BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060001-EI
FLORIDA POWER & LIGHT COMPANY

SEPTEMBER 1, 2006

IN RE: LEVELIZED FUEL COST RECOVERY AND CAPACITY COST RECOVERY INCLUDING GENERATION BASE RATE ADJUSTMENT

PROJECTIONS
JANUARY 2007 THROUGH DECEMBER 2007

TESTIMONY & EXHIBITS OF:

G. YUPP
W. GWINN
K. M. DUBIN

AFFIDAVITS OF:

R. MORLEY
S. SIM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 060001-EI

SEPTEMBER 1, 2006

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal, petroleum coke, and natural gas, (2) the availability of natural gas to FPL, (3) generating unit heat rates and availabilities and (4) the quantities and costs of wholesale (off-system) power and purchased power transactions. Additionally, I provide a review of FPL's hedging program and present FPL's Risk Management Plan for fuel procurement in 2007. Lastly, my testimony details new natural gas storage and natural gas pipeline projects for which FPL is seeking Commission approval for recovery through the Fuel Clause.

Q. Have you prepared or caused to be prepared under your supervision, direction and control an Exhibit(s) in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-2 -Appendix I
- Schedules E2 through E9 of Appendix II
- GJY-3 -MoBay Gas Storage Project Petition in Docket No. 060362-EI with the following attachments: Affidavit of Gerard Yupp, MoBay Presentation, Precedent Agreement, Storage Table and FPL's MFR Schedule B-18 for Test Year 2006.
- GJY-4 -Estimated Annual Costs of MoBay Gas Storage Project
- GJY-5 -Southeast Supply Header Documentation
- GJY-6 -Estimated Annual Costs of Southeast Supply Header

Pipeline Project

Exhibits GJY-3 through GJY-6 are bound separately as they contain confidential information.

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2007 recovery period?

For natural gas commodity prices, the forecast methodology is the NYMEX Natural Gas Futures contract (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal and petroleum coke, and the availability of natural gas, are developed internally at FPL. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time and are consistent with the prices at which FPL can transact its hedging program. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the future is incorporated into the curve at all times. The methodology allows FPL to execute hedges consistent with its forecasting method and to optimize the dispatch of its units in changing market conditions. FPL utilized forward curve prices from the close of business on August 7, 2006 for its 2007 projection filing. This was the most recent date that allowed FPL adequate time to complete its filing.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2007 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil), (2) non-OPEC crude oil supply, (3) the extent to which OPEC adheres to their quotas and reacts to fluctuating demand for OPEC crude oil, (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa, (5) the availability of refining capacity, (6) the price relationship between heavy fuel oil and crude oil, (7) the price relationship between heavy oil and natural gas, (8) the supply and demand for heavy oil in the domestic market, and (9) the terms of FPL's fuel supply and transportation contracts.

The major driver for crude oil and petroleum product prices during the remainder of 2006 and 2007 will be the continued tensions in the Middle East, West Africa (in particular Nigeria) and other producing regions in the world. With limited spare OPEC productive capacity, refineries running near capacity, and growing worldwide demand, any perceived or actual loss of supply due to political or civil unrest in these regions have, and will continue to be a major factor in the price of oil to FPL's customers.

World demand for crude oil and petroleum products is projected to increase slightly in 2007 over 2006 average levels primarily due to increases in demand in the U.S., China and other Pacific Rim countries. Although crude oil production and worldwide refining capacity will be adequate to meet the projected increase in crude oil and petroleum product demand, general adherence by OPEC members to its most recent production accord, and limited spare OPEC productive capacity, should prevent significant overproduction of crude oil which, in turn, will result in the continued tight supply of crude oil and petroleum products during most of 2007.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2007 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors are similar to those described above for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2007 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal and petroleum coke for St. Johns' River Power Park (SJRPP) and coal for Plant Scherer?

A. FPL's projected dispatch cost for SJRPP is based on FPL's price projection for spot coal and petroleum coke delivered to SJRPP. The dispatch cost for Plant Scherer is based on FPL's price projection for spot coal delivered to the plant.

In the case of SJRPP, FPL plans to blend petroleum coke with coal in order to reduce fuel costs. It is anticipated that petroleum coke will represent approximately 27% of the fuel blend at SJRPP during 2007. The lower price of petroleum coke is reflected in the blended projected dispatch cost for SJRPP.

Q. Please provide FPL's projection for the dispatch cost of SJRPP and Plant Scherer for the January through December 2007 period.

A. FPL's projection for the system average dispatch cost of "solid fuel" for this period, by plant and by month, is shown on page 3 of Appendix I.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2007 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production, (2) LNG and Canadian natural gas imports, (3) heavy fuel oil and light fuel oil prices, and (4) the terms of FPL's natural gas supply and transportation contracts. Additional factors which can influence the projected price of natural gas in 2007 are: (1) projected natural gas demand in North America will continue to grow moderately in 2007, primarily in the electric generation sector; and (2) with continued increases in domestic rig activity in the U.S. over the past few years, 2007 domestic natural gas production is expected to be slightly higher than average 2006 production levels, as a continued decline in the Gulf of Mexico region is more than offset by increases in Rocky Mountain and Mid-Continent regions. The remaining balance of supply will come from increased Canadian and LNG imports.

Q. What are the factors that affect the availability of natural gas to FPL during the January through December 2007 period?

A. The key factors are (1) the existing capacity of the Florida Gas Transmission (FGT) pipeline system into Florida, (2) the existing capacity of the Gulfstream natural gas pipeline system into Florida, (3) the limited number of operational receipt points into the Gulfstream natural gas pipeline system, (4) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month, (5) the assumed volume of natural gas which can move from the Gulfstream pipeline into FGT at the Hardee and Osceola interconnects, and (6) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is about 2,030,000 million BTU per day and the current capacity of Gulfstream is about 1,100,000 million BTU per day. FPL currently has firm natural gas transportation capacity on FGT ranging from 750,000 to 874,000 million BTU per day, depending on the month, and 350,000 million BTU per day of firm natural gas transportation on Gulfstream. FPL projects that during the January through December 2007 period between 375,000 and 725,000 million BTU per day of non-firm natural gas transportation capacity (varying by month) will be available into the state. FPL projects that it could acquire some of this capacity, if economic, to supplement FPL's firm allocation on FGT and Gulfstream. This projection is based on the current capability and availability of the two interconnections between Gulfstream and FGT pipeline systems and the availability of capacity on each pipeline.

Q. Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2007 period.

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY

Q. Please describe how FPL developed the projected Average Net Operating Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Operating Heat Rates were calculated by the POWRSYM model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to POWRSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2007?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2007.

Q. Please describe the significant planned outages for the January through December 2007 period.

A. Planned outages at our nuclear units are the most significant in relation to fuel cost recovery. Turkey Point Unit 3 is scheduled to be out of service for refueling from September 1, 2007 until October 1, 2007 or 30 days during the projected period. St. Lucie Unit 1 will be out of service for refueling, ICI thimble tube repair/replacement, and main generator rotor replacement from April 2, 2007 until May 7, 2007 or 35 days during the projected period. St. Lucie Unit 2 will be out of service for refueling, reactor head replacement, and steam generator replacement from October 1, 2007 until December 25, 2007 or 85 days during the projected period.

Q. Please list any changes to FPL's generation capacity projected to take place during the January through December 2007 period.

A. The most significant change to FPL's generation capacity in 2007 is the addition of the combined cycle Turkey Point Unit 5, which will increase FPL's net winter peak capability and the net summer peak capability by 1,104 MW and 1,144 MW respectively.

Q. Will the addition of Turkey Point Unit 5 result in fuel savings to FPL's customers?

A. Yes. The addition of this highly efficient, combined cycle unit will result in approximately $96,464,000 in fuel savings to FPL's customers from May through December, 2007.

Q. How did FPL calculate the fuel savings associated with the addition of Turkey Point Unit 5?

A. FPL utilized its POWRSYM model to quantify the benefits of Turkey Point Unit 5. This model is used to calculate the fuel costs that are included in FPL's projection filing. For this analysis, FPL ran two individual cases to determine fuel costs, one without Turkey Point

Unit 5 and one with Turkey Point Unit 5. The total fuel costs of the case that included Turkey Point Unit 5 were approximately $96,464,000 lower than the case without Turkey Point Unit 5.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2007?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. Purchasing and selling power in the wholesale market allows FPL to lower fuel costs for its customers because savings and gains are credited to the customer through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction. FPL can also purchase and sell power during emergency conditions under several types of Emergency Interchange agreements that are in place with other utilities within Florida.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases coal-by-wire electrical energy under the 1988 Unit Power Sales Agreement (UPS) with the Southern Companies. FPL has contracts to purchase nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). FPL also purchases energy from JEA's portion of the SJRPP Units. Additionally, FPL has purchased exclusive dispatch rights for the output of 6 combustion turbines (3 facilities) totaling approximately 950 MW (the output varies depending on the season). The agreements for the combustion turbines are with Southern Power Company and Reliant Energy Services. FPL provides natural gas for the operation of each of these three facilities as well as light fuel oil for two of the facilities. FPL's contract with

Reliant Energy Services (Shady Hills) for the output of 3 combustion turbines expires on February 28, 2007. Additionally, FPL's contract with Southern Power Company (Desoto) for the output of 2 combustion turbines expires on May 31, 2007. FPL has extended its contract with Southern Power Company (Oleander) for the output of 1 combustion turbine through May 31, 2012. This agreement was originally set to expire on May 31, 2007. FPL has also purchased exclusive dispatch rights for the output of Reliant Energy Services' Indian River facility totaling 576 MW. This agreement began on January 1, 2006 and runs through December 31, 2009. FPL also entered into two additional short-term capacity arrangements with Williams Power Company and Progress Ventures, Inc. for the purchase of 106 MW and 105 MW respectively. The transaction with Williams Power Company began on March 3, 2006 and runs through December 31, 2009. The transaction with Progress Ventures, Inc. began on May 1, 2006 and runs through April 30, 2009. Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. **Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2007 period.**

A. Under the UPS agreement, FPL's capacity entitlement during the period from January through December 2007 is 930 MW. Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases. The projected UPS energy (unit) cost for this period, used as an input to POWRSYM, is based on data provided by the Southern Companies. For the period, FPL projects to purchase 8,096,684 MWh of UPS energy at a cost of $154,074,000. The total UPS energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 3,149,354 MWh for the period at an energy cost of $53,621,000. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 350,454 MWh at a cost of $1,380,200. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 428,994 MWh from its short-term purchased power agreements at a cost of $37,743,907. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 5,951,033 MWh at a cost to FPL of $172,870,000.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the POWRSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales.

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) power sales?

A. FPL has projected 1,930,909 MWh of wholesale (off-system) power sales for the period of January through December 2007. The projected fuel cost related to these sales is $145,972,243. The projected transaction revenue from these sales is $169,111,791. The projected gain for these sales is $19,197,960.

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy; total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects the sale of 83,738 MWh of energy at a cost of $1,380,200. These projections are shown on Schedule E6 of Appendix II.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2007 period?

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of

1,727,679 MWh at a cost of $133,340,912. If FPL generated this energy, FPL estimates that it would cost $153,551,472. Therefore, these purchases are projected to result in savings of $19,625,703.

HEDGING OVERVIEW

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program is to reduce fuel price volatility, thereby helping to deliver greater price certainty to FPL's customers.

Q. Please summarize the cumulative results of FPL's hedging activities.

A. Since its inception, FPL's hedging activities have been successful in mitigating some of the impact of rising fuel prices and helping to deliver a greater degree of price certainty for FPL's customers. Because 2002 through 2005 was marked by extreme price volatility and generally rising prices year-on-year, FPL's hedging activities have also delivered a significant amount of fuel savings. From 2002 through 2005, FPL's hedging activities for natural gas and heavy fuel oil have resulted in approximately $926 million in fuel savings to FPL's customers.

Q. What have been FPL's hedging results in 2006 to date, and

what results does FPL expect through 2007?

A. In contrast to the upward trend in the period 2002 through 2005, natural gas prices during 2006 have trended significantly lower than the forward curve prices. This trend has resulted from an extremely mild winter, above average natural gas storage levels and a relatively inactive hurricane season to-date. Comparatively, heavy fuel oil prices have increased approximately 7% over FPL's original 2006 forecast, mainly attributed to higher crude and gasoline prices. For 2006, through July, FPL's natural gas and heavy fuel oil hedge positions have resulted in realized losses of approximately $186 million.

Although mild winter weather, above average natural gas storage levels and a relatively inactive hurricane season to-date has driven 2006 natural gas prices lower, 2007 forward prices remain relatively high. As of August 28, 2006, natural gas prices for the first quarter of 2007 are approximately $4.50 per MMBtu higher than the September, 2006 NYMEX price. Similarly, heavy fuel oil prices for the first quarter of 2007 (as of August 28, 2006) are approximately $5.70 per barrel higher than the September, 2006 price. This widening price discrepancy between current and future prices began in 2005 as FPL was executing hedges for 2006 and continues now as FPL hedges for 2007. The impact of bearish information, such as above average storage levels, on forward prices is seen only in the short-term while short-term and future prices remain poised to increase upon any information that could possibly be interpreted as bullish, such as the formation of a tropical depression. In any event, the natural gas and heavy fuel oil markets continue to be highly volatile. Hedging remains the only effective means of dampening this price volatility and FPL intends to continue its active participation in hedging its natural gas and heavy fuel oil requirements.

Q. Does FPL expect that its hedging program will deliver fuel savings each year?

A. No. This is a point that I have emphasized in all my prior testimony on hedging. While FPL is extremely pleased when its hedging program generates net savings for its customers, it does not engage in hedging for this purpose. FPL's hedging strategies are aimed at reducing fuel price volatility. Speculative hedging strategies aimed at "out guessing" the market in the hopes of potentially returning savings to FPL's customers will lead to increased volatility in prices to FPL's customers. FPL cannot predict future fuel prices as there is no certainty in predicting the main drivers of fuel price, such as weather, hurricanes or unstable conditions around the world. What FPL can continue to do is execute a well-disciplined, independently controlled hedging program that reduces fuel price volatility and delivers greater price certainty to FPL's customers. Over time, FPL expects that the cumulative impact of its hedging program will not result in significant savings or losses to FPL's customers. FPL does expect, however, that over time its customers will experience more stable rates as a result of FPL's hedging activities.

Q. Has FPL prepared a risk management plan for 2007, as required by Order PSC- 02-1484-FOF-EI issued on October 30, 2002?

A. Yes. FPL's 2007 Risk Management Plan is provided on pages 5 and 6 of Appendix I.

Q. Is FPL seeking to recover projected incremental operating and maintenance expenses with respect to maintaining an expanded, non-speculative financial and/or physical hedging program for the January through December 2007 period?

A. Yes. FPL projects to incur incremental expenses of $540,100 for its Trading and Operations Group and $30,000 for its Systems Group. By "incremental", I mean that these expenses are not reflected in FPL's base rates. The expenses projected for the Trading and Operations Group are primarily for salaries of the three personnel who were added to support FPL's enhanced hedging program. The expenses projected for the Systems Group are for incremental annual license fees for FPL's volume forecasting software.

NEW PROJECTS

MOBAY GAS STORAGE HUB

Q. Please summarize the MoBay Gas Storage Hub facility.

A. MoBay Gas Storage Hub is a high-deliverability, multi-cycle reservoir gas storage facility located in Mobile County, Alabama. When fully developed, MoBay will be the largest, most southeasterly underground natural gas storage facility in the United States. MoBay will be interconnected to four different interstate pipelines: Florida Gas Transmission (FGT), Gulfstream Natural Gas (Gulfstream), Gulf South Pipeline (Gulf South) and Transcontinental Gas Pipeline (Transco). MoBay will be the only natural gas storage facility to-date capable of directly delivering natural gas into the Gulfstream pipeline system serving the Florida market.

Q. Why is FPL proposing to participate in the MoBay Gas Storage Project?

A. FPL proposes to acquire natural gas storage in the MoBay Gas Storage Hub because its participation in the storage facility will substantially increase FPL's ability to hedge the physical supply of natural gas, resulting in a significant increase in system reliability and a reduction in natural gas volatility. This project is a critical step in helping reduce FPL's vulnerability to natural gas supply curtailments in the Destin/Mobile Bay area and limiting FPL's exposure to the volatility inherent in relying on the spot or intra-day market or alternate fuels during severe weather events and periods of high demand. The project will substantially increase FPL's ability to hedge the physical supply of natural gas, resulting in a significant increase in system reliability and a reduction in natural gas price volatility.

Q. Why does FPL believe the acquisition of natural gas storage constitutes a physical hedge?

A. Physical hedging involves the use of forward contracts to purchase the commodity itself, and/or the use of physical means of storing or producing the commodity to provide protection against future price swings. As stated previously, this project will help reduce FPL's vulnerability to natural gas supply curtailments and reduce FPL's exposure to the volatility inherent in relying on the spot or intra-day market and/or higher-priced alternate fuels during extreme weather events or periods of high demand. As such, the MoBay Gas Storage Project will serve as a physical hedge against the risks of both supply unavailability and price volatility. Natural gas storage is commonly characterized as physical hedging within the industry.

For example, the July 21, 2005 edition of Natural Gas Weekly Update published by the United States Department of Energy, commenting on market trends, explained that 47 of 54 American Gas Association (AGA) member companies surveyed report using natural gas storage as a primary hedging tool. Additionally, the publication states that "several companies noted that storage (as a physical hedge) is the only hedge they employ, choosing not to use financial hedges at all."

Q. Has FPL previously petitioned the Commission for approval of the MoBay Gas Storage Project?

A. Yes, in Docket No. 060362-EI. FPL's petition was addressed by the Commission at the August 15th Agenda Conference, but the Attorney General and others raised concerns about the petition for the first time at that agenda conference. This resulted in a deferral to the September 19th Agenda Conference. Waiting until the last minute to raise concerns about the Petition has had an unfortunate consequence for FPL and its customers. Deferral to the September 19th Agenda Conference means that there is little chance of a final Commission decision on FPL's petition before the end of September. MoBay has the right to terminate its contract with FPL if the Commission has not given final approval to the Project by September 29, 2006. FPL has tried unsuccessfully to negotiate an extension of the September 29th deadline with MoBay.

Q. What are the potential consequences to FPL and its customers if there is no final Commission approval by September 29th and MoBay exercises its termination right?

A. In the event that MoBay gave notice of termination, FPL could attempt to renegotiate the contract to avoid termination but most likely this would have to be at the current market price for MoBay's storage capacity, which is above the pricing currently in FPL's contract. While deciding on FPL's petition at the November 6-8 hearing in this docket as FPL proposes will reduce the risk to FPL and its customers of losing the benefits of the MoBay Gas Storage Hub, it cannot eliminate that risk.

Q. Is FPL seeking Commission approval of the MoBay Gas Storage Project prior to making a final commitment to proceed with the Project?

A. Yes. FPL expects the Project to provide substantial reliability and volatility-reduction benefits to our customers. To secure these benefits, however, FPL will have to incur significant costs. FPL needs to know that the Commission has approved the Project and FPL's proposed cost recovery before making its final commitment to proceed.

Q. When does FPL have to make a final commitment to proceed with the MoBay Gas Storage Project?

A. As I previously noted, both FPL and MoBay will have the right to terminate if the Commission does not give its final approval by September 29, 2006. FPL will retain its right to terminate the contract for up to 90 days thereafter, or until December 28, 2006. Therefore, FPL will have to decide before December 28th whether to proceed with the Project (assuming that MoBay has not already exercised its termination right before then).

Q. What types of costs for the MoBay Gas Storage Project does FPL seek to recover?

A. FPL is seeking recovery of the following costs associated with the MoBay Gas Storage Project:

-A monthly storage reservation charge

-Base Gas costs

-Fuel retention/commodity charges for injections and withdrawals

-A monthly inventory insurance charge

-Carrying costs associated with FPL's inventory balance

In many natural gas storage deals, base gas and insurance costs are incorporated into the monthly storage reservation fee; however for the MoBay contract, base gas and insurance charges were broken out separately at FPL's request, so that FPL would have the option to self-provide if it could do so at a lower cost.

Q Do you have an exhibit that provides detailed, supporting documentation for FPL's proposed MoBay Gas Storage Project?

A. Yes. My Exhibit GJY-3 consists of FPL's petition in Docket No. 060362-EI for approval of this Project, together with the following attachments to that petition:

-Affidavit of Gerard Yupp

-MoBay Presentation

-Precedent Agreement

-Storage Table

-FPL's MFR Schedule B-18 for Test Year 2006

Q. What does FPL anticipate the annual cost to be for its participation in MoBay Gas Storage Project?

A. Exhibit GJY-4 details FPL's estimate of the total annual costs associated with its proposed participation in the MoBay Gas Storage Project.

SOUTHEAST SUPPLY HEADER PIPELINE PROJECT

Q. What is the Southeast Supply Header (SESH) Pipeline Project?

A. The SESH Pipeline Project is a joint project of CenterPoint Energy Gas Transmission (CEGT) and Duke Energy Gas Transmission (DEGT). The potential new pipeline will have approximately 1 billion cubic feet per day of capacity and will consist of nearly 270 miles of 36-inch pipeline starting at CEGT's Perryville Hub in Northeast Louisiana and ending at the pipeline of DEGT's partially owned affiliate, Gulfstream Natural Gas System, near Mobile County, Alabama. The proposed route will cross and interconnect with many major interstate pipelines serving the eastern United States that are not currently served at the Perryville Hub, as well as both major pipelines that serve Florida. The SESH Pipeline Project will allow FPL access to growing production from natural gas basins in East Texas and North Louisiana, which will provide an important on-shore alternate natural gas supply source for markets in the Southeast and supplement the future natural gas demands of Florida.

Q. What are the key motivations for FPL's proposed participation in the SESH Pipeline Project?

A. The SESH Pipeline Project will allow FPL access to on-shore supply which will significantly increase supply security, diversify production away from the Gulf of Mexico and will likely lower prices, therefore producing customer savings. Currently, approximately forty percent of the transportation capacity on FGT and one hundred percent of the transportation capacity on Gulfstream is sourced from the Mobile Bay area. Florida's existing pipeline sourcing alternatives will continue to procure most of its production from the Gulf of Mexico in the Mobile Bay area. However, future demand for natural gas will need to be supplemented from other regions in order to maintain a secure link to natural gas production. By 2009, seventy percent of FPL's transportation capacity on FGT and Gulfstream will be sourced from the Mobile Bay area. With declining production in this area and increased demand for natural gas, FPL believes that this project will help maintain an adequate supply/demand balance in the region that will assure FPL's customers and other Florida consumers of natural gas, access to supply at reasonable prices in the future.

Additionally, the Mobile Bay area is highly susceptible to production shut-ins due to the threat or impact of severe weather events. The introduction of on-shore supply will increase the availability of natural gas during severe weather events.

Q. **What will FPL's proposed participation in the SESH Pipeline Project entail?**

A. FPL will serve as the anchor shipper and is proposing to acquire firm transportation rights to approximately 50% of the capacity on the new pipeline. By 2009, the SESH Pipeline would support 500,000 MMBtu per day of FPL's total Mobile Bay area firm transportation holdings of approximately 1,100,000 MMBtu per day or approximately forty-five percent.

Q. How will this project impact the available pipeline capacity into the state of Florida?

A. This is a supply security and future reliability enhancement project. This project will bring on-shore supply to the Mobile Bay area in the Gulf of Mexico. This project will serve to enhance the supply alternatives of the existing infrastructure of the FGT and Gulfstream pipelines in the Mobile Bay area; however it will not increase the available pipeline capacity into the state of Florida. FPL will continue to utilize its existing firm transportation contracts with FGT and Gulfstream to deliver natural gas to its plants. However, this project will impact the supply of natural gas available to FGT and Gulfstream allowing FPL the opportunity to seek more competitive supply pricing and to ensure supply availability to meet future demand and enhance access to supply if production in the Gulf of Mexico is curtailed.

Q. Is this project an important component for helping FPL meet its

future natural gas requirements?

A. Yes. Historically, the Mobile Bay area has provided the incremental supply behind existing pipeline expansions. The Mobile Bay area will continue to be an important incremental supply area to help meet future demand, but does not currently have the production growth to satisfy Florida's growing demand for natural gas. FPL's demand will grow by approximately 500,000 MMBtu per day over the next four years. In addition, the demand for natural gas in Florida, as a whole, continues to increase. According to data compiled by the FRCC from 2006 Ten Year Site Plans, Florida will need an additional 1,200,000 MMBtu per day of natural gas to meet the proposed generation expansions (natural gas) by 2010. It is critical for FPL and Florida that every effort is made to access new supplies to keep up with growing demand.

Q. Will this project expand the number of potential suppliers of natural gas to FPL?

A. Yes. This project will allow FPL access to new natural gas suppliers and on-shore supply from the Barnett Shale and Bossier Sands trends in East Texas and Northeast Louisiana. This project will increase the diversity and depth of FPL's existing supplier portfolio with the addition of domestic independent producers active in the East Texas and North Louisiana supply areas.

Q. How will this project increase supply reliability during extreme weather events?

A. Access to on-shore supply will significantly increase reliability during extreme weather events as off-shore production is prone to curtailments. Supply via FPL's transportation capacity rights on the SESH Pipeline Project would enable FPL to support approximately 4,000 MW of gas-fired capacity in the event of a supply disruption in the Gulf. This would allow FPL the opportunity to more efficiently manage fuel inventories during a loss of natural gas supply. Additionally, the introduction of new supply will create supply diversity which, in turn, will also help increase the reliability of supply.

Q. Will this project result in savings to FPL's customers?

A. Potentially. FPL believes that the introduction of 1,000,000 MMBtu per day of new supply into Mobile Bay area will have a positive impact on the overall supply/demand balance and should decrease the Mobile Bay basis (current premium above NYMEX for Mobile Bay supplies). While the primary driver of this project is to help meet future demand requirements and increase supply reliability and diversity, FPL believes that this project also may result in a lower overall cost of gas for FPL's customers.

Q. When is the SESH Pipeline Project projected to be in-service?

A. Current projections are for the project to be in-service by mid-2008.

Q. What types of costs associated with the SESH Pipeline Project is FPL seeking to recover through the Fuel Clause?

A. FPL's participation in the SESH Pipeline Project will result in two types of cost to be passed through the fuel clause: (1) fixed demand costs and, (2) variable commodity costs. Both types of costs are related to moving natural gas under firm transportation on the new pipeline. These transportation costs are identical in nature to the transportation costs that FPL incurs under its current FGT and Gulfstream firm natural gas transportation contracts, which FPL recovers through the fuel clause as a component of the total cost of gas. As discussed in the testimony of FPL witness K. Dubin, these transportation costs are recoverable through the fuel clause under existing Commission policy.

