA forecasts, PEF's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

PEF expects coal prices to increase by 1.1% annually until 2007, then increase by 1.6% annually for the remainder of the forecast horizon. PEF expects its coal price will be $2.40 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, then increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to cost $1.67 per MMBtu in 2013. Last year, PEF forecasted its coal prices to increase at 1.1% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

PEF expects residual oil prices to decrease by 3.7% annually until 2007, then increase by 2.6% annually for the remainder of the forecast horizon. PEF expects its residual oil price will be $4.39 per MMBtu in 2013. EIA forecasts residual oil prices to increase by 2.7% annually until 2007, then increase by 3.2% annually for the remainder of the forecast horizon. EIA expects residual oil to cost $5.55 per MMBtu in 2013. Last year, PEF forecasted its residual oil prices to decrease at 5.0% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

PEF expects distillate oil prices to decrease by 4.6% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon. PEF expects its distillate oil price will be $6.88 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, then increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to cost $6.88 per MMBtu in 2013. Last year, PEF forecasted its distillate oil prices to decrease by 3.1% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

PEF expects natural gas prices to decrease by 7.4% annually until 2007, then increase by 0.8% annually for the remainder of the forecast horizon. PEF expects its natural gas price will be $4.73 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, PEF expected its natural gas prices to decrease by 3.7% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

PEF expects its nuclear energy price to decrease by 1.2% annually until 2007, then increase by 1.7% annually for the remainder of the forecast horizon. PEF expects its nuclear energy price will be $0.37 per MMBtu in 2013. EIA does not provide a price forecast for nuclear energy. Last year, PEF expected its nuclear energy prices to increase by 1.1% annually from 2003 through 2012. The reporting utilities forecast nuclear energy prices to increase by an average of 0.3% until 2007, then increase by 1.8% for the remainder of the forecast horizon.

***Generation Selection***

PEF's system winter capacity is currently 10,501 MW. Of this total, 9,174 comes from PEF-owned generation. Firm interchange purchases account for 494 MW, while the remaining 833 MW comes from non-utility generators. Table 7 shows PEF's winter capacity by fuel type.

PEF plans to increase the generating capacity at the Hines Energy Complex by adding Unit 3 rated at 582 MW in 2005, Unit 4 rated at 517 MW in 2007, and Unit 5 rated at 536 MW in 2009. Three new 188 MW CT units are proposed for undetermined sites, all in 2006. The current plan includes a capacity reduction of 296 MW due to the expiration of cogeneration contracts. Firm capacity imports are forecasted to drop to zero over the planning horizon. PEF does not forecast any capacity additions from nuclear, coal, or fossil steam generating units.

***Table 7. PEF – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Nuclear | 788 | 0 |
| Coal | 2,341 | 0 |
| Firm Imports | 494 | -494 |
| Non-Utility Generation | 833 | -296 |
| Combined Cycle | 1,334 | 3,243 |
| Fossil Steam | 1,642 | 0 |
| Combustion Turbine | 3,069 | 564 |
| TOTAL | 10,501 | 3,017 |

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

<u>Department of Environmental Protection</u> – PEF's *Ten-Year Site Plan* is suitable.

<u>East Central Florida Regional Planning Council</u> -- No additional facilities are planned within the region.

<u>South Florida Water Management District</u> -- Does not have any adverse comments regarding the suitability of the proposed sites.

<u>Southwest Florida Water management District</u> – The Hines energy complex is permitted as a zero discharge site; as future units are added to the site, cooling and process water is expected to come from storm water runoff and reclaimed water. Additional sites are also expected to utilize sources other than groundwater for expansion. The District recognizes the effort to use alternative sources rather than groundwater and to provide information as to the sources.

St Johns River Water Management District – Is concerned about impact on ground and surface water resources, including impacts to wetlands, from both withdrawals and discharges that would be associated with proposed expansions at Debary site.

Tampa Bay Regional Planning Council -- The additions to the Hines site are within the Tampa Bay Region and are consistent with appropriate Council policies.

Volusia County -- Has no objection to the *Ten-Year Site Plan*.

***Suitability***

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

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

***Load and Energy Forecast***

FPL forecasts of sales, net energy for load, and peak loads are developed with the prime drivers of demographic trends, weather, economic conditions, and prices of electricity. FPL adequately identifies and describes the models, variables, data sources, assumptions, and informed judgments used to generate its demand and energy forecasts. The Commission believes that these factors have been accurately documented and that FPL's data sources are credible.

Under base-case assumptions, FPL forecasts that summer firm demand will increase at an AAGR of 2.21%, above the actual 1994-2003 AAGR of 2.65%. For the 2004-2013 planning horizon, FPL's base-case winter firm demand is forecasted to grow at an AAGR of 6.12% compared to an AAGR of 5.07% for the 1994/95-2003/04 period.

FPL's 1999-2003 retail sales forecasts have an absolute percent error of 1.24%, which is lower than the 1.40% average for the reporting utilities. For the same five-year period, FPL's retail sales forecasts have an average forecast error of -1.13%, which reflects a history of slightly under-forecasting.

***Demand-Side Management***

FPL is subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. The Commission set new conservation goals for FPL in 2004. These goals call for a cumulative reduction of 802 MW of summer peak demand, 512 MW of winter peak demand, and 1,058 GWh of energy consumption over the next ten years. FPL's new numeric goals are slightly lower than the prior numeric demand and energy conservation goals set by the Commission in 1999. Revisions to the Florida State Energy Code will take effect in 2005, resulting in increases in minimum energy efficiency levels. These new requirements are expected to reduce potential demand and energy savings attributable to FPL's DSM programs.

FPL will submit a new DSM Plan by the end of 2004. FPL's current DSM plan, approved by the Commission in 2000, contains six residential programs, eight commercial/industrial programs, and a research and development program for study of potential DSM programs. The majority of FPL's demand savings have historically come from residential and commercial load management programs.

FPL offers a green energy project in which customers may choose to pay an additional monthly fee, part of which goes to purchase tradable renewable energy credits associated with renewable sources. FPL also has a photovoltaic research project, and has committed to install additional photovoltaic generation as part of the green energy project.

***Reliability Criteria***

FPL's primary reliability criterion is reserve margin. FPL has traditionally been a summer-peaking utility, as winter peak demands have been lower than anticipated due to relatively mild winter temperatures in recent years. However, FPL forecasts that winter peak demand will be higher than summer peak during the planning horizon. Effective Summer, 2004, FPL's summer and winter peak reserve margin criteria increased from 15% to 20%. FPL also utilizes an LOLP criterion of 0.1 days per year. 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.

***Request for Proposals for LNG***

FPL is currently soliciting proposals for firm regasified LNG supplies, for a minimum of 400,000 and a maximum of 600,000 MMBTU/day, for a minimum of 15 and a maximum of 25 years. FPL's RFP specifies that delivery begin at any time between January 1, 2007 through December 31, 2010, to any interconnection of an interstate pipeline serving the state of Florida which is, or will be, directly connected to any FPL generating facility. FPL expects to announce the final selection by the end of April 2005.

