A Review of Florida Electric Utility 2005 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 the statute, the Commission performs a preliminary study of each *Ten-Year Site Plan* and must determine whether it is "suitable" or "unsuitable." The Commission receives comments from state, regional, and local planning agencies regarding various issues of concern. The Commission forwards the *Ten-Year Site Plan* review, upon completion, 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 the DEP.

PURPOSE

The intent of the *Ten-Year Site Plans* is to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. However, the *Ten-Year Site Plans* are 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 has no binding effect on the utility. Such a classification does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility’s *Ten-Year Site Plan* at a public hearing.

Because the *Ten-Year Site Plans* are planning documents containing tentative data, they may not contain sufficient information to allow regional planning councils, water management districts, and other review agencies to evaluate site-specific issues within their jurisdictions. Each utility is responsible for providing detailed data, based on in-depth environmental assessments, during Power Plant Siting Act or Transmission Line Siting Act certification proceedings.

FLORIDA RELIABILITY COORDINATING COUNCIL

As a region of the North American Electric Reliability Council (NERC), the Florida Reliability Coordinating Council (FRCC) has adopted a formal reliability assessment process to annually review and assess existing and projected generation resources in Peninsular Florida. FRCC members exchange planning and operating information related to the reliability of the bulk power supply within the FRCC region (Peninsular Florida). The FRCC has a reliability assessment group that decides which planning and operating studies to perform 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 generating unit and transmission line additions for the FRCC region as well as statewide. The *Reliability Assessment* is an aggregate study of the projected future reliability of Peninsular Florida's electric grid. The Commission used both documents to supplement its review of the utility *Ten-Year Site Plans*.

EXECUTIVE SUMMARY

SUITABILITY

The *Ten-Year Site Plans* for eleven reporting utilities were filed on April 1, 2005. The Commission also received a Ten-Year Site Plan from one independent power producer (IPP) but is not required to determine its suitability. The Commission held a public workshop on August 3, 2005 to facilitate public discussion of the plans.

In aggregate, forecasted statewide reserve margins range from 21% to 27% during summer peak seasons, and from 23% to 28% during winter peak seasons. In addition, the plans filed by FPL, PEF, and TECO continue to reflect their agreement, pursuant to stipulation in Docket No. 981890-EU, to maintain at least a 20% reserve margin through the ten-year planning horizon.

With regard to the issue of fuel diversity, the *Ten-Year Site Plans* of Peninsular Florida's utilities indicate a reduced dependence on the use of natural gas from 51.4% to 44.4% by the end of the ten-year planning period. This reduction reflects plans by several peninsular Florida utilities to construct coal-fired units during the latter years of the planning period.

As discussed in greater detail in the Areas of Concern, the Commission is concerned that, in light of current volatility in the availability and price of natural gas, Florida's utilities need to return to the practice of planning a Balanced Fuel Supply (BFS). Because of the long lead time required to construct solid fuel generation, the planned addition of coal fired generating units in the 2012 and 2013 time is a reasonable step toward attaining this goal. The Commission believes that utilities should continue to place focus on increasing the supply of solid fuel fired generation, including clean coal technologies and nuclear, in Florida. In addition, utilities need to intensify their efforts to develop alternatives such as energy conservation, demand-side management, solar, and other renewable supply-side technologies in a cost-effective manner.

Based on our review, the Commission finds the *Ten-Year Site Plans* filed by the eleven reporting utilities to be suitable. However, the Commission will continue to closely monitor the progress of utilities in the state to increase the fuel diversity of generation within the state.

SUMMARY OF RESOURCE ADDITIONS

Table 1 summarizes the 2004 and 2005 ten-year forecasts of aggregate capacity additions, by generating unit type, for the State of Florida's electric utilities.

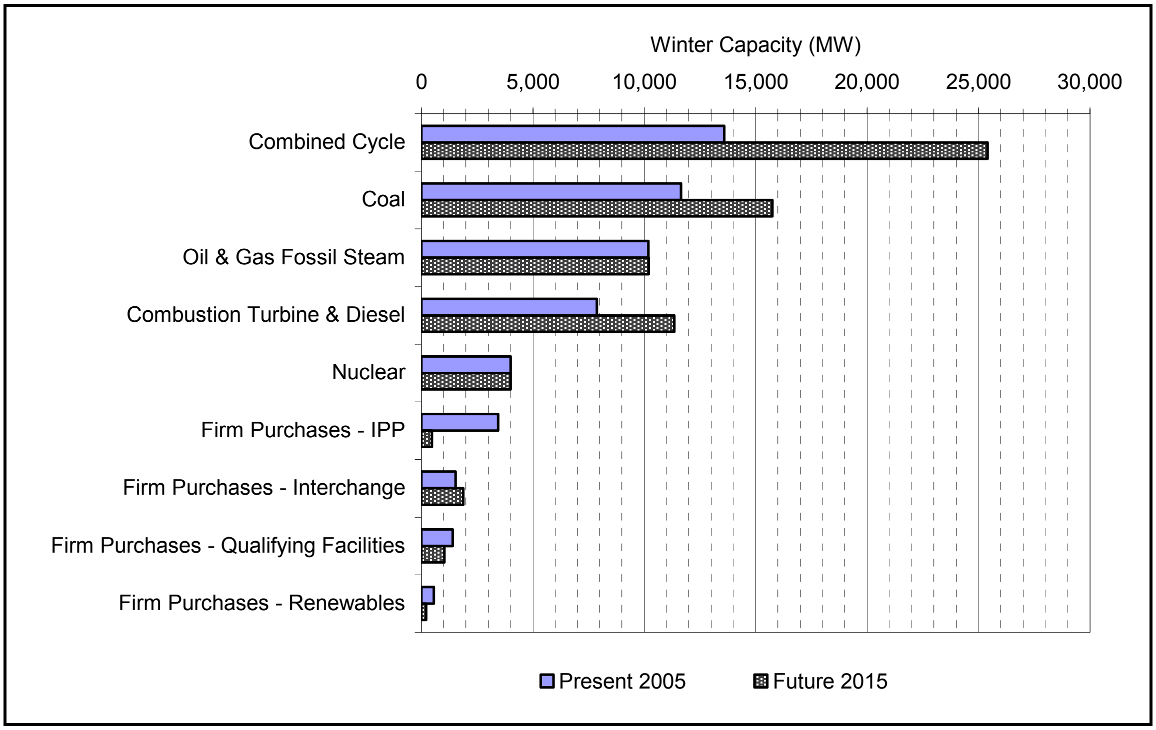
Table 1. State of Florida – Proposed Capacity Additions by Florida's Electric Utilities

UNIT TYPE	WINTER CAPACITY (MW)	
	2004 FORECAST (2004-2013)	2005 FORECAST (2005-2014)
Combined Cycle	15,250	11,820
Coal	1,078	4,100 [1]
Oil and Gas Fossil Steam	-169	18
Combustion Turbine & Diesel	5,141	3,463
Nuclear	0	0
Firm Purchases - Independent Power Producers [2]	--- [3]	-2,976
Firm Purchases - Interchange	-621	343
Firm Purchases - Qualifying Facilities [2]	-1,558 [3]	-377
Firm Purchases - Renewables [2, 4]	-312	-340
NET CAPACITY ADDITIONS	19,027	18,812

[1] Amount of proposed coal-fired capacity incorporates updated data from August 3, 2005 Commission workshop.
[2] Negative value resulting from contracts terminating during the ten-year planning horizon. Actual generating facilities remain in place.
[3] 2004 forecasts of firm purchases from independent power producers and qualifying facilities were combined.
[4] Majority of renewable capacity purchased from municipal solid waste facilities.

Figure 1 illustrates the aggregate capacity resource mix, both current and future, for the State of Florida's electric utilities. The future capacity values shown below incorporate all proposed additions, changes, and retirements from Table 1 on the prior page.

Figure 1. State of Florida – Electric Utility Capacity Mix



Figures 2 and 3, on the next page, illustrate the aggregate 2004 and 2005 forecasts, by Florida's electric utilities, of energy generation mix by fuel type at the end of the ten-year planning horizon. The tables illustrate the trend, discussed on page 5, towards reduced reliance on natural gas-fired generation and the plans to add coal-fired generating units.

Figure 2. State of Florida –2004 Forecast -- Energy Generation by Fuel Type in 2013

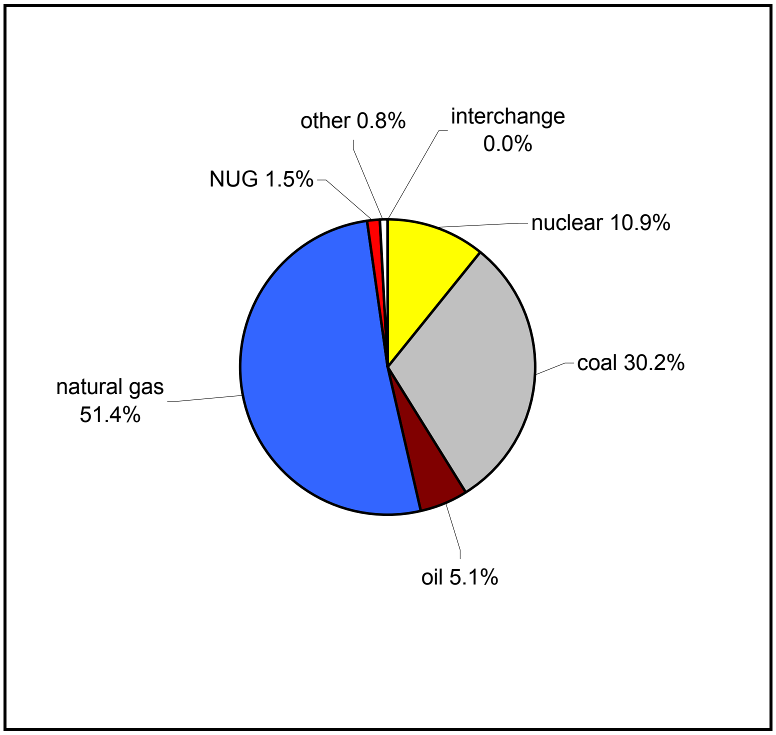


Figure 3. State of Florida –2005 Forecast -- Energy Generation by Fuel Type in 2014

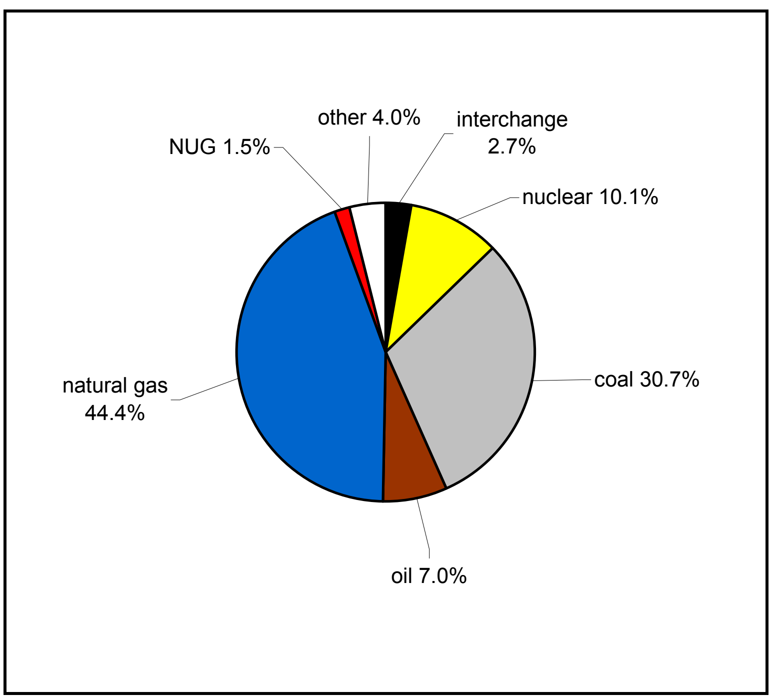


Table 2 lists all proposed generating units in the *Ten-Year Site Plans* that meet the criteria for requiring certification under Florida's Power Plant Siting Act. Solid fuel units are in ***bold italics***.

Table 2. Reporting Utilities – Proposed Generating Units Requiring Certification

UTILITY	GENERATING UNIT - NAME AND TYPE	WINTER CAPACITY (MW)	PROPOSED IN-SERVICE DATE
Florida Municipal Power Agency	Treasure Coast CC Unit [5]	318	6/2008
Seminole Electric Cooperative	Unsited CC Unit 1	182	11/2008
Seminole Electric Cooperative	Unsited CC Unit 2	182	5/2009
Florida Power & Light Company	West County Unit 1 CC	1,181	6/2009
Progress Energy Florida	Hines Unit 5 CC	548	12/2009
Florida Power & Light Company	West County Unit 2 CC 2	1,181	6/2010
Progress Energy Florida	Hines Unit 6 CC	548	12/2010
Orlando Utilities Commission	***Stanton IGCC Unit*** [6]	***311***	***1/2011***
Gainesville Regional Utilities	***Deerhaven Unit 3 CFB*** [7]	***220***	***6/2011***
Florida Municipal Power Agency / JEA / Reedy Creek / City of Tallahassee	***North Florida Power Project PC Unit*** [8]	***800***	***3/2012***
Progress Energy Florida	Unsited CC Unit 1	548	5/2012
Seminole Electric Cooperative	***Seminole Unit 3 PC***	***750***	***5/2012***
Florida Power & Light Company	***Unsited PC Unit 1***	***855***	***6/2012***
JEA	***Unsited CFB Unit***	***250***	***12/2012***
Florida Power & Light Company	***Unsited PC Unit 2***	***855***	***6/2013***
Seminole Electric Cooperative	Unsited CC Units 3 and 4	364 (total)	11/2013
Tampa Electric Company	Unsited CC Unit 1	502	1/2013
Progress Energy Florida	Unsited CC Unit 2	548	12/2013
Progress Energy Florida	Unsited CC Unit 3	548	5/2014
Seminole Electric Cooperative	Unsited CC Unit 5	182	11/2014
TOTAL REQUIRING CERTIFICATION		1780	

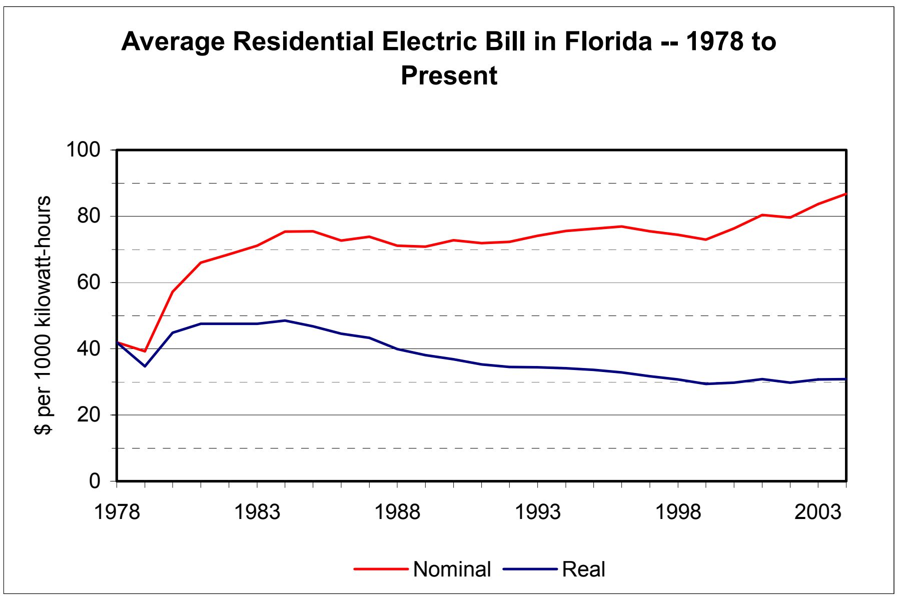
[5] Combined cycle natural gas-fired generating unit
[6] Integrated coal gasification combined cycle generating unit
[7] Circulating fluidized bed, coal-fired generating unit
[8] Pulverized coal-fired generating unit. Based on updated data from August 3, 2005 Commission workshop. TAL's participation in the project is tentative, pending a final decision later this year by the city commission.

AREAS OF CONCERN

Fuel Diversity

Since the mid 1980s and up to the turn of the century, Florida's average electricity prices remained relatively stable. Figure 4 shows the historic average residential electric prices. When adjusted for inflation, average residential prices actually declined during the period. Two major factors contributed to this stability: moderate fuel prices and a balanced generation fuel mix. Following the dramatic run up in oil prices which occurred in the mid and late 1970's, Florida's utilities made a concerted effort to replace oil fired generation with solid fuels. The Commission supported this effort with regulatory programs such as the Oil Backout Cost Recovery Factor, Coal-By-Wire from Georgia, the Energy Broker, and joint utility power plant planning.