Q. What does FPL anticipate the annual cost to be for its participation in the SESH Pipeline Project?

A. Exhibit GJY-5 details FPL's estimate of the total annual costs associated with its proposed participation in the SESH Pipeline Project.

Q Do you have an exhibit that provides detailed, supporting documentation for FPL's proposed participation in the SESH Pipeline Project?

A. Yes. Exhibit GJY-6 is being included as documentation for the SESH Pipeline Project. This Exhibit includes the Precedent Agreement, Service Agreements and other associated agreements that FPL entered into on August 2, 2006 with Southeast Supply Header, LLC.

Q. Will FPL's participation in the SESH Pipeline Project diminish its need for the MoBay Gas Storage Project?

A. No. Each project is an important component of FPL's overall fuel procurement plan. There is not one project alone that can address supply reliability, supply diversity and future demand concerns. Rather, a combination of projects is necessary to enhance supply reliability and supply diversity and also address future demand concerns. While both the MoBay and SESH Projects address reliability concerns during severe weather events, the SESH Pipeline Project primarily addresses longer-term supply/demand balance issues and will be instrumental in helping FPL and Florida meet growing demand. The MoBay Gas Storage Project will significantly increase system reliability and help reduce natural gas price volatility for FPL's customers during severe weather events and periods of high demand. The MoBay Gas Storage Project is an excellent physical hedge for these types of short-term events. However, as demand increases, the MoBay Gas Storage Project cannot, by itself, mitigate all of the risk of supply disruptions and it does not address longer-term supply issues. While the SESH Pipeline Project will also help increase reliability during severe weather events as access to on-shore supply will reduce FPL's exposure to highly vulnerable off-shore production, this project also addresses longer-term supply issues. As described previously, declining production in the Mobile Bay area coupled with Florida's projected demand growth for natural gas have created a need for additional supply. The construction of the SESH Pipeline Project will help provide that supply into the Mobile Bay area for the benefit of FPL's customers and other natural gas consumers in Florida. Additionally, the SESH Pipeline Project could potentially help to lower the overall cost of natural gas in the Mobile Bay area.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF W.E. GWINN

DOCKET NO. 060001-EI

September 1, 2006

Q. **Please state your name and address.**

A. My name is Walter E. Gwinn. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. **By whom are you employed and what is your position?**

A. I am employed by Florida Power & Light Company (FPL) as a Manager of Nuclear Finance in the Nuclear Business Unit.

Q. **Have you testified in predecessors to this docket?**

A. Yes.

Q. **What is the purpose of your testimony?**

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy (MMBTU) to be produced by our nuclear units, the costs of disposal of spent nuclear fuel, and the costs of decontamination and decommissioning (D&D). I am also updating the status of certain litigation that affects FPL's nuclear fuel costs; plant security costs and new NRC security initiatives; outage events; and the inspections and repairs to the reactor pressure vessel heads since the issuance of NRC Bulletin (IEB) 2002-02. Both nuclear fuel and disposal of spent nuclear fuel costs were input values to POWERSYM used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2007 through December 2007.

Nuclear Fuel Costs

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and their operating schedules, for the period January 2007 through December 2007.

Spent Nuclear Fuel Disposal Costs

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2007 through December 2007.

A. FPL projects the nuclear units will produce 253,892,102 MMBTU of energy at a cost of $0.3611 per MMBTU, excluding spent fuel disposal costs, for the period January 2007 through December 2007. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 16 of the Appendix II.

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2007 through December 2007 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $21.2 million are provided in Appendix II, on Schedule E-2, starting on page 10a of the Appendix. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9312 mills per net kWh generated, including transmission and distribution line losses.

<u>Decontamination and Decommissioning Costs</u>

Q. Please provide FPL's projection for DOE Decontamination and Decommissioning (D&D) costs to be paid in the period January

2007 through December 2007 and explain the basis for FPL's projection.

A. Based on the Energy Policy Act of 1992 (EPACT) requirements, FPL's final payment for these costs will be made in 2006. There are no projected D&D costs for 2007.

<u>Litigation Status Update</u>

Q. Is there currently an unresolved dispute under FPL's nuclear fuel contracts?

A. Yes.

<u>Spent Fuel Disposal Dispute</u>. This dispute arose under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. In 1995 FPL, along with a number of electric utilities, states, and state regulatory agencies filed suit against DOE over its obligation to accept spent nuclear fuel beginning in 1998. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) held that DOE is required by the Nuclear Waste Policy Act (NWPA) to take title to and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998.

On January 11, 2002, based on the D.C. Circuit's ruling, the Court of Federal Claims granted FPL's motion for partial summary judgment in favor of FPL on contract liability. There is no trial date scheduled at this time for the FPL damages claim.

The Court of Federal Claims ruled on May 21, 2004 that another nuclear plant owner, Indiana Michigan Power Company, was not entitled to any damages arising out of the Government's failure to begin disposal of spent nuclear fuel by January 31, 1998. On appeal, the U.S. Court of Appeals for the Federal Circuit upheld the Court of Federal Claims decision. This decision could impact FPL's claims against the Government. The impact on FPL's claims is unknown at this time.

Nuclear Plant Security Costs

Q. Please provide an update of the nuclear plant security costs to comply with NRC's requirements.

A. As mentioned in prior testimony, FPL expected to complete its initial Design Basis Threat (DBT) related modifications in 2005. However, a portion of the DBT modifications have been delayed. These delays resulted partially from discovering issues with the as-found material condition and configuration of the Intrusion Detection System panels and camera poles, as well as from unrelated plant events such as the Turkey Point main transformer fire and recovery from Hurricane Wilma. Additionally, shortfalls were discovered with the vendor design of the new security computer concerning its ability to integrate with and test the existing system. Resolution of this issue delayed the start of the installation of the new system to March 2006. FPL now expects to complete all initial DBT modifications by the Fall of 2006.

Q. **What is FPL's projection of the incremental security costs for the period January 2007 through December 2007?**

A. FPL presently projects that it will incur $26.5 in incremental nuclear power plant security costs in 2007.

Q. **Please provide a brief description of the items included in this projection.**

A. The projection includes adding security personnel as a result of implementing NRC's Order EA03-038, which limits the number of hours security personnel may work in a week; additional personnel training; cyber security, which assesses the communication vulnerabilities of nuclear systems and identifies appropriate risk reduction measures; additional regulatory initiatives for fires, aircraft threat strategy; protection of spent fuel pools and containments; and the purchase of new security search equipment for Turkey Point.

Q. Please provide a brief description of the new Turkey Point security search equipment.

A. FPL will replace the existing metal and explosive detection devices and X-ray machines with new enhanced technology to comply with evolving NRC threat-detection requirements.

Q. What is the projected cost for this equipment?

A. FPL projects an estimated cost of $4.8 million to replace the security search equipment.

Q. Was the cost of this new equipment included in the 2006 MFRs filed in Docket No. 050045-EI?

A. No, none of this security search equipment was included. FPL was not aware of the need to replace the equipment at the time it prepared the MFRs.

Q. Why is the estimated cost to replace the security search equipment at St. Lucie not included in the 2007 projection?

A. As a result of Hurricane Wilma, St. Lucie sustained substantial damage to its security search equipment. FPL has filed an insurance claim for the cost of the search equipment and anticipates it will be covered by insurance. However, in the event the entire cost is not reimbursed by insurance, FPL will request recovery of the uninsured amount in the Capacity Clause in a subsequent filing.

Q. Is there a possibility of further NRC security-related initiatives in 2007 and beyond, in addition to those included in FPL's projection?

A. Yes. As FPL has explained in prior testimony to the Commission, FPL is aware of new NRC regulatory initiatives to revise requirements regarding fires, propose aircraft-threat strategy revisions, make potentially significant changes in requirements for protection of spent fuel pools, conduct a study in conjunction with The Department of Homeland Security to evaluate potential threats to nuclear facilities from land, sea and air attacks, and conduct a study of buffer zones around nuclear sites.

In addition, there is a new NRC initiative to review and update the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). The DBT is the measure that all nuclear stations are designed to defend against. Some of these EAC/DBT enhancements would require extensive engineering support and significant modifications to station security defensive positions. Depending on the extent of the EAC/DBT enhancement, additional security personnel may be necessary in addition to upgrades to security hardware and/or equipment. While FPL cannot predict what future EAC/DBT enhancements might be, based on past experience it is reasonable to expect that they will come. If so, this would require a response from FPL in the form of security program upgrades.

It is not feasible for FPL to estimate at this time the future costs that will be required to comply with these various developing regulatory requirements, but the Commission should be aware that nuclear security costs could increase significantly based on the issues mentioned above.

<u>Outage Events</u>

Q. Please provide a brief description of the cause of the Condenser Tube leak at St. Lucie Unit 2 that caused an outage in January 2006.

A. The tube leak resulted from the failure of a tube in the 2B2 waterbox. The tube split lengthwise, resulting in an approximately five inch long crack.

Q. What was the duration of the St. Lucie Unit 2 outage related to this issue?

A. The outage duration was approximately 4 days.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. FPL performed Eddy Current Testing (ECT) to detect tube defects on 100% of the condenser tubes during the refueling outage in April 2006. Condenser tubes with defects were plugged to prevent future tube leaks. Periodic condenser tube ECT is conducted to monitor tube degradation and plug affected tubes prior to failure.

Q. Please provide a brief description of the cause for the outage extension at Turkey Point Unit 3 in March and April of 2006.

A. As part of a series of tests and inspections being conducted to ensure that equipment was operating properly prior to plant heat-up and restart, FPL personnel identified a small drilled hole in the pressurizer piping.

Special teams from FPL corporate security, the NRC and the FBI went to Turkey Point to review and evaluate the circumstances concerning the damage. The NRC and FBI are conducting investigations into this potential tampering event. The NRC Augmented Inspection Team issued a report on this incident with no findings in April, 2006.

The affected pressurizer piping was repaired and the plant was restarted on April 10, 2006 without further incident.

Q. What was the duration of the Turkey Point Unit 3 outage extension related to this issue?

A. The outage extension duration was approximately 5 days.

<u>**Reactor Pressure Vessel Head Inspection Status**</u>

Q. What is the status of the reactor heads for the St. Lucie and Turkey Point Units?

A. As FPL has explained in prior testimony to the Commission, the NRC issued IEB 2002-02 on August 9, 2002 to address concerns related to visual inspections of the reactor heads. This NRC Bulletin resulted in all four FPL units being categorized as high susceptibility, requiring ultrasonic testing in addition to visual inspections until the reactor heads are replaced.

St. Lucie Unit 1 replaced the reactor vessel head during the refueling outage beginning on October 17, 2005.

St. Lucie Unit 2 performed ultrasonic inspections during the refueling outage beginning on April 23, 2006. No indications were detected on the reactor vessel head and no repairs were needed. The total cost of the inspections was approximately $5 million. The St. Lucie Unit 2 reactor vessel head will be replaced in the Fall of 2007 at the same time the Unit 2 steam generators are replaced.

The Turkey Point Unit 3 and 4 reactor vessel heads were replaced during the refueling outages beginning on September 26, 2004 and April 10, 2005 respectively.

Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 060001-EI

September 1, 2006

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present for Commission review and approval the Fuel Cost Recovery (FCR) factors for the period January 2007 through December 2007.
- I present for Commission review and approval a revised 2006 FCR estimated/actual true-up amount, which has been

updated to include July actual data and which is incorporated into the calculation of the 2007 FCR Factors.

- I present for Commission review and approval FPL's proposal to levelize the Residential 1,000 kWh Bill by offsetting the Generation Base Rate Adjustment (GBRA) for Turkey Point Unit 5 with the fuel savings attributable to this new unit.
- I present for Commission review and approval FPL's proposal to recover through the FCR Clause FPL's projected costs for the MoBay and Bay Gas Storage projects and explain why that proposal is appropriate and consistent with Commission practice.
- I present for Commission review and approval FPL's proposal to recover through the FCR Clause FPL's projected costs for the Southeast Supply Header Pipeline Project (SESH) and explain why that proposal is appropriate and consistent with Commission practice.
- I present for Commission review and approval the Capacity Cost Recovery (CCR) factors for the period January 2007 through December 2007.
- I present for Commission review and approval a revised 2006 CCR estimated/actual true-up amount, which has been updated to include July actual data and which is incorporated into the calculation of the 2007 CCR Factors.
- I present for Commission review and approval FPL's

projected incremental security costs for 2007, to be recovered through the CCR Clause, including costs associated with the recently issued North American Reliability Council (NERC) Cyber Security Standards

- Finally, I provide on pages 80-81 of Appendix II FPL's proposed COG tariff sheets, which reflect 2007 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. They are as follows:

- KMD-5 -- Schedules E1, E1-A, E1-B, E1-C, E1-D E1-E, E2, E10, H1, and pages 8-9 and 73-75 included in Appendix II
- KMD-6 -- the entire Appendix III
- KMD-7 -- the entire Appendix IV

Appendix II contains the FCR related schedules, Appendix III contains the CCR related schedules, and Appendix IV provides the alternate FCR schedules prepared using the standard methodology.

FUEL COST RECOVERY CLAUSE

<u>Bill Levelization</u>

Q. Is FPL proposing to levelize the Residential 1,000 kWh bill in 2007?

A. Yes. In order to provide customers with a stable, level bill in 2007, FPL proposes to levelize the Residential 1,000 kWh bill by offsetting the Generation Base Rate Adjustment (GBRA) as approved in Docket No. 050045-EI for Turkey Point Unit 5 with the fuel savings attributable to this new unit. The fuel savings of $96,464,000 attributable to Turkey Point Unit 5 are presented in the testimony of G. Yupp.

Without levelization, FPL's customers' bills are projected to decrease in January 2007 as result of lower charges for fuel and capacity. Then, in May 2007, when Turkey Point Unit 5 begins commercial operations, the GBRA will become effective, which thereby would increase customer bills. FPL's proposal will still provide a decrease in customers' bills in January while eliminating the increase in May.

Q. How does FPL propose to calculate this levelized Residential 1,000 kWh Bill?

A. FPL proposes to offset the GBRA that becomes effective in May 2007, by crediting the Turkey Point Unit 5 fuel savings to customers over the same timeframe, May through December 2007. Under the standard methodology, fuel costs for a given year (including any fuel savings) are levelized over the twelve month period. In order to offset the impact of the GBRA on customer bills in May through December 2007, the Turkey Point Unit 5 fuel savings would be excluded from the factor calculation for January through April 2007 and levelized over the eight month period May through December 2007.

To calculate the fuel charges that would levelize the 2007 Residential 1,000 kWh Bill, FPL prepared two E1 Schedules to calculate average fuel factors for January through April 2007 (page 3a of Appendix II) and May through December 2007 (page 3b of Appendix II). FPL first calculated fuel factors assuming Turkey Point Unit 5 is not operating in 2007, meaning that the fuel savings of $96,464,000 are excluded from the calculation of the levelized average fuel factor on both E1 Schedules. This adjustment is shown on Line 1a.

The next step is to adjust the fuel factors by crediting the fuel savings. The fuel savings of $96,464,000 when jurisdictionalized are $96,022,330. Crediting all of the $96,022,330 in the May through December period more than offsets the impact of the GBRA over the same timeframe. Therefore, in order to prevent a change in the 2007 Residential 1,000 kWh Bill, $95,672,330 of the savings are credited in May through December 2007 and $350,000 of the fuel savings are credited in January through April 2007.

For January through April 2007, FPL calculated a fuel factor that credits $350,000 of the jurisdictionalized fuel savings over the four month period. The $350,000 is divided by the projected sales for January through April 2007 which results in a downward adjustment to the fuel factor of.0011¢ per kWh. This adjustment is provided on Schedule E1 for January through April, Line 33a, Page 3a of Appendix II. This results in a levelized fuel factor of 6.071¢ per kWh on Line 35 or $57.29 on a Residential 1,000 kWh Bill. The total Residential 1,000 kWh Bill for January through April 2007 is $106.68, down from the current charge of $108.61, which is provided on Schedule E10, Page 71 of Appendix II.

For the period May through December 2007, FPL then calculated a fuel factor that credits $95,672,330 of the jurisdictionalized fuel savings over the eight month period. This amount is divided by the projected sales for May through December 2007 which results in a downward adjustment to the fuel factor of (.1262¢) per kWh, shown on Schedule E1 for May through December, Page 3b, Line 33a. This results in a lower levelized fuel cost recovery factor of 5.946¢ per kWh on Line 35. This represents $56.04 on a Residential 1,000 kWh Bill in May 2007, $1.25 less than the $57.29 charge in January 2007 (see Schedule E10, Page 71 of Appendix II).

In May 2007, the Base charge on a 1,000 kWh Residential bill increases by $1.25 due to the GBRA but, under FPL's proposal, is offset by the $1.25 decrease in the fuel charge due to the fuel savings associated with Turkey Point Unit 5. As a result, there is no change in the total Residential 1,000 kWh Bill, and it remains at $106.68.

Q. Will all rate classes see a levelized bill for the January through December 2007 period?

A. Only the "Typical" 1,000 kWh Residential Bill will be completely levelized, while for other Residential consumption levels and other rate classes there will remain small differences between their bills for January through April versus the bills for May through December. However, all customer classes and consumption levels will see less of a fluctuation in their bills from April to May than they would without FPL's proposes levelization. Moreover, all rate classes will see a decrease in their bills beginning in 2007.

Q. As an alternative, is FPL also providing fuel factors using the standard methodology?

A. Yes. Although FPL requests approval of its "Levelized Bill Methodology," in the alternative FPL has also provided fuel factors using the standard methodology. Appendix IV includes Schedules E1, E1-D, E1-E, E2, and E10, which calculate the twelve-month levelized fuel factor (standard methodology). This twelve-month levelized fuel factor spreads the savings resulting from Turkey Point Unit 5 throughout the twelve months of 2007.

Q. Is FPL's levelization proposal revenue neutral?

A. Yes. The FCR Factors that FPL proposes for levelizing the bill are designed to recover the same total FCR revenues over 2007 as would standard, non-levelized FCR Factors.

Q. What are the proposed levelized fuel cost recovery (FCR) factors for which the Company requests approval?

A. For the period January through April 2007, the levelized fuel cost recovery factor is 6.071¢ per kWh. Schedule EI (January through April), Page 3a of Appendix II shows the calculation of this four-month levelized FCR factor.

For the period May through December 2007, the levelized fuel cost recovery factor is 5.946¢ per kWh. Schedule EI (May through December), Page 3b of Appendix II shows the calculation of this eight-month levelized FCR factor.

Schedule E2 (January through April), Pages 10a and 10b of Appendix II shows the monthly fuel factors for January 2007 through April 2007 and also the four-month levelized FCR factor for this period. Schedule E2 (May through December), Pages 11a and 11b of Appendix II shows the monthly fuel factors for May 2007 through December 2007 and also the eight month levelized FCR factor for this period.

Q. Has the Company developed levelized FCR factors for its Time of Use rates?

A. Yes. For the period January through April 2007, Schedule E1-D (January through April), Page 6a of Appendix II, provides the four-month levelized FCR factor of 6.757¢ per kWh on-peak and 5.764¢ per kWh off-peak for our Time of Use rate schedules for this period.

For the period May through December 2007, Schedule E1-D (May through December), Page 6b of Appendix II, provides the eight-month levelized FCR factor of 6.632¢ per kWh on-peak and 5.639¢ per kWh off-peak for our Time of Use rate schedules for this period.

The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are provided on Schedule E-1D, Page 6c of Appendix II. The SDTR was implemented pursuant to the Stipulation and Settlement Agreement approved in Docket No. 050045-EI, which incorporates a different on-peak period during the months of June through September.

FCR factors by rate group for the periods January through April 2007 and May through December 2007 are presented on Schedule E1-E, Pages 7a and 7b of Appendix II. FCR factors by rate group for the SDTR are provided on Schedule E-1D, Page 7c of Appendix II.

Q. Were these calculations made in accordance with the procedures approved in predecessors to this Docket?

A. Yes.

Q. Has FPL calculated the residential fuel charges using the inverted rate structure?

A. Yes.

<u>Revised 2006 FCR Estimated/Actual True-up</u>

Q. Has FPL revised its 2006 FCR Estimated/Actual True-up amount that was filed on August 8, 2006 to reflect July actual data?

A. Yes. The 2006 FCR Estimated/actual True-up amount has been revised to an over-recovery of $230,603,338 reflecting July actual data. The calculation of the revised 2006 FCR Estimated/actual true-up amount is shown on Revised Schedule E1-B, on Pages 4a-4b of Appendix II.

Q. What is the revised net true-up amount that FPL is requesting to include in the FCR factor for the January 2007 through

December 2007 period?

A. FPL is requesting approval of a net true-up under-recovery of $76,834,262. This $76,834,262 under-recovery represents the revised estimated/actual over-recovery for the period January 2006 through December 2006 of $230,603,338 plus the final true-up under-recovery of $307,437,600 that was filed on March 1, 2006 for the period January 2005 through December 2005. This $76,834,262 under-recovery is to be included for recovery in the FCR factor for the January 2007 through December 2007 period.

Q. What adjustments are included in the calculation of the levelized FCR factors shown on Schedule E1, Page 3a and 3b of Appendix II?

A. As shown on line 29 of Schedule E1, Pages 3a and 3b of Appendix II, the total net true-up to be included in the 2007 factors is a revised under-recovery of $76,834,262. This amount divided by the projected retail sales of 107,697,623 MWh for January 2007 through December 2007 results in an increase of .0713¢ per kWh before applicable revenue taxes. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Pam Sonnelitter, filed on April 1, 2006, calculated a reward of $8,478,098 for the period ending December 2005, which is being applied to the January 2007 through December 2007 period. This $8,478,098 reward divided by the projected retail sales of 107,697,623 MWh during the projected period results in an increase of .0079¢ per kWh, as shown on line 33 of Schedule E1, Pages 3a and 3b of Appendix II.

<u>MoBay Gas Storage Project</u>

Q. Is FPL requesting recovery of the MoBay Gas Storage Project, through the FCR Clause?

A. Yes. As discussed in the testimony of FPL witness G. Yupp, FPL is requesting fuel clause recovery treatment for the MoBay Gas Storage Costs including Base (pad) Gas and Fuel Storage Carrying Costs beginning in 2008. FPL is also requesting to recover Carrying Costs on gas stored at the Bay Gas facility through the fuel adjustment clause commencing upon approval of FPL's petition.

Q. What is the basis for requesting recovery of these gas storage project costs through the Fuel Cost Recovery Clause?

A. FPL is proposing to recover these costs through the Fuel Cost Recovery clause because the costs are gas transportation and hedging costs. Additionally, Base Gas is analogous to the "non-recoverable oil" and should be treated in the same manner. None of the costs of the Gas Storage Project are currently recovered through FPL's base rate charges or any other recovery mechanism.

Gas Transportation Costs

The monthly storage reservation charge, injection/ withdrawal charges, and insurance charges Gas Storage Project are described in the testimony of G. Yupp. Those charges are gas transportation costs and, as such, are recoverable through the fuel clause pursuant to Commission Order No. 14546 in Docket No. 850001-EI-B, issued July 8, 1985 which addressed costs that may be appropriately included in the calculation of recoverable fuel costs. The order lists transportation costs as a cost appropriate for recovery through the clause.

Base Gas

As discussed in more detail in Mr. Yupp's testimony, tenants at the Gas Storage Facility are required to provide or pay for a quantity of gas that will be injected into the storage reservoir to help maintain pressure in the reservoir and hence facilitate injection and removal of the working volume of gas. This Base Gas remains in the reservoir until the end of the storage agreement term, at which time it is either physically removed or sold to a subsequent tenant. In either event, FPL's customers would get the benefit of the Base Gas at that time. Base Gas is thus directly analogous to the "non-recoverable oil" that sits at the bottom of oil storage tanks (*i.e.,* "tank bottoms"). Non-recoverable oil is needed to keep the oil level in a tank high enough for the working volume of oil to be removed by the suction piping in the tank. Non-recoverable oil remains in the tank until it is periodically cleaned, at which time the oil is removed and burned as fuel. Pursuant to Order No. 12645, Docket No. 830001-EI, dated November 3, 1983, FPL and other utilities have been authorized to charge the cost of non-recoverable oil to the FCR Clause when the oil is loaded into the tanks, with a credit to the FCR Clause when it is ultimately removed and burned. This is precisely the treatment that FPL seeks with respect to the Base Gas Costs.

<u>Carrying Costs for Stored Gas</u>

The Gas Storage Project is a physical hedge. As described in the testimony of G. Yupp, the storage facility will substantially increase FPL's ability to hedge the physical supply of natural gas, resulting in a significant increase in system reliability and a reduction in natural gas volatility. Stored natural gas is not "fuel inventory" in the conventional sense; storing the gas serves the purpose of hedging rather than meeting ordinary operational needs of FPL's gas-fired plants. Because the purpose of storing gas is to effect a physical hedge, the gas storage carrying costs associated with the Gas Storage Project are appropriately considered hedging costs.

Pursuant to the Proposed Resolution of Issues (the "Hedging Resolution") approved by the Commission in Order No. PSC-02-1484-FOF-EI, dated October 30, 2002, hedging costs are recoverable through the FCR Clause. In the Order, the Commission stated:

> In addition, [the Hedging Resolution] maintains flexibility for each IOU to create the type of risk management program for fuel procurement that it finds most appropriate while allowing the Commission to retain the discretion to evaluate, and the parties the opportunity to address, the prudence of such programs at the appropriate time. Further, the [Hedging Resolution] appears to remove disincentives that may currently exist for IOUs to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs.

The Hedging Resolution specifically refers to both "physical" and "financial" hedging throughout, and includes a note at the end specifically clarifying that "[n]o implication concerning the relative merits of using financial versus physical hedging techniques should be drawn from this proposed resolution." Therefore, FPL believes its proposal to recover the gas storage carrying costs associated with the Gas Storage Project through the FCR Clause is appropriate and consistent with the Hedging Resolution.

Q. Is recovery of hedging costs through the FCR Clause consistent with FPL's 2005 Rate Case Stipulation?

A. Yes.

The 2005 Rate Case Stipulation itself does not speak to the recovery of hedging costs. This was an oversight, which the parties confirmed to the Commission at the August 24, 2005 hearing on the stipulation. Order No. PSC-05-0902-S-EI, Docket No. 050045-EI, dated September 14, 2005 approving the Stipulation states:

> Pursuant to a stipulation approved in Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, FPL currently recovers incremental hedging costs through the Fuel Cost Recovery Clause (Fuel Clause). In its petition for a rate increase, FPL proposed to recover these costs through base rates instead. The [2005 Rate Case Stipulation] is silent on how incremental hedging costs will be recovered. *The parties clarified that they intended for recovery of these costs to continue through the [FCR] Clause during the term of the [2005 Rate Case Stipulation]. Because the Stipulation is silent in this regard, the parties indicated that they would take action to*

> *memorialize their intent in this year's [FCR] Clause proceedings.*

(Emphasis added).