***Fuel Forecast***

For the period 2004-2013, FPL provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated FPL's price forecasts against comparable EIA forecasts, FPL's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

FPL expects its coal price to increase by 1.4% annually until 2007, then increase by 0.4% annually for the remainder of the forecast horizon. FPL expects its coal price will be $1.74 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, FPL expected its coal prices to increase by 1.2% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

FPL expects its residual oil price to decrease by 3.2% annually until 2007, then increase by 3.1% annually for the remainder of the forecast horizon. FPL expects its residual oil price will be $4.51 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, FPL expected its residual oil prices to decrease by 0.7% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

FPL expects its distillate oil price to decrease by 1.9% annually until 2007, then increase by 3.0% annually for the remainder of the forecast horizon. FPL expects its distillate oil price will be $6.38 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, FPL expected its distillate oil prices to increase by 0.1% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

FPL expects its natural gas price to decrease by 0.9% annually until 2007, then increase by 2.2% annually for the remainder of the forecast horizon. FPL expects its natural gas price will be $6.28 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, FPL expected its natural gas prices to decrease by 5.5% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

FPL expects its nuclear energy price to increase by 0.5% annually until 2007, then increase by 1.0% annually for the remainder of the forecast horizon. FPL expects its nuclear energy price will be $0.42 per MMBtu in 2013. EIA does not provide a price forecast for nuclear energy. Last year, FPL expected its nuclear energy prices to increase by 1.2% annually from 2003 through 2012. The reporting utilities forecast nuclear energy prices to increase by an average of 0.3% until 2007, then increase by 1.8% for the remainder of the forecast horizon.

***Generation Selection***

FPL has a system winter capacity of 23,560 MW. Of this total, 20,335 MW comes from FPL-owned generation. FPL purchases 2,345 MW of firm capacity from Southern Company (931 MW), JEA (390 MW), and other entities (1,024) while purchases from non-utility generators comprise the remaining 880 MW. Table 8 shows FPL's winter capacity by fuel type.

Planned additions include the conversion of two CT units at the Martin site to CC operation. Known as Martin Unit 8, the new unit will provide an additional 835 MW of generating capacity in 2005. Also in 2005, Manatee Unit 3 will add 1,201 MW of CC capacity. FPL plans to add four additional 1,200 MW class CC units: Turkey Point Unit 5, expected to enter service in 2007; the Corbett Substation site, expected to enter service in 2009; and two additional CC units planned for 2011 and 2012 at sites not yet determined. Two new CT units, with a total capacity of 362 MW, are planned for 2008 at the Midway Substation site. FPL forecasts minimal decreases in fossil steam capacity at existing units.

FPL forecasts a decrease of 285 MW from non-utility generators within the planning horizon, due to the expiration of cogeneration contracts. Firm capacity imports are expected to decrease to 1,321 MW in 2013. Of the forecasted firm import total, 931 MW is expected to come from a new contract with Southern Company to replace an existing 931 MW contract scheduled to end in 2010.

***Table 8. FPL – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Nuclear | 3,013 | 0 |
| Coal | 926 | 0 |
| Firm Imports | 2,345 | -1,154 |
| Non-Utility Generation | 880 | -285 |
| Combined Cycle | 6,250 | 7,165 |
| Fossil Steam | 7,096 | -44 |
| Combustion Turbine | 3,050 | 19 |
| TOTAL | 23,560 | 5,701 |

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

Department of Environmental Protection – FPL's *Ten-Year Site Plan* is suitable.

East Central Florida Regional Planning Council -- No additional facilities are planned within the region.

Manatee County -- Is concerned about possibility of solid fuel-based generating capacity additions and the impacts of the installations and fuel transportation on air, water and soil pollution, as well as the impact on area transportation systems.

South Florida Regional Planning Council --The *Ten-Year Site Plan* is generally within the Regional Policy Plan. Specifically, the Plan is designed to ensure adequacy of public facilities and services and encourage environmentally sound mechanisms to reduce the impact of new development on public facilities and services. The Council notes that transmission additions are limited to existing utility easements, and that the Utility's conservation measures tend to balance the impact on resources and the economy of the Region.

South Florida Water Management District -- Does not have any adverse comments regarding the suitability of the proposed sites.

Southwest Florida Water Management District -- The District recognizes use of surface water sources such as the little Manatee River, water conservation, and sources other than groundwater by the Utility.

Tampa Bay Regional Planning Council -- The plans for additions at the Manatee, Turkey Point, Midway, Corbett, Fort Myers, and Sanford sites are consistent with appropriate Council policies.

***Suitability***

FPL's *Ten-Year Site Plan* is suitable for planning purposes.

## GULF POWER COMPANY (GULF)

***Load and Energy 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 by aggregating district projections performed by district personnel based on 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 integrate end-use and econometric methods such as the Residential End-Use Energy Planning System (REEPS) and the Commercial End-Use Model (COMMEND). Surveys provide the data source to identify the responsiveness of household energy decisions to price and other variables. Gulf uses Economy.Com for its economic outlook projections. Low- and high-band forecasts were not performed.

Gulf's base-case summer peak demand forecast for the next ten years shows an annual average growth rate (AAGR) of 1.20%, which is less than half of the actual 1994-2003 AAGR of 2.62%. The base-case winter peak demand over the forecast period is 1.28%, just over a third of the historical AAGR of 3.66%.

***Demand-Side Management***

Gulf is subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. The Commission set new conservation goals for Gulf in 2004, resulting in a significant reduction in residential demand and energy goals from prior levels. Over the next ten years, cumulative goals include reductions of 85 MW in summer demand, 82 MW in winter demand, and 51 GWh of energy consumption. Revisions to the Florida State Energy Code will take effect in 2005, resulting in increases in minimum energy efficiency levels. These new requirements are expected to reduce potential demand and energy savings attributable to Gulf's DSM programs. Additionally, Gulf forecasts decreased savings from interruptible service.

Gulf will submit a new DSM Plan by the end of 2004. Gulf's current DSM plan, approved by the Commission in 2000, contains seven DSM programs and four types of audits.

***Intercompany Interchange Contract***

The Southern Company performs integrated planning and system operations for all of its members, including Gulf. In this manner, each member utility benefits from the economies of scale associated with a large system. Through an Intercompany Interchange Contract (IIC), Gulf and other Southern Company members share their capacity resources with the system. Reserve sharing provisions of the IIC allow each company to sell surplus capacity into the pool for purchase by other members with a temporary capacity deficit. Due to its small size relative to other Southern Company members, Gulf has frequently been able to rely on these shared reserves during years that Gulf's own reserves have been insufficient to meet its own native load. Gulf's reliance on the IIC for shared reserves is forecasted to continue into the future.

***Reliability Criteria***

Gulf's sole reliability criterion is reserve margin. Gulf has traditionally been a summer-peaking utility, as electric winter heating loads are reduced due to the availability of natural gas (for heating) in Gulf's service territory. Southern Company currently uses a system-wide 13.5% summer reserve margin criterion for its near-term (1-3 years) criterion. Beyond three years, the reserve margin criterion is 15%.