Figure 4. Average Residential Electric Bill -- 1978 to Present

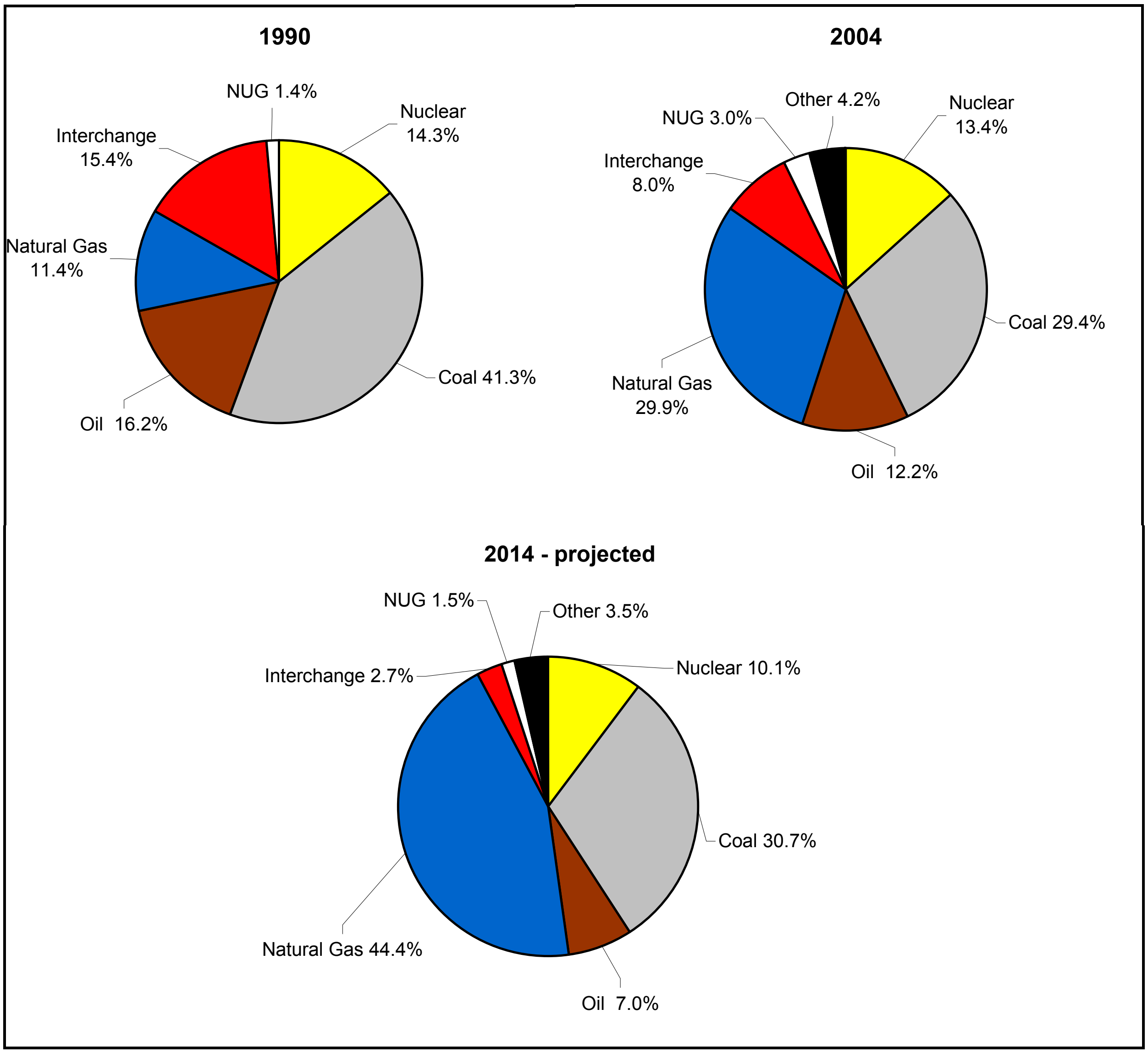


In 1987, Congress repealed the Power Plant and Industrial Fuel Use Act, which had restricted the use of natural gas as a utility boiler fuel. Natural gas demand had declined substantially because of restrictions on usage, contributing to a significant oversupply of gas and resulting in falling prices. Shortly after the repeal, major manufacturers of generating equipment stepped up efforts to develop new efficient gas-fired generating technologies. As a result, natural gas began to play a prominent role in the production of electricity. This resulted in a new era of highly efficient, flexible, and environmentally preferred combustion turbine (CT) and combined cycle (CC) technology fueled by low-cost natural gas.

Need for a Balanced Fuel Supply

Historically, Florida's electric utilities pursued fuel diversity by maintaining a balanced fuel supply (BFS) in terms of the types of fuel used to generate electricity. Florida's utilities had a relative balance of energy generation from coal, nuclear, natural gas, oil, and other sources. However, due to continued growth in the state's electricity demand and relatively low natural gas prices, Florida's utilities turned to gas-fired generating units to satisfy economic and reliability needs. Between 1990 and 2004, the vast majority of new generating capacity constructed in Florida was natural gas-fired, which led to an increase in the percentage of the state's energy generated by natural gas. This trend is projected to continue, as illustrated in Figure 5.

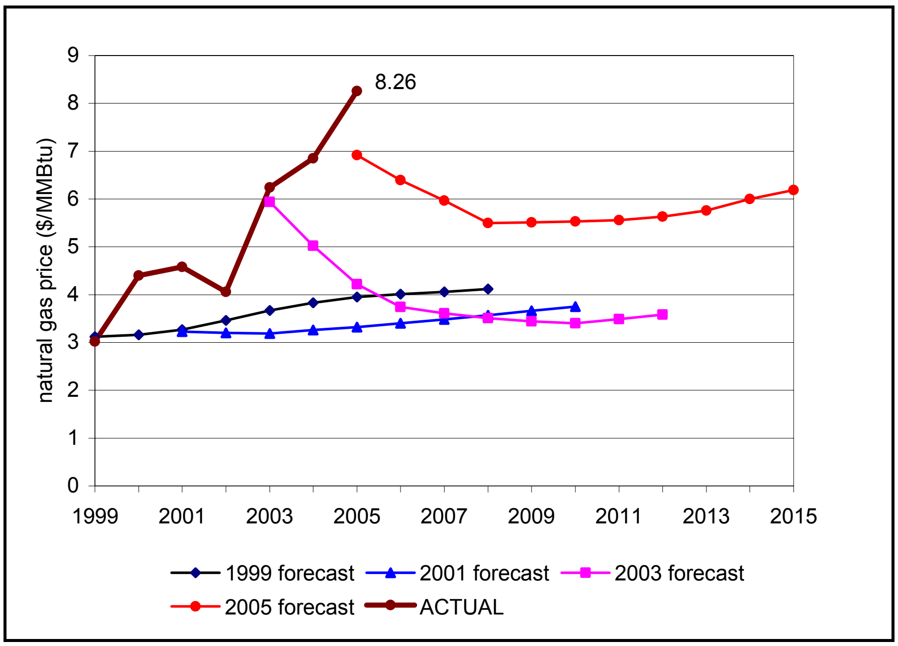
Figure 5. State of Florida – Energy Generation by Fuel Type -- 1990, 2004, and 2014



While the current *Ten-Year Site Plans* include several additional coal-fired units, the long lead time required to construct coal plants means that they will not come into service until at least 2012. As a result, natural gas is projected to comprise 44% of total energy generated by 2014.

Recent volatile increases in natural gas prices, however, appear to signal the end of the gas bubble. As late as 1999, electric utility forecasts for natural gas prices were relatively flat, with moderate growth rates being the consensus nationwide. Due to natural gas price volatility over the past few years, each of Florida's investor-owned utilities has substantially under-forecasted their natural gas prices. Using FPL as an example, in 1999, the average actual price for natural gas was approximately $3.00 per MMBtu[9]. In 2001, FPL's actual gas cost was approximately $4.50 per MMBtu. In 2003, FPL's actual gas cost had risen to $6.24 per MMBtu, yet Florida's utilities consistently forecasted future growth rates that fell below actual trends. By 2005, year-to-date actual cost has been $8.26 per MMBtu, with daily fluctuations being much higher due to supply disruptions caused by Hurricanes Katrina and Rita. Figure 6 compares past FPL natural gas price forecasts to actual prices.

Figure 6. FPL - Comparison of Actual vs. Forecasted Actual Natural Gas Prices



For 2005, the reporting utilities continue to forecast declining natural gas prices over the next three years, with a gradual increase thereafter. The utilities believe that current high prices are an aberration. The Commission remains skeptical of the utilities' natural gas forecasts, as these forecasts remain well below actual experiences. As such, planned gas-fired plants may not be a "given" in future need determination proceedings.

The effects of forecast error can be dramatic. In 2003, Florida's investor-owned utilities experienced record under-recoveries for fuel costs totaling approximately $670 million. A fuel cost under-recovery means that the utility's fuel price forecasts made the prior year were lower than actual fuel costs. In 2004, the under-recoveries totaled approximately $353 million. In 2005, the investor-owned utilities project under-recoveries of nearly $1.4 billion. The 2005 value includes the effects of Hurricanes Katrina and Rita, which shut down natural gas production in the Gulf of Mexico. During this time, Florida's utilities needed to make public appeals for conservation, and sought environmental waivers

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[9] MMBtu - million BTU

allowing them to burn back-up fuels such as light oil. By comparison, FPL has projected an overnight in-service cost for its next coal plant at approximately $2 billion. In other words, the three years of higher than predicted fuel costs are greater than the capital costs of a new coal-fired plant. If Florida continues down the current path of building natural gas-fired generation, then utility fuel costs will continue to experience volatile swings and increased prices.

Energy conservation, demand-side management, and renewable generation are important parts of an overall BFS approach to planning. However, these resources alone cannot satisfy the load growth of Florida's ratepayers. Demand-side management goals for utilities have declined in recent years for three primary reasons: (1) the Florida Building Code contains increased minimum energy efficiency levels, thus limiting the amount of incremental savings from utility sponsored DSM programs; (2) many utility DSM programs have reached a saturation in participation levels; and (3) the relatively low cost of new generating units has reduced the cost-effectiveness of DSM programs. In January 2003, the Commission, in consultation with the DEP, prepared an assessment of renewable resources in Florida. The assessment found that the majority of existing renewable resources in Florida, approximately 393 MW, come from municipal solid waste facilities. The assessment also concluded that the greatest potential for incremental renewable capacity additions, approximately 225 MW, was from Biomass facilities. Current utility load growth projections suggest a statewide total need for approximately 17,000 MW of new capacity, net of conservation, over the next ten years. The minimum amount of new capacity proposed for any single year is approximately 700 MW, nearly the current size of the City of Tallahassee's system.

The Commission will continue to encourage conservation, demand-side management, and renewable generation where cost-effective in order for these resources to play a role in Florida's energy future. As utility plans include more solid fuel generation options, the cost-effectiveness of conservation, demand-side management, and renewable resources is likely to improve. However, unless overall load growth declines, utilities must build new generation to satisfy Florida's enormous appetite for electricity.

Movement to a Balanced Fuel Supply

All generation additions proposed prior to 2009 are natural gas-fired units that are under construction or have been certified under the Power Plant Siting Act. Most new generation forecasted for the 2009-2014 period will burn natural gas, with some coal unit additions in 2012 and 2013. Thus, while some utilities have begun to take action to insulate Florida's ratepayers from the effects of rising natural gas prices, the return to a more conservative fuel mix cannot be made overnight.

For 2003, Florida's utilities forecasted a net <u>reduction</u> of 857 MW of coal-fired capacity, primarily from the repowering of TECO's Gannon Units to burn natural gas. Natural gas-fired capacity was projected to <u>increase</u> by over 19,000 MW and make up 47.2% of the state's total energy generated by 2012. The level of projected natural gas generation was clearly in excess of any historic BFS. The Commission believed at the time that increased natural gas supply would be supplemented by as many as three liquefied natural gas (LNG) pipelines from the Bahamas, all of which were scheduled to enter service by as early as 2007. In an effort to avoid a situation similar to the 1970's oil embargo, the Commission began requesting sensitivity analyses from utilities to test the cost-effectiveness of solid fuel additions. Such analyses examined higher fuel price scenarios as well as other impediments to constructing solid fuel generation. The utilities generally agreed that natural gas prices would have to escalate to approximately $5.00 per MMBtu by 2010 and that the permitting and construction of a coal-fired plant would take approximately seven years. FPL responded that a coal unit might be cost-effective for its system as early as 2010. With natural gas prices already above the $5.00 per MMBtu level, and given the lead time to permit and construct a coal unit, it appeared that utility plans would return to a more diverse and balanced fuel supply. However, the next year's plans were not much different.

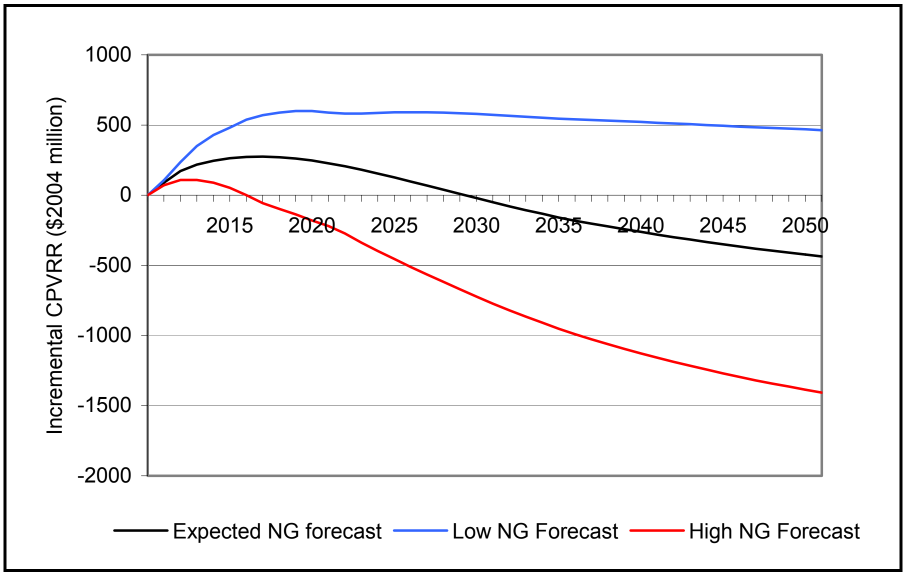
For 2004, Florida's utilities forecasted an aggregate increase of 1,100 MW of coal-fired capacity planned by Seminole Electric Cooperative, Gainesville Regional Utilities, and JEA. Natural gas-fired capacity was projected to increase by over 20,000 MW and make up 51.4% of the region's total energy generated by 2013. Once again, the projected level of natural gas generation was clearly in excess of any BFS in the past. The Commission still believed that as many as three LNG pipelines from the Bahamas would supplement the state's gas supplies. None of the three projects has made significant progress towards commercial operation at this time.

In its 2004 *Ten-Year Site Plan*, in response to concerns raised by the Commission, FPL committed to provide the Commission with a feasibility study for coal-fired alternatives by December 2004. The 2004 hurricane season delayed the filing of the study until March 2005. FPL's *Report on Clean Coal Generation* concluded that coal-fired plants were a viable, cost-effective option for future generation additions beginning in 2012.

FPL also highlighted five areas of uncertainty that could influence the decision to build a coal–fired power plant: fuel price differential, competitive fuel transportation, environmental compliance costs, licensing requirements, and capital costs. These five areas clarify the complexity involved in the generation planning process. If the fuel price differential between natural gas and coal does not materialize, the higher fixed capital costs may saddle ratepayers for 30 to 40 years without any fuel savings. Historically, utilities having rail and barge delivery options for their coal plants have enjoyed lower fuel costs than utilities with a single coal delivery mode. Fuel transportation costs are a large component for solid fuel plants, primarily because of the long distances from the source. If Florida's utilities expect to build more solid fuel-fired plants, infrastructure expansions in rail facilities and shipping ports may be required. For years, environmental costs have increased for all types of generating plants. Coal and nuclear plants in particular have a high societal hurdle to overcome. At the national level, new emission requirements are currently under discussion for substances such as mercury and carbon dioxide. Incremental environmental costs are a risk borne by ratepayers because Florida's investor-owned utilities may recover the costs of incremental environmental requirements through the Environmental Cost Recovery Clause. Because of the societal stigma of coal and nuclear plants, licensing processes may be prolonged which could also increase costs as well as hamper reliability. The lack of construction of new solid fuel plants nationwide adds uncertainty to construction costs. Utilities must consider all these factors before seeking the permitting and construction of a new solid fuel plant. In any event, the goal of a BFS is a long-term, stability-oriented strategy that utilities should pursue.

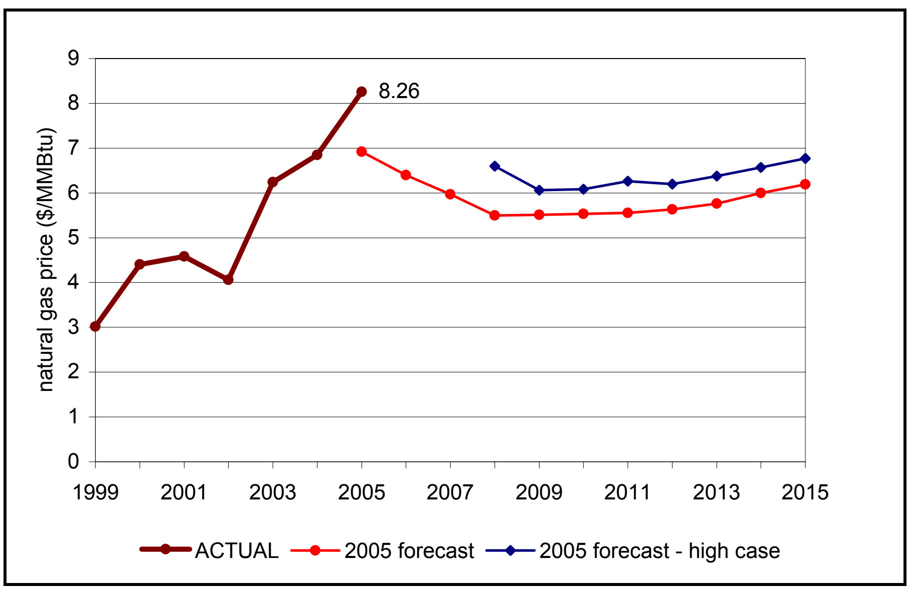
Figure 7, on the next page, is from FPL's *Report on Clean Coal Generation*. The figure shows that fuel savings associated with a coal plant can take many years to offset increased capital cost. The graph suggests that, using FPL's base case fuel price assumptions, a coal-fired plant is projected to produce cumulative net benefits by the year 2029. Using FPL's high natural gas price forecast, cumulative net benefits of coal are forecasted to occur much earlier, in 2016.