Consistent with this clarification, all of the parties to the 2005 Rate Case Stipulation that were parties to Docket No. 050001-EI entered into a stipulation on October 17, 2005 that provided in relevant part as follows:

> "ISSUE: Should FPL be allowed to continue recovering incremental hedging costs through the [FCR] Clause during the term of the [2005 Rate Case Stipulation] that was approved in Order No. PSC-05-0902-S-EI, Docket No. 050045-EI, dated September 14, 2005, on the same basis as FPL has been recovering such costs pursuant to the Proposed Resolution of Issues that was approved in Order No. PSC-02-1484-FOF-EI, Docket No. 011605-EI, dated October 30, 2002?
>
> POSITION: Yes. FPL's continued recovery of incremental hedging costs through the [FCR] Clause during the term of the [2005 Rate Case Stipulation] is reasonable and consistent with the intention of the parties to the [2005 Rate Case Stipulation]."

This stipulation was approved by the Commission as reasonable in Order No. PSC-05-1252-FOF-EI, Docket No. 050001-EI, dated

December 23, 2005. Thus the parties to the 2005 Rate Case Stipulation specifically intended and agreed that FPL would be permitted to recover hedging costs through the FCR Clause throughout the term of the 2005 Rate Case Stipulation, which will continue until at least December 31, 2009. Because the gas storage carrying costs are properly considered to be hedging costs, their recovery through the FCR Clause is appropriate and consistent with the 2005 Rate Case Stipulation.

Q. Is FPL also seeking to recover Carrying Costs on gas stored at the Bay Gas facility through the FCR?

A. Yes. FPL has utilized small scale natural gas storage arrangements for several years. Initially, FPL purchased storage capacity on a short-term basis, but in 2003 entered into a long-term storage arrangement with Bay Gas Storage Company Limited, Ltd. (the "Bay Gas Storage Contract").. FPL has included costs associated with the Bay Gas Storage Contract in the FCR clause since the contract's inception in 2003. However, until now FPL has inadvertently failed to include in the FCR clause the carrying cost associated with natural gas stored at the Bay Gas facility. FPL is not seeking recovery of these costs retroactively, even though such costs should have been appropriately recovered through the FCR Clause. Commencing upon the Commission's approval in this proceeding, FPL proposes to begin including in the FCR Clause the natural gas inventory carrying costs associated with the Bay Gas Storage Contract.

<u>**Southeast Supply Header (SESH) Pipeline Project**</u>

Q. What is the SESH Pipeline Project?

A. As further explained in the testimony of FPL witness G. Yupp, the SESH pipeline project is a joint project of CenterPoint Energy Gas Transmission (CEGT) and Duke Energy Gas Transmission (DEGT) to build nearly 270 miles of 36-inch pipeline starting at CEGT's Perryville Hub in Northeast Louisiana and ending at the pipeline of DEGT's partially owned affiliate, Gulfstream Natural Gas System, near Mobile County, Alabama. The proposed route will cross and interconnect with major interstate pipelines serving the eastern United States that are not currently served at the Perryville Hub. The SESH Pipeline Project will allow FPL access to growing production from natural gas basins in East Texas and North Louisiana, which will provide an important on-shore alternate natural gas supply source for markets in the Southeast.

Q. Is FPL requesting recovery of the SESH Pipeline Project, through the FCR Clause?

A. Yes. As discussed in Mr. Yupp's testimony, FPL is requesting fuel clause recovery treatment for the SESH Pipeline Project costs beginning in 2008.

Q. What is the basis for requesting recovery of the SESH Pipeline Project costs through the Fuel Cost Recovery Clause?

A. In Docket No. 850001-EI-B, Order No. 14546 issued July 8, 1985, the Commission addressed costs that may be appropriately included in the calculation of recoverable fuel costs. The order lists the charges that "are properly considered in the computation of the average inventory price of fuel used in the development of fuel expense in the utilities' fuel cost recovery clauses". Item No. 4 of the list states, "Transportation costs to the utility system, including detention or demurrage." Clearly, the SESH Pipeline project costs are transportation costs to the utility system and would qualify for recovery through the FCR Clause. This is the same cost recovery treatment that FPL uses for its existing gas transportation costs. Moreover, as Mr. Yupp explains in his testimony, the SESH Project will be a valuable addition to FPL's gas-transportation alternatives because it will provide FPL access to on-shore supply which, in turn, will significantly increase supply reliability, supply diversity and potentially support customer savings.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2006 CCR Estimated/Actual True-up amount that was filed on August 8, 2006 to reflect July actual data?

A. Yes. The 2006 CCR Estimated/actual True-up amount has been revised to an under-recovery of $18,215,446 reflecting July actual data. The calculation of the revised 2006 CCR Estimated/actual true-up amount is shown on page 3b of Appendix III.

Q. What is the revised net true-up amount that FPL is requesting to include in the CCR factor for the January 2007 through December 2007 period?

A. FPL is requesting approval of a net true-up under-recovery of $14,909,758. This $14,909,758 under-recovery represents the revised estimated/actual under-recovery for the period January 2006 through December 2006 of $18,215,446 plus the final true-up over-recovery of $3,305,688 that was filed on March 1, 2006 for the period January 2005 through December 2005. This $14,909,758 under-recovery is to be included for recovery in the CCR factor for the January 2007 through December 2007 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2007 through December 2007?

A. Yes. Page 3 of Appendix III provides this summary. Total Recoverable Capacity Payments are $541,636,552 (line 16) and include payments of $195,185,676 to non-cogenerators (line1), Short-term Capacity Payments of $52,399,434 (line 2), payments of $316,149,792 to cogenerators (line 3), and $3,536,928 relating to the

St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4a), $30,442,387 in Incremental Power Plant Security Costs (line 6), and $2,679,339 for Transmission of Electricity by Others (line 7). This amount is offset by $5,399,062 of Return Requirements on SJRPP Suspension Payments (line 4b), by Transmission Revenues from Capacity Sales of $3,941,588 (line 8), and by $56,945,592 of jurisdictional capacity related payments included in base rates (line 12). The resulting amount is then increased by a net under-recovery of $14,909,758 (line 13). The net under-recovery of $14,909,758 includes the final over-recovery of $3,305,688 for the January 2005 through December 2005 period that was filed with the Commission on March 1, 2006, plus the estimated/actual under-recovery of $18,215,446 for the January 2006 through December 2006 period, which includes actual data for January through July 2006 and revised estimates for August through December 2006.

<u>Incremental Power Plant Security</u>

Q. Has FPL included a projection of its 2007 Incremental Power Plant Security Costs in calculating its Capacity Cost Recovery (CCR) Factors?

A. Yes. FPL has included $30,442,387 on Appendix III, page 3, Line 6 for projected 2007 Incremental Power Plant Security Costs in the calculation of its CCR Factors. Section 14 of FPL's 2005 Rate Case Stipulation contemplates the continued use of the CCR Clause to recover incremental power plant security costs throughout the term of the stipulation. Of the total amount of projected 2007 costs, $26,547,082 is for nuclear power plant security, which is discussed in Mr. Gwinn's testimony. $1,098,942 is for fossil power plant security, which includes the costs of increased security measures for fossil power plants required by the Maritime Transportation Act, Coast Guard rules and/or recommendations from the Department of Homeland Security authorities. Additionally, FPL is seeking recovery of incremental security costs of $2,796,363 related to recently issued North American Reliability Council (NERC) Cyber Security Standards CIP-002-1 through CIP-009-1 (Cyber Security Standards).

Q. Please describe the NERC Cyber Security Standard and discuss why recovery of them as Incremental Power Plant Security Costs is appropriate.

A. NERC was recently certified by the Federal Regulatory Energy Commission (FERC) as the nation's Electric Reliability Organization (ERO), pursuant to the Energy Policy Act of 2005. As such, NERC is responsible for developing and enforcing mandatory electric reliability standards which will apply to all users, owners and operators of the bulk power system. The NERC Cyber Security Standards were approved by the NERC Board on May 3, 2006 and became effective June 1, 2006 to address cyber security concerns as a result of the September 11, 2001 terrorist attacks.

FPL is seeking recovery only of the costs of complying with the Cyber Security Standards at its power plants; it has specifically excluded from its request the compliance costs associated with the transmission and other non-power plant parts of its system. None of the costs FPL seeks to recover are presently recovered through base rates. They are clearly related to governmentally-imposed post-9/11 security requirements and hence are properly recoverable through the CCR Clause.

<u>**Calculation of CCR Factors**</u>

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 4 of Appendix III provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Have you prepared a calculation of the proposed CCR factors by rate class?

A. Yes. Page 5 of Appendix III presents this calculation.

Q. What effective date is the Company requesting for the new FCR

and CCR factors?

A. The Company is requesting that the new FCR factors for January through April and May through December become effective during these periods which will provide four months of billing on the January through March factor and eight months of billing on the May through December factor. This will provide for 12 months of billing on the new FCR factors for all our customers. FPL is requesting that the CCR factors become effective with customer bills for January 2007 through December 2007. This will provide for 12 months of billing on the CCR factors for all our customers.

Q. Under FPL's proposal to levelize the Residential 1,000 kWh Bill, what will be the charge for a Residential customer using 1,000 kWh effective January 2007?

A. The "typical" Residential 1,000 kWh Bill will be $106.68 under FPL's proposal to levelize the residential bill in 2007. For January through April 2007, this includes a base charge of $38.12, the fuel cost recovery charge is $57.29, the Capacity Cost Recovery charge is $5.57, the Conservation charge is $1.69, the Environmental Cost Recovery charge is $.24, the Gross Receipts Tax is $2.67, and an estimated storm securitization charge of $1.10. If securitization is accomplished in 2006, FPL expects that the storm charge will be reduced from its current level of $1.65 per 1,000 kWh to $1.10; if not, then the charge will be higher than $1.10. The storm securitization charge is a preliminary estimate. The actual storm recovery charge will be based on market conditions at the time the storm recovery bonds are issued. Pursuant to Order PSC-06-0464-FOF-EI issued in the Securitization docket, "prior to implementing the initial storm-recovery charges, FPL shall file tariff sheets for administrative approval, which tariff sheets will be administratively approved by Commission Staff within three (3) business days, subject to correction for any mathematical error. At Staff's request, FPL shall furnish draft tariff sheets at least five (5) business days in advance of the public offering of storm-recovery bonds."

For May through December 2007, the “Typical” Residential 1,000 kWh Bill remains at $106.68 and includes a base charge of $39.37, the fuel cost recovery charge is $56.04, the Capacity Cost Recovery charge is $5.57, the Conservation charge is $1.69, the Environmental Cost Recovery charge is $.24, the Gross Receipts Tax is $2.67, and an estimated storm securitization surcharge of $1.10. As stated above, the storm securitization charge is a preliminary estimate.

A comparison of the current Residential (1,000 kWh) Bill to FPL’s proposed January through April 2007, and May through December 2007 projected Residential (1,000 kWh) Bills is presented in Schedule E10, Page 71 of Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased power Cost Recovery Clause and Generating Performance Incentive Factor	))))	DOCKET NO. 060001-EI FILED: September 1, 2006

AFFIDAVIT

STATE OF FLORIDA
COUNTY OF MIAMI-DADE

BEFORE ME, the undersigned authority, personally appeared Rosemary Morley, who being first duly sworn deposes and says:

1. My name is Rosemary Morley. I am employed by Florida Power & Light Company ("FPL"). My business address is 9250 West Flagler St., Miami, Florida, 33174.

2. I hold a bachelors degree in economics from the University of Maryland, a masters degree in economics from Northwestern University and a doctorate in business administration from Nova Southeastern University. Since joining FPL in 1983 I have held a variety of positions in the forecasting, planning, and regulatory areas. I have previously filed testimony on rate matters before the Federal Energy Regulatory Commission and the Florida Public Service Commission ("FPSC" or "the Commission") and have appeared as a rate witness before the Florida Division of Administrative Hearings.

3. I currently hold the position of Rate Development Manager with responsibilities for rate development and tariff administration.

4. The purpose of my affidavit is to submit for the Commission's confirmation the revisions to FPL's rates and charges resulting from the commercial operation of Turkey Point Unit 5. The Stipulation and Settlement Agreement approved by Commission in its Order No. PSC-05-0902-S-EI, issued September 14, 2005 in Docket 050045-EI ("Settlement Agreement"), provides for a Generation Base Rate Adjustment ("GBRA") to FPL's rates upon commercial operation of Turkey Point Unit 5. As Dr. Sim states in his affidavit, Turkey Point Unit 5, approved through the Florida Power Plant Siting Act ("PPSA"), is expected to achieve commercial operation in May 2007.

5. Pursuant to the Settlement Agreement, the GBRA is to be implemented by adjusting base charges and non-clause recoverable credits (e.g. the transformer rider credits and the curtailable service credits) by an equal percentage. The calculation of this percentage change in rates is based on the ratio of Turkey Point Unit 5's jurisdictional annual revenue requirement and the forecasted retail base revenues from the sales of electricity during the first twelve months of the unit's operation. This ratio is the GBRA Factor. The GBRA Factor is applied to FPL's current base charges and non-clause recoverable credits to produce the revised base rate charges. I describe below in more detail the computation of the GBRA Factor.

6. As presented in Dr. Sim's affidavit, the base revenue requirement for the first twelve months of Turkey Point Unit 5's operation is $128.80 million. The Jurisidictional Separation Factors consistent with the separation of costs incorporated in

Docket 050045-EI are applied to this figure. As shown in Document No. RM-1, the resulting jurisdictional revenue requirement is $126.80 million.

7. The GBRA Factor also requires computation of the retail base revenues from the sales of electricity during the first twelve months of Turkey Point Unit 5's commercial operation. Billed retail base revenues from the sales of electricity have been projected using the same load forecast incorporated in the Company's current capacity clause filing. Document No. RM-2 shows the billed retail base revenues from the sales of electricity for the period May 2007 through April 2008 for all customer classes. Billed retail base revenues from the sales of electricity include customer, demand and energy charge revenues and non-clause recoverable credits. Thus, all the charges subject to the GBRA Factor are included in this revenue figure. In addition, unbilled retail base revenues are included in total retail base revenues from the sales of electricity in order to account for the collection lag resulting from the billing cycle. As shown in Document No. RM-2, the total retail base revenues from the sales of electricity over the first twelve months of Turkey Point Unit 5's commercial operation are projected be $3,876.80 million.

8. The GBRA Factor is calculated based on the ratio of Turkey Point Unit 5's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of Turkey Point Unit 5's commercial operation. The computation and resulting GBRA Factor, 3.271%, is provided in Document No. RM-3. Document No. RM-4 shows the revised charges that result from applying the GBRA Factor to FPL's current base charges and non-clause recoverable credits. Pursuant to the Settlement Agreement, these new charges will be applied to

meter readings made on and after the commercial in service date of Turkey Point Unit 5, currently projected to occur in May 2007. FPL will submit for the FPSC staff's administrative approval revised tariff sheets reflecting these new charges prior to the actual commercial in service date.

8. Once Turkey Point Unit 5's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial GBRA Factor for Turkey Point Unit 5, a one-time credit will be made through the capacity clause. In order to determine the amount of this credit a revised GBRA Factor will be computed using the same data and methodology incorporated into the initial GBRA Factor, with the exception that Turkey Point Unit 5's actual capital costs will be used in lieu of the capital cost the need determination was based on. On a going forward basis, base rates will be adjusted to reflect the revised GBRA Factor for Turkey Point Unit 5. The difference between the cumulative base revenues since the implementation of the initial GBRA Factor and the cumulative base revenues that would have resulted if the revised GBRA Factor had been in-place during the same time period will be credited to customers through the capacity clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109.

Rosemary Morley

Rosemary Morley

I hereby certify that on this 29th day of AUGUST, 2006 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Rosemary Morley who is personally known to me, and she acknowledge before me that she executed this certification of signature as her free act and deed who did not take an oath.

I witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as this 29th day of AUGUST, 2006.

E Martin

Notary Public

State of Florida

My Commission Expires:
NOV. 17, 2008

NOTARY PUBLIC-STATE OF FLORIDA
E. Martin
Commission #DD372939
Expires: NOV. 17, 2008
Bonded Thru Atlantic Bonding Co., Inc.

Docket No 060001-EI
R. Morley, Exhibit No. _______
Document No. RM-1, Page 1 of 1
Separation Of Turkey Point Costs

	System ($million)	Jurisdictional Factor	($million)
Capital Revenue Requirement	$116.05	98.451%	$114.25
Fixed O&M and Capital Replacement	11.67	98.439%	11.49
Variable O&M	1.07	98.439%	1.06
Total Revenue Requirement	$128.80	98.450%	$126.80

Note: Totals may not add due to rounding.

Docket No. 060001-EI
R. Morley, Exhibit No. _______
Document No. RM-2, Page 1 of 1
Retail Base Revenues For The First 12 Months Of Turkey Point Unit 5's Commercial Operation

Customer Class	2007 May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	$177,556,790	$211,709,515	$232,135,575	$234,491,009	$231,376,796	$213,325,680	$182,470,240	$182,607,690
Commercial	$110,034,335	$116,414,425	$119,549,579	$120,386,791	$121,202,000	$117,655,699	$110,678,360	$109,159,045
Industrial	$6,721,581	$7,336,634	$6,595,864	$7,019,631	$7,090,561	$6,856,521	$7,053,774	$6,722,891
Street & Highway	$3,609,645	$3,614,911	$3,620,177	$3,625,443	$3,630,924	$3,636,405	$3,641,886	$3,647,641
Other	$126,828	$129,824	$131,444	$131,569	$131,630	$129,618	$126,163	$123,398
Railroads & Railways	$216,036	$234,346	$228,319	$229,827	$235,330	$234,390	$229,719	$223,926
Total Billed Retail Base Revenue	$298,265,216	$339,439,654	$362,260,957	$365,884,269	$363,667,242	$341,838,313	$304,200,143	$302,484,591

Customer Class	2008 Jan	Feb	Mar	Apr	12 Month Ending
Residential	$201,744,675	$172,631,949	$171,395,250	$166,113,281	$2,377,558,448
Commercial	$109,533,074	$105,899,180	$109,009,271	$111,100,421	$1,360,622,179
Industrial	$6,808,629	$7,175,460	$6,966,301	$6,893,599	$83,241,446
Street & Highway	$3,653,396	$3,659,151	$3,665,870	$3,672,590	$43,678,040
Other	$121,682	$121,175	$122,327	$124,222	$1,519,880
Railroads & Railways	$220,945	$216,351	$228,473	$227,502	$2,725,164
Total Billed Retail Base Revenue	$322,082,401	$289,703,266	$291,387,491	$288,131,614	$3,869,345,157

	12 Month Ending
Total Billed Retail Base Revenues From the Sales of Electricity	$3,869,345,157
Unbilled Retail Base Revenues	$7,457,421
Total Retail Base Revenues From the Sales of Electricity	$3,876,802,579

Note: Totals may not add due to rounding.

Docket No. 060001-EI
R. Morley, Exhibit No. _______
Document No. RM-3, Page 1 of 1
GBRA FACTOR

		($million)	source
(A)	Jurisdictional Annualized Revenue Requirement	$126.80	Doc. No. RM-1
(B)	Total Retail Base Revenues From the Sales of Electricity	$3,876.80	Doc. No. RM-2
(C)	GBRA FACTOR [(A) / (B)]	3.271%	

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
RS-1	Residential Service			
	Customer Charge/Minimum	$5.17	$5.34	3.3%
	Base Energy Charge (¢ per kWh)			
	First 1,000 kWh	3.295	3.403	3.3%
	All additional kWh	4.295	4.435	3.3%
RST-1	Residential Service -Time of Use			
	Customer Charge/Minimum	$8.20	$8.47	3.3%
	with Lump-sum metering payment	$5.17	$5.34	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	6.914	7.140	3.3%
	Off-Peak	2.123	2.192	3.3%
	Lump-sum payment for time of use metering cost	$145.60	$150.36	3.3%
GS-1	General Service - Non Demand (0-20 kW)			
	Customer Charge/Minimum			
	Metered	$8.24	$8.51	3.3%
	Unmetered	$5.49	$5.67	3.3%
	Base Energy Charge (¢ per kWh)	3.802	3.927	3.3%
GST-1	General Service - Non Demand - Time of Use (0-20 kW)			
	Customer Charge/Minimum	$11.27	$11.64	3.3%
	with Lump-sum metering payment	$8.24	$8.51	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	7.431	7.674	3.3%
	Off-Peak	2.143	2.213	3.3%
	Lump-sum payment for time of use metering cost	$145.60	$150.36	3.3%
GSD-1	General Service Demand (21-499 kW)			
	Customer Charge	$32.05	$33.10	3.3%
	Demand Charge ($/kW)			
	Demand Charge - All kW ($/kW)	$4.94	$5.10	3.2%
	Base Energy Charge (¢ per kWh)	1.348	1.392	3.3%
	Minimum	$135.79	$140.20	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
GSDT-1	General Service Demand - Time of Use (21-499 kW)			
	Customer Charge	$38.00	$39.24	3.3%
	with Lump-sum metering payment	$32.05	$33.10	3.3%
	Demand Charge - On-Peak ($/kW)	$4.94	$5.10	3.2%
	Base Energy Charge (¢ per kWh)			
	On-Peak	3.146	3.249	3.3%
	Off-Peak	0.865	0.893	3.2%
	Lump-sum payment for time of use metering cost	$354.39	$365.98	3.3%
GSLD-1	General Service Large Demand (500-1999 kW)			
	Customer Charge	$37.55	$38.78	3.3%
	Demand Charge ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)	1.067	1.102	3.3%
	Mimimum	$2,897.55	$2,993.78	3.3%
GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)			
	Customer Charge	$37.55	$38.78	3.3%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.113	2.182	3.3%
	Off-Peak	0.641	0.662	3.3%
	Mimimum	$2,897.55	$2,993.78	3.3%
CS-1	Curtailable Service (500-1999 kW)			
	Customer Charge	$100.74	$104.04	3.3%
	Demand Charge ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)	1.068	1.103	3.3%
	Monthly Credit ($ per kW)	($1.56)	($1.61)	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
CS-1	Curtailable Service (500-1999 kW) (continued)			
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.56	$1.61	3.2%
	Penalty Charge-current month (per kW)	$3.36	$3.47	3.3%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	3.0%
	Minimum	$2,960.74	$3,059.04	3.3%
CST-1	Curtailable Service -Time of Use (500-1999 kW)			
	Customer Charge	$100.74	$104.04	3.3%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.114	2.183	3.3%
	Off-Peak	0.641	0.662	3.3%
	Monthly Credit (per kW)	($1.56)	($1.61)	3.2%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.56	$1.61	3.2%
	Penalty Charge-current month (per kW)	$3.36	$3.47	3.3%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	3.0%
	Minimum	$2,960.74	$3,059.04	3.3%
GSLD-2	General Service Large Demand (2000 kW +)			
	Customer Charge	$155.68	$160.77	3.3%
	Demand Charge ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)	1.064	1.099	3.3%
	Minimum	$11,595.68	$11,980.77	3.3%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$155.68	$160.77	3.3%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.219	2.292	3.3%
	Off-Peak	0.600	0.620	3.3%
	Minimum	$11,595.68	$11,980.77	3.3%
CS-2	Curtailable Service (2000 kW +)			
	Customer Charge	$155.68	$160.77	3.3%
	Demand Charge ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)	1.064	1.099	3.3%
	Monthly Credit (per kW)	($1.56)	($1.61)	3.2%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.56	$1.61	3.2%
	Penalty Charge-current month (per kW)	$3.36	$3.47	3.3%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	3.0%
	Minimum	$11,595.68	$11,980.77	3.3%
CST-2	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$155.68	$160.77	3.3%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.222	2.295	3.3%
	Off-Peak	0.600	0.620	3.3%
	Monthly Credit (per kW)	($1.56)	($1.61)	3.2%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.56	$1.61	3.2%
	Penalty Charge-current month (per kW)	$3.36	$3.47	3.3%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	3.0%
	Minimum	$11,595.68	$11,980.77	3.3%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
GSLD-3	General Service Large Demand (2000 kW +)			
	Customer Charge	$366.30	$378.28	3.3%
	Demand Charge ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)	0.553	0.571	3.3%
GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$366.30	$378.28	3.3%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.615	0.635	3.3%
	Off-Peak	0.493	0.509	3.2%
CS-3	Curtailable Service (2000 kW +)			
	Customer Charge	$366.30	$378.28	3.3%
	Demand Charge ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)	0.553	0.571	3.3%
	Monthly Credit (per kW)	($1.56)	($1.61)	3.2%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.56	$1.61	3.2%
	Penalty Charge-current month (per kW)	$3.36	$3.47	3.3%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	3.0%
CST-3	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$366.30	$378.28	3.3%
	Demand Charge - On-Peak ($/kW)	$5.72	$5.91	3.3%
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.615	0.635	3.3%
	Off-Peak	0.493	0.509	3.2%
	Monthly Credit (per kW)	($1.56)	($1.61)	3.2%
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 36 months (per kW)	$1.56	$1.61	3.2%
	Penalty Charge-current month (per kW)	$3.36	$3.47	3.3%
	Early Termination Penalty charge (per kW)	$0.99	$1.02	3.0%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
OS-2	Sports Field Service			
	Customer Charge/Minimum	$8.24	$8.51	3.3%
	Base Energy Charge (¢ per kWh)	5.656	5.841	3.3%
MET	Metropolitan Transit Service			
	Customer Charge	$196.89	$203.33	3.3%
	Base Demand Charge ($/kW)	$9.57	$9.88	3.2%
	Base Energy Charge (¢ per kWh)	0.432	0.446	3.2%
CDR	Commercial/Industrial Demand Reduction Rider			
	Monthly Administrative Adder			
	GSD-1	$517.40	$534.32	3.3%
	GSDT-1	$511.45	$528.18	3.3%
	GSLD-1, GSLDT-1	$511.90	$528.64	3.3%
	GSLD-2, GSLDT-2	$393.77	$406.65	3.3%
	GSLD-3, GSLDT-3	$2,564.11	$2,647.98	3.3%
CILC-1	Commercial/Industrial Load Control Program			
	Customer Charge			
	(G) 200-499kW	$549.45	$567.42	3.3%
	(D) above 500kW	$549.45	$567.42	3.3%
	(T) transmission	$2,930.41	$3,026.26	3.3%
	Base Demand Charge ($/kW)			
	per kW of Max Demand All kW:			
	(G) 200-499kW	$2.17	$2.24	3.2%
	per kW of Max Demand:			
	(D) above 500kW	$2.23	$2.30	3.1%
	(T) transmission	None	None	N/A
	per kW of Load Control On-Peak:			
	(G) 200-499kW	$1.03	$1.06	2.9%
	per kW of Load Control On-Peak:			
	(D) above 500kW	$1.06	$1.09	2.8%
	(T) transmission	$1.05	$1.08	2.9%
	per kW of Firm On-Peak Demand All kW:			
	(G) 200-499kW	$4.39	$4.53	3.2%
	Per kW of Firm On-Peak Demand			
	(D) above 500kW	$5.36	$5.54	3.4%
	(T) transmission	$5.72	$5.91	3.3%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
CILC-1	Commercial/Industrial Load Control Program (continued)			
	Base Energy Charge (¢ per kWh)			
	On-Peak			
	(G) 200-499kW	0.949	0.980	3.3%
	(D) above 500kW	0.660	0.682	3.3%
	(T) transmission	0.487	0.503	3.3%
	Off-Peak			
	(G) 200-499kW	0.949	0.980	3.3%
	(D) above 500kW	0.660	0.682	3.3%
	(T) transmission	0.487	0.503	3.3%
SL-1	Street Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$3.55	$3.67	3.4%
	Sodium Vapor 9,500 lu 100 watts	$3.62	$3.74	3.3%
	Sodium Vapor 16,000 lu 150 watts	$3.72	$3.84	3.2%
	Sodium Vapor 22,000 lu 200 watts	$5.64	$5.82	3.2%
	Sodium Vapor 50,000 lu 400 watts	$5.71	$5.90	3.3%
	* Sodium Vapor 12,800 lu 150 watts	$3.88	$4.01	3.4%
	* Sodium Vapor 27,500 lu 250 watts	$6.00	$6.20	3.3%
	* Sodium Vapor 140,000 lu 1,000 watts	$9.04	$9.34	3.3%
	* Mercury Vapor 6,000 lu 140 watts	$2.81	$2.90	3.2%
	* Mercury Vapor 8,600 lu 175 watts	$2.84	$2.93	3.2%
	* Mercury Vapor 11,500 lu 250 watts	$4.74	$4.90	3.4%
	* Mercury Vapor 21,500 lu 400 watts	$4.73	$4.88	3.2%
	* Mercury Vapor 39,500 lu 700 watts	$6.68	$6.90	3.3%
	* Mercury Vapor 60,000 lu 1,000 watts	$6.85	$7.07	3.2%
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.36	$1.40	2.9%
	Sodium Vapor 9,500 lu 100 watts	$1.37	$1.41	2.9%
	Sodium Vapor 16,000 lu 150 watts	$1.40	$1.45	3.6%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	3.4%
	Sodium Vapor 50,000 lu 400 watts	$1.76	$1.82	3.4%
	* Sodium Vapor 12,800 lu 150 watts	$1.56	$1.61	3.2%
	* Sodium Vapor 27,500 lu 250 watts	$1.90	$1.96	3.2%
	* Sodium Vapor 140,000 lu 1,000 watts	$3.47	$3.58	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.23	$1.27	3.3%
	* Mercury Vapor 8,600 lu 175 watts	$1.23	$1.27	3.3%
	* Mercury Vapor 11,500 lu 250 watts	$1.77	$1.83	3.4%
	* Mercury Vapor 21,500 lu 400 watts	$1.75	$1.81	3.4%
	* Mercury Vapor 39,500 lu 700 watts	$2.96	$3.06	3.4%
	* Mercury Vapor 60,000 lu 1,000 watts	$2.88	$2.97	3.1%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
SL-1	Street Lighting (continued)			
	Energy Non-Fuel+			
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	3.4%
	Sodium Vapor 9,500 lu 100 watts	$0.83	$0.86	3.6%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	3.3%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.84	2.8%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	3.2%
	* Sodium Vapor 12,800 lu 150 watts	$1.22	$1.26	3.3%
	* Sodium Vapor 27,500 lu 250 watts	$2.35	$2.43	3.4%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.34	$8.61	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	3.2%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	2.5%
	* Mercury Vapor 11,500 lu 250 watts	$2.11	$2.18	3.3%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.35	3.1%
	* Mercury Vapor 39,500 lu 700 watts	$5.52	$5.70	3.3%
	* Mercury Vapor 60,000 lu 1,000 watts	$7.81	$8.07	3.3%
	Total Charge-Fixtures, Maintenance & Energy			
	* Incandescent 1,000 lu 103 watts	$6.90	$7.13	3.3%
	* Incandescent 2,500 lu 202 watts	$7.15	$7.38	3.2%
	* Incandescent 4,000 lu 327 watts	$8.37	$8.64	3.2%
	* Incandescent 6,000 lu 448 watts	$9.33	$9.64	3.3%
	* Incandescent 10,000 lu 690 watts	$11.23	$11.60	3.3%