Gulf's *Ten-Year Site Plan* indicates that the summer reserve margin criterion will be violated in all years of the planning horizon, in amounts ranging from 10 MW to 338 MW (in 2007). The winter reserve margin criterion is expected to be violated in three years: 2006/07 (20 MW), 2007/08 (59 MW), and 2008/09 (84 MW). Gulf's *Ten-Year Site Plan* discusses at length the company's ability to rely on the reserve sharing provisions of the IIC to meet 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.

***Fuel Forecast***

For the period 2004-2013, Gulf provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated Gulf's price forecasts against comparable EIA forecasts, Gulf's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

Gulf expects its coal price to decrease by 2.6% annually until 2007, then decrease by 0.5% annually for the remainder of the forecast horizon. Gulf expects its coal price will be $1.78 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, Gulf expected its coal prices to increase by 2.3% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

Gulf expects its residual oil price to decrease by 5.6% annually until 2007, then decrease by 1.4% annually for the remainder of the forecast horizon. Gulf expects its residual oil price will be $3.34 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, Gulf expected its residual oil prices to decrease by 2.6% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

Gulf expects its distillate oil price to decrease by 3.0% annually until 2007, then decrease by 0.6% annually for the remainder of the forecast horizon. Gulf expects its distillate oil price will be $6.38 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, Gulf expected its distillate oil prices to decrease by 2.0% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

Gulf expects its natural gas price to decrease by 5.9% annually until 2007, then decrease by 1.2% annually for the remainder of the forecast horizon. Gulf expects its natural gas price will be $5.05 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per

MMBtu in 2013. Last year, Gulf expected its natural gas prices to decrease by 3.9% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

***Generation Selection***

Gulf has a system winter capacity of 2,663 MW. Gulf owns 2,828 MW of capacity and 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. Table 9 shows Gulf's winter capacity by fuel type.

Gulf plans to add approximately 360 MW of capacity during the planning horizon. Two new 166 MW gas-fired CT units are planned for a yet-to-be determined site in 2009. Firm imports are expected to increase by 217 MW over the planning period. Firm exports are not projected to change.

Gulf plans to retire 59 MW of fossil steam capacity from Crist Units 2 and 3 in 2006, as well as 92 MW of coal-fired capacity from Scholz Units 1 and 2 in 2011. All four of these units have been in service for over 50 years. Smith Unit 3, a CC unit, will have a capacity derating of 17 MW by 2006 to reflect age and wear. Gulf's 19 MW of non-utility generator capacity is set to expire in 2005.

***Table 9. Gulf – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Coal | 2,131 | -92 |
| Firm Imports | 27 | 217 |
| Firm Exports | -211 | 0 |
| Non-Utility Generation | 19 | -19 |
| Combined Cycle | 584 | -17 |
| Fossil Steam | 59 | -59 |
| Combustion Turbine | 54 | 332 |
| TOTAL | 2,663 | 362 |

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

Department of Environmental Protection – Gulf's *Ten-Year Site Plan* is suitable.

West Florida Regional Planning Council – Regarding the potential Mossy Head site, the Council is concerned about environmental impacts to the Shoal River, as well as groundwater use for cooling and possible impacts on the aquifer that supplies Pensacola. The Council is further interested in the various conservation programs and the number of participants attracted to those programs.

***Suitability***

The Commission notes that Gulf is expected to violate its summer reserve margin criterion in all ten summer seasons and three winter seasons during the ten-year planning horizon. As in past years, Gulf will continue to rely on firm capacity purchases from the Southern Company shared power pool during times of need. Furthermore, it should be noted that Gulf's capacity deficiency is small in magnitude relative to the size of the Southern Company. For this reason, Gulf's *Ten-Year Site Plan* is suitable for planning purposes.

## *TAMPA ELECTRIC COMPANY (TECO)*

***Load and Energy Forecast***

In the past year, TECO made significant changes to its forecasting tools and methodology. TECO's retail customer demand and energy forecast is the result of six separate forecasting analyses: economic, customer, energy, peak demand, phosphate, and conservation programs. TECO's energy models are based on Statistical Adjusted Engineering, which specifies end-use variables such as heating, cooling, and base use appliances and equipment. Phosphate demand and energy is forecast separately and then combined in the final forecast. TECO's methodology is detailed. TECO also tested high- and low-case sensitivities using an explicit assumption of 0.5%+/- expected change in growth in the number of customers, employment, and income.

TECO's base-case summer peak demand is projected to increase at an average annual growth rate (AAGR) of 3.02%, which is slightly lower than the summer peak historical growth rate of 3.54%. TECO's base-case winter peak demand is projected to increase at an AAGR of 2.91%, much lower than the winter historical growth rate of 4.61%. However, TECO projects slower population growth of 1.6%.

TECO's 1999-2003 retail sales forecasts have an absolute percent error of 0.76%, which is lower than the numeric average of 1.40% for the nine reporting utilities with sufficient historical data. For the same five-year period, TECO's retail sales forecasts have an average forecast error of -0.76%, which reflects a history of slightly under-forecasting.

***Demand-Side Management***

TECO is subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. The Commission set new conservation goals for TECO in 2004, resulting in a significant reduction in demand and energy goals from prior levels. Over the next ten years, cumulative goals include reductions of 30.5 MW in summer demand, 28.3 MW in winter demand, and 85 GWh of energy consumption. Revisions to the Florida State Energy Code will take effect in 2005, resulting in increases in minimum energy efficiency levels. These new requirements are expected to reduce potential demand and energy savings attributable to TECO's DSM programs. Additionally, some of TECO's DSM programs have reached saturation, such that future participation is not expected.

TECO will submit a new DSM Plan by the end of 2004. TECO's current DSM plan, approved by the Commission in 2000, contains eight residential programs, eight commercial/industrial programs, and a research and development program for study of potential DSM programs.

***Reliability Criteria***

TECO's sole reliability criterion is reserve margin, and TECO has traditionally been a summer-peaking utility. However, winter peak demands are a primary concern to utilities in Florida. Effective Summer, 2004, TECO's summer and winter peak reserve margin criteria increased from 15% to 20%. A subcomponent of this criterion is a 7% summer supply-side requirement. 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 the reliability criteria in each year of the planning horizon.

***Fuel Forecast***

For the period 2004-2013, TECO provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated TECO's price forecasts against comparable EIA forecasts, TECO's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

TECO expects its coal price to increase by 1.6% annually until 2007, then increase by 1.7% annually for the remainder of the forecast horizon. TECO expects its coal price will be $2.17 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, TECO expected its coal prices to increase by 0.8% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

TECO expects its residual oil price to decrease by 4.1% annually until 2007, then decrease by 0.2% annually for the remainder of the forecast horizon. TECO expects its residual oil price will be $4.17 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, TECO expected its residual oil prices to remain unchanged through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

TECO expects its distillate oil price to decrease by 5.9% annually until 2007, then increase by 0.8% annually for the remainder of the forecast horizon. TECO expects its distillate oil price will be $5.44 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, TECO expected its distillate oil prices to decrease by 3.4% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

TECO expects its natural gas price to increase by 1.6% annually until 2007, then remain unchanged for the remainder of the forecast horizon. TECO expects its natural gas price will be $5.62 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, TECO expected its natural gas prices to increase by 0.1% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

***Generation Selection***

TECO's system winter capacity is currently 4,832 MW. Of this total, 4,323 MW comes from TECO-owned generation. TECO currently purchases 449 MW from other utilities and 60 MW from non-utility generators. Over the last few years, TECO has moved away from coal-fired generation. All coal-fired generation at the Gannon site was discontinued by 2003, and the steam boilers from Gannon Units 5 and 6 were repowered into two new gas-fired CC units, Bayside 1 and 2. Bayside Unit 1, with a winter capacity of 779 MW, entered service in 2003. Bayside Unit 2, with a winter capacity of 1,040 MW, entered service in January of this year. The remaining four Gannon units were retired in January of this year. Table 10 shows TECO's winter capacity by fuel type.