Figure 7. FPL - Breakeven Analysis of Solid Fuel and Natural Gas Generating Units



As shown in Figure 8, FPL's high case natural gas forecast remains below actual 2004 natural gas prices throughout the planning horizon. If current natural gas prices continue, the cumulative benefits of a coal unit would occur much sooner.

Figure 8. FPL - Comparison of Actual vs. Forecasted Natural Gas Prices - Base and High Case



Since utilities must decide which type of plant to build several years in advance -- four years for combined cycle, seven years for coal, and 10+ years for nuclear, the risk associated with the selection of generation technology is highly dependent on the accuracy of the long-term fuel price forecast.

Utility Plans for a Balanced Fuel Supply

The outlook for achieving a BFS in Florida appears to be improving. As previously mentioned, Florida's enormous growth requires approximately 17,000 MW of capacity additions over the next ten years, the majority of which is planned to be in-service by 2010. Even before the recent stormy seasons, natural gas prices have steadily climbed higher and higher. The planned additions of solid fuel plants in the later years of the planning horizon will hopefully allow ratepayers to tread water and not be swamped by rising natural gas prices. Unfortunately, the effects of past decisions will continue to impact ratepayers for several years to come. While some utilities have begun to take action to insulate Florida's ratepayers from the effects of rising natural gas prices, the return to a more conservative BFS cannot be made overnight. One of the first efforts to maintain a BFS for Florida was to purchase "coal-by-wire" from the Southern Company. During the early 1980's, both PEF and FPL entered into contracts with the Southern Company, who had an abundance of coal-fired generation resources already constructed. In 2005, both PEF and FPL filed for approval of extensions to these purchased power agreements. The Commission approved both agreements, but the seller restricted the amount of coal-fired capacity available under the contracts. While the existing contracts provide over 1,300 MW of coal capacity, the new contracts, which start in 2010, contain approximately 230 MW of coal capacity. Such a drop in available coal capacity is indicative of how valuable a resource solid-fuel generation has become in recent times, and is a sign that Florida's utilities can no longer rely on their neighbors to satisfy a BFS goal. . In the early 1990's, studies were performed to determine the cost-effectiveness of constructing additional transmission lines that would increase the amount of import capability into the state from the north. However, local opposition to construction and wholesale pricing policies caused these projects to be abandoned. Even if additional transmission could be constructed to the north, it appears that only gas-fired capacity is available for sale. As such, new interstate transmission construction is not likely to contribute towards a BFS and Florida's utilities must seek out self-sustaining solutions to meet the ever growing demand for power.

As part of its 2004 *Ten-Year Site Plan* review comments, the Commission stated, "[B]ased 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." The reporting utilities' 2005 *Ten-Year Site Plans* include seven new coal plants totaling over 4,000 MW of capacity. JEA, GRU, and SEC each propose to build new coal-fired generating units. FPL plans to build two new coal-fired generating units. The Florida Municipal Power Agency, JEA, Reedy Creek, and the City of Tallahassee propose joint ownership in a new coal-fired project and the Orlando Utilities Commission plans to build an integrated coal gasification combined cycle unit. All these coal units have projected in-service dates between 2012 and 2013. More detailed information can be found in each utility's *Ten-Year Site Plan*. SEC expects to file its need determination with the Commission in March 2006. Members of the joint ownership project anticipate filing a need determination with the Commission by April 2006. FPL expects to issue a Request for Proposals for its coal units during the summer of 2006. In addition, PEF has recently announced that it is pursuing two licenses for new nuclear plants with an in-service date as early as 2015. In a recent press release, PEF stated, "We have made it clear that we will keep the option open to build new nuclear generation. Keeping a balanced generation mix ensures reliability and price stability for our customers, and affirms our commitment to the environment." While not a formal part of this year's review, the Commission will closely monitor the progress of the announced nuclear facilities in future *Ten-Year Site Plans*.

Conclusion

The stability of retail rates enjoyed by ratepayers over the past twenty years was due primarily to utilities maintaining a diverse and balanced fuel supply. However, current utility plans indicate a level of dependence on natural gas that is similar to Florida's dependence on oil during the 1970's. Events of the past few years place utility planners, local government officials, and energy policy makers at a critical junction in the road. Historically, natural gas has been plentiful and inexpensive, and forecasts nationwide predicted stable prices and sufficient supplies. However, recent trends indicate an entirely different future in which volatility in price and supply of natural gas appears to be the norm. Utility forecasts of a return to lower natural gas prices have not materialized. While Florida's demand for energy was once believed to be leveling off, per-capita energy use and total demand continue to grow. Conservation, demand-side management, and renewable generation cannot keep pace with Florida's continued explosive growth. Even if new interstate transmission lines could be constructed to the north, it is likely that available purchased power will consist of more gas-fired generation. If Florida continues down the current path of building natural gas-fired generation, then utility fuel costs will continue to experience volatile swings and increased prices.

The return to a BFS approach to generation planning should help mitigate volatile increases in fuel costs that are borne by ratepayers in Florida. Maintaining a diverse fuel supply will also enhance the reliability of the entire electric system in Florida. Until such time, planned gas-fired plants may not be a "given" in future need determination proceedings. Utilities should not blindly continue the addition of natural gas-fired power plants without first critically reviewing their reliability criteria, conservation programs, and renewable generation alternatives. Future need determination proceedings should also explore the proposed site's compatibility for multiple fuel usage, such as the conversion of a gas plant to coal-gasification. Florida's utilities should explore ways to accelerate the certification and construction of solid fuel plants and continue their education efforts with regard to the benefits of a BFS approach to utility planning.

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 2000 and 2004 to energy sales forecasts made three, four, and five years prior. For example, the Commission evaluated actual 2004 energy sales against projected 2004 forecasts made in 1999, 2000, and 2001. From these differences, the Commission calculated 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 shows the historical forecast accuracy of total retail energy sales for the 2003, 2004, and 2005 *Ten-Year Site Plans*. Only nine reporting utilities had sufficient historical data for the Commission to analyze. In general, Florida's utilities have done a better job of forecasting retail energy sales in the last three years. A detailed discussion of individual utility forecasts is included starting on page 41.

Table 3. Total Retail Energy Sales – Historical Forecast Accuracy

UTILITY	AVERAGE FORECAST ERROR (%)	AVERAGE ABSOLUTE FORECAST ERROR (%)
Progress Energy Florida	-0.43	0.69
Florida Power & Light Company	-1.25	1.36
Gulf Power Company	-0.78	1.13
Tampa Electric Company	-0.73	0.73
Gainesville Regional Utilities	-1.00	1.00
JEA	-0.36	1.25
City of Lakeland	1.04	1.04
City of Tallahassee	0.31	0.53
Seminole Electric Cooperative	-0.47	1.46
WEIGHTED AVERAGE (2000-2004) - 2005 TYSP	-0.41	1.02
WEIGHTED AVERAGE (1999-2003) - 2004 TYSP	-0.72	1.40
WEIGHTED AVERAGE (1998-2002) - 2003 TYSP	-1.69	2.26

DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) reduces customer peak demand and energy requirements, resulting in the deferral of need for new generating units. Utilities have offered DSM programs since 1980 due to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). 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 sets numeric conservation goals, and utilities continue to develop and implement DSM programs to meet these goals. The Commission's broad-based authority over electric utility conservation measures and programs is contained in Rules 25-17.001 through 25-17.015, Florida Administrative Code.

Florida's utilities have been successful in meeting the overall objectives of FEECA. As shown in Table 4, utility conservation programs have reduced statewide summer peak demand by 4951 MW, winter peak demand by 5511 MW, and annual energy consumption by 5488 GWh. By 2014, DSM programs are forecasted to reduce summer peak demand by 5563 MW, winter peak demand by 6068 MW, and annual energy consumption by 6883 GWh. Figures 9, 10, and 11, on the next two pages, illustrate the impact of DSM savings on summer peak demand, winter peak demand, and annual energy consumption.

Table 4. State of Florida – Estimated Savings from Electric Utility DSM Programs

DSM Savings	2005	By 2014
Summer Peak Demand	4951 MW	5511 MW
Winter Peak Demand	5563 MW	6068 MW
Annual Energy Consumption	5488 GWh	6883 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)[10], JEA, and OUC.

The Commission set new numeric demand and energy goals for these seven utilities in July 2004. The new numeric goals were generally lower than the previous goals set by the Commission in 1999 for three primary reasons: (1) the Florida Building Code contains increased minimum energy efficiency levels, thus limiting the amount of incremental savings from utility sponsored programs; (2) many utility DSM programs have reached a saturation in participation levels; and (3) the relatively low cost of new generating units has reduced the cost-effectiveness of several DSM programs.

[10] FPUC is a non-generating entity subject to FEECA's requirements due to its status as an investor-owned utility

Figure 9. State of Florida – Impact of DSM on Summer Peak Demand

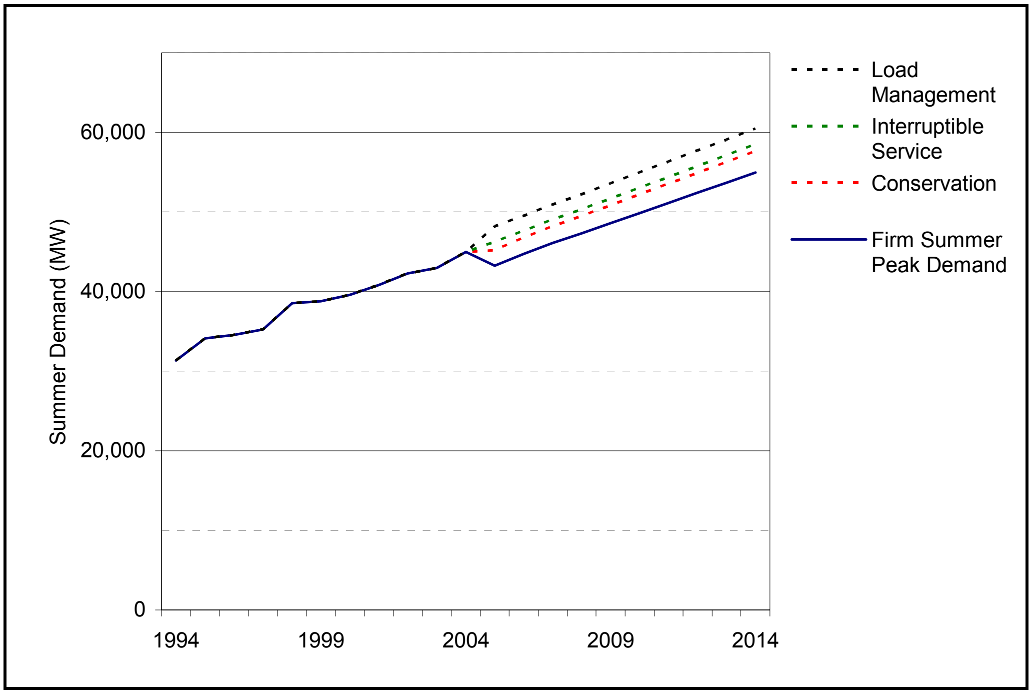


Figure 10. State of Florida – Impact of DSM on Winter Peak Demand

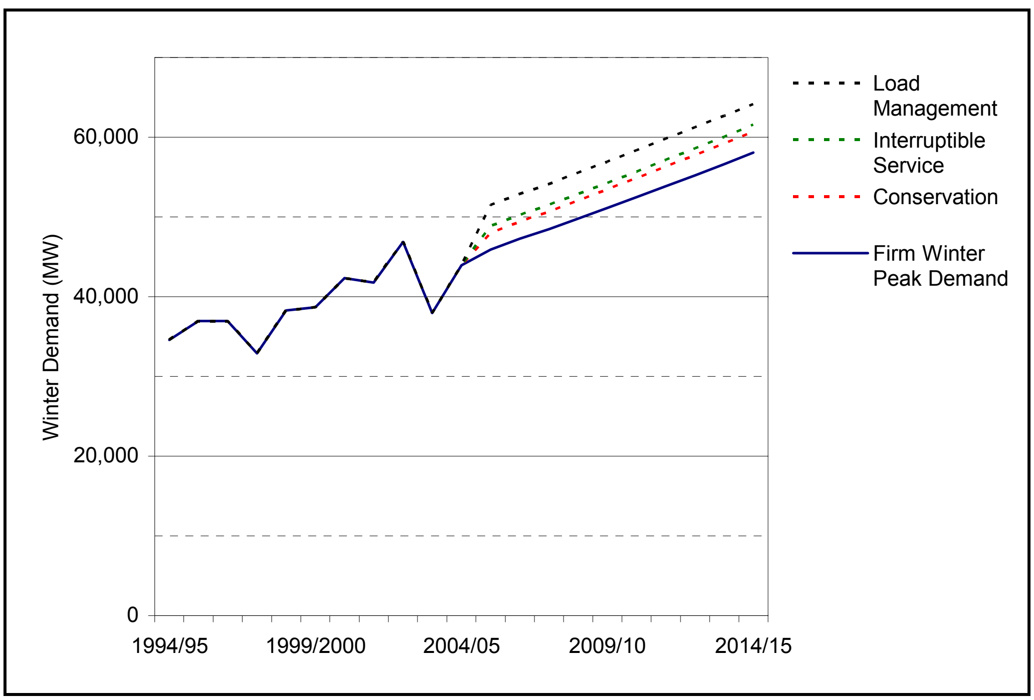
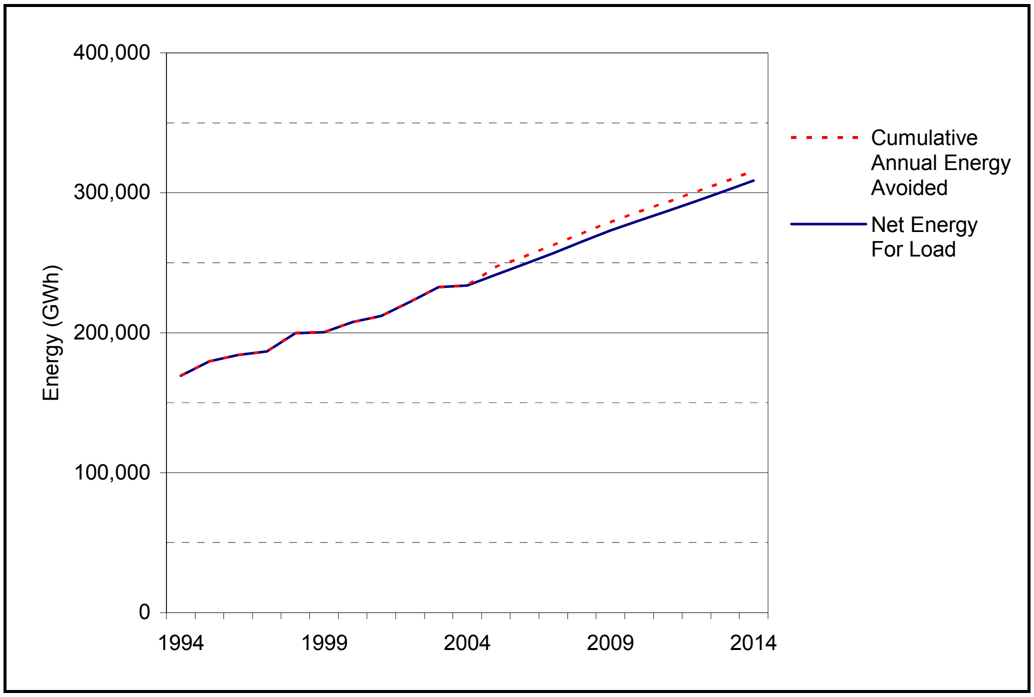


Figure 11. State of Florida – Impact of DSM on Net Energy for Load



As part of their numeric conservation goals filings, PEF, FPUC, JEA, and OUC also filed new DSM plans that the Commission approved in July 2004. The Commission approved DSM plans filed by TECO and Gulf in February 2005 and March 2005, respectively. The Commission originally approved FPL's DSM plan in February 2005; however, the Commission's approval is currently under appeal. The Commission held a hearing in October 2005, and the Commission expects to render a final decision on December 20, 2005.

Energy Conservation Cost Recovery

Investor-owned utilities have the opportunity to recover prudently incurred expenditures associated with Commission-approved DSM programs through the Energy Conservation Cost Recovery Clause (ECCR). Since 1981, Florida's investor-owned utilities have collected approximately $4.15 billion through the ECCR clause, with nearly $2.54 billion of that amount recovered in the last ten years. Annual ECCR expenditures have stabilized at just under $250 million per year over the past six years for two primary reasons: DSM programs have reached saturation in participation levels; and, DSM program cost-effectiveness continues to decline due to the relatively lower cost of new generating units. However, as utility plans include more solid fuel generation options, DSM program cost-effectiveness will improve.