* These units are closed to new FPL installations

+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	Charge for Customer-Owned Units			
	Relamping and Energy			
	Sodium Vapor 5,800 lu 70 watts	$1.28	$1.32	3.1%
	Sodium Vapor 9,500 lu 100 watts	$1.53	$1.58	3.3%
	Sodium Vapor 16,000 lu 150 watts	$1.92	$1.98	3.1%
	Sodium Vapor 22,000 lu 200 watts	$2.49	$2.57	3.2%
	Sodium Vapor 50,000 lu 400 watts	$4.12	$4.25	3.2%
	* Sodium Vapor 12,800 lu 150 watts	$2.15	$2.22	3.3%
	* Sodium Vapor 27,500 lu 250 watts	$3.09	$3.19	3.2%
	* Sodium Vapor 140,000 lu 1,000 watts	$9.98	$10.31	3.3%
	* Mercury Vapor 6,000 lu 140 watts	$1.95	$2.01	3.1%
	* Mercury Vapor 8,600 lu 175 watts	$2.26	$2.33	3.1%
	* Mercury Vapor 11,500 lu 250 watts	$2.85	$2.94	3.2%
	* Mercury Vapor 21,500 lu 400 watts	$3.97	$4.10	3.3%
	* Mercury Vapor 39,500 lu 700 watts	$7.08	$7.31	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
SL-1	Street Lighting (continued)			
	* Mercury Vapor 60,000 lu 1,000 watts	$8.79	$9.08	3.3%
	* Incandescent 1,000 lu 103 watts	$2.45	$2.53	3.3%
	* Incandescent 2,500 lu 202 watts	$3.16	$3.26	3.2%
	* Incandescent 4,000 lu 327 watts	$4.12	$4.25	3.2%
	* Incandescent 6,000 lu 448 watts	$4.97	$5.13	3.2%
	* Incandescent 10,000 lu 690 watts	$6.85	$7.07	3.2%
	* Fluorescent 19,800 lu 300 watts	$3.38	$3.49	3.3%
	* Fluorescent 39,600 lu 700 watts	$6.54	$6.75	3.2%
	Energy Only+			
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	3.4%
	Sodium Vapor 9,500 lu 100 watts	$0.83	$0.86	3.6%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	3.3%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.84	2.8%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	3.2%
	* Sodium Vapor 12,800 lu 150 watts	$1.22	$1.26	3.3%
	* Sodium Vapor 27,500 lu 250 watts	$2.35	$2.43	3.4%
	* Sodium Vapor 140,000 lu 1,000 watts	$8.34	$8.61	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	3.2%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	2.5%
	* Mercury Vapor 11,500 lu 250 watts	$2.11	$2.18	3.3%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.35	3.1%
	* Mercury Vapor 39,500 lu 700 watts	$5.52	$5.70	3.3%
	* Mercury Vapor 60,000 lu 1,000 watts	$7.81	$8.07	3.3%
	* Incandescent 1,000 lu 103 watts	$0.73	$0.75	2.7%
	* Incandescent 2,500 lu 202 watts	$1.44	$1.49	3.5%
	* Incandescent 4,000 lu 327 watts	$2.35	$2.43	3.4%
	* Incandescent 6,000 lu 448 watts	$3.20	$3.30	3.1%
	* Incandescent 10,000 lu 690 watts	$4.95	$5.11	3.2%
	* Fluorescent 19,800 lu 300 watts	$2.47	$2.55	3.2%
	* Fluorescent 39,600 lu 700 watts	$5.36	$5.54	3.4%
	Non-Fuel Energy (¢ per kWh)	2.029	2.095	3.2%
	Other Charges			
	Wood Pole	$2.54	$2.62	3.1%
	Concrete Pole	$3.49	$3.60	3.2%
	Fiberglass Pole	$4.13	$4.27	3.4%
	Underground conductors not under paving (¢ per foot)	1.91	1.97	3.1%
	Underground conductors under paving (¢ per foot)	4.66	4.81	3.2%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
SL-1	Street Lighting (continued)			

* These units are closed to new FPL installations

+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the street light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
PL-1	Premium Lighting			
	Non-Fuel Energy (¢ per kWh)	2.029	2.095	3.2%
OL-1	Outdoor Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$4.06	$4.19	3.2%
	Sodium Vapor 9,500 lu 100 watts	$4.17	$4.31	3.4%
	Sodium Vapor 16,000 lu 150 watts	$4.31	$4.45	3.2%
	Sodium Vapor 22,000 lu 200 watts	$6.27	$6.48	3.3%
	Sodium Vapor 50,000 lu 400 watts	$6.67	$6.89	3.3%
	* Sodium Vapor 12,000 lu 150 watts	$4.61	$4.76	3.3%
	* Mercury Vapor 6,000 lu 140 watts	$3.12	$3.22	3.2%
	* Mercury Vapor 8,600 lu 175 watts	$3.14	$3.24	3.2%
	* Mercury Vapor 21,500 lu 400 watts	$5.16	$5.33	3.3%
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.36	$1.40	2.9%
	Sodium Vapor 9,500 lu 100 watts	$1.37	$1.41	2.9%
	Sodium Vapor 16,000 lu 150 watts	$1.40	$1.45	3.6%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	3.4%
	Sodium Vapor 50,000 lu 400 watts	$1.76	$1.82	3.4%
	* Sodium Vapor 12,000 lu 150 watts	$1.56	$1.61	3.2%
	* Mercury Vapor 6,000 lu 140 watts	$1.23	$1.27	3.3%
	* Mercury Vapor 8,600 lu 175 watts	$1.23	$1.27	3.3%
	* Mercury Vapor 21,500 lu 400 watts	$1.75	$1.81	3.4%
	Energy Non-Fuel+			
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	3.4%
	Sodium Vapor 9,500 lu 100 watts	$0.84	$0.86	2.4%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	3.3%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	3.4%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	3.2%
	* Sodium Vapor 12,000 lu 150 watts	$1.22	$1.26	3.3%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	3.2%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	2.5%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.36	3.4%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
OL-1	Outdoor Lighting			
	Charges for Customer Owned Units			
	Total Charge-Relamping & Energy			
	Sodium Vapor 5,800 lu 70 watts	$1.28	$1.32	3.1%
	Sodium Vapor 9,500 lu 100 watts	$1.54	$1.59	3.2%
	Sodium Vapor 16,000 lu 150 watts	$1.92	$1.98	3.1%
	Sodium Vapor 22,000 lu 200 watts	$2.48	$2.56	3.2%
	Sodium Vapor 50,000 lu 400 watts	$4.12	$4.25	3.2%
	* Sodium Vapor 12,000 lu 150 watts	$2.15	$2.22	3.3%
	* Mercury Vapor 6,000 lu 140 watts	$1.95	$2.01	3.1%
	* Mercury Vapor 8,600 lu 175 watts	$2.26	$2.33	3.1%
	* Mercury Vapor 21,500 lu 400 watts	$3.97	$4.10	3.3%
	Energy Only+			
	Sodium Vapor 5,800 lu 70 watts	$0.59	$0.61	3.4%
	Sodium Vapor 9,500 lu 100 watts	$0.84	$0.86	2.4%
	Sodium Vapor 16,000 lu 150 watts	$1.22	$1.26	3.3%
	Sodium Vapor 22,000 lu 200 watts	$1.79	$1.85	3.4%
	Sodium Vapor 50,000 lu 400 watts	$3.41	$3.52	3.2%
	* Sodium Vapor 12,000 lu 150 watts	$1.22	$1.26	3.3%
	* Mercury Vapor 6,000 lu 140 watts	$1.26	$1.30	3.2%
	* Mercury Vapor 8,600 lu 175 watts	$1.57	$1.61	2.5%
	* Mercury Vapor 21,500 lu 400 watts	$3.25	$3.36	3.4%

* These units are closed to new FPL installations

\+ The Proposed Non-Fuel Energy Charges were calculated based on the monthly kWh usage of the outdoor light unit times the Proposed Non-Fuel Energy Rate
Proposed Non-Fuel Energy Rate = Current Non-Fuel Rate * (1 + GBRA Factor)

	Non-Fuel Energy (¢ per kWh)	2.031	2.097	3.2%
	Other Charges			
	Wood Pole	$3.18	$3.28	3.1%
	Concrete Pole	$4.29	$4.43	3.3%
	Fiberglass Pole	$5.03	$5.19	3.2%
	Underground conductors excluding			
	Trenching per foot	$0.015	$0.015	0.0%
	Down-guy, Anchor and Protector	$1.85	$1.91	3.2%
SL-2	Traffic Signal Service			
	Base Energy Charge (¢ per kWh)	3.311	3.419	3.3%
	Minimum charge at each point	$2.61	$2.70	3.4%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
SST-1	Standby and Supplemental Service			
	Customer Charge			
	SST-1(D1)	$123.63	$127.67	3.3%
	SST-1(D2)	$123.63	$127.67	3.3%
	SST-1(D3)	$178.57	$184.41	3.3%
	SST-1(T)	$389.19	$401.92	3.3%
	Distribution Demand $/kW Contract Standby Demand			
	SST-1(D1)	$1.96	$2.02	3.1%
	SST-1(D2)	$2.30	$2.38	3.5%
	SST-1(D3)	$2.02	$2.09	3.5%
	SST-1(T)	N/A	N/A	N/A
	Reservation Demand $/kW			
	SST-1(D1)	$0.73	$0.75	2.7%
	SST-1(D2)	$0.72	$0.74	2.8%
	SST-1(D3)	$0.72	$0.74	2.8%
	SST-1(T)	$0.70	$0.72	2.9%
	Daily Demand (On-Peak) $/kW			
	SST-1(D1)	$0.34	$0.35	2.9%
	SST-1(D2)	$0.33	$0.34	3.0%
	SST-1(D3)	$0.33	$0.34	3.0%
	SST-1(T)	$0.33	$0.34	3.0%
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	SST-1(D1)	0.685	0.707	3.2%
	SST-1(D2)	0.702	0.725	3.3%
	SST-1(D3)	0.694	0.717	3.3%
	SST-1(T)	0.628	0.649	3.3%
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	SST-1(D1)	0.685	0.707	3.2%
	SST-1(D2)	0.702	0.725	3.3%
	SST-1(D3)	0.694	0.717	3.3%
	SST-1(T)	0.628	0.649	3.3%
ISST-1	Interruptible Standby and Supplemental Service			
	Customer Charge			
	Distribution	$572.34	$591.06	3.3%
	Transmission	$2,953.31	$3,049.91	3.3%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
ISST-1	Interruptible Standby and Supplemental Service (continued)			
	Distribution Demand			
	Distribution	$2.23	$2.30	3.1%
	Transmission	N/A	N/A	N/A
	Reservation Demand-Interruptible			
	Distribution	$0.15	$0.15	0.0%
	Transmission	$0.14	$0.14	0.0%
	Reservation Demand-Firm			
	Distribution	$0.72	$0.74	2.8%
	Transmission	$0.70	$0.72	2.9%
	Daily Demand (On-Peak) Firm Standby			
	Distribution	$0.33	$0.34	3.0%
	Transmission	$0.33	$0.34	3.0%
	Daily Demand (On-Peak) Interruptible Standby			
	Distribution	$0.07	$0.07	0.0%
	Transmission	$0.07	$0.07	0.0%
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	Distribution	0.691	0.714	3.3%
	Transmission	0.487	0.503	3.3%
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	Distribution	0.691	0.714	3.3%
	Transmission	0.487	0.503	3.3%
WIES-1	Wireless Internet Electric Service			
	Non-Fuel Energy (¢ per kWh)	17.538	18.112	3.3%
TR	Transformation Rider			
	Transformer Credit (per kW of Billing Demand)	($0.36)	($0.37)	2.8%
GSCU-1	GENERAL SERVICE CONSTANT USAGE			
	Customer Charge:	$9.14	$9.44	3.3%
	Non-Fuel Energy Charges:			
	Base Energy Charge (¢ per kWh)*	2.371	2.449	3.3%

* The non-fuel energy charges will be assessed on the Constant Usage kWh

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
HLFT-1	HIGH LOAD FACTOR – TIME OF USE			
	Customer Charge:			
	For customers with an Annual Maximum Demand less than 500 kW:	$38.00	$39.24	3.3%
	For customers with an Annual Maximum Demand less than 2000 kW:	$37.55	$38.78	3.3%
	For customers with an Annual Maximum Demand of 2000 kW or more:	$155.68	$160.77	3.3%
	Demand Charges:			
	On-peak Demand Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$6.81	$7.03	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$6.80	$7.02	3.2%
	For customers with an Annual Maximum Demand 2000+ kW:	$6.80	$7.02	3.2%
	Maximum Demand Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$1.45	$1.50	3.4%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$1.49	$1.54	3.4%
	For customers with an Annual Maximum Demand 2000+ kW:	$1.47	$1.52	3.4%
	Non-Fuel Energy Charges: (¢ per kWh)			
	Base Energy Charge (¢ per kWh):			
	On-Peak Period			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.540	1.590	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.484	0.500	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	0.484	0.500	3.3%
	Off-Peak Period			
	For customers with an Annual Maximum Demand 21 - 499 kW:	0.484	0.500	3.3%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.484	0.500	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	0.484	0.500	3.3%
SDTR	SEASONAL DEMAND -TIME OF USE RIDER			
	Customer Charge:			
	For customers with an Annual Maximum Demand less than 500 kW:			
	Otherwise applicable Rate Schedule GSD-1	$32.05	$33.10	3.3%
	Otherwise applicable Rate Schedule GSDT-1	$38.00	$39.24	3.3%
	For customers with an Annual Maximum Demand less than 2000 kW:	$37.55	$38.78	3.3%
	For customers with an Annual Maximum Demand of 2000 kW or more:	$155.68	$160.77	3.3%
	Demand and Energy Charges during June through September (SEASONAL):			
	Demand Charges:			
	Seasonal On-Peak Demand Charge per kW of Seasonal On-Peak Demand:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$5.52	$5.70	3.3%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$6.09	$6.29	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	$6.09	$6.29	3.3%

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) PROPOSED RATE	(5) PERCENT INCREASE
SDTR	SEASONAL DEMAND -TIME OF USE RIDER (continued)			
	Non-Fuel Energy Charges (¢ per kWh):			
	Base Seasonal Off-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.028	1.062	3.3%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.814	0.841	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	0.811	0.838	3.3%
	Base Seasonal On-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	3.890	4.017	3.3%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	2.978	3.075	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	2.970	3.067	3.3%
	OPTION A: Non-Seasonal Standard Rate			
	Demand Charges:			
	Non-Seasonal Demand Charge per kW of Non-Seasonal Maximum Demand:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.64	$4.79	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.53	$5.71	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.53	$5.71	3.3%
	Non-Fuel Energy Charges: (¢ per Non-Seasonal kWh)			
	Non-Seasonal Energy Charge:			
	For customers with an Annual Maximum Demand 21 - 499 kW:	1.348	1.392	3.3%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	1.067	1.102	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	1.064	1.099	3.3%
	OR			
	OPTION B: Non-Seasonal Time of Use Rate			
	Demand Charges per kW of Non-Seasonal Demand occurring during the Non-Seasonal On-Peak period:			
	Non-Seasonal Demand Charge :			
	For customers with an Annual Maximum Demand 21 - 499 kW:	$4.64	$4.79	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	$5.53	$5.71	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	$5.53	$5.71	3.3%
	OPTION B: Non-Seasonal Time of Use Rate			
	Non-Fuel Energy Charges: (¢ per kWh)			
	Non-Seasonal On-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	3.146	3.249	3.3%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	2.113	2.182	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	2.219	2.292	3.3%
	Non-Seasonal Off-Peak kWh			
	For customers with an Annual Maximum Demand 21 - 499 kW:	0.865	0.893	3.2%
	For customers with an Annual Maximum Demand 500 - 1999 kW:	0.641	0.662	3.3%
	For customers with an Annual Maximum Demand 2000+ kW:	0.600	0.620	3.3%

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased power Cost Recovery Clause and Generating Performance Incentive Factor	))))	DOCKET NO. 060001-EI FILED: September 1, 2006

AFFIDAVIT

STATE OF FLORIDA
COUNTY OF MIAMI-DADE

BEFORE ME, the undersigned authority, personally appeared Steven R. Sim, who being first duly sworn deposes and says:

1. My name is Steven R. Sim and I am employed by Florida Power & Light Company ("FPL") as Supervisor in the Resource Assessment & Planning ("RAP") Department.

2. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles ("UCLA") in 1979.

In 1979 I joined FPL. From 1979 until 1991 I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost-effectiveness of demand side management ("DSM") programs. In 1991 I joined my current department, then named the System Planning Department, as a Supervisor whose responsibilities included the cost-effectiveness analyses of a variety of individual supply and DSM options. In 1993 I assumed my present position.

3. In my role as Supervisor in the RAP department, I supervise a group that is responsible for determining the magnitude and timing of FPL's resource needs and then developing the integrated resource plan through which FPL will meet those resource needs.

4. In 2003 FPL issued a Request for Proposal ("RFP") for a 2007 capacity need after the RAP department performed the work described above. In addition to my involvement in developing the RFP, I was responsible for performing the economic evaluation of Turkey Point Unit 5, FPL's alternative generating unit, and all capacity options received in response to the RFP. Through this RFP process, Turkey Point Unit 5 was selected as the best option to meet the future capacity needs of FPL's customers. Subsequent to the RFP process that selected Turkey Point Unit 5 and, pursuant to the Florida Power Plant Siting Act ("PPSA"), the Florida Public Service Commission ("FPSC") issued Order No. PSC-04-0609-FIF-EI in Docket No. 040206-EI granting FPL's Petition for a Determination of Need to build Turkey Point Unit 5. The Final Order of Certification under the PPSA was issued by the Governor and Cabinet sitting as the Siting Board on February 1, 2005 (PSD-FL-338).

5. The purpose of my affidavit and supporting documentation is to provide the base revenue requirements for the first 12-months of operation for Turkey Point Unit 5 that Dr. Rosemary Morley used to compute the Generation Base Rate Adjustment

pursuant to the Stipulation and Settlement Agreement approved by the Commission in Docket No. 050045-EI. Those base revenue requirements are as follows:

a) Capital cost	$116.05 million
b) Fixed O&M and Capital Replacement	$ 11.67 million
c) Variable O&M	$ 1.07 million
d) Total base revenue requirements for first 12 months	$128.80 million[1]

These first 12-month base revenue requirements were calculated using the projected total installed cost value for Turkey Point Unit 5 of $580.3 million reflected in the Company's Petition for a Determination of Need and upon which Order No. PSC-04-0609-FIF-EI was based, using a rate of return on equity of 11.75% in accordance with the Stipulation and Settlement Agreement approved in Order No. PSC-05-0902-S-EI in Docket No. 050045-EI, and based on an in-service date of May 1, 2007.

6. The input values for the base revenue requirements are as follows (in 2007 $):

a.	Installed Capital cost =	$580.3 million
b.	Fixed O&M cost =	$3.57/kw-year
c.	Capital Replacement cost =	$6.49/kw-year
d.	Variable O&M cost =	$0.13/mwh

These four cost input values are found on page J-1 of Appendix J of FPL's Need Study for Electrical Power Plant 2007 ("Need Study") document submitted in Docket No.

[1] The sum of the component values does not equal the total due to rounding.

040206-EI. The capital cost value also is presented separately in Table III.G.1 on page 30 of the Need Study.

7. Attachment 1 provides the separate revenue requirement calculations for Capital, for Fixed O&M and Capital Replacement, and for Variable O&M. The document shows a portion of the calculation of Capital revenue requirements for the first 12 months of operation and references values for full year Capital revenue requirements that were separately calculated. Attachment 2 presents the full year Capital revenue requirements calculation that is used in Attachment 1.

8. FPL's Need filing for Turkey Point Unit 5 included a projection of base revenue requirements.[2] For ease of reference, I identify below the location of each reference in the need study. These values were included in Appendix C-2, EGEAS Runs for All Portfolios – TP CC 5 presenting the EGEAS-based analysis results for Turkey Point Unit 5 to the Need Study. The Variable O&M base revenue requirement and the Fixed O&M and Capital Replacement base revenue requirement are on page 29 of

[2] The base revenue requirements value for the first 12 months of Turkey Point Unit 5's operation in the Need filing were projected to be $122.788 million consisting of $110.222 million Capital, $11.509 million Fixed O&M and Capital Replacement, and $1.057 million for Variable O&M. The differences between the values found in the Need filing and FPL's current projection are primarily due to two factors: (1) the use of 11.75% ROE value (instead of the 11% ROE value used in the Need filing) that increases the Capital value; and (2) escalation of the Fixed O&M and Capital Replacement value, and the Variable O&M value, for the 4 months of 2008 included in the current calculation as opposed to no escalation of these values in the Need filing due to the modeling assumption of all options, including Turkey Point Unit 5, having a 1/1/2007 start date.

Appendix C-2. (This page is also Bates numbered 0081 DON.)[3] The Capital cost base revenue requirement value is on page 262 of the EGEAS run. (This page is also Bates numbered 0252 DON.)

9. In conclusion, the base revenue requirements for the first 12 months of operation of Turkey Point Unit 5 are $128.80 million. These values were calculated using the same starting point values and assumptions included in FPL's Need filing except for a change in the in-service date to show May 1, 2007 and the use of an 11.75% ROE as discussed above.