TECO forecasts a decrease of 39 MW from non-utility generators within the planning horizon, due to the expiration of a cogeneration contract. TECO also forecasts that firm capacity will increase by 200 MW but has yet to determine a supplier. TECO issued an RFP for this capacity in July 2003, but its *Ten-Year Site Plan* does not contain any additional information. Planned additions include two 180 MW CT units at Bayside (in 2006 and 2007) and three 180 MW CT units at Polk (in 2010, 2011, and 2013). TECO also plans to add a 502 MW gas-fired CC unit, at a yet-to-be determined site, in 2013. An 80 MW CT unit at Big Bend, currently on cold standby, is expected to return to service in 2006.

***Table 10. TECO – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Coal | 1,759 | 0 |
| Firm Imports | 449 | -249 |
| Integrated Coal Gasification Combined Cycle | 260 | 0 |
| Non-Utility Generation | 60 | -39 |
| Combined Cycle | 779 | 1,550 |
| Combustion Turbine | 485 | 980 |
| TOTAL | 3,792 | 2,242 |

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

Department of Environmental Protection – TECO's *Ten-Year Site Plan* is suitable.

Hillsborough County -- TECO's *Ten-Year Site Plan* is suitable as a general planning document and is consistent with local efforts to improve air quality.

Southwest Florida Water Management District -- The District recommends use of any available means to help conserve groundwater. Particularly mentioned are sited power plant expansions, or possibly some planned and currently un-sited expansions, that fall within the Most Impacted Area or the Southern Water Use Caution Area. Resource constraints may pose significant permitting challenges, and surface water, storm water, or reclaimed water should be used in any application where feasible.

Tampa Bay Regional Planning Council -- The conversion of Gannon to Bayside will have a net positive effect to air and water quality in the region. Although the Polk Power Station is not located in the Region, expansion or change in fuel used there may adversely impact the Tampa Bay Region; the Council recommends that it be notified of future actions and related transmission line construction.

***Suitability***

TECO's Ten-Year Site Plan is 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.

### ***Load and Energy Forecast***

To estimate the energy needs for its All-Requirements Project members, FMPA uses standardized techniques including: econometric modeling of customer class requirements, statistical analysis, incremental load analysis, and informed judgment. 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 forecast data to enable the Commission to compare FMPA's forecast accuracy to other utilities.

For the 1994-2003 period, FMPA's base-case summer peak demand increased at an average annual growth rate (AAGR) of 12.78% and 11.97% winter peak demand, due primarily to the addition of new member utilities. The projected AAGR for summer peak demand for the next ten years is 2.38%. For the ten year planning horizon, FMPA forecasts winter peak demand to increase at an AAGR of 2.36%.

### ***Demand-Side Management***

Neither FMPA nor any of its All-Requirements Project members are subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. However, FMPA assists member utilities in promoting conservation programs to retail customers and evaluating new programs to ensure cost effectiveness. Five residential DSM programs and two commercial DSM programs are available to the All-Requirements Project participants. FMPA also participates in a utility partnership formed to assist in the development of photovoltaic systems as renewable energy sources.

### ***Reliability Criteria***

FMPA's sole reliability criterion is reserve margin, and FMPA has historically been a summer-peaking entity. As a result, FMPA utilizes summer reserve margin criterion of 18%. Forecasted reserve margins, as shown in FMPA's *Ten-Year Site Plan*, are expected to meet or exceed the reserve margin criterion in each year of the planning horizon.

### ***Fuel Forecast***

For the period 2004-2013, FMPA provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated FMPA's price forecasts against comparable EIA forecasts, FMPA's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

FMPA expects its coal price to increase by 2.5% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon. FMPA expects its coal price will be $2.32 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6%

annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, FMPA expected its coal prices to increase by 1.3% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

FMPA expects its residual oil price to increase by 3.2% annually until 2007, then increase by 3.5% annually for the remainder of the forecast horizon. FMPA expects its residual oil price will be $4.27 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, FMPA expected its residual oil prices to increase by 3.0% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

FMPA expects its distillate oil price to increase by 2.9% annually until 2007, then increase by 3.1% annually for the remainder of the forecast horizon. FMPA expects its distillate oil price will be $7.10 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, FMPA expected its distillate oil prices to increase by 2.9% annually from 2003 through 2012. Florida utilities forecast distillate oil prices to decrease by 0.9% annually until 2007, and increase by 2.5% annually for the remainder of the forecast horizon.

FMPA expects its natural gas price to decrease by 6.7% annually until 2007, then increase by 4.3% annually for the remainder of the forecast horizon. FMPA expects its natural gas price will be $4.88 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, FMPA expected its natural gas prices to increase by 2.7% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

FMPA expects its nuclear energy price to increase by 2.6% annually until 2007, then increase by 2.3% annually for the remainder of the forecast horizon. FMPA expects its nuclear energy price will be $0.78 per MMBtu in 2013. EIA does not provide a price forecast for nuclear energy. Last year, FMPA expected its nuclear energy prices to increase by 2.3% annually from 2003 through 2012. The reporting utilities forecast nuclear energy prices to increase by an average of 0.3% until 2007, then increase by 1.8% for the remainder of the forecast horizon.

***Generation Selection***

FMPA's All-Requirements Project currently has a winter system generating capacity of 1,742 MW. However, the combined generation of FMPA's members, currently 1,437 MW, is insufficient to meet aggregate load. To serve load that exceeds generation, FMPA currently purchases 305 MW of capacity from other utilities. FMPA does not export any capacity. FMPA has partial requirements contracts with PEF and FPL, who serve FMPA's load within their regions that exceeds FMPA's own generation and capacity purchases. Table 11 shows FMPA's winter capacity by fuel type.

FMPA plans to add a net of 522 MW of capacity during the planning period. Current plans call for the addition of 22 MW CT units in Key West in 2006 and 2012, 175 MW CT units at Cane Island in

2008 and 2010, and 97 MW CT units at Ft. Pierce in 2008 and 2013, Lake Worth in 2008, and Vero Beach in 2011. Firm imports are forecasted to decrease to 45 MW by 2012.

***Table 11. FMPA – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Nuclear | 75 | 0 |
| Coal | 245 | 0 |
| Firm Imports | 305 | -260 |
| Member-Owned Capacity | 764 | 0 |
| Combined Cycle | 206 | 0 |
| Combustion Turbine | 147 | 782 |
| TOTAL | 1,742 | 522 |

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

Department of Environmental Protection – FMPA's *Ten-Year Site Plan* is suitable.