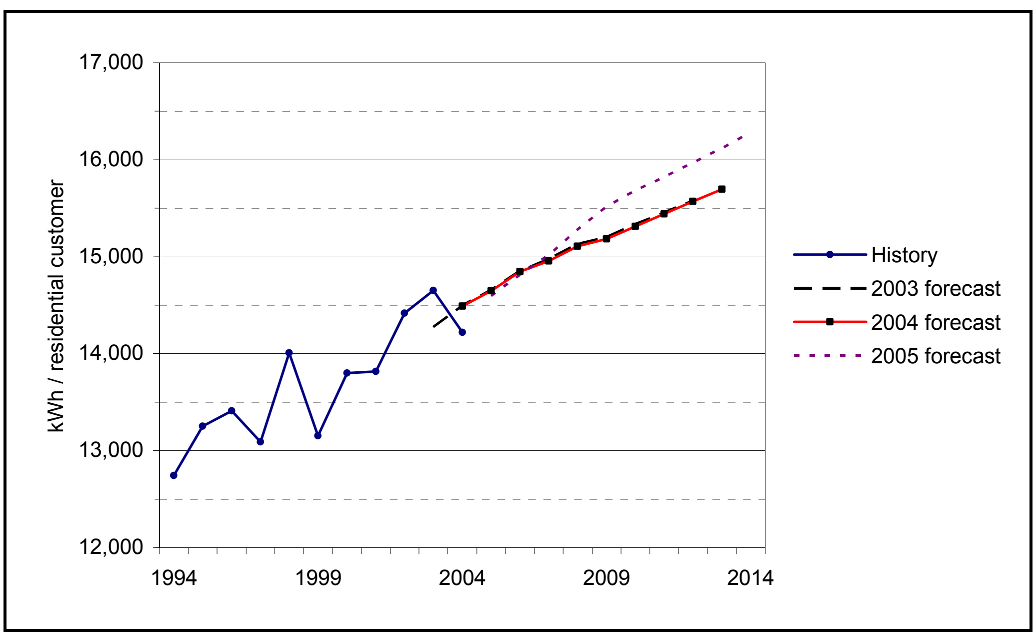
State Comprehensive Plan

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 control the growth of 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 minimize the growth in per-capita energy consumption.

Despite these efforts, residential per-capita energy consumption has consistently risen in the past, and forecasts indicate that this trend will continue over the planning horizon. Past increases in per-capita consumption may be due to the following factors: (1) natural gas, used by many residents nationwide for heating, water heating, and cooking, is still relatively unavailable in parts of Florida; (2) average home size continues to increase over time; and (3) today's homes have more, and larger, electricity-consuming appliances than in past years. In addition, per-capita income has risen since the mid 1980's while electric rates have remained been stable over the same period. When adjusted for inflation, electric rates have actually declined since the mid 1980's. As a result, electricity consumption has been affordable.

Figure 12 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, while forecasted growth is an average of 1.5% per year over the planning horizon. The 2005 forecast of per-capita residential energy consumption is higher than comparable period forecasts made in 2003 and 2004, which were nearly identical. The 2005 forecast increase above past levels is due primarily to FPL, who because of its size has the most impact on statewide forecasts. FPL increased its population growth forecast for 2005 over past years' forecasts. FPL also increased its 2005 per-capita energy consumption forecast over past forecasts for two reasons: increased customer growth in the interior of the state, where the climate is harsher than in coastal areas; and, the growth in non-weather sensitive electrical appliances.

Figure 12. 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 comprised of demand-side[11] and supply-side[12] 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. Forced outages of generating units 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). The typical LOLP planning criterion is 0.1 days per year, meaning 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 forecasted capacity shortfalls. The expected unserved energy (EUE) criterion accounts for both the probability and magnitude of forecasted energy shortfalls. One way to analyze EUE is as a ratio of expected unserved energy to net energy for load (EUE/NEL), and a 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. Table 5, on the next page, illustrates the reliability criteria used by each reporting utility.

Over the past decade, Florida's utilities have placed into service several new, efficient generating units and have enhanced their maintenance practices on older generating units. As a result, the utilities as a whole have seen higher unit availabilities and lower forced outage rates, both of which contribute to relatively small LOLP values. Therefore, reserve margin continues to be the primary criterion driving the need for capacity additions in the state. Due to Commission concerns in the late 1990's over the potential adverse impact of declining reserve margins on reliability, PEF, FPL, and TECO agreed to stipulate to a 20% reserve margin criterion that took effect in 2004. For regional reliability purposes, the FRCC uses a 15% reserve margin criterion. Figure 13, on the next page, shows the forecasted summer and winter reserve margin over the next ten years for Peninsular Florida and statewide.

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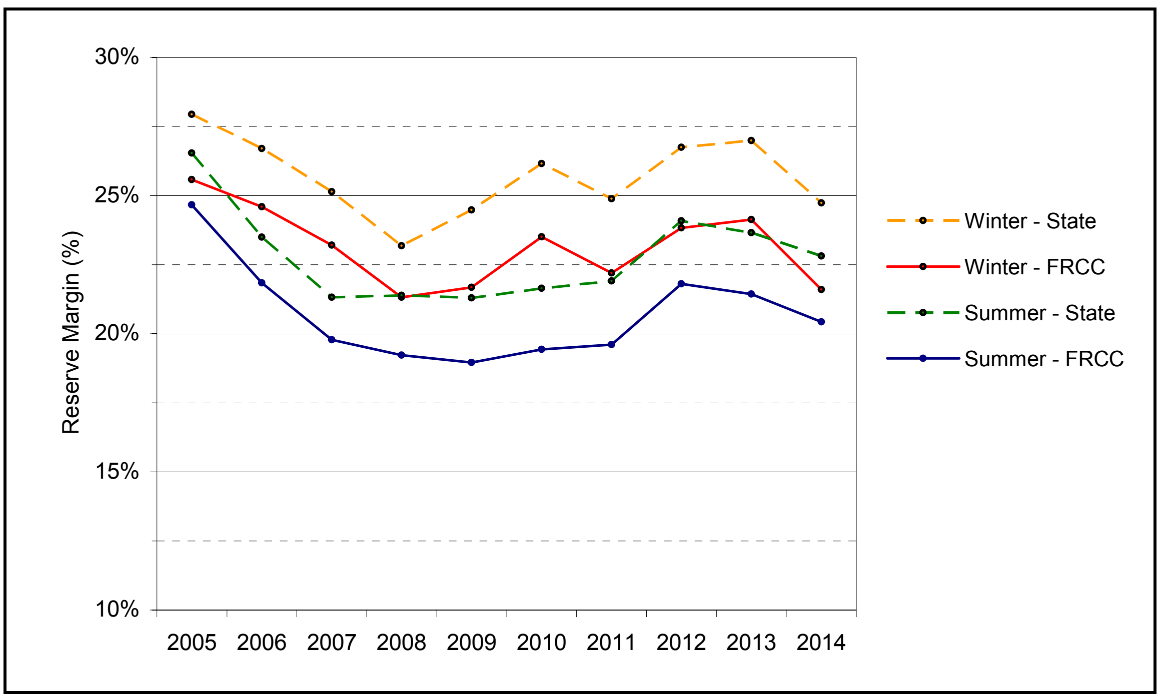
[11] Load management, interruptible service, curtailable service

[12] Owned generation and firm capacity purchases

Table 5. Reliability Criteria

UTILITY	RESERVE MARGIN SUM	RESERVE MARGIN WIN	LOLP (days/year)	EUE/NEL (%)
Progress Energy Florida	20%	20%	0.1	---
Florida Power & Light Company	20%	20%	0.1	---
Gulf Power Company	13.5% [13]	---	---	---
Tampa Electric Company	20% [14]	20%	---	---
Florida Municipal Power Agency	18%	---	---	---
Gainesville Regional Utilities	15%	15%	---	---
JEA	15%	15%	---	---
City of Lakeland	15%	15%	---	---
Orlando Utilities Commission	15%	15%	---	---
City of Tallahassee	17%	---	---	---
Seminole Electric Cooperative	15%	15%	---	1%

Figure 13. Forecasted Reserve Margin



[13] Near-term (1-3 years) criterion. Long-term criterion (2008 and beyond) is 15%.
[14] TECO also utilizes a 7% summer supply-side reserve margin criterion.

Proposed New Independent Power Producer (IPP) Capacity

Currently, there are 28 IPP units in the state with a total winter capacity of approximately 4,870 MW. Approximately 3,450 MW of existing IPP capacity is currently under contract with electric utilities. The vast majority of these contracts, totaling approximately 2,975 MW of capacity, are set to expire over the next ten years.

Two years ago, the FRCC's *2003 Regional Load and Resource Plan* identified proposals for 53 new IPP units totaling nearly 8,100 MW of additional winter capacity. However, in its 2003 *Ten-Year Site Plan* review, the Commission stated its belief that many of these proposed IPP units would not be completed. Only 850 MW of capacity from five new IPP units has entered service since the start of 2003. At this time, there are no proposals to add new IPP units in the state over the planning horizon.

FUEL PRICE FORECAST

Fuel price is the primary factor affecting the type of generating unit added by an electric utility. Generally, the capital cost of a generating unit is inversely proportional to the fuel costs to generate electricity from that unit. For example, a coal-fired or nuclear unit typically has higher capital costs, but lower fuel costs, than a natural gas-fired unit. When the forecasted price difference between coal or nuclear and natural gas is small, a utility is more likely to add a natural gas-fired unit. As the fuel price gap widens, a coal-fired or nuclear unit is the more likely choice.

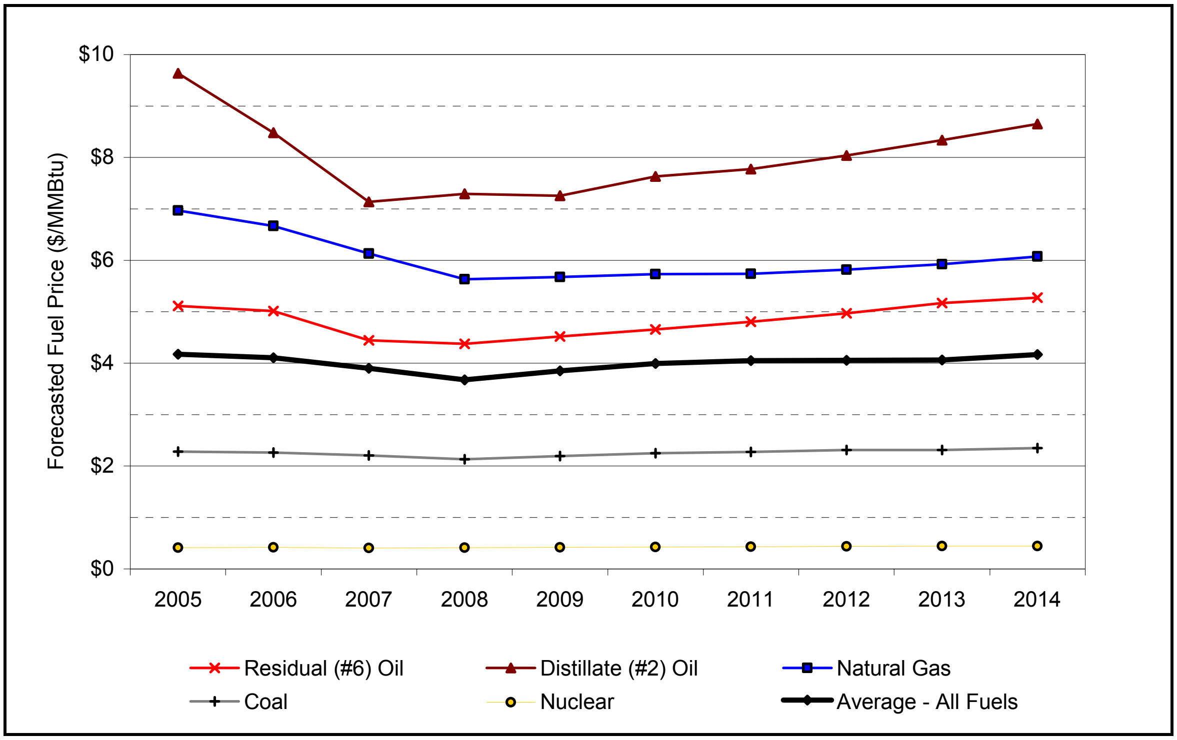
Utilities run the risk of choosing the wrong generating unit addition if they do not contemplate the impact of significant fuel price increases over current levels. Developing nations, such as China, India, South Korea, and Brazil, will increasingly contribute a larger share of worldwide energy use. In 2001, developing nations claimed 35% of worldwide energy consumption. By 2015, this number could approach 40% due to stronger population and economic growth compared to the industrialized nations. As developing nations consume a greater percentage of global energy resources, Florida's utilities will increasingly compete for fuel supplies for electric generation. For example, China has reportedly strengthened its commercial, diplomatic, and military ties around the globe to gain greater access to coal, oil, and natural gas resources. Increased demand will place upward pressure on the world market price for these energy resources. As appropriate and necessary, utilities should monitor and respond to these changes in the world market price for each fuel.

In recent years, the Commission has observed that Florida's electric utilities have projected coal prices to increase at lower rates than natural gas prices. As the difference between natural gas and coal prices increase, utilities will become increasingly likely to build new coal-fired or nuclear units rather than natural gas units to meet incremental load. However, one factor that may limit the amount of new coal-fired generation is the high costs borne by utilities to transport coal from the mine to the generating plant. In part, the Commission can attribute these high costs to the distance between Florida and the coal-producing regions of this country and the world. However, a competitive market for coal transportation and delivery, or lack thereof, may have a direct impact on the costs that utilities incur to produce coal-fired generation.

The Commission evaluated each reporting utility's fuel price forecast 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. On average, the reporting utilities forecast relatively stable nuclear fuel and coal prices over the planning horizon. Nearly all utilities forecast prices for natural gas, residual oil, and distillate oil to decline for the next three years, followed by increases over the remainder of the planning horizon.

Figure 14, on the next page, illustrates the weighted average forecasted fuel price for the eleven reporting utilities. The forecasted price for each fuel type is weighted by energy generation, meaning that utilities that generate large amounts of electricity for a particular fuel type will have more of an influence on the average.

Figure 14. Fuel Price Forecast - Weighted Average for All Reporting Utilities [15]



There is wide disparity in fuel price forecasts between and among the reporting utilities. Utilities that have forecasted a price decline over the next three years believe that current high prices are an aberration and will soon return to historical levels. However, the Commission cannot discount that recent fuel price increases reflect an ever-increasing tension between increasing global demand for all types of fuel and stagnant production levels. Table 6, on the next page, shows the forecasted annual average growth rate (AAGR) in price for each fuel, as forecasted by the reporting utilities and by the EIA, over the near-term (2005-2008) and long-term (2008-2014).

Fuel prices are adversely affected by natural disasters such as hurricanes. Hurricanes Katrina and Rita caused the shutdown of natural gas production in the Gulf of Mexico for several days each. In response to natural gas shortages, Florida's utilities needed to make public appeals for conservation, and the utilities sought environmental waivers allowing them to burn back-up fuels such as light oil.

[15] Based on data as of December 31, 2004.

Table 6. Fuel Price Forecast – Average Annual Growth Rate

UTILITY	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near-term	Long-term	Near-term	Long-term	Near-term	Long-term	Near-term	Long-term	Near-term	Long-term
Progress Energy Florida	-3.2%	1.4%	-7.5%	5.4%	-12.2%	4.4%	-5.7%	1.2%	1.4%	2.0%
Florida Power & Light Company	-3.1%	1.5%	-4.1%	2.5%	-3.6%	5.3%	-7.8%	1.6%	-0.8%	1.1%
Gulf Power Company	-7.8%	0.6%	NA	NA	-5.4%	-0.4%	-7.9%	-0.1%	NA	NA
Tampa Electric Company	-3.5%	3.7%	-6.3%	3.0%	-5.0%	2.9%	-2.1%	-1.1%	NA	NA
Florida Municipal Power Agency	-8.3%	1.9%	-4.0%	0.6%	-4.0%	0.6%	-6.7%	3.2%	2.5%	2.3%
Gainesville Regional Utilities	4.9%	2.1%	-4.9%	2.4%	-4.7%	1.9%	-7.4%	2.3%	0.8%	0.4%
JEA	6.1%	3.1%	-5.4%	1.0%	-5.9%	0.8%	-2.5%	-0.4%	NA	NA
City of Lakeland	0.1%	1.0%	-7.0%	0.2%	-9.5%	-0.5%	-5.6%	-0.1%	NA	NA
Orlando Utilities Commission	5.5%	3.5%	-4.4%	-2.0%	-4.5%	-1.8%	-4.3%	-1.6%	2.3%	2.4%
City of Tallahassee	-11.1%	1.7%	5.3%	0.3%	6.6%	0.6%	-4.1%	-0.8%	NA	NA
Seminole Electric Cooperative	1.4%	2.4%	-2.8%	0.5%	-9.9%	0.5%	-8.5%	-0.7%	-1.6%	0.5%
WEIGHTED AVERAGE	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

Coal

EIA reports that the average U.S. delivered cost of coal to electric utilities in 2004 increased to \$27.15/ton, up \$1.45/ton from 2003. Over the planning horizon, EIA forecasts that delivered coal prices will increase at an average of 2.3% per year in the near-term and 2.4% per year in the long-term. EIA anticipates that coal prices will grow slowly due to moderate growth in coal demand, modest improvements in mining productivity, and an increasing share of low sulfur coal from the Powder River Basin. As shown in Table 6, the reporting utilities forecast an AAGR for coal prices ranging from -11.1% (TAL) to +6.1% (JEA) in the near-term, with a weighted average decrease of -2.3%. Long-term coal prices are forecasted to increase at an average of 1.7% per year, reflecting individual forecasts between +0.6% (Gulf) and +3.7% (TECO).

In 2004, nationwide coal consumption by electric utilities increased by 10 million tons to a record 1,015 million tons, and EIA expects consumption to rise to 1,176 million tons by 2014. Electric utilities drove coal consumption to its record level as coal-fired generation displaced relatively higher priced natural gas-fired generation. U.S. and global coal consumption is projected to increase at an average of 1.6% per year, but coal consumption in developing countries is expected to increase at an average of 2.5% per year. In Florida, electric utilities increased their coal consumption to 29.8 million tons, an increase of 5.4 million tons above 2003 levels. Florida's electric utilities expect to increase coal consumption at an average of 2.8% per year, to 39.1 million tons by 2014.