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[3] Note that the "Fixed O&M" value shown in EGEAS includes costs for Fixed O&M, Capital Replacement, and firm gas transportation. Therefore, from the $35.9 million value shown in EGEAS as "Fixed O&M", the firm gas transportation value of approximately $24.4 million must be subtracted to derive the $11.5 million value shown above for the remaining cost components of Fixed O&M and Capital Replacement. Variances in the fixed O&M and capital replacement and variable components of the base revenue requirement are due to using an actual projected in-service date as opposed to the January 1st in-service date that the EGEAS model automatically assumes for all options analyzed. Therefore, the original 12-month base revenue requirement projection calculated in EGEAS projected those costs over the January 2007 through December 2007 time period. The current projection assumes a May 1st 2007 in-service date for the unit. The fact that not all of the first 12 months occur in 2007 results in escalation of non-capital cost values for 2008. Fixed O&M, Capital Replacement, and Variable O&M costs must now be escalated from their 2007 values to address the four months (January through April) of 2008 that are now a part of the 12-month period.

Steven R. Sim

Steven R. Sim

I hereby certify that on this 28th day of August, 2006 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Steven R. Sim who is personally known to me, and he acknowledge before me that he executed this certification of signature as his free act and deed who did not take an oath.

I witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as this 28th day of August, 2006.

E Martin

Notary Public

State of Florida

My Commission Expires:
NOV. 17, 2008

NOTARY PUBLIC-STATE OF FLORIDA
E. Martin
Commission #DD372838
Expires: NOV. 17, 2008
Bonded Thru Atlantic Bonding Co., Inc.

ATTACHMENT 1

Turkey Point # 5 Revenue Requirements Projection for First 12 Months

I. Capital Revenue Requirements:

(1)	(2)	(3) = (1)	(4) = (2) x 4/12	(5) = (3) + (4)
2007 Annual Rev Reqs ($ millions)	2008 Annual Rev Reqs ($ millions)	2007 Rev Reqs for 8 months ($ millions)	2008 Rev Reqs for 4 months ($ millions)	Total Rev Reqs for 12 months ($ millions)
78.181	113.613	78.181	37.871	116.052

Note: Source for (1) and (2) is FPL's Economic Decision Making (EDM) model

II. FOM and Capital Replacement Revenue Requirements:

	(1)	(2)	(3) = (1)x(2)x1000 x(8/12)/1000000	(4) = (1)x(2)x1.043x1000 x(4/12)/1000000	(5) = (3) + (4)
	Starting Point Inputs * ($/kw-year)	Turkey Point # 5 Summer Capacity MW	2007 Rev Reqs for 8 months ($ millions)	2008 Rev Reqs for 4 months ($ millions)	Total Rev Reqs for 12 months ($ millions)
FOM	3.57	1144	2.723	1.420	4.143
Cap. Repl.	6.49	1144	4.950	2.581	7.531
					11.674
2008 escalation rate * =		0.043			

* values are from Need filing

III. VOM Revenue Requirements:

	(1)	(2) = (1)x8134.5x1000 x(8/12)/1000000	(3) = (1)x1.012x8403.7x1000 x(4/12)/1000000	(4) = (2) + (3)
	Starting Point Input * ($/kw-year)	2007 Rev Reqs for 8 months ($ millions)	2008 Rev Reqs for 4 months ($ millions)	Total Rev Reqs for 12 months ($ millions)
	0.13	0.705	0.369	1.074
2007 unit output projection * =	8134.5	GWH		
2008 unit output projection * =	8403.7	GWH		
2008 escalation rate * =	0.012			

* values are from Need filing

ATTACHMENT 2

INPUT SHEET #1

GENERAL ASSUMPTIONS

PROJECT TITLE: TP5 - May Start

I) COMPOSITE INCOME TAX RATE 38.5750%

STATE INCOME TAX RATE 5.50%

FEDERAL INCOME TAX RATE 35.00%

II) COST OF CAPITAL:

SOURCE	WEIGHT	LONG LIVE ASSETS COST	WTD COST	AFTER TAX
DEBT	45.0%	6.40%	2.880%	1.769%
PREFERRED	0.0%	0.0%	0.000%	0.000%
COMMON	55.0%	11.75%	6.463%	6.463%
		AFUDC rate	7.84%	8.23%

DISCOUNT RATE: 8.23%

III) PROPERTY TAXES 2.09000%

PROPERTY INSURANCE 0.37%

IV) BONUS TAX DEPRECIATION RATES

YEAR	5	7	10	15	20	39
1	20.00%	14.29%	10.00%	5.00%	3.75%	1.39%
2	32.00%	24.49%	18.00%	9.50%	7.22%	2.56%
3	19.20%	17.49%	14.40%	8.55%	6.68%	2.56%
4	11.52%	12.49%	11.52%	7.70%	6.18%	2.56%
5	11.52%	8.93%	9.22%	6.93%	5.71%	2.56%
6	5.76%	8.92%	7.37%	6.23%	5.29%	2.56%
7		8.93%	6.55%	5.90%	4.89%	2.56%
8		4.46%	6.55%	5.90%	4.52%	2.56%
9			6.56%	5.91%	4.46%	2.56%
10			6.55%	5.90%	4.46%	2.56%
11			3.28%	5.91%	4.46%	2.56%
12				5.90%	4.46%	2.56%
13				5.91%	4.46%	2.56%
14				5.90%	4.46%	2.56%
15				5.91%	4.46%	2.56%
16				2.95%	4.46%	2.56%
17					4.46%	2.56%
18					4.46%	2.56%
19					4.46%	2.56%
20					4.46%	2.56%
21					2.23%	2.56%
22						2.56%
23						2.56%
24						2.56%
25						2.56%
26						2.56%
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28						2.56%
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30						2.56%
31						2.56%
32						2.56%
33						2.56%
34						2.56%
35						2.56%
36						2.56%
37						2.56%
38						2.56%
39						2.56%
40						1.18%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

TP5 - May Start

INPUT SHEET #5 - CAPITAL INVESTMENTS THAT REQUIRE CONSTRUCTION

TITLE FOR INVESTMENT #1	Inv #1	TP 5 I/S May
TITLE FOR INVESTMENT #2	Inv #2	
TITLE FOR INVESTMENT #3	Inv #3	

ASSUMPTIONS:

		INV. #1	INV. #2	INV. #3
ESCALATE CONSTRUCTION CASH FLOWS		NO	NO	NO
COMPUTE AFUDC		YES	YES	NO
CONSTRUCTION START MONTH		JAN	JAN	JAN
CONSTRUCTION START YEAR		2004	2007	2020
CONSTRUCTION END MONTH		SEP	DEC	JAN
CONSTRUCTION END YEAR		2007	2011	2020
IN-SERVICE MONTH		MAY	JAN	JAN
IN-SERVICE YEAR		2007	2012	2020
USEFUL LIFE (Refer to Asset Lives Tab)		25	25	10
BOOK DEPRECIATION RATE		4.00%	4.00%	10.00%
TAX LIFE (Refer to Asset Lives Tab)		20	20	39
BONUS DEPRECIATION ELIGIBILITY	Consult Tax Dept	NOT ELIGIBLE	NOT ELIGIBLE	NOT ELIGIBLE

CASH FLOWS

		LABOR	MATERIALS		LABOR	MATERIALS		LABOR	MATERIALS
YEAR 1	2004		23,923.76	2007		0	2020		
YEAR 2	2005		235,788.84	2008		0	2021		
YEAR 3	2006		242,464.42	2009		0	2022		
YEAR 4	2007		29,650.62	2010		0	2023		
YEAR 5	2008			2011		0	2024		
YEAR 6	2009			2012		0.00	2025		
YEAR 7	2010			2013			2026		
YEAR 8	2011			2014			2027		
YEAR 9	2012			2015			2028		
YEAR 10	2013			2016			2029		
TOTAL CASH FLOWS		0.00	531,827.64		0.00	0.00		0.00	0.00

TP5 - May Start

Calculation Sheet #1 - In-Service Cost for Capital Expenditures Requiring Construction

Inv #1

				AFUDC provided by PGD						
Year	Construction Months	Nominal $ Cash Flow	Cumulative Cash Flows	Total AFUDC	Cumulative AFUDC	Debt AFUDC	Const. Period Int.	Cumulative CPI	Deferred Taxes	Cumulative Def. Taxes
2004	12	23,923.76	23,923.76	0.00	0.00	0.00	765.56	765.56	(295.31)	(295.31)
2005	12	235,788.84	259,712.60	6,380.36	6,380.36	1,966.86	9,125.36	9,890.92	(2,761.39)	(3,056.70)
2006	12	242,464.42	502,177.02	28,375.45	34,755.81	8,747.26	25,013.49	34,904.41	(6,274.70)	(9,331.40)
2007	9	29,650.62	531,827.64	13,763.58	48,519.39	4,242.88	26,491.52	61,395.93	(8,582.41)	(17,913.81)
2008	0	0.00	531,827.64	0.00	48,519.39	0.00	0.00	61,395.93	0.00	(17,913.81)
2009	0	0.00	531,827.64	0.00	48,519.39	0.00	0.00	61,395.93	0.00	(17,913.81)
2010	0	0.00	531,827.64	0.00	48,519.39	0.00	0.00	61,395.93	0.00	(17,913.81)
2011	0	0.00	531,827.64	0.00	48,519.39	0.00	0.00	61,395.93	0.00	(17,913.81)
2012	0	0.00	531,827.64	0.00	48,519.39	0.00	0.00	61,395.93	0.00	(17,913.81)
2013	0	0.00	531,827.64	0.00	48,519.39	0.00	0.00	61,395.93	0.00	(17,913.81)

Inv #2

Year	Construction Months	Nominal $ Cash Flow	Cumulative Cash Flows	Total AFUDC	Cumulative AFUDC	Debt AFUDC	Const. Period Int.	Cumulative CPI	Deferred Taxes	Cumulative Def. Taxes
2007	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Inv #3

Year	Construction Months	Nominal $ Cash Flow	Cumulative Cash Flows	Total AFUDC	Cumulative AFUDC	Debt AFUDC	Const. Period Int.	Cumulative CPI	Deferred Taxes	Cumulative Def. Taxes
2020	12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TP5 - May Start

Calculation Sheet #4 - Revenue Requirements for Projects Requiring Construction

Inv #1

Book Basis	580,347.03
Book Basis for Deferred Taxes	546,784.65
Tax Basis	593,223.57
Deferred Taxes During Construction	(17,913.81)
Equity AFUDC Capitalized	33,562.38

	Year	In-Service Months	End of Yr RateBase	Annual Rev Req	Tax Depreciation
1	2007	8	579,828.17	76,180.75	22,245.88
2	2008	12	548,531.50	113,613.01	42,824.81
3	2009	12	518,475.13	109,025.31	39,609.54
4	2010	12	489,562.93	104,610.56	36,643.42
5	2011	12	461,712.64	100,349.34	33,890.86
6	2012	12	434,841.56	96,228.40	31,351.87
7	2013	12	408,879.07	92,228.48	28,996.77
8	2014	12	383,754.11	88,349.13	26,825.57
9	2015	12	358,766.45	84,534.36	26,469.64
10	2016	12	333,781.09	80,728.79	26,463.70
11	2017	12	308,793.43	76,924.22	26,469.64
12	2018	12	283,808.06	73,120.79	26,463.70
13	2019	12	258,820.41	69,317.26	26,469.64
14	2020	12	233,835.04	65,513.29	26,463.70
15	2021	12	208,847.38	61,710.33	26,469.64
16	2022	12	183,862.01	57,907.76	26,463.70
17	2023	12	158,874.36	54,106.47	26,469.64
18	2024	12	133,888.99	50,305.37	26,463.70
19	2025	12	108,901.33	46,504.47	26,469.64
20	2026	12	83,915.97	42,704.03	26,463.70
21	2027	12	64,033.64	39,244.59	13,234.82
22	2028	12	49,256.65	36,468.45	0.00
23	2029	12	34,479.65	34,035.16	0.00
24	2030	12	19,702.66	31,602.92	0.00
25	2031	12	4,925.66	29,172.21	0.00
26	2032	4	(0.00)	9,133.76	0.00
27	2033	0	0.00	0.00	0.00
28	2034	0	0.00	0.00	0.00
29	2035	0	0.00	0.00	0.00
30	2036	0	0.00	0.00	0.00
31	2037	0	0.00	0.00	0.00
32	2038	0	0.00	0.00	0.00
33	2039	0	0.00	0.00	0.00
34	2040	0	0.00	0.00	0.00
35	2041	0	0.00	0.00	0.00
36	2042	0	0.00	0.00	0.00
37	2043	0	0.00	0.00	0.00
38	2044	0	0.00	0.00	0.00
39	2045	0	0.00	0.00	0.00
40	2046	0	0.00	0.00	0.00

Inv #2

Book Basis	0.00
Book Basis for Deferred Taxes	0.00
Tax Basis	0.00
Deferred Taxes During Construction	0.00
Equity AFUDC Capitalized	0.00

	Year	In-Service Months	End of Yr RateBase	Annual Rev Req	Tax Depreciation
1	2012	12	0.00	0.00	0.00
2	2013	12	0.00	0.00	0.00
3	2014	12	0.00	0.00	0.00
4	2015	12	0.00	0.00	0.00
5	2016	12	0.00	0.00	0.00
6	2017	12	0.00	0.00	0.00
7	2018	12	0.00	0.00	0.00
8	2019	12	0.00	0.00	0.00
9	2020	12	0.00	0.00	0.00
10	2021	12	0.00	0.00	0.00
11	2022	12	0.00	0.00	0.00
12	2023	12	0.00	0.00	0.00
13	2024	12	0.00	0.00	0.00
14	2025	12	0.00	0.00	0.00
15	2026	12	0.00	0.00	0.00
16	2027	12	0.00	0.00	0.00
17	2028	12	0.00	0.00	0.00
18	2029	12	0.00	0.00	0.00
19	2030	12	0.00	0.00	0.00
20	2031	12	0.00	0.00	0.00
21	2032	12	0.00	0.00	0.00
22	2033	12	0.00	0.00	0.00
23	2034	12	0.00	0.00	0.00
24	2035	12	0.00	0.00	0.00
25	2036	12	0.00	0.00	0.00
26	2037	0	0.00	0.00	0.00
27	2038	0	0.00	0.00	0.00
28	2039	0	0.00	0.00	0.00
29	2040	0	0.00	0.00	0.00
30	2041	0	0.00	0.00	0.00
31	2042	0	0.00	0.00	0.00
32	2043	0	0.00	0.00	0.00
33	2044	0	0.00	0.00	0.00
34	2045	0	0.00	0.00	0.00
35	2046	0	0.00	0.00	0.00
36	2047	0	0.00	0.00	0.00
37	2048	0	0.00	0.00	0.00
38	2049	0	0.00	0.00	0.00
39	2050	0	0.00	0.00	0.00
40	2051	0	0.00	0.00	0.00

Inv #3

Book Basis	0.00
Book Basis for Deferred Taxes	0.00
Tax Basis	0.00
Deferred Taxes During Construction	0.00
Equity AFUDC Capitalized	0.00

	Year	In-Service Months	End of Yr RateBase	Annual Rev Req	Tax Depreciation
1	2020	12	0.00	0.00	0.00
2	2021	12	0.00	0.00	0.00
3	2022	12	0.00	0.00	0.00
4	2023	12	0.00	0.00	0.00
5	2024	12	0.00	0.00	0.00
6	2025	12	0.00	0.00	0.00
7	2026	12	0.00	0.00	0.00
8	2027	12	0.00	0.00	0.00
9	2028	12	0.00	0.00	0.00
10	2029	12	0.00	0.00	0.00
11	2030	0	0.00	0.00	0.00
12	2031	0	0.00	0.00	0.00
13	2032	0	0.00	0.00	0.00
14	2033	0	0.00	0.00	0.00
15	2034	0	0.00	0.00	0.00
16	2035	0	0.00	0.00	0.00
17	2036	0	0.00	0.00	0.00
18	2037	0	0.00	0.00	0.00
19	2038	0	0.00	0.00	0.00
20	2039	0	0.00	0.00	0.00
21	2040	0	0.00	0.00	0.00
22	2041	0	0.00	0.00	0.00
23	2042	0	0.00	0.00	0.00
24	2043	0	0.00	0.00	0.00
25	2044	0	0.00	0.00	0.00
26	2045	0	0.00	0.00	0.00
27	2046	0	0.00	0.00	0.00
28	2047	0	0.00	0.00	0.00
29	2048	0	0.00	0.00	0.00
30	2049	0	0.00	0.00	0.00
31	2050	0	0.00	0.00	0.00
32	2051	0	0.00	0.00	0.00
33	2052	0	0.00	0.00	0.00
34	2053	0	0.00	0.00	0.00
35	2054	0	0.00	0.00	0.00
36	2055	0	0.00	0.00	0.00
37	2056	0	0.00	0.00	0.00
38	2057	0	0.00	0.00	0.00
39	2058	0	0.00	0.00	0.00
40	2059	0	0.00	0.00	0.00

TP5 - May Start

Results - Revenue Requirements

	1 2004	2 2005	3 2006	4 2007	5 2008	6 2009	7 2010	8 2011	9 2012	10 2013	11 2014	12 2015
Capital Carrying Cost												
Projects With No Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inv #1	0.00	0.00	0.00	78,180.75	113,613.01	109,025.31	104,610.56	100,349.34	96,226.40	92,228.48	88,349.13	84,534.36
Inv #2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inv #3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Land	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Annual Carrying Cost	0.00	0.00	0.00	78,180.75	113,613.01	109,025.31	104,610.56	100,349.34	96,226.40	92,228.48	88,349.13	84,534.36
Operating Savings												
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transportation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Savings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs												
Property Taxes & Insurance	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fom Unit 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fom Unit 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Annual Revenue Requirements	0.00	0.00	0.00	78,180.75	113,613.01	109,025.31	104,610.56	100,349.34	96,226.40	92,228.48	88,349.13	84,534.36
Present Value @ 8.23%	0.00	0.00	0.00	61,664.94	82,796.64	73,410.49	65,080.74	57,681.65	51,105.02	45,256.45	40,055.66	35,411.23
Cumulative Present Value	0.00	0.00	0.00	61,664.94	144,461.58	217,872.08	282,952.82	340,634.47	391,739.48	436,995.94	477,051.60	512,462.83
Total Present Value Revenue Requirements	728,765.36											

TP5 - May Start

Results - Revenue Requirements

	13 2016	14 2017	15 2018	16 2019	17 2020	18 2021	19 2022	20 2023	21 2024	22 2025	23 2026	24 2027
Capital Carrying Cost												
Projects With No Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inv #1	80,728.79	76,924.22	73,120.79	69,317.26	65,513.29	61,710.33	57,907.75	54,106.47	50,305.37	46,504.47	42,704.03	39,244.59
Inv #2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inv #3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Land	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Annual Carrying Cost	80,728.79	76,924.22	73,120.79	69,317.26	65,513.29	61,710.33	57,907.75	54,106.47	50,305.37	46,504.47	42,704.03	39,244.59
Operating Savings												
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transportation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Savings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs												
Property Taxes & Insurance	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fom Unit 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fom Unit 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Annual Revenue Requirements	80,728.79	76,924.22	73,120.79	69,317.26	65,513.29	61,710.33	57,907.75	54,106.47	50,305.37	46,504.47	42,704.03	39,244.59
Present Value @ 8.23%	31,246.13	27,508.27	24,159.45	21,160.88	18,478.55	16,082.09	13,943.36	12,037.22	10,340.41	8,832.10	7,493.49	6,362.70
Cumulative Present Value	543,707.96	571,216.23	595,375.68	616,536.57	635,015.12	651,097.22	665,040.58	677,077.81	687,418.21	696,250.31	703,743.81	710,106.51
Total Present Value Revenue Requirements												

TP5 - May Start

Results - Revenue Requirements

	25 2028	26 2029	27 2030	28 2031	29 2032	30 2033	31 2034	32 2035	33 2036	34 2037	35 2038	36 2039
Capital Carrying Cost												
Projects With No Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inv #1	36,468.45	34,035.16	31,602.92	29,172.21	9,133.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inv #2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inv #3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Land	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Annual Carrying Cost	36,468.45	34,035.16	31,602.92	29,172.21	9,133.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Savings												
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transportation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Savings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs												
Property Taxes & Insurance	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fom Unit 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fom Unit 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Annual Revenue Requirements	36,468.45	34,035.16	31,602.92	29,172.21	9,133.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.23%	5,462.92	4,710.66	4,041.36	3,446.80	997.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	715,569.43	720,280.10	724,321.46	727,768.25	728,765.36	728,765.36	728,765.36	728,765.36	728,765.36	728,765.36	728,765.36	728,765.36
Total Present Value Revenue Requirements												

Docket No. 060001-EI
S. Sim, Exhibit No. ____
Document No. SRS-2, Page 7 of 8
GBRA Capital Revenue Requirements with EDM

Docket No. 060001-EI
S. Sim, Exhibit No. _____
Document No. SRS-2, Page 8 of 8
GBRA Capital Revenue Requirements with EDM

TP5 - May Start

Results - Revenue Requirements

	37 2040	38 2041	39 2042	40 2043
Capital Carrying Cost				
Projects With No Construction	0.00	0.00	0.00	0.00
Inv #1	0.00	0.00	0.00	0.00
Inv #2	0.00	0.00	0.00	0.00
Inv #3	0.00	0.00	0.00	0.00
Land	0.00	0.00	0.00	0.00
Total Annual Carrying Cost	0.00	0.00	0.00	0.00
Operating Savings				
	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00
Gas Transportation	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00
Total Operating Savings	0.00	0.00	0.00	0.00
Operating Costs				
Property Taxes & Insurance	0.00	0.00	0.00	0.00
Fom Unit 1	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00
Fom Unit 2	0.00	0.00	0.00	0.00
Cap Rep	0.00	0.00	0.00	0.00
Gas Transport	0.00	0.00	0.00	0.00
Total Operating Costs	0.00	0.00	0.00	0.00
Total Annual Revenue Requirements	0.00	0.00	0.00	0.00
Present Value @ 8.23%	0.00	0.00	0.00	0.00
Cumulative Present Value	728,765.36	728,765.36	728,765.36	728,765.36
Total Present Value Revenue Requirements				

APPENDIX I

FUEL COST RECOVERY

GJY-2

DOCKET NO. 060001-EI

EXHIBIT_____________

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APPENDIX I

FUEL COST RECOVERY

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Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2007

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
1.0% Sulfur Grade ($/Bbl)	61.25	62.23	62.19	61.70	62.61	63.62	64.42	64.49	64.55	64.45	65.05	65.65
1.0% Sulfur Grade ($/mmBtu)	9.57	9.72	9.72	9.64	9.78	9.94	10.07	10.08	10.09	10.07	10.16	10.26

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	99.15	99.86	99.38	97.49	95.43	94.67	95.01	95.77	96.67	97.57	98.62	99.67
0.05% Sulfur Grade ($/mmBtu)	17.01	17.13	17.05	16.72	16.37	16.24	16.30	16.43	16.58	16.74	16.92	17.10

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	760,000	760,000	760,000	859,000	894,000	894,000	894,000	894,000	894,000	859,000	760,000	760,000
Firm Gulfstream (mmBtu/Day)	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
Non-Firm FGT (mmBtu/Day)	200,000	200,000	200,000	175,000	110,000	110,000	110,000	110,000	110,000	115,000	140,000	140,000
Non-Firm Gulfstream (mmBtu/Day)	525,000	525,000	525,000	325,000	265,000	265,000	265,000	265,000	265,000	265,000	465,000	465,000
Total Projected Daily Availability (mmBtu/Day)	1,835,000	1,835,000	1,835,000	1,709,000	1,619,000	1,619,000	1,619,000	1,619,000	1,619,000	1,589,000	1,715,000	1,715,000

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/mmBtu)	11.46	11.48	11.25	9.06	8.86	8.95	9.05	9.13	9.23	9.40	10.11	10.94
Firm Gulfstream ($/mmBtu)	11.37	11.39	11.16	9.08	8.90	8.98	9.08	9.16	9.26	9.41	10.00	10.81
Non-Firm FGT ($/mmBtu)	11.90	11.92	11.68	9.60	9.57	9.77	9.87	9.96	9.93	9.94	10.49	11.33
Non-Firm Gulfstream ($/mmBtu)	11.96	11.98	11.75	9.67	9.50	9.58	9.68	9.76	9.85	10.00	10.59	11.41

Solid Fuel	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	2.38	2.37	2.36	2.34	2.33	2.31	2.30	2.29	2.27	2.26	2.24	2.23
SJRPP ($/mmBtu)	1.83	1.79	1.74	1.70	1.63	1.59	1.57	1.56	1.53	1.56	1.56	1.58

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2007

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 1	1.3	6.8	7.7	04/28/07 - 05/25/07					
Cape Canaveral 2	1.4	8.2	0.0	NONE					
Cutler 5	1.2	0.6	0.0	NONE					
Cutler 6	1.3	1.9	19.2	10/14/07 - 12/22/07					
Lauderdale 4	0.9	1.2	13.4	03/03/07 - 04/20/07					
Lauderdale 5	0.9	0.6	3.8	10/06/07 - 10/19/07					
Lauderdale GTs	1.0	7.2	0.0	NONE					
Fort Myers 2 CC	0.9	2.5	12.2	02/24/07 - 04/06/07 *	09/22/07 - 10/16/07 *	10/20/07 - 11/13/07 *	11/24/07 - 12/03/07 *	12/04/07 - 12/08/07	12/09/07 - 12/18/07
Ft. Myers 3	1.2	2.0	14.8	05/12/07 - 05/26/07 *	09/01/07 - 09/24/07 *				
Ft. Myers GTs	0.3	1.3	3.1	01/06/07 - 01/19/07 *	02/01/07 - 03/14/07 *	04/05/07 - 05/16/07 *			
Manatee 1	1.1	4.0	7.7	10/20/07 - 11/16/07					
Manatee 2	1.0	4.0	0.0	NONE					
Manatee 3	1.0	2.5	1.0	01/20/07 - 02/02/07 *					
Martin 1	1.0	4.0	0.0	NONE					
Martin 2	0.9	4.0	19.2	10/06/07 - 12/14/07					
Martin 3	0.9	4.6	1.6	10/13/07 - 10/24/07 *					
Martin 4	1.0	0.5	0.0	NONE					
Martin 8 CC	1.0	2.5	1.0	02/17/07 - 03/02/07 *					
Port Everglades 1	1.7	1.8	5.8	12/01/07 - 12/21/07					
Port Everglades 2	1.8	1.2	19.2	09/08/07 - 11/16/07					
Port Everglades 3	1.2	5.3	17.3	03/01/07 - 05/02/07					
Port Everglades 4	1.3	5.7	0.0	NONE					
Port Everglades GTs	1.9	9.7	0.0	NONE					
Putnam 1	1.1	2.5	0.0	NONE					
Putnam 2	1.0	2.5	9.6	05/26/07 - 06/29/07					
Riviera 3	3.0	2.2	13.4	05/06/07 - 06/23/07					
Riviera 4	2.9	7.3	0.0	NONE					
Sanford 3	1.8	3.1	0.0	NONE					
Sanford 4 CC	1.0	2.5	5.8	04/21/07 - 05/04/07	11/24/07 - 12/21/07 *				
Sanford 5 CC	1.0	2.5	1.9	02/03/07 - 02/16/07 *	02/24/07 - 03/02/07 *	05/12/07 - 05/18/07 *			
Turkey Point 1	1.4	3.5	0.0	NONE					
Turkey Point 2	1.3	3.5	19.2	01/26/07 - 04/05/07					
Turkey Point 3	1.1	1.1	8.2	09/01/07 - 10/01/07					
Turkey Point 4	1.3	1.3	0.0	NONE					
Turkey Point 5	2.2	3.7	0.0	NONE					
St. Lucie 1	1.1	1.1	9.6	04/02/07 - 05/07/07					
St. Lucie 2	1.0	1.0	23.3	10/01/07 - 12/25/07					
Saint Johns River Power Park 1	1.8	1.0	8.2	02/24/07 - 03/25/07					
Saint Johns River Power Park 2	2.0	1.0	0.0	NONE					
Scherer 4	1.8	1.0	0.0	NONE					

*Partial Planned Outage

2007 Risk Management Plan

1. Identify overall quantitative and qualitative risk management objectives.
   A. FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel procurement strategy to achieve the goals of fuel price stability (volatility minimization), to potentially achieve fuel cost minimization, and to achieve asset optimization. FPL's fuel procurement strategy aims to mitigate fuel price increases and reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers. FPL plans to hedge a percentage of its residual fuel oil and natural gas purchases with a combination of fixed price transactions and options.