East Central Florida Regional Planning Council -- No additional facilities are planned within the region.

Monroe County – Is interested in the possibility of renewable energy as a possible alternative to the CT units proposed for Stock Island.

South Florida Water Management District -- Does not have any adverse comments regarding the suitability of the proposed sites.

***Suitability***

FMPA's *Ten-Year Site Plan* is suitable for planning purposes.

## GAINESVILLE REGIONAL UTILITIES (GRU)

***Load and Energy Forecast***

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

Under base-case assumptions, GRU forecasts that summer peak demand will increase at an average annual growth rate (AAGR) of 2.33% , somewhat less than the 2.60% AAGR for the 1994-2003 period. Under base-case conditions, GRU forecasts that winter peak demand will increase at an AAGR of 2.49%, which is above the previous ten year period of 1.21%.

GRU's 1999-2003 retail sales forecasts have an absolute percent error of 1.42%, higher than the average of 1.40% for the nine reporting utilities with sufficient available historical data. For the same period, GRU's retail sales forecasts have an average forecast error of -1.42%, which reflects a history of under-forecasting.

***Demand-Side Management***

GRU is not subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. However, 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.

GRU is promoting renewable energy with a 10 KW photovoltaic project funded by customer contributions and grants from state and federal government. GRU plans to implement a green pricing program, under which energy produced at a local landfill may be packaged with other renewable sources and marketed to GRU's residential and commercial customers.

***Reliability Criteria***

GRU's sole reliability criterion is reserve margin, and GRU has historically been a summer-peaking utility. GRU utilizes a summer and winter peak reserve margin criteria of 15%. 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.

***Fuel Forecast***

For the period 2004-2013, GRU provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated GRU's price forecasts against comparable EIA forecasts, GRU's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

GRU expects its coal price to decrease by 7.9% annually until 2007, then increase by 1.8% annually for the remainder of the forecast horizon. GRU expects its coal price will be $2.15 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013.

Last year, GRU expected its coal prices to increase by 1.2% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

GRU expects its residual oil price to decrease by 0.7% annually until 2007, then increase by 3.1% annually for the remainder of the forecast horizon. GRU expects its residual oil price will be $5.97 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, GRU expected its residual oil prices to increase by 2.0% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

GRU expects its distillate oil price to increase by 0.6% annually until 2007, then increase by 2.7% annually for the remainder of the forecast horizon. GRU expects its distillate oil price will be $8.61 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, GRU expected its distillate oil prices to increase by 4.0% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

GRU expects its natural gas price to increase by 1.6% annually until 2007, then increase by 4.1% annually for the remainder of the forecast horizon. GRU expects its natural gas price will be $7.66 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, GRU expected its natural gas prices to increase by 3.9% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

GRU expects its nuclear energy price to decrease by 1.0% annually until 2007, then increase by 1.3% annually for the remainder of the forecast horizon. GRU expects its nuclear energy price will be $0.45 per MMBtu in 2013. EIA does not provide a price forecast for nuclear energy. Last year, GRU expected its nuclear energy prices to decrease by 0.2% annually from 2003 through 2012. The reporting utilities forecast nuclear energy prices to increase by an average of 0.3% until 2007, then increase by 1.8% for the remainder of the forecast horizon.

***Generation Selection***

GRU has a net system winter capacity of 628 MW. GRU owns 631 MW of capacity but exports 3 MW to other utilities. GRU does not import any capacity. Table 12 shows GRU's winter capacity by fuel type.

GRU is currently evaluating options to meet future capacity needs. Although not yet approved by GRU's governing board, a new 220 MW generating unit, burning coal and a mix of other solid fuels, is planned for 2011. GRU plans to retire J.R. Kelly Unit 7, a 23 MW steam turbine unit, in 2011. Firm exports are forecasted to go to zero during the planning horizon.

***Table 12. GRU – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Nuclear | 11 | 0 |
| Coal | 228 | 220 |
| Firm Exports | -3 | 3 |
| Combined Cycle | 118 | 0 |
| Fossil Steam | 106 | -23 |
| Combustion Turbine | 168 | 0 |
| TOTAL | 628 | 200 |

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

Department of Environmental Protection – GRU's *Ten-Year Site Plan* is suitable.

North Central Florida Regional Planning Council – Offers no comment.

St Johns River Water Management District – Mentions that the only proposal for generation expansion would use potable water sources wholly located within the Suwannee River Water Management District.

***Suitability***

GRU's *Ten-Year Site Plan* is suitable for planning purposes.

## JEA

### *Load and Energy Forecast*

JEA's base-case forecast uses trend analysis based on weather normalized historical data. JEA states that trend analysis methodology has dramatically increased the accuracy of its forecasts. However, trend analysis does not explicitly capture the impact of projected growth in personal income, population, or other variables related to electricity usage. JEA's trending results over the last five years have improved significantly. The methodology used to review forecasting error incorporates past years' higher error rates. Although still declining, JEA's forecast error averages are still higher than other utilities.

JEA's 1999-2003 retail sales forecasts covering the previous 3-5 years forecast averages, have an absolute percent error of 2.79%, higher than the average of 1.40% for the state's reporting utilities and the highest among all utilities. For the same period, JEA's retail sales forecasts have an average forecast error of -1.95%, which shows a tendency to under-forecast.

JEA's base-case winter peak demand forecast reflects an average annual growth rate (AAGR) of 2.73% over the planning horizon, which is lower than the historical winter peak AAGR of 5.16%. The base-case summer peak demand forecast shows an AAGR of 2.12%, which is lower than the historical summer peak AAGR of 2.92%.

### *Demand-Side Management*

JEA is subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. The Commission set numeric conservation goals of zero for JEA in 2004 because no DSM measure was cost-effective for JEA. JEA's prior numeric conservation goals, set by the Commission in 2000, were also zero. However, JEA has continued its existing DSM programs including energy 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.

JEA has a Green Power program and a Clean Power Capacity program to encourage the application of renewable energy technology and use of renewable energy resources. 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 over 600 solar photovoltaic modules around Jacksonville.

### *Reliability Criteria*

JEA's sole reliability criterion is reserve margin. 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 utilizes a summer and winter peak reserve margin criteria of 15%.

JEA's *Ten-Year Site Plan* includes unspecified capacity purchases, starting at 100 MW in 2007 and escalating to 200 MW by 2010, from renewable sources. If unable to secure the renewable capacity, The Energy Authority should be able to timely secure the needed 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.