The Commission compared each investor-owned utility's 2002, 2003, and 2004 coal price forecasts with actual 2004 coal prices. PEF and TECO consistently under-forecasted their coal prices by as much as 15% and 13%, respectively. FPL's coal price forecast error was 2% or less from 2002 through 2004. Gulf's coal price forecast error was as high as 24% and as low as -22%.

The Commission reviewed how each utility encourages and promotes competition within and among coal transportation modes. A utility with a coal-fired generating unit with river or ocean access is in the best position to encourage and promote competition between barge and rail delivery modes. An inland utility who seeks an alternative to rail delivery must off-load the coal from an ocean barge, and then transport the coal by truck 30 to 100 miles over public highways to its coal-fired unit. These additional trucking costs for an inland location can make transportation by barge cost-prohibitive compared with rail delivery. Although utilities which burn large quantities of coal (i.e., investor-owned utilities) can find cost savings by procuring coal transportation separately from the coal itself; however, several municipal utilities indicated that seeking bids for coal at a delivered price can ensure that the utility purchases coal at the best price, regardless of delivery mode.

Residual (#6) Oil

EIA reports that the average U.S. delivered cost of residual oil to electric utilities was $30.68/barrel in 2004, up $0.88/barrel from 2003. Through 2014, EIA forecasts that delivered residual oil prices will increase at an average of 0.5% per year in the near-term and 2.6% in the long-term. As shown in Table 6, the reporting utilities forecast an AAGR for residual oil prices ranging from -7.5% (PEF) to +5.3% (TAL) in the near-term, with a weighted average decrease of -5.1%. Long-term residual oil prices are projected to increase at an average of 3.2% per year, reflecting individual forecasts between -2.0% (OUC) and +5.4% (PEF).

In 2004, nationwide residual oil consumption was 281.8 million barrels, an increase of 26.3 million barrels above 2003 levels. Through 2014, EIA expects residual oil consumption to increase to 306.5 million barrels. In Florida, electric utilities decreased their residual oil consumption in 2004 by 0.5 million barrels below 2003 levels, to 45.0 million barrels. Florida's electric utilities expect to decrease residual oil consumption by an average of -3.3% per year, to 32.0 million barrels by 2014.

The Commission compared each investor-owned utility's 2002, 2003, and 2004 residual oil price forecasts with actual 2004 residual oil prices, except for Gulf which does not burn significant quantities of residual oil. PEF, FPL, and TECO consistently under-forecasted their residual oil prices during this period. However, the forecast error dropped for each utility from 2002 to 2003 and again from 2003 to 2004. The average 2002 forecast error was 50%, but was only 8.6% in 2004.

Distillate (#2) Oil

EIA reports that the average U.S. delivered cost of distillate oil for electric utilities was $48.46/barrel in 2004, up $8.27/barrel from 2003. Through 2014, EIA forecasts that delivered distillate oil prices will decrease at an average of -0.2% per year in the near-term, then increase at an average of 2.0% per year in the long-term. As shown in Table 6, the reporting utilities forecast an AAGR for distillate oil prices ranging from -12.2% (PEF) to +6.6% (TAL) in the near-term, with a weighted average decrease of -8.9%. Long-term distillate oil prices are projected to increase at an average of 2.9% per year, reflecting individual forecasts between -1.8% (OUC) and +5.3% (FPL).

In 2004, nationwide distillate oil consumption was 1,433.4 million barrels, an increase of 55.2 million barrels above 2003 levels. Through 2014, EIA expects distillate oil consumption to increase to 1,822.7 million barrels. In Florida, electric utilities decreased their distillate oil consumption by 500,000 barrels below 2003 levels, to 1.8 million barrels. Florida's electric utilities expect to increase distillate oil consumption by an average of 3.0% per year, to 2.5 million barrels by 2014.

The Commission compared each investor-owned utility's 2002, 2003, and 2004 distillate oil price forecast with actual 2004 distillate oil prices, except for Gulf which does not burn significant quantities of distillate oil. PEF, FPL, and TECO consistently under-forecasted their residual oil prices during this period. For FPL and TECO, forecast errors consistently above 40% and 22%, respectively. Forecast errors for PEF's distillate oil price improved in the same general pattern as for its residual oil price forecasts.

Natural Gas

EIA reports that the average cost of natural gas for U.S. electric utilities was $5.94 per MMBtu in 2004, up $0.57 per MMBtu from 2003 levels. Through 2014, EIA forecasts that delivered natural gas prices will decrease at an average of 1.0% per year in the near-term, then increase at an average of 2.9% per year in the long-term. As shown in Table 6, the reporting utilities forecast an AAGR for natural gas prices ranging from -8.5% (SEC) to -2.1% (TECO) in the near-term, with a weighted average decrease of -6.9%. The reporting utilities project long-term natural gas prices to increase at an average of 1.3% per year, reflecting individual forecasts between -1.6% (OUC) to 3.2% (FMPA).

In 2004, nationwide natural gas consumption by electric utilities increased by 217 billion cubic feet (Bcf) over 2003 levels to 5,352 Bcf. Through 2014, EIA expects natural gas consumption to increase at an average of 1.4% per year, reflecting an expectation that natural gas use in the residential, commercial, non-utility industrial, and transportation sectors will remain relatively constant. Current forecasts indicate that worldwide natural gas consumption will increase at a higher average of 2.2% per year, with developing countries' consumption expected to increase at an even higher average of 2.9% per year. Florida's electric utilities expect to increase their natural gas consumption by 74 Bcf above 2003 levels, to 528.9 Bcf. In Florida, electric utilities expect to increase natural gas consumption by an average of 6.6% per year, to 997.8 Bcf by 2014.

The Commission compared each investor-owned utility's 2002, 2003, and 2004 natural gas price forecast with actual 2004 natural gas prices. Each utility consistently and substantially under-forecasted its natural gas prices by 60% to 100% during this period. Forecast errors did progressively decrease during this period in a manner similar to residual oil price forecasts. The Commission is concerned that the magnitude of natural gas price forecast errors may influence utility choices of future generating units. For example, if a 60% forecast error continues, Gulf's 2007 actual natural gas price may be closer to \$8.56 per MMBtu rather than the forecasted \$5.35 per MMBtu (the lowest 2007 price among the four utilities).

Since 2003, Florida's investor-owned utilities experienced record under-recoveries for fuel costs totaling approximately \$2.4 billion. A fuel cost under-recovery means that a utility's fuel price forecasts made the prior year were lower than actual fuel costs. Hurricanes Katrina and Rita shut down natural gas production in the Gulf of Mexico in 2005. During this time, Florida's utilities needed to make public appeals for conservation, and the utilities sought environmental waivers allowing them to burn back-up fuels such as light oil.

For 2005, the reporting utilities continue to forecast declining natural gas prices over the next three years, with a gradual increase thereafter. Utilities that forecasted a price decline over the next three years believe that current high prices are an aberration. While some utilities have taken action to insulate Florida's ratepayers from the effects of rising natural gas prices, the return to a more conservative BFS cannot be made overnight.

Liquefied Natural Gas

A refrigeration process transforms natural gas to a liquid state at -260°F. This process reduces the natural gas volume by a factor of 610, allowing the transport of liquefied natural gas (LNG) over long distances when pipeline transportation is neither feasible nor economic. Double-hulled ships with custom-designed tanks transport LNG to a receiving terminal to be stored in heavily insulated tanks. A warming process then re-gasifies the LNG, which then enters the pipeline system for distribution and sale to customers as part of their natural gas supply.

LNG may play an increasingly larger role in satisfying the nation's natural gas requirements for electric generation. Domestic production has not kept and will not keep pace with the growing demand for natural gas, and the U.S. has increasingly relied upon imported natural gas to keep supply and demand in balance. Historically, the U.S. has received its imported natural gas from Canada by pipelines, but increased LNG imports have come from Trinidad & Tobago and Algeria. Indonesia, Malaysia, and Qatar are also large LNG suppliers to non-U.S. customers.

Some of Florida's utilities have evaluated the potential to use LNG for their generating units. One proposed pipeline will deliver LNG from an existing facility at Elba Island, Georgia to a point near Jacksonville. PEF plans to use LNG delivered from the proposed pipeline. Three gas pipeline companies have proposed new pipelines between the Bahamas and south Florida and have received FERC approval. All three companies have incurred delays, as their projects must first receive approval from the Bahamian government before construction can begin.

Unlike domestic or Canadian natural gas, LNG may expose a utility and its ratepayers to unfamiliar risks such as catastrophic events or host country risk. The Commission will closely monitor to ensure that a utility entering into a long-term LNG agreement acts reasonably and prudently to protect itself and its ratepayers from unduly excessive risks and costs.

As a sensitivity test, EIA has analyzed the impact on natural gas prices if supplies are restricted long-term for the following reasons: no Alaskan natural gas pipeline prior to 2025; no new LNG regasification terminals built in the U.S.; and slower than expected growth in drilling technology. Under these assumptions, EIA forecasts that by 2015, delivered natural gas wellhead prices will be 17% higher than the base forecast. As a result, natural gas consumption will likely grow more slowly as utilities dispatch natural gas-fired units later in their dispatch queue and move to site new generating units that do not burn natural gas. EIA estimates that these higher wellhead natural gas prices would increase rates for electric service nationwide from 3%-5% during the planning horizon.

Nuclear

EIA assumes that nationwide nuclear capacity will increase slightly during the planning horizon, as the retirement of some nuclear units will 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 cents/KWh fee on nuclear generation to finance the management and disposal of spent nuclear fuel. Nationwide, ratepayers pay nearly $600 million annually 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, the 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 the DOE does not remove spent nuclear fuel from on-site storage facilities, as many as 80% of the utilities' spent fuel pools could 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. A coal-fired unit consumes more water than does a gas-fired unit of comparable size, a concern in Florida where water supplies may have an uncertain future. Further, coal-capable sites that provide sufficient land area and access to coal delivery are in short supply. Uncertainty over future changes to environmental requirements, as well as emissions control technologies, could discourage construction of coal units in the future. Concerns over high construction costs and uncertainty over spent fuel disposal could also hinder future development of nuclear units.

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. Oil price increases adversely affected these plants, and Florida's utilities began to look to other fuel types 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 30% to over 44% of total energy consumed, during the planning horizon. With the state's reliance on natural gas approaching the levels of its reliance on oil in the 70's, and with the price of natural gas expected to remain at relatively high levels throughout the planning horizon, Florida's utilities should once again evaluate the benefits of maintaining a balanced fuel supply (BFS). 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. Additionally, nuclear units may once again become a viable option to Florida's utilities because of minimal emissions and low fuel costs.

Figures 15 and 16, on the next page, illustrate the past, current, and future generation mix by fuel type for Florida's electric utilities.

Figure 15. State of Florida – Energy Generation by Fuel Type (GWh) [16]

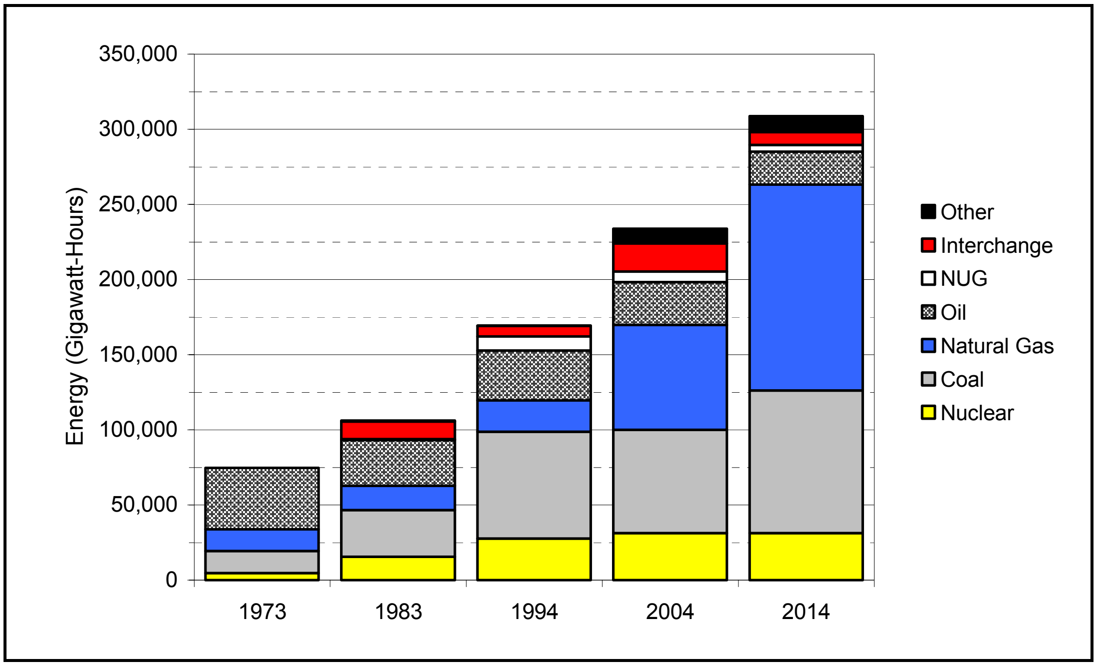
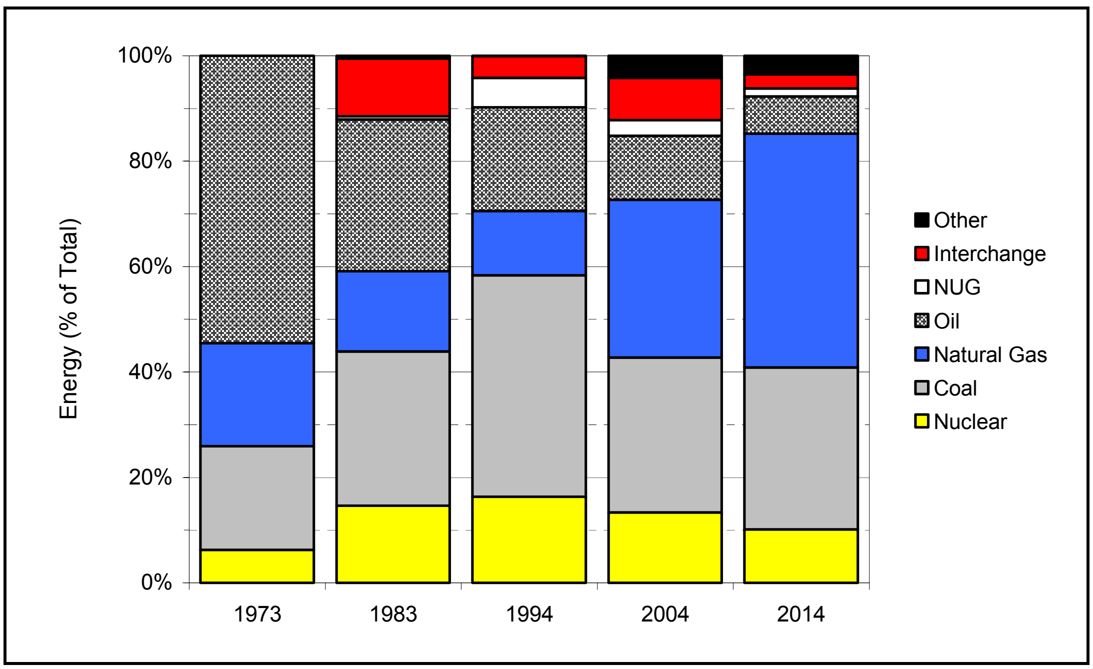


Figure 16. State of Florida – Energy Generation by Fuel Type (Percentage of Total)



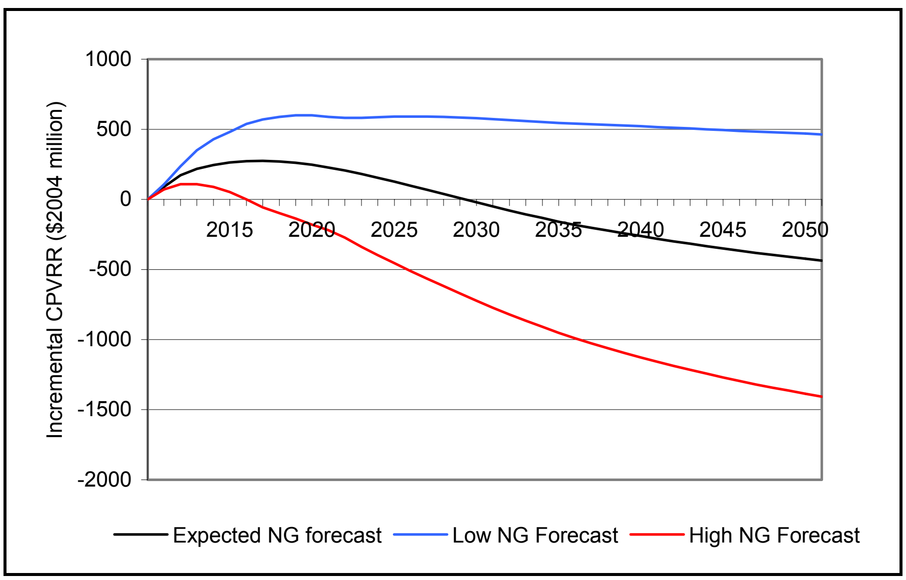
[16] The "Other" fuel type category includes petroleum coke and coal gasification.