3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement.
   A. The potential risks that FPL encounters with its fuel procurement are supplier credit, fuel supply and transportation availability, product quality, delivery timing, weather, environmental and supplier failure to deliver. The utility determines acceptable levels of risk for fuel procurement by performing various analyses that include forecasted/expected levels of activity, forecasted price levels and price changes, price volatility, and Value-at-Risk (VaR) calculations. The analyses are then presented to the Exposure Management Committee for review and approval. Approval is given to remain within specified VaR limits. These VaR limits are specified in FPL's policies and procedures that were filed on a confidential basis with the Commission on June 24, 2002 as part of FPL's response to Staff's Second Request for Production of Documents in Docket No. 011605-EI. FPL's policies and procedures are updated as necessary.

4. Describe the utility's oversight of its fuel procurement activities.
   A. The utility has a separate and independent middle office risk management department that provides oversight of fuel procurement activities at the deal level. In addition, an executive-level, Exposure Management Committee meets monthly to review performance and discuss current procurement/hedging activities and monitors daily results of procurement activity.

5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight.
   A. Please see response to No. 4.

6. Describe the utility's corporate risk policy regarding fuel procurement activities.
   A. The utility has a written policy and procedures that define VaR and duration limits for all forward activity by portfolio. FPL's policies and procedures were filed on a confidential basis with the Commission on June 24, 2002 as part of FPL's response to Staff's Second Request for Production of Documents in Docket No. 011605-EI. FPL's policies and procedures are updated as necessary. In addition, individual procurement strategies must be documented and approved by front and middle office management prior to deal execution.

7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement activities.
   A. Please see response to No. 6.

8. Describe the utility's strategy to fulfill its risk management objectives.
   A. Please see response to No. 1.

9. Verify that the utility has sufficient policies and procedures to implement its strategy.
   A. Please see response to No. 6.

13. Describe the utility's reporting system for fuel procurement activities.
    A. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, a database for maintaining current and historical pricing, deal information, and valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

14. Verify that the utility's reporting system consistently and comprehensively identifies, measures, and monitors all forms of risk associated with fuel procurement activities.
    A. Please see response to No. 13.

15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan for developing the resources, policies, and procedures for acquiring the ability to use effectively the hedging techniques.
    A. FPL does not believe that there are any such limitations currently.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-5
DOCKET NO. 060001-EI
FPL WITNESS: K. M. DUBIN
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APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2007 – December 2007

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SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2007 - APRIL 2007

		(a)		(b)	(c)
		DOLLARS		MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$6,035,202,342		100,510,348	6.0046
1a	Adjustment for TP5	96,464,000		100,510,348	0.0960
2	Nuclear Fuel Disposal Costs (E2)	21,188,807		22,754,302	0.0931
3	Fuel Related Transactions (E2)	3,265,273		0	0.0000
3a	Incremental Hedging Costs (E2)	570,098		0	
4	Fuel Cost of Sales to FKEC / CKW (E2)	(67,227,136)		(1,006,871)	6.6768
5	TOTAL COST OF GENERATED POWER	$6,089,463,384		99,503,477	6.1198
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	246,819,107		12,025,486	2.0525
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	42,901,485		557,411	7.6966
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	90,439,427		1,170,268	7.7281
9		0		0	0.0000
10		0		0	0.0000
11	Okeelanta/Osceola Settlement (E2)	$0		0	0.0000
12	Payments to Qualifying Facilities (E8)	172,870,000		5,951,033	2.9049
13	TOTAL COST OF PURCHASED POWER	$553,030,019		19,704,198	2.8067
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			119,207,675	
15	Fuel Cost of Economy Sales (E6)	(145,972,243)		(1,930,909)	7.5598
16	Gain on Economy Sales (E6A)	0		0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,380,200)		(83,738)	1.6482
18	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
18a	Revenues from Off-System Sales	(19,197,960)		(2,014,647)	0.9529
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($166,550,403)		(2,014,647)	8.2670
19a	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$6,475,943,000		117,193,028	5.5259
21	Net Unbilled Sales	56,966,777	**	1,030,909	0.0527
22	Company Use	19,427,829	**	351,579	0.0180
23	T & D Losses	420,936,295	**	7,617,547	0.3891
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,475,943,000		108,192,993	5.9855
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$29,650,752		495,370	5.9855
26	Jurisdictional MWH Sales	$6,446,292,248		107,697,623	5.9855
27	Jurisdictional Loss Multiplier	-		-	1.00054
28	Jurisdictional MWH Sales Adjusted for Line Losses	$6,449,773,246		107,697,623	5.9888
29	FINAL TRUE-UP JAN 05 - DEC 05 $307,437,600 underrecovery; EST/ACT TRUE-UP JAN 06 - DEC 06 $230,603,338 overrecovery	76,834,262		107,697,623	0.0713
30	TOTAL JURISDICTIONAL FUEL COST	$6,526,607,508		107,697,623	6.0601
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes	6,531,306,665			6.0645
33	GPIF ***	$8,478,098		107,697,623	0.0079
33a	Jurisdictionalized Savings-Turkey Point Unit 5	($350,000)		31,815,177	-0.0011
34	Fuel Factor including GPIF (Line 32 + Line 33)	6,539,434,763		107,697,623	6.0713
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				6.071

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: MAY 2007 - DECEMBER 2007

		(a)		(b)	(c)
		DOLLARS		MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$6,035,202,342		100,510,348	6.0046
1a	Adjustment for Turkey Point Unit 5	96,464,000		100,510,348	0.0960
2	Nuclear Fuel Disposal Costs (E2)	21,188,807		22,754,302	0.0931
3	Fuel Related Transactions (E2)	3,265,273		0	0.0000
3a	Incremental Hedging Costs (E2)	570,098		0	
4	Fuel Cost of Sales to FKEC / CKW (E2)	(67,227,136)		(1,006,871)	6.6768
5	TOTAL COST OF GENERATED POWER	$6,089,463,384		99,503,477	6.1198
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	246,819,107		12,025,486	2.0525
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	42,901,485		557,411	7.6966
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	90,439,427		1,170,268	7.7281
9		0		0	0.0000
10		0		0	0.0000
11	Okeelanta/Osceola Settlement (E2)	$0		0	0.0000
12	Payments to Qualifying Facilities (E8)	172,870,000		5,951,033	2.9049
13	TOTAL COST OF PURCHASED POWER	$553,030,019		19,704,198	2.8067
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			119,207,675	
15	Fuel Cost of Economy Sales (E6)	(145,972,243)		(1,930,909)	7.5598
16	Gain on Economy Sales (E6A)	0		0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,380,200)		(83,738)	1.6482
18	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
18a	Revenues from Off-System Sales	(19,197,960)		(2,014,647)	0.9529
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($166,550,403)		(2,014,647)	8.2670
19a	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$6,475,943,000		117,193,028	5.5259
21	Net Unbilled Sales	56,966,777	**	1,030,909	0.0527
22	Company Use	19,427,829	**	351,579	0.0180
23	T & D Losses	420,936,295	**	7,617,547	0.3891
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,475,943,000		108,192,993	5.9855
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$29,650,752		495,370	5.9855
26	Jurisdictional MWH Sales	$6,446,292,248		107,697,623	5.9855
27	Jurisdictional Loss Multiplier	-		-	1.00054
28	Jurisdictional MWH Sales Adjusted for Line Losses	$6,449,773,246		107,697,623	5.9888
29	FINAL TRUE-UP JAN 05 - DEC 05 $307,437,600 underrecovery; EST/ACT TRUE-UP JAN 06 - DEC 06 $230,603,338 overrecovery	76,834,262		107,697,623	0.0713
30	TOTAL JURISDICTIONAL FUEL COST	$6,526,607,508		107,697,623	6.0601
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes	6,531,306,665			6.0645
33	GPIF ***	$8,478,098		107,697,623	0.0079
33a	Jurisdictionalized Savings - Turkey Point Unit 5	($95,672,330)		75,882,446	-0.1262
34	Fuel Factor including GPIF (Line 32 + Line 33)	6,444,112,433		107,697,623	5.9462
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				5.946

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2007 - DECEMBER 2007

1. Estimated/Actual over/(under) recovery (January 2006 - September 2006)	$ 230,603,338
2. Final over/(under) recovery (January 2005 - December 2005)	$ (307,437,600)
3. Total over/(under) recovery to be included in the January 2007 - December 2007 projected period (Schedule E1, Line 29)	$ (76,834,262)
4. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	107,697,623
5. True-Up Factor (Lines 3/4) c/kWh:	(0.0713)

			CALCULATION OF ACTUAL TRUE-UP AMOUNT FLORIDA POWER & LIGHT COMPANY FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER 2006						
LINE NO.				(1) ACTUAL JAN	(2) ACTUAL FEB	(3) ACTUAL MAR	(4) ACTUAL APR	(5) ACTUAL MAY	(6) ACTUAL JUN
A			**Fuel Costs & Net Power Transactions**						
	1	a	Fuel Cost of System Net Generation	$ 315,112,786.91	$ 296,130,097.03	$ 362,988,224.09	$ 427,175,558.67	$ 465,395,517.69	$ 498,860,024.27
		b	Incremental Hedging Costs	56,882.90	35,540.78	22,232.89	98,578.88	27,955.24	38,795.73
		c	Nuclear Fuel Disposal Costs	1,960,611.39	1,856,366.50	1,711,034.47	1,731,522.31	1,472,295.17	1,751,905.80
		d	Scherer Coal Cars Depreciation & Return	306,661.88	304,687.26	302,712.64	300,738.01	298,763.40	296,788.79
		e	Gas Pipelines Depreciation & Return	0.00	0.00	0.00	0.00	0.00	0.00
		f	DOE D&D Fund Payment	0.00	0.00	0.00	0.00	0.00	0.00
	2	a	Fuel Cost of Power Sold (Per A6)	(11,797,386.00)	(11,663,894.00)	(10,895,956.00)	(3,517,465.00)	(4,158,008.00)	(3,554,605.00)
		b	Gains from Off-System Sales	(3,248,253.00)	(3,480,746.00)	(2,438,709.00)	(727,924.00)	(777,282.00)	(486,429.00)
	3	a	Fuel Cost of Purchased Power (Per A7)	19,228,529.00	16,922,824.00	22,823,782.00	24,788,396.00	27,451,007.00	29,479,518.00
		b	Energy Payments to Qualifying Facilities (Per A8)	13,591,316.00	11,810,443.00	10,591,302.00	11,664,026.00	14,221,903.00	15,217,211.00
		c	Okeelanta Settlement Amortization including interest	811,624.61	809,549.56	807,448.56	805,613.63	803,012.93	800,473.88
	4		Energy Cost of Economy Purchases (Per A9)	8,081,737.00	3,796,966.00	7,374,033.00	9,586,158.00	20,151,662.00	6,224,615.00
	5		Total Fuel Costs & Net Power Transactions	$ 344,104,510.69	$ 316,521,834.13	$ 393,286,104.65	$ 471,905,202.50	$ 524,886,826.43	$ 548,628,298.47
	6		**Adjustments to Fuel Cost**						
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(4,658,460.30)	(3,907,151.56)	(3,724,406.14)	(4,711,300.29)	(5,149,413.81)	(5,650,334.60)
		b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	3,135.83	(35,017.95)	(99,944.47)	(52,487.41)	(69,189.70)	(9,915.74)
		c	Inventory Adjustments	29,862.00	(54,039.50)	387,944.09	(140,608.94)	9,949.79	(1,069,539.93)
		d	Non Recoverable Oil/Tank Bottoms	0.00	0.00	0.00	(27,965.72)	(25,591.59)	0.00
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 339,479,048.22	$ 312,525,625.12	$ 389,849,698.13	$ 466,972,840.14	$ 519,652,581.12	$ 541,898,508.20
B			**kWh Sales**						
	1		Jurisdictional kWh Sales	8,025,135,582	7,283,681,362	7,191,005,176	7,616,707,944	8,445,324,075	9,560,737,906
	2		Sale for Resale (excluding FKEC & CKW)	48,619,701	38,867,924	35,275,521	47,211,219	46,778,639	51,572,882
	3		Sub-Total Sales (excluding FKEC & CKW)	8,073,755,283	7,322,549,286	7,226,280,697	7,663,919,163	8,492,102,714	9,612,310,788
	6		**Jurisdictional % of Total Sales (B1/B3)**	99.39781%	99.46920%	99.51184%	99.38398%	99.44915%	99.46347%
C			**True-up Calculation**						
	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 472,878,511.50	$ 445,267,978.65	$ 439,184,910.14	$ 466,888,615.67	$ 520,556,662.64	$ 593,092,512.08
	2		**Fuel Adjustment Revenues Not Applicable to Period**						
		a	Prior Period True-up (Collected)/Refunded This Period	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)
		b	GPIF, Net of Revenue Taxes (a)	(900,746.66)	(900,746.66)	(900,746.66)	(900,746.66)	(900,746.66)	(900,746.66)
		c	Other						
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 410,049,420.67	$ 382,438,887.82	$ 376,355,819.31	$ 404,059,524.84	$ 457,727,571.81	$ 530,263,421.25
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 339,479,048.22	$ 312,525,625.12	$ 389,849,698.13	$ 466,972,840.14	$ 519,652,581.12	$ 541,898,508.20
		b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0.00	0.00	0.00	0.00	0.00	0.00
		c	RTP Incremental Fuel -100% Retail	0.00	0.00	0.00	0.00	0.00	0.00
		d	D&D Fund Payments -100% Retail	0.00	0.00	0.00	0.00	0.00	0.00
		e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	339,479,048.22	312,525,625.12	389,849,698.13	466,972,840.14	519,652,581.12	541,898,508.20
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.39781 %	99.46920 %	99.51184 %	99.38398 %	99.44915 %	99.46347 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00065(b)) +(Lines C4b,c,d)	$ 337,654,072.00	$ 311,068,802.00	$ 388,198,773.00	$ 464,397,857.00	$ 517,125,988.00	$ 539,341,404.00
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 72,395,348.67	$ 71,370,085.82	$ (11,842,953.69)	$ (60,338,332.16)	$ (59,398,416.19)	$ (9,077,982.75)
	8		Interest Provision for the Month (Line D10)	(3,609,923.03)	(3,213,803.98)	(2,966,566.37)	(3,010,712.77)	(3,085,807.25)	(3,082,350.05)
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(743,140,130.00)	(612,426,360.19)	(482,341,734.18)	(435,222,910.08)	(436,643,610.84)	(437,199,490.11)
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)
	10		Prior Period True-up Collected/(Refunded) This Period	61,928,344.17	61,928,344.17	61,928,344.17	61,928,344.17	61,928,344.17	61,928,344.17
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (919,863,960.12)	$ (789,779,334.11)	$ (742,660,510.01)	$ (744,081,210.77)	$ (744,637,090.04)	$ (694,869,078.67)

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER 2006

LINE NO.				(7) ACTUAL JUL	(8) ESTIMATED AUG	(9) ESTIMATED SEP	(10) ESTIMATED OCT	(11) ESTIMATED NOV	(12) ESTIMATED DEC	(13) TOTAL PERIOD
A			**Fuel Costs & Net Power Transactions**							
	1	a	Fuel Cost of System Net Generation	$ 496,788,361.82	$ 501,352,335.15	$ 459,867,650.83	$ 430,067,102.49	$ 368,765,834.93	$ 372,287,913.81	$ 4,994,791,407.69
		b	Incremental Hedging Costs	39,718.16	39,575.00	39,575.00	56,683.00	39,575.00	39,575.00	534,687.58
		c	Nuclear Fuel Disposal Costs	1,968,400.20	1,985,275.56	1,921,233.22	1,939,973.62	1,500,833.66	2,003,941.47	21,803,393.37
		d	Scherer Coal Cars Depreciation & Return	294,814.16	292,839.54	290,864.94	288,890.31	286,915.69	284,941.07	3,549,617.69
		e	Gas Pipelines Depreciation & Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		f	DOE D&D Fund Payment	0.00	0.00	0.00	0.00	7,076,000.00	0.00	7,076,000.00
	2	a	Fuel Cost of Power Sold (Per A6)	(4,049,245.00)	(7,469,434.00)	(2,428,277.00)	(3,539,995.00)	(9,016,965.00)	(20,792,161.00)	(92,883,391.00)
		b	Gains from Off-System Sales	(619,665.00)	(1,057,241.00)	(346,946.00)	(467,277.00)	(1,267,006.00)	(4,998,371.00)	(19,915,849.00)
	3	a	Fuel Cost of Purchased Power (Per A7)	28,666,676.00	33,093,347.00	25,703,803.00	19,729,200.00	20,480,711.00	17,556,604.00	285,924,397.00
		b	Energy Payments to Qualifying Facilities (Per A8)	14,834,881.00	16,909,000.00	16,400,000.00	12,403,000.00	9,656,000.00	15,429,000.00	162,728,082.00
		c	Okeelanta Settlement Amortization including interest	797,756.37	778,750.00	778,750.00	778,750.00	778,750.00	778,750.00	9,529,229.54
	4		Energy Cost of Economy Purchases (Per A9)	5,074,148.00	7,033,832.00	8,960,071.00	17,432,848.00	14,579,287.00	6,931,799.00	115,227,156.00
	5		Total Fuel Costs & Net Power Transactions	$ 543,795,845.71	$ 552,958,279.25	$ 511,186,724.99	$ 478,689,175.42	$ 412,879,936.28	$ 389,521,992.35	$ 5,488,364,730.87
	6		**Adjustments to Fuel Cost**							
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(5,465,123.31)	(6,490,626.06)	(6,589,492.00)	(6,295,088.34)	(5,919,694.65)	(5,434,206.12)	(63,995,297.16)
		b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(64,704.78)	0.00	0.00	0.00	0.00	0.00	(328,124.22)
		c	Inventory Adjustments	20,429.81	0.00	0.00	0.00	0.00	0.00	(816,002.68)
		d	Non Recoverable Oil/Tank Bottoms	0.00	0.00	0.00	0.00	0.00	0.00	(53,557.31)
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 538,286,447.43	$ 546,467,653.19	$ 504,597,232.99	$ 472,394,087.07	$ 406,960,241.64	$ 384,087,786.23	$ 5,423,171,749.49
B			**kWh Sales**							
	1		Jurisdictional kWh Sales	10,009,127,890	10,224,636,208	9,947,157,230	9,606,959,104	7,955,474,499	8,471,924,664	104,337,871,641
	2		Sale for Resale (excluding FKEC & CKW)	47,151,365	48,816,612	43,527,178	45,220,055	47,828,782	42,179,519	543,049,396
	3		Sub-Total Sales (excluding FKEC & CKW)	10,056,279,255	10,273,452,820	9,990,684,408	9,652,179,159	8,003,303,281	8,514,104,183	104,880,921,037
	6		**Jurisdictional % of Total Sales (B1/B3)**	99.53113%	99.52483%	99.56432%	99.53150%	99.40239%	99.50459%	N/A
C			**True-up Calculation**							
	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 622,084,992.99	$ 631,325,389.52	$ 614,192,308.18	$ 593,186,600.97	$ 491,214,839.80	$ 523,103,319.20	$ 6,412,976,641.32
	2		**Fuel Adjustment Revenues Not Applicable to Period**							
		a	Prior Period True-up (Collected)/Refunded This Period	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)	(61,928,344.17)	(743,140,130.00)
		b	GPIF, Net of Revenue Taxes (a)	(900,746.66)	(900,746.66)	(900,746.66)	(900,746.66)	(900,746.66)	(900,746.66)	(10,808,959.94)
		c	Other							0.00
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 559,255,902.16	$ 568,496,298.69	$ 551,363,217.35	$ 530,357,510.14	$ 428,385,748.97	$ 460,274,228.37	$ 5,659,027,551.38
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 538,286,447.43	$ 546,467,653.19	$ 504,597,232.99	$ 472,394,087.07	$ 406,960,241.64	$ 384,087,786.23	$ 5,423,171,749.49
		b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		c	RTP Incremental Fuel -100% Retail	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		d	D&D Fund Payments -100% Retail	0.00	0.00	0.00	0.00	7,076,000.00	0.00	7,076,000.00
		e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	538,286,447.43	546,467,653.19	504,597,232.99	472,394,087.07	399,884,241.64	384,087,786.23	5,416,095,749.49
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.53113 %	99.52483 %	99.56432 %	99.53150 %	99.40239 %	99.50459 %	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00065(b)) +(Lines C4b,c,d)	$ 536,110,829.00	$ 544,224,519.00	$ 502,725,363.00	$ 470,486,538.00	$ 404,828,865.00	$ 382,433,397.00	$ 5,398,596,407.00
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 23,145,073.16	$ 24,271,779.69	$ 48,637,854.35	$ 59,870,972.14	$ 23,556,883.97	$ 77,840,831.37	$ 260,431,144.38
	8		Interest Provision for the Month (Line D10)	(2,894,724.89)	(2,510,925.03)	(2,088,291.45)	(1,585,328.81)	(1,135,431.19)	(643,942.02)	(29,827,806.84)
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(387,431,478.74)	(305,252,786.30)	(221,563,587.48)	(113,085,680.41)	7,128,307.08	91,478,104.03	(743,140,130.00)
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)	(307,437,599.93)
	10		Prior Period True-up Collected/(Refunded) This Period	61,928,344.17	61,928,344.17	61,928,344.17	61,928,344.17	61,928,344.17	61,928,344.17	743,140,130.00
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (612,690,386.23)	$ (529,001,187.41)	$ (420,523,280.34)	$ (300,309,292.85)	$ (215,959,495.90)	$ (76,834,262.39)	$ (76,834,262.39)

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2007 - DECEMBER 2007

1. TOTAL AMOUNT OF ADJUSTMENTS:	85,312,360
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$8,478,098
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 76,834,262
2. TOTAL JURISDICTIONAL SALES (MWH)	107,697,623
3. ADJUSTMENT FACTORS c/kWh:	0.0792
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0079
B. TRUE-UP FACTOR	0.0713

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2007 - APRIL 2007

NET ENERGY FOR LOAD (%)

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.93	34.47
OFF PEAK	69.07	65.53
	100.00	100.00

FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$6,475,943,000	$2,232,257,552	$4,243,685,448
2 MWH SALES	108,192,993	33,464,093	74,728,900
3 COST PER KWH SOLD	5.9855	6.6706	5.6788
4 JURISDICTIONAL LOSS FACTOR	1.00054	1.00054	1.00054
5 JURISDICTIONAL FUEL FACTOR	5.9888	6.6742	5.6818
6 TRUE-UP	0.0713	0.0713	0.0713
7			
8 TOTAL	6.0601	6.7455	5.7531
9 REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10 RECOVERY FACTOR	6.0645	6.7504	5.7572
11 GPIF	0.0079	0.0079	0.0079
11a FUEL SAVINGS DUE TO TP5	(0.0011)	(0.0011)	(0.0011)
12 RECOVERY FACTOR including GPIF	6.0713	6.7572	5.7640
13 RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	6.071	6.757	5.764

HOURS:	ON-PEAK	24.73 %
	OFF-PEAK	75.27 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D
Page 1 of 2

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

MAY 2007 - DECEMBER 2007

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	30.93	34.47
OFF PEAK	69.07	65.53
	100.00	100.00

FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$6,475,943,000	$2,232,257,552	$4,243,685,448
2 MWH SALES	108,192,993	33,464,093	74,728,900
3 COST PER KWH SOLD	5.9855	6.6706	5.6788
4 JURISDICTIONAL LOSS FACTOR	1.00054	1.00054	1.00054
5 JURISDICTIONAL FUEL FACTOR	5.9888	6.6742	5.6818
6 TRUE-UP	0.0713	0.0713	0.0713
7			
8 TOTAL	6.0601	6.7455	5.7531
9 REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10 RECOVERY FACTOR	6.0645	6.7504	5.7572
11 GPIF	0.0079	0.0079	0.0079
11a FUEL SAVINGS DUE TO TP5	(0.1262)	(0.1262)	(0.1262)
12 RECOVERY FACTOR including GPIF	5.9462	6.6321	5.6389
13 RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	5.946	6.632	5.639

HOURS:		
ON-PEAK	24.73	%
OFF-PEAK	75.27	%

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2007 THROUGH SEPTEMBER 2007 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	24.12	26.41
OFF PEAK	75.88	73.59
	100.00	100.00

SDTR FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,475,943,000	$1,710,296,546	$4,765,646,454
2	MWH SALES	108,192,993	26,096,150	82,096,843
3	COST PER KWH SOLD	5.9855	6.5538	5.8049
4	JURISDICTIONAL LOSS FACTOR	1.00054	1.00054	1.00054
5	JURISDICTIONAL FUEL FACTOR	5.9888	6.5574	5.8080
6	TRUE-UP	0.0713	0.0713	0.0713
7				
8	TOTAL	6.0601	6.6287	5.8793
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	SDTR RECOVERY FACTOR	6.0645	6.6335	5.8835
11	GPIF	0.0079	0.0079	0.0079
11a	FUEL SAVINGS DUE TO TP5	(0.1262)	(0.1262)	(0.1262)
12	SDTR RECOVERY FACTOR including GPIF	5.9462	6.5152	5.7652
13	SDTR RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	5.946	6.515	5.765

HOURS:		
	ON-PEAK	19.93 %
	OFF-PEAK	80.07 %

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1D, Page 1 of 2.