***Fuel Forecast***

For the period 2004-2013, JEA provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated JEA's price forecasts against comparable EIA forecasts, JEA's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

JEA expects its coal price to increase by 0.1% annually until 2007, then increase by 2.3% annually for the remainder of the forecast horizon. JEA expects its coal price will be $1.85 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, JEA expected its coal prices to increase by 1.4% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

JEA expects its residual oil price to increase by 1.4% annually until 2007, then increase by 2.7% annually for the remainder of the forecast horizon. JEA expects its residual oil price will be $4.28 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, JEA expected its residual oil prices to increase by 1.3% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

JEA expects its distillate oil price to increase by 1.2% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon. JEA expects its distillate oil price will be $6.30 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, JEA expected its distillate oil prices to increase by 1.3% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

JEA expects its natural gas price to decrease by 4.2% annually until 2007, then increase by 1.8% annually for the remainder of the forecast horizon. JEA expects its natural gas price will be $6.05 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, JEA expected its natural gas prices to decrease by 2.3% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

***Generation Selection***

JEA has a net winter capacity of 3,238 MW. JEA owns 3,476 MW of capacity but exports 445 MW to other utilities and imports 207 MW. Table 13 shows JEA's winter capacity by fuel type.

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 191 MW CT units at the Brandy Branch site. The resulting 573 MW CC unit is expected to enter service in May 2005. JEA also plans to add two 86 MW CT units in 2010 at a yet-to-be determined site. JEA plans to add two 250 MW fluidized bed coal units, in 2011 and 2013, respectively, at greenfield sites to be determined.

Both imports and exports are expected to show net decreases during the planning period. JEA forecasts that firm exports will decrease to 383 MW. Firm purchases are expected to decrease by a net of 7 MW, to 200 MW. This value incorporates the expiration of a 207 MW purchased power agreement with Southern Company in 2010, plus the addition of 200 MW of renewable generation under JEA's Clean Power Capacity program during the planning horizon.

***Table 13. JEA – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Coal | 1,771 | 500 |
| Firm Imports | 207 | -7 |
| Firm Exports | -445 | 62 |
| Combined Cycle | 0 | 573 |
| Fossil Steam | 505 | 0 |
| Combustion Turbine | 1,200 | -211 |
| TOTAL | 3,238 | 917 |

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

Department of Environmental Protection – JEA's *Ten-Year Site Plan* is suitable.

Jacksonville – Duval County – JEA's *Ten-Year Site Plan* is a suitable planning document.

St Johns River Water Management District – Provides no comment.

***Suitability***

JEA's *Ten-Year Site Plan* is suitable for planning purposes.

## *CITY OF LAKELAND (LAK)*

***Load and Energy Forecast***

LAK's load forecast methodology includes econometric and multiple regression modeling, study of historical relationships and growth rates, trend analysis, and exponential smoothing. The winter peak demand forecast model uses various independent variables including temperature at time of winter peak, annual minimum temperature, and minimum temperature of week prior to winter peak. The summer peak demand model forecast uses annual maximum temperature, temperature at time of summer peak, and Polk County population.

Under base case conditions, winter peak demand is projected to increase at an average annual growth rate (AAGR) of 2.36% over the next ten years, which is less than half the 5.06% AAGR for the 1994-2003 period. Summer peak demand is projected to increase at an AAGR of 2.11%, lower than the 2.71% AAGR for the 1994-2003 period.

LAK's 1999-2003 retail sales forecasts have an absolute percent error of 1.48%, higher than the numeric average of 1.40% for the nine reporting utilities with sufficient available historical data. For the same period, LAK's retail sales forecasts have an average forecast error of 1.48%.

***Demand-Side Management***

LAK is not subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. However, LAK offers energy audits, a residential load management program, a residential loan program, a commercial lighting program, and thermal energy storage. LAK also offers an interruptible service tariff. LAK is also involved in several renewable energy program activities such as a solar street light program, a solar thermal water heating project, residential photovoltaic systems, and a green pricing program.

***Reliability Criteria***

LAK's sole reliability criterion is reserve margin, and LAK has historically been a winter-peaking utility. LAK utilizes a reserve margin criterion of 20% summer peak / 22% winter peak. Forecasted reserve margins, as shown in LAK's *Ten-Year Site Plan*, are expected to meet or exceed the reserve margin criterion in each year of the planning horizon.

***Fuel Forecast***

For the period 2004-2013, LAK provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated LAK's price forecasts against comparable EIA forecasts, LAK's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

LAK expects its coal price to increase by 5.3% annually until 2007, then increase by 3.9% annually for the remainder of the forecast horizon. LAK expects its coal price will be $3.09 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, LAK expected its coal prices to increase by 1.0% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

LAK expects its residual oil price to decrease by 0.1% annually until 2007, then increase by 4.0% annually for the remainder of the forecast horizon. LAK expects its residual oil price will be $7.23 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, LAK expected its residual oil prices to decrease by 0.9% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

LAK expects its distillate oil price to increase by 3.6% annually until 2007, then increase by 3.2% annually for the remainder of the forecast horizon. LAK expects its distillate oil price will be $9.56 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, LAK expected its distillate oil prices to decrease by 1.4% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

LAK expects its natural gas price to increase by 2.1% annually until 2007, then increase by 3.9% annually for the remainder of the forecast horizon. LAK expects its natural gas price will be $8.43 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, LAK expected its natural gas prices to decrease by 0.2% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

***Generation Selection***

LAK has a winter system capacity of 945 MW. LAK owns 1,045 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 export to FMPA is scheduled to expire in 2010. Table 14 shows LAK's winter capacity by fuel type.

***Table 14. LAK – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Coal | 205 | 0 |
| Firm Exports | -100 | 100 |
| Combined Cycle | 495 | 0 |
| Fossil Steam | 243 | 0 |
| Combustion Turbine | 102 | 0 |
| TOTAL | 945 | 100 |

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

Department of Environmental Protection – LAK's *Ten-Year Site Plan* is suitable.

***Suitability***

LAK's *Ten-Year Site Plan* is suitable for planning purposes.

## *ORLANDO UTILITIES COMMISSION (OUC)*

***Load and Energy Forecast***

OUC uses linear regression sales models as its forecasting methodology. OUC uses the Statistically Adjusted Engineering (SAE) model to which entails specifying end-use variables of heating, cooling, and base use for the sales regression models. OUC's methodology and assumptions are appropriate. There were insufficient data to measure the absolute percent error of OUC's 1999-2003 retail sales forecasts.

Under base case conditions, summer peak demand is projected to increase at an average annual growth rate (AAGR) of 1.50% over the forecast period, much lower than the 6.13% AAGR actually experienced during the 1994-2003 period. Winter peak demand is forecast to increase at an AAGR of 2.00%, lower than the historical AAGR of 5.51%.

***Demand-Side Management***

OUC is subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. The Commission set numeric conservation goals of zero for OUC in 2004 because no DSM measure was cost-effective for OUC. OUC's prior numeric conservation goals, set by the Commission in 2000, were also zero. However, OUC has continued its existing DSM programs including energy audits, heat pump replacement, water heating, weatherization, and home energy fix-up. OUC has an interruptible service tariff but no load management program.

***Reliability Criteria***

OUC's sole reliability criterion is reserve margin, and OUC is primarily a summer-peaking utility. OUC utilizes a summer and winter peak reserve margin criteria of 15%. Forecasted reserve margins, as shown in OUC's *Ten-Year Site Plan*, are expected to meet or exceed the reserve margin criterion in each year of the planning horizon.