Economics

Over the past decades, gas-fired generating units have typically been a more cost-effective alternative to coal-fired units. Higher thermal efficiency, lower capital costs, and smaller permitting and construction times are the primary reasons. New gas-fired combined cycle (CC) units achieve heat rates near 7,600 Btu/KWh compared to 10,000 Btu/KWh for new coal-fired units. Further, gas-fired CC units have capital costs of approximately $500/KW versus $1,500/KW for coal, making these units cheaper to construct. Finally, permitting and construction of new CC units takes approximately three years, versus the seven or more years required for coal-fired units. Given these advantages, gas-fired capacity has contributed nearly 92% of all new capacity constructed in the state over the last ten years. Despite forecasted fuel prices, forecasts indicate that natural gas-fired units will comprise 96% of all planned generating capacity additions in the state 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 price difference between the two fuels widens, the break-even period decreases. In other words, as natural gas prices increase to higher levels at a faster rate than the price of coal, the number of years required fuel savings to outweigh the higher upfront cost of coal-fired generation decreases. Figure 17, from FPL's *Report on Clean Coal Generation*, illustrates this phenomenon.

Figure 17. FPL - Breakeven Analysis of Solid Fuel and Natural Gas 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, which has enabled Florida's utilities to purchase firm capacity and economy energy from coal-fired resources owned by the Southern Company. PEF and FPL recently received Commission approval to extend their long-term interchange contracts with the Southern Company from 2010 to 2015. While the existing contracts provide over 1,300 MW of coal capacity, the new contracts contain approximately 230 MW of coal capacity. Such a drop in available coal capacity is indicative of how valuable a resource solid-fuel generation has become in recent times, and is a sign that Florida's utilities can no longer rely on their neighbors to satisfy a BFS goal.

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, highly efficient, 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. Integrated coal gasification combined cycle (IGCC) is one type of advanced coal technology developed in part due the CCT Program. IGCC technology may provide utilities the flexibility to meet potential environmental restrictions and address concerns with the high initial capital investment. IGCC units have higher thermal efficiencies and fewer emissions than traditional coal-fired units do. However, IGCC technology has higher capital costs and limitations on unit size such that the technology might not be an appropriate option for every utility.

Three IGCC units have been built in the U.S. to date, and a fourth unit is set to enter service by 2008. All four units were demonstration projects partially funded under the CCT Program. One of these projects was Tampa Electric Company's Polk Unit 1, a 260 MW IGCC unit that entered commercial service in 1996. Orlando Utilities Commission and the Southern Company announced a joint project to develop an IGCC unit at OUC's Stanton site under the CCT Program. The proposed unit is forecasted to enter commercial service in 2011. OUC's share of the unit is 311 MW.

IGCC units may be built in stages, with the combined cycle portion of the plant 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 CC 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

To minimize price and supply volatility, electric utilities must rely on a BFS in planning future generating units. According to the utilities' *Ten-Year Site Plans*, natural gas will play an even more dominant role in electric power generation in Florida over the next five to seven years. As a result, Florida's utilities should evaluate potential sites for coal capability. To lessen the capital cost impact of building coal-fired and nuclear 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, and four municipal utilities have proposed a joint project to construct a new coal-fired unit during the planning horizon. Joint ownership makes sense because the typical size of coal units is much greater than the capacity need of a single municipal utility.

Utilities should also investigate the possibility of receiving financial assistance through the DOE's CCT Program. TECO's Polk Unit 1, an IGCC unit built using DOE funding, has been in operation for nearly a decade. OUC and the Southern Company have proposed to build an IGCC unit at the Stanton site using DOE funding. As emerging research and development in coal-fired generation reduces high capital costs, emissions, permitting lead times, and investment risk, coal may once again play a critical role in electric power generation in Florida.

Over the past couple of years, natural gas prices have increased substantially over prior levels. As natural gas sustains these higher prices, utilities will increasingly look to coal-fired options. This year, as listed in Table 2, several utilities included coal-fired generation in their *Ten-Year Site Plans*.

Natural Gas

Florida's utilities continue to project a substantial increase in natural gas-fired generation. Natural gas-fired generation, currently at 29.9% of total statewide energy consumption, is expected to increase substantially to 44.4% over the next ten years. Of the approximately 19,100 MW in gross capacity additions [17] projected in the state over the planning horizon, nearly 15,300 MW will 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, many utilities still use oil in peaking CT units, both as a primary and a secondary fuel. Due to escalating natural gas prices, utilities have recently burned oil more frequently in baseload and intermediate CC units for economic reasons. In addition, recent experience with Hurricanes Katrina and Rita illustrate the need for electric utilities to have oil available as a backup fuel when interruptions to natural gas supplies occur. Nonetheless, forecasts indicate that oil-fired energy will decrease from 12.2% to 7.0% of total statewide energy production over the next ten years.

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. Just last year, the state's utilities forecasted increases in coal-fired capacity of approximately 1,100 MW. This year's forecasts reflect an expected increase of 3,786 MW over the next ten years, reflecting an increase from 29.4% to 30.7% of total statewide energy production.

Nuclear

Nuclear generation increased considerably during the 1970's and early 1980's. Nuclear plants were built based on low fuel price forecasts relative to oil or natural gas. However, nuclear plants are capital-intensive, take as much as ten years to certify and build, and bring persistent concerns surrounding the storage and disposal of spent fuel rods. No new nuclear plants have entered service in Florida since

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[17] Gross additions exclude capacity decreases due to unit derating, retirement, or contracts terminating.

1983. While no utility's Ten-Year Site Plan contains any proposed nuclear units, PEF recently announced its intention to pursue a new nuclear generating unit in Florida within 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 3,600 MW over the Southern Company-Florida interconnection. Approximately 2,500 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 1,100 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 8.0% to 2.7% of statewide energy consumption. The forecasted decrease is due primarily to the expected increase in native generation in the state during the planning horizon. PEF and FPL recently received Commission approval to extend their long-term interchange contracts with the Southern Company from 2010 to 2015. The contracts did not receive final approval until after publication of this year's *Ten-Year Site Plans*. Therefore, the capacity and energy from the contracts is expected to maintain the current level of interchange energy entering Peninsular Florida from the Southern Company. While the existing contracts with the Southern Company provide over 1,300 MW of coal capacity, the seller restricted the amount of coal-fired capacity available under the contracts to approximately 230 MW.

The transfer capability from the Southern Company into Peninsular Florida is expected to remain at approximately 3,600 MW. As a result, some capacity and energy from the Southern Company, primarily from natural gas-fired units, should 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. Forecasts indicate that the amount of NUG electricity purchased by Florida's utilities will decrease from 3.0% to 1.5% of statewide energy consumption during the planning horizon. The forecasted decrease is due to the expiration of 377 MW of firm purchase contracts with qualifying facilities and 339 MW of firm purchase contracts with renewable sources (see below). However, once the current contracts expire, these generators will remain in place in Florida and should remain 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 sites, one utility-owned and one operated by the Federal government, 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 2.5 MW of capacity to GRU and JEA. Florida's utilities purchase 506 MW of non-utility generator capacity fired by municipal solid waste, wood and wood waste, and waste heat. However, the scheduled expiration of contracts during the planning horizon will reduce the amount of firm renewable capacity to 167 MW by 2014, a decrease of 339 MW.

STATUS OF NEED DETERMINATIONS AND SITE CERTIFICATIONS

The Commission has granted a Determination of Need for several generating units and two transmission lines 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 not yet entered commercial service.

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 December 2005.

FPL – Turkey Point Unit 5

In June 2004, the Commission granted FPL's petition to build a 1,181 MW gas-fired CC unit at the existing Turkey Point site in Dade County. Turkey Point Unit 5 was certified under the Power Plant Siting Act in February 2005 and is expected to enter service in June 2007.

PEF -- Hines Unit 4

In November 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 was certified under the Power Plant Siting Act in June 2005 and is expected to enter service in December 2007.

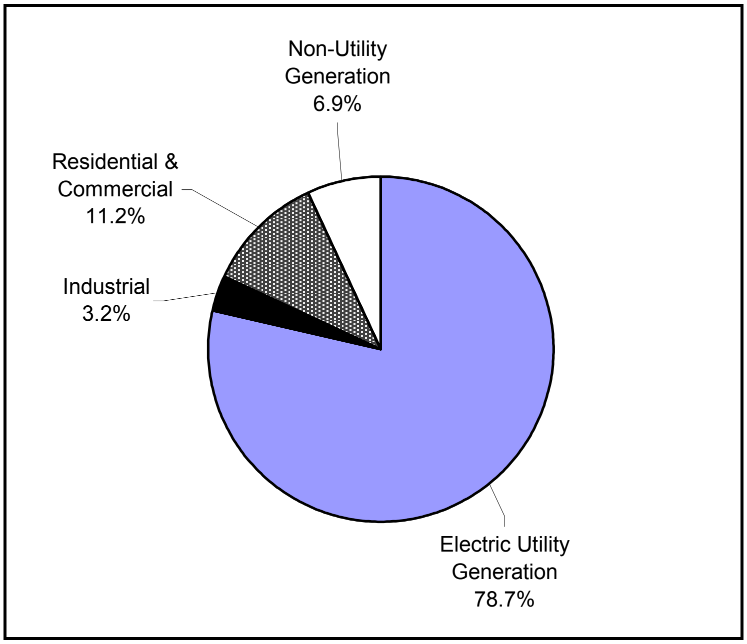
FPL – St. Johns-Pellicer-Pringle 230 kV line

In May 2005, the Commission granted FPL's petition to build a 230 kV transmission line in a new corridor starting at the existing St. Johns substation in St. Johns County, continuing through the proposed Pellicer substation in St. Johns County, and terminating at the proposed Pringle substation in Flagler County. The 25-mile line is expected to enter service in December 2008 and is awaiting certification under the Transmission Line 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 (over 85%) is for electricity generation, both by utilities and non-utility generators. Figure 18 shows a breakdown of natural gas consumption by end-user.

Figure 18. Natural Gas Consumption by End-User -- 2004



Forecasts indicate that electric utility generation will cause 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 affect 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 focus future analyses. The FRCC task force stated 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 expansion of gas pipelines.

Based on the forecasted requirements of electric utilities and other sectors, the Commission estimates that total pipeline demand will require an average of 3.15 Bcf/day by 2014. Given the current pipeline capacity of FGT and Gulfstream, it would appear that, at a minimum, sufficient capacity currently exists to serve forecasted 2014 requirements. However, the Commission's estimate could be understated because it relies on average daily demand rather than on maximum delivery levels specified in gas transportation contracts. Since the Commission does not have jurisdiction over interstate pipelines, the Commission does not have the authority to require interstate pipeline companies to submit their contracts for review. Because the Commission's estimate does not incorporate any additional capacity that might be necessary during peak demand periods, the forecast may be understated.

Because the 2014 forecasted pipeline capacity requirement, based on the average demand, might understate gas capacity need, the Commission also conducted a forecast based on the projected peak demand for gas capacity. Based on this methodology, the Commission estimates that by 2014, incremental pipeline capacity requirements could increase up to 1.34 Bcf/day.

FGT

FGT operates 5,000 miles of pipeline nationwide, 3,300 miles of which are in Florida. Six expansions have occurred since its inception in 1959, which have increased the pipeline's capacity from its original 0.278 Bcf/day to its current 2.2 Bcf/day. In October 2005, FGT filed an application with the FERC seeking authority to construct its Phase VII Expansion Project. This project involves the construction of 33 miles of 36-inch diameter pipeline looping and the installation of 9,800 horsepower of compression. The expansion will provide approximately 0.16 Bcf/day of additional capacity to transport natural gas from a connection with Southern Natural Gas Company's proposed Cypress Pipeline project described below.

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. In February 2005, Phase II, a 110-mile extension to Florida's east coast, recently entered service to serve FPL's gas-fired generating units at the Martin and Manatee plant sites.

Cypress

Southern Natural Gas (SNG) has proposed to expand its existing interstate natural gas pipeline system between Port Wentworth, Georgia and an interconnection with FGT's System near Jacksonville. Project construction will occur in three phases. Phase I includes the initial pipeline of 165 miles of 24-inch diameter pipe. Phase II and III will consists of additional compression and looping. The source of natural gas will be SNG's Elba Island LNG facility near Savannah, Georgia. The Cypress pipeline will have the ability to flow gas between Florida and Georgia in both directions. In addition, the pipeline will provide the state of Florida with a new, geographically diverse source of gas that will help mitigate supply disruptions caused by natural disasters such as hurricanes. In 2005, the Commission approved PEF's long-term contract to purchase gas supply on the Cypress pipeline. Phase I of the pipeline is expected to be in service in 2007, with Phase II and III becoming operational in 2009 and 2010, respectively.

Bahamas Projects

Three companies have proposed pipeline projects to transport LNG from the Bahamas to Florida. Two of the projects, the Tractabel Calypso Project and the AES Ocean Express Project, have received FERC approval, granting both projects a Presidential Permit to construct. The third project, the El Paso Seafarer Pipeline System, filed its certificate application with the FERC in November 2004. Seafarer's application is pending before the FERC. These projects must first receive approval from the Bahamian government before construction can begin

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 PEF has accurately documented all of these factors. 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 are 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 2.78% per year over the 2005-2014 planning horizon, which is greater than the -0.26% AAGR for the 1995-2004 period. Excluding consideration of the mild winter of 2004, the 1995-2003 period saw winter peak demand actually increasing at an average of 3.09% per year. Over the next ten years, summer peak demand is forecasted to increase at an average of 2.90% per year, which is slightly less than the historic AAGR of 2.93%. 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 2005 and 2014.

PEF's 2000-2004 retail sales forecasts have an absolute forecast error of 0.69%, which is lower than the 1.02% average for the reporting utilities. Over the same period, PEF's retail sales forecasts have an average forecast error of -0.43%, 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 Building Code related to energy efficiency for building construction took effect this year, resulting in increased minimum energy efficiency levels. These new requirements may reduce the 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.

The Commission approved PEF's new DSM Plan 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. PEF minimally modified the remaining four programs to ensure cost-effectiveness.

Reliability Criteria

PEF's primary reliability criterion is reserve margin, and PEF has historically been a winter-peaking utility. Pursuant to stipulation, PEF utilizes a 20% reserve margin criterion for both summer and winter peak demand. 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 2005-2014, PEF provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated PEF's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 7 illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 7. PEF - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
PEF - 2005	-3.2%	1.4%	-7.5%	5.4%	-12.2%	4.4%	-5.7%	1.2%	1.4%	2.0%
PEF - 2004	1.1%	1.6%	-3.7%	2.6%	-4.6%	2.5%	-7.4%	0.8%	1.2%	1.7%
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, PEF expects its coal price will be \$2.81 per MMBtu, while EIA forecasts coal to be \$1.64 per MMBtu. PEF expects its residual oil price will be \$6.02 per MMBtu by 2014, with EIA forecasting residual oil to be \$5.75 per MMBtu. PEF expects its distillate oil price will be \$8.80 per MMBtu by 2014, compared to EIA's forecast of \$7.20 per MMBtu. By 2014, PEF expects its natural gas price will be \$6.49 per MMBtu, while EIA forecasts natural gas prices will be \$6.28 per MMBtu. PEF expects its nuclear energy price will be \$0.41 per MMBtu by 2014, while EIA does not provide a price forecast for nuclear energy.

Generation Selection

PEF's system winter capacity is currently 10,666 MW. Of this total, 9,174 MW comes from PEF-owned generation. Firm capacity purchases account for 672 MW, while the remaining 820 MW comes from non-utility generators. Table 8, on the next page, shows PEF's winter capacity by fuel type.

All of PEF's proposed generating additions are natural gas-fired combined cycle units, with Hines Unit 3 (582 MW) to enter service by the end of this year, Unit 4 (517 MW) in 2007, Unit 5 (548 MW) in 2009, and Unit 6 (548 MW) in 2010. PEF plans to add three new 548 MW CC units at undetermined sites, one each in 2012, 2013, and 2014. The current plan includes a capacity reduction of 318 MW from the expiration of cogeneration contracts. Firm capacity imports are forecasted to drop to increase by 398 MW. PEF does not forecast any capacity additions from nuclear, coal, or fossil steam generating units.

Table 8. PEF – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Nuclear	788	0
Coal	2,341	0
Firm Imports	672	398
Non-Utility Generation	820	-318
Combined Cycle	1,334	3,839
Fossil Steam	1,642	0
Combustion Turbine	3,069	0
TOTAL	10,666	3,919

State, Regional, and Local Agency Comments

Central Florida Regional Planning Council – Provided general comments on PEF's plans for transmission system additions.

Department of Environmental Protection – PEF's *Ten-Year Site Plan* is adequate for planning purposes.

East Central Florida Regional Planning Council -- PEF's proposed projects appear to be suitable.

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

Southwest Florida Water management District – 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, such as Anclote and Bartow, are also expected to use 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 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 using demographic trends, weather data, 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 FPL has been accurately documented these factors, and that FPL's data sources are credible.

Under base-case assumptions, FPL forecasts that summer firm demand will increase at an average of 2.25% per year, which is lower than the historic AAGR of 2.54%. For the 2005-2014 planning horizon, FPL's base-case winter firm demand is forecasted to grow at an average of 4.03% per year, which is lower than the 5.23% AAGR for the 1995-2004 period.

FPL's 2000-2004 retail sales forecasts have an absolute percent error of 1.36%, which is higher than the 1.02% average for the reporting utilities. For the same five-year period, FPL's retail sales forecasts have an average forecast error of -1.25%, which reflects a tendency to under-forecast.

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 Building Code related to energy efficiency for building construction took effect this year, resulting in increased minimum energy efficiency levels. These new requirements may reduce the potential demand and energy savings attributable to FPL's DSM programs.

FPL submitted a new DSM Plan that was approved by the Commission in February 2005. However, the Commission's decision has been appealed, and the Commission held a hearing in October 2005. The Commission expects to make a final decision in December 2005. 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, winter peak demands are a primary concern to utilities in Florida, and FPL forecasts that its winter peak demand will be slightly higher than summer peak during the planning horizon. Pursuant to stipulation, FPL utilizes a 20% reserve margin criterion for both summer and winter peak demand. 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.