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

JANUARY 2007 - APRIL 2007

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		6.071	1.00194	5.729
	all additional kWh		6.071	1.00194	6.729
A	GS-1, SL-2, GSCU-1		6.071	1.00194	6.083
A-1*	SL-1, OL-1, PL-1		5.923	1.00194	5.934
B	GSD-1		6.071	1.00187	6.083
C	GSLD-1 & CS-1		6.071	1.00077	6.076
D	GSLD-2, CS-2, OS-2 & MET		6.071	0.99464	6.039
E	GSLD-3 & CS-3		6.071	0.95644	5.807
A	RST-1, GST-1	ON-PEAK	6.757	1.00194	6.770
		OFF-PEAK	5.764	1.00194	5.775
B	GSDT-1, CILC-1(G),	ON-PEAK	6.757	1.00187	6.770
	HLFT (21-499 kW)	OFF-PEAK	5.764	1.00187	5.775
C	GSLDT-1, CST-1,	ON-PEAK	6.757	1.00077	6.762
	HLFT (500-1,999 kW)	OFF-PEAK	5.764	1.00077	5.768
D	GSLDT-2, CST-2,	ON-PEAK	6.757	0.99571	6.728
	HLFT (2,000+)	OFF-PEAK	5.764	0.99571	5.739
E	GSLDT-3,CST-3,	ON-PEAK	6.757	0.95644	6.463
	CILC -1(T)	OFF-PEAK	5.764	0.95644	5.513
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	6.757	0.99298	6.710
	ISST-1(D)	OFF-PEAK	5.764	0.99298	5.724

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E
Page 1 of 2

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

MAY 2007 - DECEMBER 2007

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		5.946	1.00194	5.604
	all additional kWh		5.946	1.00194	6.604
A	GS-1, SL-2, GSCU-1		5.946	1.00194	5.958
A-1*	SL-1, OL-1, PL-1		5.798	1.00194	5.809
B	GSD-1		5.946	1.00187	5.957
C	GSLD-1 & CS-1		5.946	1.00077	5.951
D	GSLD-2, CS-2, OS-2 & MET		5.946	0.99464	5.914
E	GSLD-3 & CS-3		5.946	0.95644	5.687
A	RST-1, GST-1	ON-PEAK	6.632	1.00194	6.645
		OFF-PEAK	5.639	1.00194	5.650
B	GSDT-1, CILC-1(G),	ON-PEAK	6.632	1.00187	6.645
	HLFT (21-499 kW)	OFF-PEAK	5.639	1.00187	5.649
C	GSLDT-1, CST-1,	ON-PEAK	6.632	1.00077	6.637
	HLFT (500-1,999 kW)	OFF-PEAK	5.639	1.00077	5.643
D	GSLDT-2, CST-2,	ON-PEAK	6.632	0.99571	6.604
	HLFT (2,000+)	OFF-PEAK	5.639	0.99571	5.615
E	GSLDT-3,CST-3,	ON-PEAK	6.632	0.95644	6.343
	CILC -1(T)	OFF-PEAK	5.639	0.95644	5.393
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	6.632	0.99298	6.586
	ISST-1(D)	OFF-PEAK	5.639	0.99298	5.599

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2007 THROUGH SEPTEMBER 2007 - WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

(1) GROUP	(2) OTHERWISE APPLICABLE RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1	ON-PEAK	6.515	1.00187	6.527
		OFF-PEAK	5.765	1.00187	5.776
C	GSLD(T)-1	ON-PEAK	6.515	1.00077	6.520
		OFF-PEAK	5.765	1.00077	5.770
D	GSLD(T)-2	ON-PEAK	6.515	0.99571	6.487
		OFF-PEAK	5.765	0.99571	5.740

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Florida Power & Light Company
2005 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	54,143,233	1.07456355	58,180,344	0.930610	4,037,112	1.00194
2							
3	GS-1 Sec	5,981,112	1.07456355	6,427,085	0.930610	445,973	1.00194
4							
5	GSD-1 Pri	61,590	1.04795283	64,543	0.954241	2,953	
6	GSD-1 Sec	23,135,985	1.07456355	24,861,086	0.930610	1,725,101	
7	Subtotal GSD-1	23,197,574	1.07449290	24,925,629	0.930672	1,728,055	1.00187
8							
9	OS-2 Pri	18,449	1.04795283	19,334	0.954241	885	
10	OS-2 Sec	-	1.07456355	-	0.000000	-	
11	Subtotal OS-2	18,449	1.04795283	19,334	0.954241	885	0.97713
12							
13	GSLD-1 Pri	445,147	1.04795283	466,493	0.954241	21,346	
14	GSLD-1 Sec	10,100,616	1.07456355	10,853,754	0.930610	753,138	
15	Subtotal GSLD-1	10,545,763	1.07344028	11,320,247	0.931584	774,484	1.00089
16							
17	CS-1 Pri	65,179	1.04795283	68,305	0.954241	3,126	
18	CS-1 Sec	209,679	1.07456355	225,313	0.930610	15,634	
19	Subtotal CS-1	274,858	1.06825314	293,618	0.936108	18,760	0.99606
20							
21	Subtotal GSLD-1 / CS-1	10,820,622	1.07330852	11,613,866	0.931699	793,244	1.00077
22							
23	GSLD-2 Pri	393,112	1.04795283	411,963	0.954241	18,851	
24	GSLD-2 Sec	1,282,857	1.07456355	1,378,511	0.930610	95,654	
25	Subt GSLD-2	1,675,968	1.06832179	1,790,473	0.936048	114,505	0.99612
26							
27	CS-2 Pri	68,503	1.04795283	71,788	0.954241	3,285	
28	CS-2 Sec	94,618	1.07456355	101,673	0.930610	7,055	
29	Subtotal CS-2	163,121	1.06338830	173,461	0.940390	10,340	0.99152
30							
31	Subtotal GSLD-2 / CS-2	1,839,090	1.06788421	1,963,935	0.936431	124,845	0.99571
32							
33	GSLD-3 Trn	211,890	1.02576275	217,349	0.974884	5,459	0.95644
34							
35	CS-3 Trn	16,567	1.02576275	16,993	0.974884	427	0.95644
36							
37	Subtotal GSLD-3 / CS-3	228,457	1.02576275	234,342	0.974884	5,886	0.95644
38							
39	ISST-1 Sec	0	1.07456355	0	0.000000	0	0.00000
40							
41	SST-1 Pri	2,104	1.04795283	2,205	0.954241	101	
42	SST-1 Sec	8,549	1.07456355	9,186	0.930610	637	
43	Subtotal SST-1 (D)	10,653	1.06930736	11,391	0.935185	738	0.99704
44							
45	SST-1 Trn	101,775	1.02576275	104,397	0.974884	2,622	0.95644
46							
47	CILC-1D Pri	1,148,814	1.04795283	1,203,903	0.954241	55,089	
48	CILC-1D Sec	2,031,118	1.07456355	2,182,565	0.930610	151,447	
49	Subtotal CILC-1D	3,179,931	1.06494990	3,386,468	0.939011	206,536	0.99298
50							
51	CILC-1G Pri	0	1.04795283	0	0.000000	0	
52	CILC-1G Sec	206,681	1.07456355	222,092	0.930610	15,411	

Florida Power & Light Company
2005 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
53	Subtotal CILC-1G	206,681	1.07456355	222,092	0.930610	15,411	1.00194
54							
55	Subtotal CILC-1D / CILC-1G	3,386,612	1.06553660	3,608,559	0.938494	221,947	0.99352
56							
57	Subtotal GSD-1 & CILC-1G	23,404,255	1.07449352	25,147,720	0.930671	1,743,465	1.00187
58							
59	CILC-1T Trn	1,546,354	1.02576275	1,586,192	0.974884	39,838	0.95644
60							
61	Subtotal ISST-D & CILC-1D	3,179,931	1.06494990	3,386,468	0.939011	206,536	0.99298
62							
63	MET Pri	94,230	1.04795283	98,748	0.954241	4,519	0.97713
64							
65	Subtotal OS-2, GSLD-2, CS-2, & ME	1,951,768	1.06673354	2,082,017	0.937441	130,248	0.99464
66							
67	OL-1 Sec	107,788	1.07456355	115,825	0.930610	8,037	1.00194
68							
69	SL-1 Sec	444,636	1.07456355	477,790	0.930610	33,154	1.00194
70							
71	Subtotal OL-1 / SL-1	552,424	1.07456355	593,614	0.930610	41,191	1.00194
72							
73	SL-2 Sec	59,000	1.07456355	63,399	0.930610	4,399	1.00194
74							
75	Total FPSC	101,979,583	1.07306612	109,430,835	0.931909	7,451,253	1.00054
76							
77	Total FERC Sales	1,514,660	1.03303758	1,564,701	0.968019	50,041	
78							
79	Total Company	103,494,243	1.07248029	110,995,537	0.932418	7,501,293	
80							
81	Company Use	136,493	1.07456355	146,670	0.930610	10,177	
82							
83	Total FPL	103,630,736	1.07248304	111,142,207	0.932416	7,511,471	1.00000
84							
85	**Summary of Sales by Voltage:**						
86							
87	Transmission	2,894,678	1.02576275	2,969,252	0.974884	74,575	
88							
89	Primary	2,793,696	1.04795283	2,927,662	0.954241	133,966	
90							
91	Secondary	97,805,870	1.07456355	105,098,622	0.930610	7,292,753	
92							
93	Total	103,494,243	1.07248029	110,995,537	0.932418	7,501,293	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2007 - APRIL 2007

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL
A1	FUEL COST OF SYSTEM GENERATION	$410,009,339	$382,021,424	$419,563,868	$465,948,288	$518,657,274	$547,707,147	$2,743,907,340
1a	NUCLEAR FUEL DISPOSAL	2,035,188	1,838,234	2,035,188	1,391,057	1,875,581	1,921,233	11,096,481
1b	COAL CAR INVESTMENT	282,966	280,992	279,017	277,043	275,068	273,093	1,668,179
1c	ADJUSTMENT FOR TURKEY POINT UNIT 5	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	48,232,000
1d	NUCLEAR SLEEVING	0	0	0	0	0	0	0
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0
1f	INCREMENTAL HEDGING COSTS	43,967	43,967	44,658	62,450	44,658	44,658	284,358
2	FUEL COST OF POWER SOLD	(22,462,215)	(18,191,330)	(16,104,155)	(11,742,670)	(6,524,801)	(7,665,658)	(82,690,829)
2a	REVENUES FROM OFF-SYSTEM SALES	(3,562,601)	(2,460,808)	(1,759,868)	(1,154,571)	(794,342)	(657,886)	(10,390,076)
3	FUEL COST OF PURCHASED POWER	18,701,324	15,733,000	16,061,300	21,844,883	21,914,950	20,234,012	114,489,469
3b	OKEELANTA/OSCEOLA SETTLEMENT	0	0	0	0	0	0	0
3c	QUALIFYING FACILITIES	15,469,000	14,209,000	15,277,000	8,786,000	14,412,000	15,286,000	83,439,000
4	ENERGY COST OF ECONOMY PURCHASES	6,055,781	6,487,952	8,689,396	10,364,270	15,008,245	8,505,366	55,111,010
4a	FUEL COST OF SALES TO FKEC / CKW	(4,905,120)	(4,902,312)	(4,809,096)	(5,237,849)	(5,445,445)	(5,783,586)	(31,083,408)
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$429,706,296	$403,098,786	$447,315,975	$498,577,567	$567,461,854	$587,903,046	$2,934,063,524
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,521,049	7,794,503	7,884,492	7,796,021	8,497,229	9,661,031	50,154,325
7	COST PER KWH SOLD (¢/KWH)	5.0429	5.1716	5.6734	6.3953	6.6782	6.0853	5.8501
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054
7b	JURISDICTIONAL COST (¢/KWH)	5.0456	5.1744	5.6764	6.3987	6.6818	6.0886	5.8532
9	TRUE-UP (¢/KWH)	0.0755	0.0826	0.0817	0.0826	0.0758	0.0666	0.0770
10	TOTAL	5.1211	5.2570	5.7581	6.4813	6.7576	6.1552	5.9302
11	REVENUE TAX FACTOR 0.00072	0.0037	0.0038	0.0041	0.0047	0.0049	0.0044	0.0043
12	RECOVERY FACTOR ADJUSTED FOR TAXES	5.1248	5.2608	5.7622	6.4860	6.7625	6.1596	5.9345
13	GPIF (¢/KWH)	0.0083	0.0091	0.0090	0.0091	0.0084	0.0073	0.0085
13a	JURISDICTIONALIZED SAVINGS-TURKEY POINT UNIT 5	(0.0010)	(0.0011)	(0.0011)	(0.0011)	0.0000	0.0000	(0.0011)
14	RECOVERY FACTOR including GPIF	5.1321	5.2688	5.7701	6.4940	6.7709	6.1669	5.9419
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.132	5.269	5.770	6.494	6.771	6.167	5.942

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2007 - APRIL 2007

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD
A1	FUEL COST OF SYSTEM GENERATION	$624,312,849	$611,170,268	$594,681,887	$549,021,467	$426,827,738	$485,280,793	$6,035,202,342
1a	NUCLEAR FUEL DISPOSAL	1,985,276	1,985,276	1,468,214	1,502,983	1,495,010	1,655,567	$21,188,807
1b	COAL CAR INVESTMENT	271,119	269,144	267,170	265,195	263,220	261,246	$3,265,273
1c	ADJUSTMENT FOR TURKEY POINT UNIT 5	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	$96,464,000
1d	NUCLEAR SLEEVING	0	0	0	0	0	0	$0
1e	DOE DECONTAMINATION AND	0	0	0	0	0	0	$0
	DECOMMISSIONING COSTS							$0
1f	INCREMENTAL HEDGING COSTS	44,658	44,658	44,658	62,450	44,658	44,658	$570,098
2	FUEL COST OF POWER SOLD	(6,760,763)	(8,819,878)	(2,912,343)	(4,502,294)	(11,288,800)	(30,377,536)	($147,352,443)
2a	REVENUES FROM OFF-SYSTEM SALES	(671,043)	(1,057,241)	(346,946)	(467,277)	(1,267,006)	(4,998,371)	($19,197,960)
3	FUEL COST OF PURCHASED POWER	22,048,982	21,316,448	23,629,133	23,296,893	22,365,782	19,672,400	$246,819,107
3b	OKEELANTA/OSCEOLA SETTLEMENT	0	0	0	0	0	0	$0
3c	QUALIFYING FACILITIES	15,875,000	15,803,000	15,593,000	12,682,000	13,758,000	15,720,000	$172,870,000
4	ENERGY COST OF ECONOMY PURCHASES	9,974,528	8,563,248	11,195,847	22,733,292	17,159,236	8,603,752	$133,340,912
4a	FUEL COST OF SALES TO FKEC / CKW	(6,135,492)	(6,381,854)	(6,501,714)	(6,243,297)	(5,750,367)	(5,131,003)	($67,227,136)
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$668,983,780	$650,931,735	$645,157,573	$606,390,079	$471,646,137	$498,770,172	$6,475,943,000
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,312,762	10,381,920	10,314,403	9,690,394	8,658,475	8,680,716	108,192,995
7	COST PER KWH SOLD (¢/KWH)	6.4870	6.2699	6.2549	6.2576	5.4472	5.7457	5.9855
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054
7b	JURISDICTIONAL COST (¢/KWH)	6.4905	6.2732	6.2583	6.2610	5.4502	5.7488	5.9888
9	TRUE-UP (¢/KWH)	0.0623	0.0620	0.0623	0.0664	0.0744	0.0738	0.0713
10	TOTAL	6.5528	6.3352	6.3206	6.3274	5.5246	5.8226	6.0601
11	REVENUE TAX FACTOR 0.00072	0.0047	0.0046	0.0046	0.0046	0.0040	0.0042	0.0044
12	RECOVERY FACTOR ADJUSTED FOR TAXES	6.5575	6.3398	6.3252	6.3320	5.5286	5.8268	6.0645
13	GPIF (¢/KWH)	0.0069	0.0068	0.0069	0.0073	0.0082	0.0081	0.0079
13a	JURISDICTIONALIZED SAVINGS-TURKEY POINT UNIT 5	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0011)
14	RECOVERY FACTOR including GPIF	6.5644	6.3466	6.3321	6.3393	5.5368	5.8349	6.0713
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	6.564	6.347	6.332	6.339	5.537	5.835	6.071

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD MAY 2007 - DECEMBER 2007

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL
A1	FUEL COST OF SYSTEM GENERATION	$410,009,339	$382,021,424	$419,563,868	$465,948,288	$518,657,274	$547,707,147	$2,743,907,340
1a	NUCLEAR FUEL DISPOSAL	2,035,188	1,838,234	2,035,188	1,391,057	1,875,581	1,921,233	11,096,481
1b	COAL CAR INVESTMENT	282,966	280,992	279,017	277,043	275,068	273,093	1,668,179
1c	ADJUSTMENT FOR TURKEY POINT UNIT 5	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	48,232,000
1d	NUCLEAR SLEEVING	0	0	0	0	0	0	0
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0
1f	INCREMENTAL HEDGING COSTS	43,967	43,967	44,658	62,450	44,658	44,658	284,358
2	FUEL COST OF POWER SOLD	(22,462,215)	(18,191,330)	(16,104,155)	(11,742,670)	(6,524,801)	(7,665,658)	(82,690,829)
2a	REVENUES FROM OFF-SYSTEM SALES	(3,562,601)	(2,460,808)	(1,759,868)	(1,154,571)	(794,342)	(657,886)	(10,390,076)
3	FUEL COST OF PURCHASED POWER	18,701,324	15,733,000	16,061,300	21,844,883	21,914,950	20,234,012	114,489,469
3b	OKEELANTA/OSCEOLA SETTLEMENT	0	0	0	0	0	0	0
3c	QUALIFYING FACILITIES	15,469,000	14,209,000	15,277,000	8,786,000	14,412,000	15,286,000	83,439,000
4	ENERGY COST OF ECONOMY PURCHASES	6,055,781	6,487,952	8,689,396	10,364,270	15,008,245	8,505,366	55,111,010
4a	FUEL COST OF SALES TO FKEC / CKW	(4,905,120)	(4,902,312)	(4,809,096)	(5,237,849)	(5,445,445)	(5,783,586)	(31,083,408)
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$429,706,296	$403,098,786	$447,315,975	$498,577,567	$567,461,854	$587,903,046	$2,934,063,524
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,521,049	7,794,503	7,884,492	7,796,021	8,497,229	9,661,031	50,154,325
7	COST PER KWH SOLD (¢/KWH)	5.0429	5.1716	5.6734	6.3953	6.6782	6.0853	5.8501
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054
7b	JURISDICTIONAL COST (¢/KWH)	5.0456	5.1744	5.6764	6.3987	6.6818	6.0886	5.8532
9	TRUE-UP (¢/KWH)	0.0755	0.0826	0.0817	0.0826	0.0758	0.0666	0.0770
10	TOTAL	5.1211	5.2570	5.7581	6.4813	6.7576	6.1552	5.9302
11	REVENUE TAX FACTOR 0.00072	0.0037	0.0038	0.0041	0.0047	0.0049	0.0044	0.0043
12	RECOVERY FACTOR ADJUSTED FOR TAXES	5.1248	5.2608	5.7622	6.4860	6.7625	6.1596	5.9345
13	GPIF (¢/KWH)	0.0083	0.0091	0.0090	0.0091	0.0084	0.0073	0.0085
13a	JURISDICTIONALIZED SAVINGS-TURKEY POINT UNIT 5	0.0000	0.0000	0.0000	0.0000	(0.1416)	(0.1244)	(0.1325)
14	RECOVERY FACTOR including GPIF	5.1331	5.2699	5.7712	6.4951	6.6293	6.0425	5.8105
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.133	5.270	5.771	6.495	6.629	6.043	5.811

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD MAY 2007 - DECEMBER 2007

LINE NO.		(h)	(i)	(j)	(k)	(l)	(m)	(n)
				ESTIMATED				12 MONTH
		JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	PERIOD
A1	FUEL COST OF SYSTEM GENERATION	$624,312,849	$611,170,268	$594,681,887	$549,021,467	$426,827,738	$485,280,793	$6,035,202,342
1a	NUCLEAR FUEL DISPOSAL	1,985,276	1,985,276	1,468,214	1,502,983	1,495,010	1,655,567	$21,188,807
1b	COAL CAR INVESTMENT	271,119	269,144	267,170	265,195	263,220	261,246	$3,265,273
1c	ADJUSTMENT FOR TURKEY POINT UNIT 5	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	8,038,667	$96,464,000
1d	NUCLEAR SLEEVING	0	0	0	0	0	0	$0
1e	DOE DECONTAMINATION AND	0	0	0	0	0	0	$0
	DECOMMISSIONING COSTS							$0
1f	INCREMENTAL HEDGING COSTS	44,658	44,658	44,658	62,450	44,658	44,658	$570,098
2	FUEL COST OF POWER SOLD	(6,760,763)	(8,819,878)	(2,912,343)	(4,502,294)	(11,288,800)	(30,377,536)	($147,352,443)
2a	REVENUES FROM OFF-SYSTEM SALES	(671,043)	(1,057,241)	(346,946)	(467,277)	(1,267,006)	(4,998,371)	($19,197,960)
3	FUEL COST OF PURCHASED POWER	22,048,982	21,316,448	23,629,133	23,296,893	22,365,782	19,672,400	$246,819,107
3b	OKEELANTA/OSCEOLA SETTLEMENT	0	0	0	0	0	0	$0
3c	QUALIFYING FACILITIES	15,875,000	15,803,000	15,593,000	12,682,000	13,758,000	15,720,000	$172,870,000
4	ENERGY COST OF ECONOMY PURCHASES	9,974,528	8,563,248	11,195,847	22,733,292	17,159,236	8,603,752	$133,340,912
4a	FUEL COST OF SALES TO FKEC / CKW	(6,135,492)	(6,381,854)	(6,501,714)	(6,243,297)	(5,750,367)	(5,131,003)	($67,227,136)
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$668,983,780	$650,931,735	$645,157,573	$606,390,079	$471,646,137	$498,770,172	$6,475,943,000
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,312,762	10,381,920	10,314,403	9,690,394	8,658,475	8,680,716	108,192,995
7	COST PER KWH SOLD (¢/KWH)	6.4870	6.2699	6.2549	6.2576	5.4472	5.7457	5.9855
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054
7b	JURISDICTIONAL COST (¢/KWH)	6.4905	6.2732	6.2583	6.2610	5.4502	5.7488	5.9888
9	TRUE-UP (¢/KWH)	0.0623	0.0620	0.0623	0.0664	0.0744	0.0738	0.0713
10	TOTAL	6.5528	6.3352	6.3206	6.3274	5.5246	5.8226	6.0601
11	REVENUE TAX FACTOR 0.00072	0.0047	0.0046	0.0046	0.0046	0.0040	0.0042	0.0044
12	RECOVERY FACTOR ADJUSTED FOR TAXES	6.5575	6.3398	6.3252	6.3320	5.5286	5.8268	6.0645
13	GPIF (¢/KWH)	0.0069	0.0068	0.0069	0.0073	0.0082	0.0081	0.0079
13a	JURISDICTIONALIZED SAVINGS-TURKEY POINT UNIT 5	(0.1165)	(0.1158)	(0.1165)	(0.1241)	(0.1390)	(0.1379)	(0.1262)
14	RECOVERY FACTOR including GPIF	6.4479	6.2308	6.2156	6.2152	5.3978	5.6970	5.9462
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	6.448	6.231	6.216	6.215	5.398	5.697	5.946

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Generating System Comparative Data by Fuel Type

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
Fuel Cost of System Net Generation ($)						
1 Heavy Oil	$46,163,575	$44,544,527	$61,853,617	$90,477,391	$84,609,059	$90,444,901
2 Light Oil	$0	$0	$0	$0	$0	$0
3 Coal	$10,797,000	$9,342,000	$9,408,000	$10,162,000	$12,571,000	$11,410,000
4 Gas	$344,565,764	$320,506,897	$339,895,252	$359,298,897	$413,311,215	$437,508,247
5 Nuclear	$8,483,000	$7,628,000	$8,407,000	$6,010,000	$8,166,000	$8,344,000
6 ***Total***	$410,009,339	$382,021,424	$419,563,868	$465,948,288	$518,657,274	$547,707,147
System Net Generation (MWH)						
7 Heavy Oil	437,637	422,477	611,615	933,169	843,809	914,482
8 Light Oil	0	0	0	0	0	0
9 Coal	583,795	509,859	504,737	557,285	648,118	630,300
10 Gas	4,117,051	3,808,556	4,110,904	4,640,440	5,290,936	5,602,998
11 Nuclear	2,185,554	1,974,049	2,185,554	1,493,833	2,014,155	2,063,180
12 ***Total***	7,324,037	6,714,941	7,412,810	7,624,727	8,797,018	9,210,960
Units of Fuel Burned						
13 Heavy Oil (BBLS)	670,243	644,694	922,842	1,394,395	1,293,921	1,379,416
14 Light Oil (BBLS)	0	0	0	0	0	0
15 Coal (TONS)	303,275	266,773	272,203	291,665	343,658	334,412
16 Gas (MCF)	29,657,615	27,434,208	29,448,272	33,726,212	39,586,420	42,318,136
17 Nuclear (MBTU)	24,094,594	21,762,856	24,094,594	16,888,950	22,657,106	23,187,296
BTU Burned (MMBTU)						
18 Heavy Oil	4,289,557	4,126,041	5,906,191	8,924,126	8,281,095	8,828,263
19 Light Oil	0	0	0	0	0	0
20 Coal	5,842,074	5,106,750	5,070,829	5,608,667	6,533,636	6,353,397
21 Gas	29,657,615	27,434,208	29,448,272	33,726,212	39,586,420	42,318,136
22 Nuclear	24,094,594	21,762,856	24,094,594	16,888,950	22,657,106	23,187,296
23 ***Total***	63,883,840	58,429,855	64,519,886	65,147,955	77,058,257	80,687,092