***Fuel Forecast***

For the period 2004-2013, OUC provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated OUC's price forecasts against comparable EIA forecasts, OUC's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

OUC expects its coal price to increase by 2.6% annually until 2007, then increase by 3.7% annually for the remainder of the forecast horizon. OUC expects its coal price will be $2.67 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, OUC expected its coal prices to increase by 4.8% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

OUC expects its residual oil price to decrease by 1.8% annually until 2007, then increase by 1.7% annually for the remainder of the forecast horizon. OUC expects its residual oil price will be $4.83 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2%

for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, OUC expected its residual oil prices to increase by 1.5% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

OUC expects its distillate oil price to decrease by 2.1% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon. OUC expects its distillate oil price will be $6.27 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

OUC expects its natural gas price to decrease by 1.7% annually until 2007, then increase by 0.8% annually for the remainder of the forecast horizon. OUC expects its natural gas price will be $5.67 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, OUC expected its natural gas prices to increase by 1.0% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

OUC expects its nuclear energy price to increase by 2.4% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon. OUC expects its nuclear energy price will be $0.51 per MMBtu in 2013. EIA does not provide a price forecast for nuclear energy. Last year, OUC expected its nuclear energy prices to increase by 2.5% annually from 2003 through 2012. The reporting utilities forecast nuclear energy prices to increase by an average of 0.3% until 2007, then increase by 1.8% for the remainder of the forecast horizon.

***Generation Selection***

OUC has a winter system capacity of 1,814 MW. Of this total, 1,256 MW comes from OUC-owned generation and another 21 MW from the City of St. Cloud generating units which are operated and managed by OUC. Currently, OUC imports 656 MW and exports 119 MW to other utilities. Table 15 shows OUC's winter capacity by fuel type.

OUC plans to add 323 MW of net winter capacity over the planning horizon. Four 175 MW CT units are planned for a yet-to-be determined site, one each in 2007, 2009, 2011, and 2012, respectively. The St. Cloud units are scheduled for retirement in 2006. Over the planning period, OUC expects to decrease imports to 181 MW by 2013, while exports are expected to decrease to zero by 2007.

***Table 15. OUC – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Nuclear | 65 | 0 |
| Coal | 759 | 0 |
| Firm Imports | 656 | -475 |
| Firm Exports | -119 | 119 |
| Combined Cycle | 184 | 0 |
| Combustion Turbine | 269 | 679 |
| TOTAL | 1,814 | 323 |

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

Department of Environmental Protection – OUC's *Ten-Year Site Plan* is suitable.

East Central Florida Regional Planning Council -- No additional facilities are planned within the region.

St Johns River Water Management District – Provides no comment.

***Suitability***

OUC's *Ten-Year Site Plan* is suitable for planning purposes.

## *CITY OF TALLAHASSEE (TAL)*

***Load and Energy Forecast***

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

Under base-case conditions, summer peak demand is projected to increase at an average annual growth rate (AAGR) of 1.57% over the forecast period, lower than the 2.67% AAGR actually experienced during the 1994-2003 period. Under base-case assumptions, TAL forecasts winter peak demand to increase at an AAGR of 1.81%, compared to an historical AAGR of 1.20%.

TAL's 1999-2003 retail sales forecasts have an absolute percent error of 0.55%, which is lower than the 1.40% numeric average for the nine reporting utilities with sufficient available historical data. For the same period, TAL's retail sales forecasts have an average forecast of 0.33%, which reflects a history of very slightly over-forecasting.

***Demand-Side Management***

TAL is not subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. However, TAL offers energy audits, five residential DSM programs, 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 is preparing a new DSM plan in conjunction with an updated integrated resource plan study.

TAL promotes the use of renewable energy. TAL has an 11 MW hydroelectric generator on Lake Talquin. In addition, there are currently 40 KW of photovoltaic projects in TAL's service area, with plans for additional installations. TAL also promotes solar pool heating and solar water heating projects, and has a green pricing program.

***Reliability Criteria***

TAL's sole reliability criterion is reserve margin, and TAL is primarily a summer-peaking utility. TAL utilizes a summer reserve margin criterion of 17%. Forecasted reserve margins, as shown in TAL's *Ten-Year Site Plan*, are expected to meet or exceed the reserve margin criterion in each year of the planning horizon.

***Fuel Forecast***

For the period 2004-2013, TAL provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated TAL's price forecasts against comparable EIA forecasts, TAL's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

TAL expects its coal price to decrease by 4.4% annually until 2007, then decrease by 0.4% annually for the remainder of the forecast horizon. TAL expects its coal price will be $1.90 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013.

Last year, TAL expected its coal prices to increase by 1.6% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

TAL expects its residual oil price to decrease by 1.4% annually until 2007, then increase by 3.1% annually for the remainder of the forecast horizon. TAL expects its residual oil price will be $6.16 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, TAL expected its residual oil prices to increase by 1.6% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

TAL expects its distillate oil price to decrease by 5.5% annually until 2007, then increase by 4.9% annually for the remainder of the forecast horizon. TAL expects its distillate oil price will be $8.12 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, TAL expected its distillate oil prices to increase by 1.1% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

TAL expects its natural gas price to decrease by 4.2% annually until 2007, then increase by 0.8% annually for the remainder of the forecast horizon. TAL expects its natural gas price will be $6.06 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, TAL expected its natural gas prices to decrease by 0.8% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

***Generation Selection***

TAL has a winter system capacity of 710 MW. Of this total, 699 MW comes from TAL's owned generation, while 11 MW comes from a firm capacity purchase. Table 16 shows TAL's winter capacity by fuel type.

TAL plans to add a 50 MW CT unit at the Hopkins site in 2005. At the same time, TAL also plans to add 51 MW of distributed generation from nine quick-start turbines, six at the Hopkins site and three at the Substation 12 site. TAL is currently performing an integrated resource planning process to determine future needs. At the current time, TAL plans to add CC capacity, through shared ownership or purchase, in the following increments: 25 MW in 2009, 25 MW in 2010, 50 MW in 2011, and 25 MW in 2013. TAL also plans to retire 70 MW of capacity at the Purdom site between 2008 and 2011.

***Table 16. TAL – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Firm Imports | 11 | 0 |
| Combined Cycle | 262 | 125 |
| Fossil Steam | 366 | -50 |
| Hydroelectric | 11 | 0 |
| Combustion Turbine | 60 | 81 |
| TOTAL | 710 | 156 |

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

Department of Environmental Protection – TAL's *Ten-Year Site Plan* is suitable.

Tallahassee-Leon County Planning Department -- TAL's *Ten-Year Site Plan* is suitable.

***Suitability***

TAL's *Ten-Year Site Plan* is 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.

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

SEC expects to continue to be a winter-peaking utility primarily due to continued prominence of electric space-heating appliance saturation. Under base case conditions, winter peak demand forecast is projected to increase at an average annual growth rate (AAGR) of 4.16% over the forecast period. While the winter peak demand forecast is lower than the 6.37% AAGR actually experienced during the 1994-2003 period, it is still one of the highest winter peak growth rates in the state. SEC's base-case summer peak demand is forecast to grow at an AAGR of 4.06%, lower than the historical AAGR of 4.95%.