Fuel Forecast

For the period 2005-2014, FPL provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated FPL's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 9 illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 9. FPL - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
FPL - 2005	-3.1%	1.5%	-4.1%	2.5%	-3.6%	5.3%	-7.8%	1.6%	-0.8%	1.1%
FPL - 2004	-1.4%	0.4%	-3.2%	3.1%	-1.9%	3.0%	-0.9%	2.2%	0.6%	0.9%
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, FPL expects its coal price will be $1.81 per MMBtu, while EIA forecasts coal to be $1.64 per MMBtu. FPL expects its residual oil price will be $5.08 per MMBtu by 2014, with EIA forecasting residual oil to be $5.75 per MMBtu. FPL expects its distillate oil price will be $8.75 per MMBtu by 2014, compared to EIA's forecast of $7.20 per MMBtu. By 2014, FPL expects its natural gas price will be $5.67 per MMBtu, while EIA forecasts natural gas prices will be $6.28 per MMBtu. FPL expects its nuclear energy price will be $0.44 per MMBtu by 2014, while EIA does not provide a price forecast for nuclear energy.

Generation Selection

FPL has a system winter capacity of 23,357 MW. Of this total, 20,158 MW comes from FPL-owned generation. FPL purchases 2,329 MW of firm capacity from the Southern Company (931 MW), part of JEA's share of the jointly owned St. Johns River Power Park (390 MW), and other entities (1,164). Purchases from non-utility generators comprise the remaining 870 MW. Table 10, on the next page, shows FPL's winter capacity by fuel type.

FPL's planned additions include the Martin Unit 8 CC conversion (835 MW) and Manatee Unit 3 (1,197 MW). These two units entered commercial service this year. FPL plans to add three additional 1,200 MW class CC units: Turkey Point Unit 5 in 2007; and, two units at the new West County Energy

Center in Palm Beach County, one each in 2009 and 2010. FPL also plans to add two new supercritical pulverized coal-fired units, at a new site in St. Lucie County, to enter service in 2012 and 2013. FPL forecasts minimal decreases in fossil steam and combustion turbine capacity at existing units.

FPL forecasts a decrease of 275 MW from non-utility generators within the planning horizon, due to the expiration of cogeneration contracts. Firm capacity imports are expected to decrease by 1,009 MW by 2014. FPL's capacity imports (1,320 MW) remaining at the end of the planning horizon are scheduled to come from extension of the purchased power agreements with the Southern Company (930 MW) and continuation of the St. Johns River Power Park purchase from JEA (390 MW)..

Table 10. FPL – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Nuclear	3,013	0
Coal	884	1,752
Firm Imports	2,329	-1,009
Non-Utility Generation	870	-275
Combined Cycle	6,192	5,677
Fossil Steam	7,019	73
Combustion Turbine	3,050	21
TOTAL	23,357	6,239

State, Regional, and Local Agency Comments

Central Florida Regional Planning Council – Provided general comments regarding potential water requirements for coal generation technologies that could be built at the Desoto plant site.

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

East Central Florida Regional Planning Council -- FPL's proposed projects appear to be suitable.

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

South Florida Regional Planning Council --The *Ten-Year Site Plan* is generally compatible with the goals and policies of the region's Strategic Regional Policy Plan.

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 that the recently completed Manatee unit incorporates water conservation efforts and uses water sources other than groundwater.

St. Johns River Water Management District -- Provided general comments regarding the potential use of the existing Cape Canaveral site for future plant additions.

Tampa Bay Regional Planning Council -- FPL's proposed plant additions 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. Gulf bases its short-term forecasts a variety of forecasting methods. Customer growth estimates result from the compilation of 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 uses the economic outlook website economy.com for its projections. Gulf did not perform low- and high-band forecasts.

Under Gulf's base-case assumptions, summer firm demand for the 2005-2014 period is expected to increase at an average of 1.89% per year, which is slightly less than the 1.92% AAGR for the 1995-2004 period. Base-case winter firm demand is forecasted to grow at an average of 1.65% per year, which is higher than the historical -0.07% AAGR for the 1995-2004 period.

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 Building Code related to energy efficiency for building construction took effect this year, resulting in increased minimum energy efficiency levels. These new requirements may reduce the potential demand and energy savings attributable to Gulf's DSM programs. Additionally, Gulf forecasts decreased savings from interruptible service.

Gulf submitted a new DSM Plan that was approved by the Commission in March 2005. Gulf's DSM plan contains seven DSM programs and four types of audits.

Intercompany Interchange Contract

The Southern Company performs integrated planning and system operations, including unit dispatch, for Gulf and other members. In this manner, each member utility benefits from the economies of scale associated with a large generating 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 provide surplus capacity and energy into a reserves pool, which other members use when they experience 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 expects to continue its reliance on the IIC for shared reserves throughout the planning horizon.

Reliability Criteria

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

As an individual utility, Gulf forecasts that its capacity resources will be insufficient to meet the Southern Company's summer reserve margin criterion in all years of the planning horizon, in amounts ranging from 31 MW to 354 MW. Forecasts indicate that the winter reserve margin criterion will be violated in two years: 2007/08 (85 MW) and 2008/09 (131 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 2005-2014, Gulf provided price forecasts for coal, distillate oil, and natural gas. The Commission evaluated Gulf's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 11 illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 11. Gulf - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
Gulf - 2005	-7.8%	0.6%	NA	NA	-5.4%	-0.4%	-7.9%	-0.1%	NA	NA
Gulf - 2004	-2.6%	-0.5%	NA	NA	-3.0%	-0.6%	-5.9%	-1.2%	NA	NA
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, Gulf expects its coal price will be \$1.64 per MMBtu, while EIA also forecasts coal to be \$1.64 per MMBtu. Gulf expects its distillate oil price will be \$6.30 per MMBtu by 2014, compared to EIA's forecast of \$7.20 per MMBtu. By 2014, Gulf expects its natural gas price will be \$4.97 per MMBtu, while EIA forecasts natural gas prices will be \$6.28 per MMBtu.

Generation Selection

Gulf has a system winter capacity of 2,636 MW. Gulf owns 2,828 MW of capacity and purchases 19 MW from a non-utility generator. Gulf currently does not purchase any additional capacity but exports 211 MW of firm capacity to other utilities. Table 12, on the next page, shows Gulf's winter capacity by fuel type.

Gulf plans to add approximately 600 MW of net capacity during the planning horizon. Two new 166 MW gas-fired CT units are planned for a yet-to-be determined site in 2012. Firm imports are expected to increase by 470 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. The 19 MW contract for non-utility generator capacity expired this year. Gulf also forecasts minimal decreases in generating capacity at existing coal and combined cycle units.

Table 12. Gulf – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Coal	2,131	-116
Firm Imports	0	470
Firm Exports	-211	0
Non-Utility Generation	19	-19
Combined Cycle	584	-10
Fossil Steam	59	-59
Combustion Turbine	54	332
TOTAL	2,636	598

State, Regional, and Local Agency Comments

Apalachee Regional Planning Council – Has concerns about groundwater consumption and air pollution resulting from potential additions at the Scholz site.

Department of Environmental Protection – Gulf's *Ten-Year Site Plan* is adequate for planning purposes.

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

Suitability

The Commission notes that Gulf expects to violate the Southern Company's system-wide summer reserve margin criterion in all ten summer seasons and two 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's shared power pool during times of need. Furthermore, 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

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 uses the MetrixND statistical program for analysis and forecasting. TECO bases its energy models on Statistical Adjusted Engineering, which specifies end-use variables such as heating, cooling, and base use appliances and equipment. TECO performs separate forecasts for phosphate demand and energy and then combines them 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 for the 2005-2014 period is projected to increase at an average of 3.29% per year, which is higher than the 3.07% AAGR for the 1995-2004 period. TECO's base-case winter peak demand is projected to increase at an average of 3.31% per year, which is substantially higher than the historical AAGR of 0.96%. TECO expects population in the Hillsborough County area to increase at an average of 1.7% per year but uses a higher growth rate for employment and economic output.

TECO's 2000-2004 retail sales forecasts have an absolute percent error of 0.73%, which is lower than the 1.02% average for the reporting utilities. For the same five-year period, TECO's retail sales forecasts have an average forecast error of -0.73%, which reflects a slight tendency to under-forecast.

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 Building Code related to energy efficiency for building construction took effect this year, resulting in increased minimum energy efficiency levels. These new requirements may reduce the potential demand and energy savings attributable to TECO's DSM programs. Some of TECO's DSM programs have reached saturation, such that TECO does not expect future participation.

TECO submitted a new DSM Plan that was approved by the Commission in February 2005. TECO's DSM plan contains nine residential programs (including a price-responsive load management pilot program), eight commercial/industrial programs, a research and development program for study of potential DSM programs, and a renewable energy pilot program.

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. Pursuant to stipulation, TECO utilizes a 20% reserve margin criterion for both summer and winter peak demand. 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 2005-2014, TECO provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated TECO's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 13 illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 13. TECO - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
TECO - 2005	-3.5%	3.7%	-6.3%	3.0%	-5.0%	2.9%	-2.1%	-1.1%	NA	NA
TECO - 2004	1.6%	1.7%	-4.1%	-0.2%	-5.9%	0.8%	1.6%	0.0%	NA	NA
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, TECO expects its coal price will be \$2.98 per MMBtu, while EIA forecasts coal to be \$1.64 per MMBtu. TECO expects its residual oil price will be \$7.13 per MMBtu by 2014, with EIA forecasting residual oil to be \$5.75 per MMBtu. TECO expects its distillate oil price will be \$9.95 per MMBtu by 2014, compared to EIA's forecast of \$7.20 per MMBtu. By 2014, TECO expects its natural gas price will be \$7.57 per MMBtu, while EIA forecasts natural gas prices will be \$6.28 per MMBtu.

Generation Selection

TECO's system winter capacity is currently 4,927 MW. Of this total, 4,423 MW comes from TECO-owned generation. TECO currently purchases 441 MW from other utilities and 63 MW from non-utility generators. Table 14, on the next page, shows TECO's winter capacity by fuel type.

TECO forecasts a decrease of 40 MW from non-utility generators within the planning horizon, due to the expiration of a cogeneration contract. 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. TECO's *Ten-Year Site Plan* also discusses a 400 MW unspecified purchase for 2008, 2009, and 2010, reflecting projected capacity needs while three of the Big Bend coal units are out of service for the installation of environmental control equipment. TECO will secure a firm capacity supplier in the near future.

Table 14. TECO – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Coal	1,737	0
Firm Imports	441	-441
Integrated Coal Gasification Combined Cycle	260	0
Non-Utility Generation	63	-40
Combined Cycle	1,841	502
Combustion Turbine	585	1,440
TOTAL	4,927	1,461

State, Regional, and Local Agency Comments

Central Florida Regional Planning Council – Proposed CT units at Polk plant site are not expected to adversely impact groundwater and surface water systems.

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

South Florida Water Management District -- Has no adverse comments regarding the suitability of TECO's proposed plant sites.

Southwest Florida Water Management District -- Noted that the five planned units at known sites are CT units, which require relatively less water for cooling purposes. Provided comments regarding water usage for the four planned units at sites to be determined.

Tampa Bay Regional Planning Council -- TECO's *Ten-Year Site Plan* is generally consistent with regional planning policies.

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. FMPA identifies some general economic and demographic assumptions but only one data source. Applying generalized economic assumptions across all relevant member systems may not sufficiently 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 2005-2014 period, FMPA's base-case summer peak demand is projected to increase at an average of 2.47% per year, which is substantially lower than the 12.14% AAGR for the 1995-2004 period. FMPA's base-case winter peak demand is projected to increase at an average of 3.06% per year, which again is substantially lower than the 10.33% AAGR for the 1995-2004 period. The large AAGR increases for summer and winter peak demand over the past ten years reflect FMPA's addition of new member cities to the All-Requirements Project during that time.

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 a 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 2005-2014, FMPA provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated FMPA's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 15 illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 15. FMPA - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
FMPA - 2005	-8.3%	1.9%	-4.0%	0.6%	-4.0%	0.6%	-6.7%	3.2%	2.5%	2.3%
FMPA - 2004	2.5%	1.9%	3.2%	3.5%	2.9%	3.1%	-6.7%	4.3%	2.0%	2.3%
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, FMPA expects its coal price will be \$2.38 per MMBtu, while EIA forecasts coal to be \$1.64 per MMBtu. FMPA expects its residual oil price will be \$5.20 per MMBtu by 2014, with EIA forecasting residual oil to be \$5.75 per MMBtu. FMPA expects its distillate oil price will be \$9.95 per MMBtu by 2014, compared to EIA's forecast of \$7.20 per MMBtu. By 2014, FMPA expects its natural gas price will be \$5.62 per MMBtu, while EIA forecasts natural gas prices will be \$6.28 per MMBtu. FMPA expects its nuclear energy price will be \$0.80 per MMBtu by 2014, while EIA does not provide a price forecast for nuclear energy.

Generation Selection

FMPA's All-Requirements Project currently has a winter system generating capacity of 1,744 MW. The combined generation of FMPA's members, currently 1,343 MW, is insufficient to meet aggregate load. To serve load that exceeds generation, FMPA purchases firm capacity from other utilities. Additionally, FMPA has partial requirements contracts with PEF and FPL, both of whom serve FMPA's load within their regions that exceeds FMPA's own capacity resources. Combined partial requirements and other capacity purchases currently total 401 MW. FMPA does not export any capacity or purchase capacity from qualifying facilities. Table 16, on the next page, shows FMPA's winter capacity by fuel type.

FMPA plans to add a net 461 MW of capacity during the planning period. Current plans call for the addition of a 42 MW CT unit at Key West in 2006, two 49 MW CT units at Lake Worth in 2007, a 318 MW gas-fired combined cycle unit in St. Lucie County in 2008, and a 49 MW CT unit at a site not yet determined. FMPA also plans to participate in a new jointly owned 800 MW class pulverized coal-fired unit with other municipal utilities. The plant has tentatively been planned for a new site in Taylor County and is scheduled to enter service in 2012. FMPA's share of the plant is 250 MW.

Table 16. FMPA – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Nuclear	85	0
Coal	220	250
Firm Imports	401	-296
Member-Owned Capacity	704	0
Combined Cycle	201	318
Combustion Turbine	133	189
TOTAL	1,744	461

State, Regional, and Local Agency Comments

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

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

South Florida Regional Planning Council -- FMPA's *Ten-Year Site Plan* is generally consistent with the goals and policies of the Council, but the Council is concerned over plans to build CT units on Stock Island in the Florida Keys.

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 obtained its historical data from reputable sources, and GRU outlined the key assumptions of its forecast. The assumptions include normal weather conditions, prices adjusted for inflation, a 2.7% average annual inflation rate throughout the forecast, and declining real electricity prices.

Under base-case assumptions, GRU forecasts that summer peak demand will increase at an average of 2.44% per year, which is higher than the historical AAGR of 2.02%. Under base-case conditions, GRU forecasts that winter peak demand will increase at an average of 2.50% per year, which is well above the previous ten-year period of 0.99%.

GRU's 2000-2004 retail sales forecasts have an absolute percent error of 1.00%, which is nearly the same as the 1.02% average for the reporting utilities. For the same period, GRU's retail sales forecasts have an average forecast error of -1.00%, which reflects a tendency to under-forecast.

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. However, GRU utilizes a 20% reserve margin criterion for both summer and winter peak demand. 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 2005-2014, GRU provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated GRU's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 17, on the next page, illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 17. GRU - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
GRU - 2005	4.9%	2.1%	-4.9%	2.4%	-4.7%	1.9%	-7.4%	2.3%	0.8%	0.4%
GRU - 2004	-7.9%	1.8%	-0.7%	3.1%	0.6%	2.7%	1.6%	4.1%	0.8%	0.4%
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, GRU expects its coal price will be \$2.96 per MMBtu, while EIA forecasts coal to be \$1.64 per MMBtu. GRU expects its residual oil price will be \$5.54 per MMBtu by 2014, with EIA forecasting residual oil to be \$5.75 per MMBtu. GRU expects its distillate oil price will be \$6.93 per MMBtu by 2014, compared to EIA's forecast of \$7.20 per MMBtu. By 2014, GRU expects its natural gas price will be \$6.53 per MMBtu, while EIA forecasts natural gas prices will be \$6.28 per MMBtu. GRU expects its nuclear energy price will be \$0.45 per MMBtu by 2014, while EIA does not provide a price forecast for nuclear energy.

Generation Selection

GRU has a net system winter capacity of 627 MW. GRU owns 630 MW of capacity but exports 3 MW to other utilities. GRU owns 1 MW of renewable capacity generated by landfill gas from the Southwest Landfill. GRU does not import any firm capacity from other utilities or purchase capacity from qualifying facilities. Table 18, on the next page, 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 coal-fired generating unit, Deerhaven Unit 3, is planned for 2011. The capacity of Deerhaven Unit 1 is forecasted to decrease by 13 MW in 2010 due to the addition of equipment to reduce plant emissions. 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 18. GRU – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Nuclear	11	0
Coal	228	207
Firm Exports	-3	3
Renewables	1	0
Combined Cycle	118	0
Fossil Steam	106	-23
Combustion Turbine	166	0
TOTAL	627	187

State, Regional, and Local Agency Comments

Department of Environmental Protection – GRU's *Ten-Year Site Plan* is adequate for planning purposes.

North Central Florida Regional Planning Council – Offers no comment.

St Johns River Water Management District – Discusses possibility of increased water usage at the Deerhaven Site.

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 2000-2004 retail sales forecasts have an absolute percent error of 1.25%, which is lower than the average of 1.02% for the reporting utilities. For the same period, JEA's retail sales forecasts have an average forecast error of -0.36%, which reflects a slight tendency to under-forecast.