SEC's 1999-2003 retail sales forecasts have an absolute percent error of 1.71%, with an average forecast error of -0.72%. This result reflects SEC's history of slightly under-forecasting.

### *Demand-Side Management*

Neither SEC nor any of its member systems are subject to FEECA's requirement to meet Commission-prescribed numeric conservation goals. However, member systems individually manage and promote their own conservation programs with SEC's assistance. Some member systems have load management programs whose dispatch is coordinated by SEC. 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.

### *Reliability Criteria*

SEC's primary reliability criterion is reserve margin. SEC expects to continue to be a winter-peaking utility primarily due to a forecasted increase in electric space-heating appliance saturation. SEC's summer and winter peak reserve margin criteria is 15% summer and winter reserve margin. SEC also utilizes an EUE/NEL ratio of 1%. 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.

### *Fuel Forecast*

For the period 2004-2013, SEC provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated SEC's price forecasts against comparable EIA forecasts, SEC's 2003-2012 price forecasts, and comparable forecasts made by other reporting utilities.

SEC expects its coal price to increase by 1.2% annually until 2007, then increase by 1.2% annually for the remainder of the forecast horizon. SEC expects its coal price will be $1.92 per MMBtu in 2013. EIA forecasted coal prices to increase by 2.4% annually until 2007, and increase by 2.6% annually for the remainder of the forecast horizon. EIA expects coal to be $1.67 per MMBtu in 2013. Last year, SEC expected its coal prices to increase by 1.2% annually from 2003 through 2012. The reporting utilities forecast coal prices to remain flat until 2007, then increase by 1.8% annually for the remainder of the forecast horizon.

SEC expects its residual oil price to decrease by 3.1% annually until 2007, then increase by 3.5% annually for the remainder of the forecast horizon. SEC expects its residual oil price will be $4.07 per MMBtu in 2013. EIA forecasted residual oil prices to increase by 2.7% until 2007, and increase by 3.2% for the remainder of the forecast horizon. EIA expects residual oil to be $5.55 per MMBtu in 2013. Last year, SEC expected its residual oil prices to increase by 3.1% annually from 2003 through 2012. The reporting utilities forecast residual oil prices to decrease by an average of 1.8% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

SEC expects its distillate oil price to increase by 4.4% annually until 2007, then increase by 3.4% annually for the remainder of the forecast horizon. SEC expects its distillate oil price will be $6.73 per MMBtu in 2013. EIA forecasted distillate oil prices to increase by 1.3% until 2007, and increase by 2.5% for the remainder of the forecast horizon. EIA expects distillate oil to be $6.88 per MMBtu in 2013. Last year, SEC expected its distillate oil prices to increase by 1.9% annually from 2003 through 2012. The reporting utilities forecast distillate oil prices to decrease by an average of 1.0% annually until 2007, then increase by 2.5% annually for the remainder of the forecast horizon.

SEC expects its natural gas price to decrease by 2.4% annually until 2007, then increase by 3.2% annually for the remainder of the forecast horizon. SEC expects its natural gas price will be $6.00 per MMBtu in 2013. EIA forecasted natural gas prices to increase by 3.8% annually until 2007, and increase by 5.1% annually for the remainder of the forecast horizon. EIA expects natural gas to be $6.14 per MMBtu in 2013. Last year, SEC expected its natural gas prices to increase by 1.8% annually from 2003 through 2012. The reporting utilities forecast natural gas prices to decrease by an average of 2.4% annually until 2007, then increase by 1.9% annually for the remainder of the forecast horizon.

SEC expects its nuclear energy price to decrease by 2.8% annually until 2007, then increase by 1.2% annually for the remainder of the forecast horizon. SEC expects its nuclear energy price will be $0.48 per MMBtu in 2013. EIA does not provide a price forecast for nuclear energy. Last year, SEC expected its nuclear energy prices to increase by 0.9% annually from 2003 through 2012. The reporting utilities forecast nuclear energy prices to increase by an average of 0.3% until 2007, then increase by 1.8% for the remainder of the forecast horizon.

***Generation Selection***

SEC has a total system winter capacity of 4,715 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 1,420 MW of winter firm capacity from other utilities, 362 MW from Hardee Power Station, and 35 MW of cogeneration. Partial requirements and full requirements purchases currently provide 981 MW. Table 17 shows SEC's winter capacity by fuel type.

Although SEC plans to add nearly 4,946 MW of new generating capacity during the planning horizon, net system capacity is expected to increase by only 2,199 MW. SEC expects its reliance on firm purchases, the Hardee Power Station Contract, and cogeneration to decrease to zero during the planning horizon, resulting in a combined decrease of 1,817 MW. The amount of partial requirements and full requirements capacity imports is forecasted to decrease by 930 MW by that time.

SEC plans to add 310 MW of CT capacity in 2006 from five units at the Payne Creek site. An additional 2,548 MW of CT capacity is planned from fourteen new units at yet-to-be-determined sites. These units are planned to be placed into service as follows: three in 2009, two in 2012, and nine in 2013. Also planned is 1,638 MW of CC capacity from nine new units at a yet-to-be determined site. These units are planned to be placed into service as follows: one in 2007, one in 2008, three in 2009, one in 2010, and three in 2013. Finally, SEC plans to add a total of 450 MW of coal capacity, 150 MW in 2012 and 300 MW in 2013.

***Table 17. SEC – Winter Capacity By Fuel Type***

| UNIT TYPE | EXISTING CAPACITY (MW) | PROPOSED ADDITIONS (MW) |
|---|---|---|
| Nuclear | 15 | 0 |
| Coal | 1,330 | 450 |
| Firm Imports | 1,420 | -1,420 |
| Partial Requirements Purchases | 981 | -930 |
| Non-Utility Generation | 397 | -397 |
| Combined Cycle | 572 | 1,638 |
| Combustion Turbine | 0 | 2,858 |
| TOTAL | 4,715 | 2,199 |

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

Department of Environmental Protection – SEC's *Ten-Year Site Plan* is suitable.

Hardee County – Provides no comment.

St Johns River Water Management District – Provides no comment.

Southwest Florida Water Management District -- The additional gas turbine units at Payne Creek Generating Station fall within the Southern Water Use Caution Area, and ten additional unsited units are planned which may fall within the Caution Area as well. No information regarding potential additional water use, future demands or sources to meet those demands is provided. Use of sources other than groundwater and conservation of water needs to be addressed in planning and future reports.

***Suitability***

SEC's *Ten-Year Site Plan* is suitable for planning purposes.

### *INDEPENDENT POWER PRODUCERS*

One IPP, Calpine Construction Finance Company (Calpine), filed a *Ten-Year Site Plan* for 2004. Calpine's *Ten-Year Site Plan* contains two gas-fired CC units at the Blue Heron site in Indian River County. 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. IPPs having a contract to sell the output from a proposed CC unit to a retail-serving utility can be a co-applicant with that utility under the Power Plant Siting Act. The proposed Blue Heron CC units are forecasted to enter service in 2007 and 2009, respectively. However, the status of these units remains uncertain at this time because there currently is not a contract to sell the output to a retail-serving utility.