Under base-case assumptions, JEA forecasts that winter peak demand will increase at an average of 2.79% per year over the planning horizon, which is higher than the historical AAGR of 2.22%. For the 2005-2014 period, base-case summer peak demand is forecasted to increase at an average of 1.95% per year, which is lower than the 2.31% AAGR for the 1995-2004 period.

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 JEA can document are expected to come from 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 assisted with the installation of 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 15% reserve margin criterion for both summer and winter peak demand.

JEA's *Ten-Year Site Plan* includes unspecified seasonal capacity purchases of 60 MW in the summer of 2010 and 30 MW in the winter of 2010/11. As it has in past years, JEA plans to rely on The Energy Authority to timely secure needed capacity from outside the FRCC region. Without these purchases, JEA forecasts a 13% reserve margin for summer 2010 and a 14% reserve margin for winter 2010/11. With these two exceptions, forecasted reserve margins, as shown in JEA's *Ten-Year Site Plan*, are expected to exceed the 15% reserve margin criterion in each year of the planning horizon.

Fuel Forecast

For the period 2005-2014, JEA provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated JEA's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 19 illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 19. JEA - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
JEA - 2005	6.1%	3.1%	-5.4%	1.0%	-5.9%	0.8%	-2.5%	-0.4%	NA	NA
JEA - 2004	0.1%	2.3%	1.4%	2.7%	1.2%	2.5%	-4.2%	1.8%	NA	NA
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, JEA expects its coal price will be $2.74 per MMBtu, while EIA forecasts coal to be $1.64 per MMBtu. JEA expects its residual oil price will be $4.17 per MMBtu by 2014, with EIA forecasting residual oil to be $5.75 per MMBtu. JEA expects its distillate oil price will be $9.25 per MMBtu by 2014, compared to EIA's forecast of $7.20 per MMBtu. By 2014, JEA expects its natural gas price will be $5.81 per MMBtu, while EIA forecasts natural gas prices will be $6.28 per MMBtu.

Generation Selection

JEA has a net winter capacity of 3,300 MW. JEA owns 3,476 MW of capacity but exports 383 MW to other utilities and imports 207 MW. JEA does not purchase capacity from qualifying facilities. JEA owns 1 MW of renewable capacity generated by landfill gas from the Girvin Landfill. Table 20, on the next page, shows JEA's winter capacity by fuel type.

JEA plans net winter capacity additions of 844 MW over the planning horizon. This year, JEA completed its conversion of two 191 MW CT units at the Brandy Branch site to combined cycle operation totaling 610 MW. Three 86 MW CT units are proposed for 2011 at a yet-to-be determined site. JEA plans to participate in a new jointly owned 800 MW class pulverized coal-fired unit with other municipal utilities. The plant has tentatively been planned for a new site in Taylor County and is scheduled to enter service in 2012. JEA's share of the plant is 236 MW. Also planned is a 250 MW fluidized bed coal unit in 2013 at a Greenfield site to be determined. JEA also forecasts minimal increases in generating capacity at several of its existing generating units.

The amount of firm capacity imported by JEA is expected to decrease to 22 MW by the end of the planning period. This value incorporates the expiration of a purchased power agreement with the Southern Company in 2010.

Table 20. JEA – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Coal	1,771	503
Firm Imports	207	-185
Firm Exports	-383	0
Renewables	1	0
Combined Cycle	0	623
Fossil Steam	505	18
Combustion Turbine	1,199	-115
TOTAL	3,300	844

State, Regional, and Local Agency Comments

Department of Environmental Protection – JEA's *Ten-Year Site Plan* is adequate for planning purposes.

St Johns River Water Management District – Provides no comment, as JEA's *Ten-Year Site Plan* provides no reference to any water resource issues.

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 independent variables such as temperature at time of peak, annual minimum temperature, and minimum temperature of week prior to winter peak. The summer peak demand forecast model uses annual maximum temperature, temperature at time of peak, and Polk County population.

Under base case conditions, LAK forecasts that winter peak demand will increase at an average of 2.03% per year over the next ten years, which is substantially higher than the historic AAGR of 0.67%. For the 2005-2014 period, summer peak demand is projected to increase at an average of 2.12% per year, which is nearly the same as the 2.10% AAGR for the 1995-2004 period.

LAK's 2000-2004 retail sales forecasts have an absolute percent error of 1.04%, which is nearly the same as the 1.40% average for the nine reporting utilities. For the same period, LAK's retail sales forecasts have an average forecast error of 1.04%, reflecting a tendency to over-forecast.

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, 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. However, LAK utilizes a 15% reserve margin criterion for both summer and winter peak demand. 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 2005-2014, LAK provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated LAK's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 21, on the next page, illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

By 2014, LAK expects its coal price will be $2.66 per MMBtu, while EIA forecasts coal to be $1.64 per MMBtu. LAK expects its residual oil price will be $4.12 per MMBtu by 2014, with EIA forecasting residual oil to be $5.75 per MMBtu. LAK expects its distillate oil price will be $6.91 per MMBtu by 2014, compared to EIA's forecast of $7.20 per MMBtu. By 2014, LAK expects its natural gas price will be $6.56 per MMBtu, while EIA forecasts natural gas prices will be $6.28 per MMBtu.

Table 21. LAK - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
LAK - 2005	0.1%	1.0%	-7.0%	0.2%	-9.5%	-0.5%	-5.6%	-0.1%	NA	NA
LAK - 2004	5.3%	3.9%	-0.1%	4.0%	3.6%	3.2%	2.1%	3.9%	NA	NA
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

Generation Selection

LAK has a winter system capacity of 895 MW. LAK owns 995 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 2007. Table 22 shows LAK's winter capacity by fuel type.

Table 22. LAK – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Coal	205	0
Firm Exports	-100	100
Combined Cycle	495	0
Fossil Steam	193	0
Combustion Turbine	102	0
TOTAL	895	100

State, Regional, and Local Agency Comments

Department of Environmental Protection – No additional generating capacity is anticipated during the planning horizon. LAK's *Ten-Year Site Plan* is adequate for planning purposes.

Suitability

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

ORLANDO UTILITIES COMMISSION (OUC)

Load and Energy Forecast

OUC has engaged Itron, formerly Regional Economic Research, Inc. to develop forecasts of peak demand and energy consumption. Linear regression sales models are developed and end-use concepts are blended into the regression model specification. OUC uses the Statistically Adjusted Engineering (SAE) model, 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 2000-2004 retail sales forecasts.

Under base-case assumptions, OUC forecasts that summer peak demand will increase at an average of 1.75% per year over the 2005-2014 forecast period, which is much lower than the 4.76% AAGR for the 1995-2004 period. Winter peak demand is forecast to increase at an average of 2.85% per year, which is lower than the historical AAGR of 3.20%.

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. However, OUC utilizes a 15% reserve margin criterion for both summer and winter peak demand. 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 2005-2014, OUC provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated OUC's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 23, on the next page, illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

By 2014, OUC expects its coal price will be \$3.06 per MMBtu, while EIA forecasts coal to be \$1.64 per MMBtu. OUC expects its residual oil price will be \$4.67 per MMBtu by 2014, with EIA forecasting residual oil to be \$5.75 per MMBtu. OUC expects its distillate oil price will be \$6.08 per MMBtu by 2014, compared to EIA's forecast of \$7.20 per MMBtu. By 2014, OUC expects its natural gas price will be \$5.89 per MMBtu, while EIA forecasts natural gas prices will be \$6.28 per MMBtu. OUC expects its nuclear energy price will be \$0.52 per MMBtu by 2014, while EIA does not provide a price forecast for nuclear energy.

Table 23. OUC - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
OUC - 2005	5.5%	3.5%	-4.4%	-2.0%	-4.5%	-1.8%	-4.3%	-1.6%	2.3%	2.4%
OUC - 2004	2.6%	3.7%	-1.8%	1.7%	-2.1%	1.9%	-1.7%	0.8%	2.4%	2.5%
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

Generation Selection

OUC has a winter system capacity of 1,614 MW. Of this total, 1,257 MW comes from OUC-owned generation and another 21 MW from the City of St. Cloud generating units that OUC manages and operates. Currently, OUC imports 358 MW and exports 22 MW to other utilities. Table 24 shows OUC's winter capacity by fuel type.

Table 24. OUC – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Nuclear	65	0
Coal	760	0
Integrated Coal Gasification Combined Cycle	0	311
Firm Imports	358	-15
Firm Exports	-22	22
Combined Cycle	185	0
Combustion Turbine	268	-21
TOTAL	1,614	297

OUC plans to add 297 MW of net winter capacity over the planning horizon. The St. Cloud units are scheduled for retirement in 2006. OUC expects to decrease imports to 343 MW by 2014, while exports are expected to decrease to zero by 2007. OUC's only planned generating unit addition is a joint project, with the Southern Company, to build an integrated coal gasification combined cycle unit at the

Stanton site. The U.S. Department of Energy's Clean Coal Technology Program will provide partial funding for the plant. OUC's expected share of the unit, expected to enter service in 2011, is 311 MW.

State, Regional, and Local Agency Comments

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

East Central Florida Regional Planning Council -- OUC's proposed project appears suitable.

South Florida Water Management District – Has no adverse comments regarding the suitability of the proposed sites.

St Johns River Water Management District – Notes that OUC's application for Supplemental Site Certification for the proposed Stanton IGCC unit will include the District in the review process. No "potential conflicts with natural resources" can be determined from information provided in OUC's *Ten-Year Site Plan*.

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 its data sources and tests its load forecast sensitivities for high load growth and low load growth cases.

Under base-case conditions, TAL's summer peak demand is projected to increase at an average of 1.59% per year over the 2005-2014 forecast period, which is slightly higher than the 1.44% AAGR for the 1995-2004 period. Winter peak demand is projected to increase at an average of 2.02% per year, which is higher than the historical AAGR of -0.02%.

TAL's 2000-2004 retail sales forecasts have an absolute percent error of 0.53%, which is lower than the 1.02% average for the reporting utilities. For the same period, TAL's retail sales forecasts have an average forecast of 0.31%, which reflects a slight tendency to over-forecast.

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. As a result, 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 2005-2014, TAL provided price forecasts for coal, residual oil, distillate oil, and natural gas. The Commission evaluated TAL's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 25, on the next page, illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 25. TAL - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
TAL - 2005	-11.1%	1.7%	5.3%	0.3%	6.6%	0.6%	-4.1%	-0.8%	NA	NA
TAL - 2004	-4.4%	-0.4%	-1.4%	3.1%	-5.5%	4.9%	-4.2%	0.8%	NA	NA
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA - 2005	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, TAL expects its coal price will be $2.38 per MMBtu, while EIA forecasts coal to be $1.64 per MMBtu. TAL expects its residual oil price will be $6.98 per MMBtu by 2014, with EIA forecasting residual oil to be $5.75 per MMBtu. TAL expects its distillate oil price will be $11.18 per MMBtu by 2014, compared to EIA's forecast of $7.20 per MMBtu. By 2014, TAL expects its natural gas price will be $6.16 per MMBtu, while EIA forecasts natural gas prices will be $6.28 per MMBtu.

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 26 shows TAL's winter capacity by fuel type.

Table 26. TAL – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Firm Imports	11	0
Combined Cycle	262	125
Fossil Steam	366	-50
Hydroelectric	11	0
Combustion Turbine	60	80
TOTAL	710	155

TAL recently added two 50 MW CT units at the Hopkins site. TAL plans to add CC capacity, through purchase, repowering of an existing unit, or shared ownership in a new unit. The proposed addition is expected to occur in the following increments: 25 MW in 2010, 75 MW in 2011, and 25 MW in 2013. TAL also plans to retire 70 MW of capacity at the Purdom site between 2010 and 2011.

Several Florida municipal utilities plan to participate in a new jointly owned 800 MW class pulverized coal-fired unit. The plant has tentatively been planned for a new site in Taylor County and is scheduled to enter service in 2012. TAL's *Ten-Year Site Plan* does not discuss plans for TAL to take part in the proposed coal plant, although participation may occur pending an upcoming decision by the city commission. A final decision is expected later this year. If TAL participates in the proposed coal plant, its share of the capacity will be 200 MW.

State, Regional, and Local Agency Comments

Apalachee Regional Planning Council – Existing facilities and services are consistent with Council policies, and no additional plant sites are identified within the region.

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

Tallahassee-Leon County Planning Department -- For the recently added CT units at the Hopkins site, impacts on natural resources were addressed in the permitting process. Regarding the four planned substations, impacts to natural resources will be addresses in the permitting process.

Suitability

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

SEMINOLE ELECTRIC COOPERATIVE (SEC)

SEC is a generation and transmission cooperative that provides full requirements wholesale 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 loads up to specified capacity levels and provide adequate reserves. Partial requirements providers (PEF, TECO, JEA, OUC, and GRU) serve SEC's entire 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, 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 of 4.13% per year over the 2005-2014 forecast period. While lower than the historic AAGR of 4.24% for the 1995-2004 period, SEC's winter peak demand forecast still reflects one of the highest growth rates in the state. SEC's base-case summer peak demand is forecasted to grow at an average of 4.04% per year, which is lower than the historical AAGR of 4.26%.

SEC's 2000-2004 retail sales forecasts have an absolute percent error of 1.46%, which is higher than the 1.02% average for the reporting utilities. For the same five-year period, SEC's retail sales forecasts have an average forecast error of -0.47%, which reflects a slight tendency to under-forecast.

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. Since winter peak demands are a primary concern to utilities in Florida, SEC utilizes a 15% reserve margin criterion for both summer and winter peak demand. SEC also utilizes a 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 2005-2014, SEC provided price forecasts for coal, residual oil, distillate oil, natural gas, and nuclear energy. The Commission evaluated SEC's price forecasts against similar forecasts from last year for 2004-2013, as well as comparable forecasts made by EIA and the other reporting utilities. Table 27 illustrates these forecasts for both the near-term (1-3 years) and long-term (4-10 years).

Table 27. SEC - Fuel Price Forecast – Average Annual Growth Rate

FORECAST	COAL		RESIDUAL OIL		DISTILLATE OIL		NATURAL GAS		NUCLEAR	
	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term	Near term	Long term
SEC - 2005	1.4%	2.4%	-2.8%	0.5%	-9.9%	0.5%	-8.5%	-0.7%	-1.6%	0.5%
SEC - 2004	1.2%	1.2%	-3.1%	3.5%	4.4%	3.4%	-2.4%	3.2%	-2.8%	1.2%
WEIGHTED AVERAGE OF REPORTING UTILITIES - 2005	-2.3%	1.7%	-5.1%	3.2%	-8.9%	2.9%	-6.9%	1.3%	-0.3%	1.3%
EIA	2.3%	2.4%	0.5%	2.6%	-0.2%	2.0%	-1.0%	2.9%	NA	NA

By 2014, SEC expects its coal price will be \$2.30 per MMBtu, while EIA forecasts coal to be \$1.64 per MMBtu. SEC expects its residual oil price will be \$5.59 per MMBtu by 2014, with EIA forecasting residual oil to be \$5.75 per MMBtu. SEC expects its distillate oil price will be \$7.48 per MMBtu by 2014, compared to EIA's forecast of \$7.20 per MMBtu. By 2014, SEC expects its natural gas price will be \$6.57 per MMBtu, while EIA forecasts natural gas prices will be \$6.28 per MMBtu. SEC expects its nuclear energy price will be \$0.45 per MMBtu by 2014, while EIA does not provide a price forecast for nuclear energy.

Generation Selection

SEC has a total system winter capacity of 4,653 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 1,474 MW of winter firm capacity from other utilities and 353 MW from Hardee Power Station. Partial requirements and full requirements purchases currently provide 909 MW. Table 28, on the next page, shows SEC's winter capacity by fuel type.

Although SEC plans to add 3,426 MW (winter) of new generating units during the planning horizon, net system capacity is expected to increase by only 2,292 MW. SEC expects its reliance on firm purchases to drop to 13 MW, a decrease by 1,814 MW, primarily due to the expiration of the Hardee Power Station purchase and other purchased power contracts. The amount of partial requirements and full requirements capacity imports is forecasted to increase by 680 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 1,456 MW of CT capacity is planned from eight new units at yet-to-be-determined sites. These units are planned to enter commercial service as follows: one in 2007, four in 2009, one in 2010, one in 2012, and one in 2013. Also planned is 910 MW of CC capacity from five new units at a yet-to-be determined site. These units are planned to enter commercial service as follows: one in 2008, one in 2009, two in 2013, and one in 2014. Finally, in 2012, SEC plans to add a 750 MW coal unit at the existing Seminole site in Putnam County.

Table 28. SEC – Winter Capacity by Fuel Type

UNIT TYPE	CAPACITY (MW) 1/1/2005	PROPOSED ADDITIONS (MW)
Nuclear	15	0
Coal	1,330	750
Firm Imports	1,827	-1,814
Partial Requirements Purchases	909	680
Combined Cycle	572	910
Combustion Turbine	0	1,766
TOTAL	4,653	2,292

State, Regional, and Local Agency Comments

Central Florida Regional Planning Council – The five proposed CT units at the Payne Creek site should not affect the ground and surface water systems.

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

Southwest Florida Water Management District – Expressed concerns over potential for additional water usage from proposed project.

St Johns River Water Management District – Noted that potential conflict with natural resources might result from expansion of generating or transmission facilities.

Suitability

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

INDEPENDENT POWER PRODUCERS

One IPP, Calpine, filed a *Ten-Year Site Plan* for 2005. Calpine's *Ten-Year Site Plan* contains two proposed 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 could be completed and enter service as early as 2008. However, Calpine has not identified an in-service date at this time. The status of the Blue Heron units remains uncertain at this time because there currently is not a contract to sell the output to a retail-serving utility.