Generating System Comparative Data by Fuel Type

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
Generation Mix (%MWH)						
24 Heavy Oil	5.98%	6.29%	8.25%	12.24%	9.59%	9.93%
25 Light Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26 Coal	7.97%	7.59%	6.81%	7.31%	7.37%	6.84%
27 Gas	56.21%	56.72%	55.46%	60.86%	60.14%	60.83%
28 Nuclear	29.84%	29.40%	29.48%	19.59%	22.90%	22.40%
29 ***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Cost per Unit						
30 Heavy Oil ($/BBL)	68.8759	69.0941	67.0251	64.8865	65.3897	65.5675
31 Light Oil ($/BBL)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
32 Coal ($/ton)	35.6014	35.0185	34.5624	34.8413	36.5800	34.1196
33 Gas ($/MCF)	11.6181	11.6827	11.5421	10.6534	10.4407	10.3386
34 Nuclear ($/MBTU)	0.3521	0.3505	0.3489	0.3559	0.3604	0.3599
Fuel Cost per MMBTU ($/MMBTU)						
35 Heavy Oil	10.7619	10.7959	10.4727	10.1385	10.2171	10.2449
36 Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37 Coal	1.8481	1.8293	1.8553	1.8118	1.9240	1.7959
38 Gas	11.6181	11.6827	11.5421	10.6534	10.4407	10.3386
39 Nuclear	0.3521	0.3505	0.3489	0.3559	0.3604	0.3599
BTU burned per KWH (BTU/KWH)						
40 Heavy Oil	9,802	9,766	9,657	9,563	9,814	9,654
41 Light Oil	0	0	0	0	0	0
42 Coal	10,007	10,016	10,046	10,064	10,081	10,080
43 Gas	7,204	7,203	7,163	7,268	7,482	7,553
44 Nuclear	11,024	11,024	11,024	11,306	11,249	11,239
Generated Fuel Cost per KWH (cents/KWH)						
45 Heavy Oil	10.5484	10.5437	10.1132	9.6957	10.0270	9.8903
46 Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47 Coal	1.8495	1.8323	1.8639	1.8235	1.9396	1.8102
48 Gas	8.3692	8.4154	8.2681	7.7428	7.8117	7.8085
49 Nuclear	0.3881	0.3864	0.3847	0.4023	0.4054	0.4044
50 ***Total***	5.5981	5.6891	5.6600	6.1110	5.8958	5.9463

Generating System Comparative Data by Fuel Type

	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Fuel Cost of System Net Generation ($)							
1 Heavy Oil	$144,979,411	$129,999,676	$129,047,165	$124,931,722	$44,673,172	$70,904,684	$1,062,628,900
2 Light Oil	$0	$0	$0	$0	$0	$0	$0
3 Coal	$11,905,000	$11,747,000	$11,351,000	$11,847,000	$11,620,000	$11,760,000	$133,920,000
4 Gas	$458,845,438	$460,878,593	$447,830,722	$405,303,745	$363,797,567	$395,233,109	$4,746,975,444
5 Nuclear	$8,583,000	$8,545,000	$6,453,000	$6,939,000	$6,737,000	$7,383,000	$91,678,000
6 ***Total***	$624,312,849	$611,170,268	$594,681,887	$549,021,467	$426,827,738	$485,280,793	$6,035,202,344
System Net Generation (MWH)							
7 Heavy Oil	1,490,442	1,333,070	1,325,918	1,258,084	431,331	692,348	10,694,382
8 Light Oil	0	0	0	0	0	0	0
9 Coal	651,310	651,310	630,300	651,310	638,824	660,119	7,317,267
10 Gas	5,926,216	5,911,220	5,738,194	5,191,905	4,605,205	4,800,773	59,744,397
11 Nuclear	2,131,954	2,131,954	1,576,690	1,614,028	1,605,466	1,777,885	22,754,302
12 ***Total***	10,199,922	10,027,554	9,271,102	8,715,327	7,280,826	7,931,125	100,510,348
Units of Fuel Burned							
13 Heavy Oil (BBLS)	2,248,329	2,015,298	2,000,020	1,894,724	650,455	1,050,443	16,164,780
14 Light Oil (BBLS)	0	0	0	0	0	0	0
15 Coal (TONS)	345,658	345,757	334,699	345,954	337,308	348,652	3,870,014
16 Gas (MCF)	44,207,556	44,201,556	42,649,809	37,786,308	32,981,290	34,755,366	438,752,748
17 Nuclear (MBTU)	23,960,208	23,960,208	17,623,820	18,230,568	17,772,888	19,659,014	253,892,102
BTU Burned (MMBTU)							
18 Heavy Oil	14,389,306	12,897,903	12,800,126	12,126,235	4,162,910	6,722,837	103,454,590
19 Light Oil	0	0	0	0	0	0	0
20 Coal	6,565,177	6,565,177	6,353,397	6,565,177	6,403,420	6,616,872	73,584,573
21 Gas	44,207,556	44,201,556	42,649,809	37,786,308	32,981,290	34,755,366	438,752,748
22 Nuclear	23,960,208	23,960,208	17,623,820	18,230,568	17,772,888	19,659,014	253,892,102
23 ***Total***	89,122,247	87,624,844	79,427,152	74,708,288	61,320,508	67,754,089	869,684,013

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Generating System Comparative Data by Fuel Type

	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Generation Mix (%MWH)							
24 Heavy Oil	14.61%	13.29%	14.30%	14.44%	5.92%	8.73%	10.64%
25 Light Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26 Coal	6.39%	6.50%	6.80%	7.47%	8.77%	8.32%	7.28%
27 Gas	58.10%	58.95%	61.89%	59.57%	63.25%	60.53%	59.44%
28 Nuclear	20.90%	21.26%	17.01%	18.52%	22.05%	22.42%	22.64%
29 ***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Cost per Unit							
30 Heavy Oil ($/BBL)	64.4832	64.5064	64.5229	65.9366	68.6799	67.4998	65.7373
31 Light Oil ($/BBL)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
32 Coal ($/ton)	34.4416	33.9747	33.9141	34.2444	34.4492	33.7299	34.6045
33 Gas ($/MCF)	10.3793	10.4268	10.5002	10.7262	11.0304	11.3719	10.8192
34 Nuclear ($/MBTU)	0.3582	0.3566	0.3662	0.3806	0.3791	0.3756	0.3611
Fuel Cost per MMBTU ($/MMBTU)							
35 Heavy Oil	10.0755	10.0791	10.0817	10.3026	10.7312	10.5468	10.2715
36 Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37 Coal	1.8134	1.7893	1.7866	1.8045	1.8147	1.7773	1.8199
38 Gas	10.3793	10.4268	10.5002	10.7262	11.0304	11.3719	10.8192
39 Nuclear	0.3582	0.3566	0.3662	0.3806	0.3791	0.3756	0.3611
BTU burned per KWH (BTU/KWH)							
40 Heavy Oil	9,654	9,675	9,654	9,639	9,651	9,710	9,674
41 Light Oil	0	0	0	0	0	0	0
42 Coal	10,080	10,080	10,080	10,080	10,024	10,024	10,056
43 Gas	7,460	7,478	7,433	7,278	7,162	7,240	7,344
44 Nuclear	11,239	11,239	11,178	11,295	11,070	11,058	11,158
Generated Fuel Cost per KWH (cents/KWH)							
45 Heavy Oil	9.7273	9.7519	9.7327	9.9303	10.3571	10.2412	9.9363
46 Light Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47 Coal	1.8279	1.8036	1.8009	1.8189	1.8190	1.7815	1.8302
48 Gas	7.7426	7.7967	7.8044	7.8065	7.8997	8.2327	7.9455
49 Nuclear	0.4026	0.4008	0.4093	0.4299	0.4196	0.4153	0.4029
50 ***Total***	6.1208	6.0949	6.4149	6.2995	5.8624	6.1200	6.0046

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Estimated For The Period of : Jan-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	388	44,350	17.5	95.1	50.9	9,649	Heavy Oil BBLS ->	66,466	6,400,009	425,383	4,582,002	10.3315
2			6,050					Gas MCF ->	60,930	1,000,000	60,930	705,582	11.6625
3													
4	TURKEY POINT 2	393	40,009	17.0	75.9	50.9	9,844	Heavy Oil BBLS ->	60,949	6,399,974	390,072	4,201,598	10.5016
5			9,629					Gas MCF ->	98,568	1,000,000	98,568	1,141,462	11.8550
6													
7	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,816,494	1,000,000	5,816,494	1,929,900	0.3711
8													
9	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,816,494	1,000,000	5,816,494	2,244,600	0.4316
10													
11	TURKEY POINT 5	1,104		0.0	0.0		0						
12													
13	LAUDERDALE 4	443	151,490	46.0	97.6	82.8	7,976	Gas MCF ->	1,208,311	1,000,000	1,208,311	14,232,725	9.3952
14													
15	LAUDERDALE 5	443	157,390	47.8	98.4	85.4	7,819	Gas MCF ->	1,230,681	1,000,000	1,230,681	14,604,228	9.2790
16													
17	PT EVERGLADES 1	206	2,549	2.0	96.3	58.1	10,527	Heavy Oil BBLS ->	4,155	6,399,759	26,591	286,056	11.2223
18			564					Gas MCF ->	6,175	1,000,000	6,175	71,526	12.6887
19													
20	PT EVERGLADES 2	206	2,812	2.2	96.2	60.6	10,372	Heavy Oil BBLS ->	4,519	6,400,089	28,922	311,122	11.0641
21			559					Gas MCF ->	6,032	1,000,000	6,032	69,895	12.5148
22													
23	PT EVERGLADES 3	370	53,895	23.2	92.2	54.7	9,750	Heavy Oil BBLS ->	81,478	6,400,034	521,462	5,609,119	10.4075
24			9,912					Gas MCF ->	100,700	1,000,000	100,700	1,166,120	11.7646
25													
26	PT EVERGLADES 4	381	47,048	21.6	93.0	46.5	9,916	Heavy Oil BBLS ->	72,061	6,399,967	461,188	4,960,792	10.5441
27			14,210					Gas MCF ->	146,256	1,000,000	146,256	1,693,701	11.9193
28													
29	RIVIERA 3	274	7,710	4.2	94.0	71.6	9,760	Heavy Oil BBLS ->	11,696	6,399,966	74,854	805,229	10.4440
30			927					Gas MCF ->	9,445	1,000,000	9,445	109,428	11.8109
31													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	RIVIERA 4	281	36,721	31.7	89.8	36.4	10,478	Heavy Oil BBLS ->	58,810	6,399,966	376,382	4,049,053	11.0265
33			29,621					Gas MCF ->	318,790	1,000,000	318,790	3,691,744	12.4632
34													
35	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,880	Nuclear Othr ->	6,732,330	1,000,000	6,732,330	2,218,300	0.3585
36													
37	ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,880	Nuclear Othr ->	5,729,277	1,000,000	5,729,277	2,090,600	0.3970
38													
39	CAPE CANAVERAL 1	390	41,966	16.8	91.3	50.7	9,956	Heavy Oil BBLS ->	64,827	6,400,019	414,894	4,465,255	10.6402
40			6,904					Gas MCF ->	71,668	1,000,000	71,668	829,987	12.0220
41													
42	CAPE CANAVERAL 2	390	38,391	14.9	90.4	47.9	9,845	Heavy Oil BBLS ->	58,726	6,399,959	375,844	4,045,014	10.5364
43			4,956					Gas MCF ->	50,945	1,000,000	50,945	589,938	11.9035
44													
45	CUTLER 5	67		0.0	98.2		0						
46													
47	CUTLER 6	110		0.0	96.0		0						
48													
49	FORT MYERS 2	1,451	959,018	88.8	96.1	88.8	7,047	Gas MCF ->	6,758,302	1,000,000	6,758,302	78,420,507	8.1772
50													
51	FORT MYERS 3A_B	166	1,316	0.5	96.3	99.1	10,256	Gas MCF ->	13,494	1,000,000	13,494	163,497	12.4276
52													
53	SANFORD 3	140	837	1.0	95.1	54.3	10,303	Heavy Oil BBLS ->	1,337	6,397,906	8,554	94,351	11.2725
54			152					Gas MCF ->	1,636	1,000,000	1,636	18,951	12.4350
55													
56	SANFORD 4	964	626,663	87.4	96.3	90.4	6,976	Gas MCF ->	4,371,618	1,000,000	4,371,618	50,890,786	8.1209
57													
58	SANFORD 5	960	505,774	70.8	96.5	90.7	6,989	Gas MCF ->	3,534,963	1,000,000	3,534,963	41,063,957	8.1190
59													
60	PUTNAM 1	250	2,313	1.2	96.4	77.1	9,159	Gas MCF ->	21,182	1,000,000	21,182	256,548	11.0940
61													

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Estimated For The Period of : Jan-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	PUTNAM 2	250	2,386	1.3	96.1	79.5	9,086	Gas MCF ->	21,680	1,000,000	21,680	262,655	11.0082
63													
64	MANATEE 1	810	46,197	8.6	94.4	50.0	9,804	Heavy Oil BBLS ->	70,391	6,399,994	450,502	4,847,211	10.4925
65			5,615					Gas MCF ->	57,495	1,000,000	57,495	665,844	11.8581
66													
67	MANATEE 2	810	17,863	3.2	95.0	56.2	9,723	Heavy Oil BBLS ->	27,052	6,399,970	173,132	1,862,756	10.4280
68			1,263					Gas MCF ->	12,850	1,000,000	12,850	148,859	11.7889
69													
70	MANATEE 3	1,111	494,181	59.8	87.2	68.7	7,011	Gas MCF ->	3,465,117	1,000,000	3,465,117	40,310,661	8.1571
71													
72	MARTIN 1	823	45,598	13.3	95.0	45.5	10,034	Heavy Oil BBLS ->	69,946	6,400,009	447,655	4,815,832	10.5615
73			36,087					Gas MCF ->	371,992	1,000,000	371,992	4,307,767	11.9373
74													
75	MARTIN 2	814	11,692	3.0	93.9	53.8	9,938	Heavy Oil BBLS ->	17,831	6,400,146	114,121	1,227,727	10.5006
76			6,688					Gas MCF ->	68,538	1,000,000	68,538	793,715	11.8685
77													
78	MARTIN 3	465	179,741	52.0	94.4	86.5	7,363	Gas MCF ->	1,323,567	1,000,000	1,323,567	15,327,470	8.5276
79													
80	MARTIN 4	466	195,328	56.3	98.6	89.2	7,273	Gas MCF ->	1,420,721	1,000,000	1,420,721	16,452,529	8.4230
81													
82	MARTIN 8	1,112	708,319	85.6	96.5	85.6	6,926	Gas MCF ->	4,905,961	1,000,000	4,905,961	56,575,311	7.9873
83													
84	FORT MYERS 1-12	627		0.0	94.7		0						
85													
86	LAUDERDALE 1-24	766		0.0	91.7		0						
87													
88	EVERGLADES 1-12	383		0.0	88.3		0						
89													
90	ST JOHNS 1O	130	94,440	97.6	96.9	97.6	9,756	Coal TONS ->	37,289	24,708,869	921,369	1,662,100	1.7600
91													

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Estimated For The Period of : Jan-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	ST JOHNS 2O	130	94,459	97.7	97.0	97.7	9,650	Coal	TONS ->	36,894	24,708,814	911,607	1,644,500	1.7410
93	----------													
94	SCHERER 4	648	394,896	82.0	97.2	82.0	10,152	Coal	TONS ->	229,091	17,500,028	4,009,099	7,490,200	1.8968
95	----------													
96	TOTAL	21,734	7,324,039				8,722					63,883,844	410,008,710	5.5981

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Estimated For The Period of : Feb-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	388	47,175	20.5	95.1	49.1	9,653	Heavy Oil BBLS ->	70,738	6,399,969	452,721	4,892,370	10.3707
2			6,349					Gas MCF ->	63,977	1,000,000	63,977	744,778	11.7303
3													
4	TURKEY POINT 2	393		0.0	0.0		0						
5													
6	TURKEY POINT 3	717	469,777	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,253,608	1,000,000	5,253,608	1,735,300	0.3694
7													
8	TURKEY POINT 4	717	469,777	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,253,608	1,000,000	5,253,608	2,018,400	0.4297
9													
10	TURKEY POINT 5	1,104		0.0	0.0		0						
11													
12	LAUDERDALE 4	443	132,216	44.4	97.6	87.5	7,924	Gas MCF ->	1,047,793	1,000,000	1,047,793	12,470,735	9.4321
13													
14	LAUDERDALE 5	443	142,328	47.8	98.4	88.0	7,828	Gas MCF ->	1,114,244	1,000,000	1,114,244	13,271,347	9.3245
15													
16	PT EVERGLADES 1	206	1,234	1.1	96.3	57.6	10,553	Heavy Oil BBLS ->	2,015	6,401,489	12,899	139,172	11.2781
17			307					Gas MCF ->	3,368	1,000,000	3,368	39,162	12.7564
18													
19	PT EVERGLADES 2	206	1,231	1.1	96.2	57.3	10,444	Heavy Oil BBLS ->	1,989	6,401,709	12,733	137,395	11.1613
20			303					Gas MCF ->	3,290	1,000,000	3,290	38,342	12.6541
21													
22	PT EVERGLADES 3	370	49,573	22.8	92.2	56.5	9,683	Heavy Oil BBLS ->	74,540	6,399,987	477,055	5,148,252	10.3852
23			7,047					Gas MCF ->	71,202	1,000,000	71,202	828,928	11.7635
24													
25	PT EVERGLADES 4	381	54,732	24.7	93.0	51.5	9,723	Heavy Oil BBLS ->	82,593	6,400,022	528,597	5,704,483	10.4226
26			8,613					Gas MCF ->	87,347	1,000,000	87,347	1,016,861	11.8056
27													
28	RIVIERA 3	274	43,790	35.7	94.0	43.3	10,341	Heavy Oil BBLS ->	69,596	6,399,951	445,411	4,807,365	10.9782
29			21,888					Gas MCF ->	233,770	1,000,000	233,770	2,721,545	12.4339
30													

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Estimated For The Period of : Feb-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	RIVIERA 4	281	14,408	9.0	89.8	55.1	9,861	Heavy Oil BBLS ->	22,032	6,399,873	141,002	1,521,848	10.5625
32			2,610					Gas MCF ->	26,821	1,000,000	26,821	312,266	11.9633
33	------------												
34	ST LUCIE 1	853	558,883	97.5	97.5	97.5	10,880	Nuclear Othr ->	6,080,814	1,000,000	6,080,814	1,994,500	0.3569
35	------------												
36	ST LUCIE 2	726	475,613	97.5	97.5	97.5	10,880	Nuclear Othr ->	5,174,827	1,000,000	5,174,827	1,879,500	0.3952
37	------------												
38	CAPE CANAVERAL 1	390	47,048	20.6	91.3	50.4	9,920	Heavy Oil BBLS ->	72,458	6,399,956	463,728	5,007,222	10.6428
39			7,024					Gas MCF ->	72,692	1,000,000	72,692	846,309	12.0492
40	------------												
41	CAPE CANAVERAL 2	390	46,939	20.8	90.4	44.3	9,927	Heavy Oil BBLS ->	72,313	6,399,970	462,801	4,997,133	10.6460
42			7,480					Gas MCF ->	77,437	1,000,000	77,437	901,524	12.0525
43	------------												
44	CUTLER 5	67		0.0	98.2		0						
45	------------												
46	CUTLER 6	110		0.0	96.0		0						
47	------------												
48	FORT MYERS 2	1,451	855,016	87.7	93.2	87.7	7,077	Gas MCF ->	6,051,478	1,000,000	6,051,478	70,601,178	8.2573
49	------------												
50	FORT MYERS 3A_B	166		0.0	96.3		0						
51	------------												
52	SANFORD 3	140	661	0.7	95.1	59.0	10,036	Heavy Oil BBLS ->	1,036	6,399,614	6,630	73,379	11.1012
53	------------												
54	SANFORD 4	964	548,200	84.6	96.3	90.1	6,984	Gas MCF ->	3,828,988	1,000,000	3,828,988	44,745,921	8.1623
55	------------												
56	SANFORD 5	960	385,426	59.7	80.1	80.1	7,119	Gas MCF ->	2,744,159	1,000,000	2,744,159	31,993,605	8.3009
57	------------												
58	PUTNAM 1	250		0.0	96.4		0						
59	------------												
60	PUTNAM 2	250		0.0	96.1		0						
61	------------												

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Estimated For The Period of : Feb-07

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 1	810	30,364	6.1	94.4	52.4	9,741	Heavy Oil	BBLS ->	46,030	6,400,000	294,592	3,180,036	10.4730
63			2,717					Gas	MCF ->	27,683	1,000,000	27,683	322,287	11.8601
64														
65	MANATEE 2	810	7,370	1.4	95.0	56.9	9,621	Heavy Oil	BBLS ->	11,079	6,400,126	70,907	765,407	10.3854
66														
67	MANATEE 3	1,111	638,539	85.5	94.8	86.3	6,964	Gas	MCF ->	4,446,949	1,000,000	4,446,949	52,085,019	8.1569
68														
69	MARTIN 1	823	74,024	21.9	95.0	49.3	9,896	Heavy Oil	BBLS ->	112,278	6,400,025	718,582	7,755,830	10.4775
70			47,202					Gas	MCF ->	481,118	1,000,000	481,118	5,601,166	11.8664
71														
72	MARTIN 2	814	3,928	1.1	93.9	51.1	9,930	Heavy Oil	BBLS ->	5,997	6,400,367	38,383	414,282	10.5469
73			1,893					Gas	MCF ->	19,420	1,000,000	19,420	226,072	11.9438
74														
75	MARTIN 3	465	171,245	54.8	94.4	91.8	7,297	Gas	MCF ->	1,249,634	1,000,000	1,249,634	14,548,206	8.4956
76														
77	MARTIN 4	466	191,955	61.3	98.6	93.8	7,218	Gas	MCF ->	1,385,676	1,000,000	1,385,676	16,132,033	8.4041
78														
79	MARTIN 8	1,112	630,200	84.3	86.2	84.3	6,977	Gas	MCF ->	4,397,164	1,000,000	4,397,164	51,059,274	8.1021
80														
81	FORT MYERS 1-12	627		0.0	85.2		0							
82														
83	LAUDERDALE 1-24	766		0.0	91.7		0							
84														
85	EVERGLADES 1-12	383		0.0	88.3		0							
86														
87	ST JOHNS 1O	130	70,068	80.2	79.6	97.6	9,756	Coal	TONS ->	27,704	24,674,993	683,596	1,192,700	1.7022
88														
89	ST JOHNS 2O	130	85,318	97.7	97.0	97.7	9,650	Coal	TONS ->	33,369	24,675,178	823,386	1,436,600	1.6838
90														
91	SCHERER 4	648	354,473	81.5	97.2	81.5	10,155	Coal	TONS ->	205,701	17,500,002	3,599,768	6,712,800	1.8937
92														

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Estimated For The Period of : Feb-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
93	TOTAL	21,734	6,714,943				8,701				58,429,857	382,020,532	5.6891

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Estimated For The Period of : Mar-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	388	68,800	25.4	95.1	59.6	9,514	Heavy Oil BBLS ->	101,970	6,400,020	652,610	6,841,710	9.9443
2			4,486					Gas MCF ->	44,682	1,000,000	44,682	514,358	11.4653
3													
4	TURKEY POINT 2	393		0.0	0.0		0						
5													
6	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,816,494	1,000,000	5,816,494	1,911,900	0.3676
7													
8	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,816,494	1,000,000	5,816,494	2,224,800	0.4278
9													
10	TURKEY POINT 5	1,104		0.0	0.0		0						
11													
12	LAUDERDALE 4	443	7,364	2.2	6.3	97.8	7,754	Gas MCF ->	57,101	1,000,000	57,101	673,065	9.1402
13													
14	LAUDERDALE 5	443	166,303	50.5	98.4	91.3	7,775	Gas MCF ->	1,293,135	1,000,000	1,293,135	15,217,434	9.1504
15													
16	PT EVERGLADES 1	206		0.0	96.3		0						
17													
18	PT EVERGLADES 2	206	1,480	1.3	96.2	39.1	10,872	Heavy Oil BBLS ->	2,481	6,399,033	15,876	166,223	11.2313
19			535					Gas MCF ->	6,032	1,000,000	6,032	69,441	12.9699
20													
21	PT EVERGLADES 3	370		0.0	0.0		0						
22													
23	PT EVERGLADES 4	381	88,300	33.6	93.0	66.5	9,551	Heavy Oil BBLS ->	131,309	6,399,995	840,377	8,797,723	9.9634
24			6,911					Gas MCF ->	69,065	1,000,000	69,065	795,111	11.5045
25													
26	RIVIERA 3	274	19,088	10.7	94.0	67.7	9,808	Heavy Oil BBLS ->	29,077	6,400,110	186,096	1,948,458	10.2078
27			2,614					Gas MCF ->	26,762	1,000,000	26,762	308,098	11.7856
28													
29	RIVIERA 4	281	72,506	43.5	89.8	51.6	9,961	Heavy Oil BBLS ->	111,720	6,400,000	715,008	7,486,171	10.3249
30			18,503					Gas MCF ->	191,581	1,000,000	191,581	2,205,492	11.9200
31													

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Estimated For The Period of : Mar-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,880	Nuclear Othr ->	6,732,330	1,000,000	6,732,330	2,198,100	0.3552
33													
34	ST LUCIE 2	726	526,572	97.5	97.5	97.5	10,880	Nuclear Othr ->	5,729,277	1,000,000	5,729,277	2,071,700	0.3934
35													
36	CAPE CANAVERAL 1	390	71,459	27.6	91.3	63.1	9,769	Heavy Oil BBLS ->	108,508	6,399,980	694,449	7,274,031	10.1793
37			8,529					Gas MCF ->	87,025	1,000,000	87,025	1,001,885	11.7475
38													
39	CAPE CANAVERAL 2	390	57,776	21.6	90.4	53.1	9,726	Heavy Oil BBLS ->	87,473	6,400,021	559,829	5,863,932	10.1494
40			4,807					Gas MCF ->	48,908	1,000,000	48,908	563,057	11.7133
41													
42	CUTLER 5	67		0.0	98.2		0						
43													
44	CUTLER 6	110		0.0	96.0		0						
45													
46	FORT MYERS 2	1,451	849,951	78.7	79.8	78.7	7,124	Gas MCF ->	6,055,071	1,000,000	6,055,071	69,710,345	8.2017
47													
48	FORT MYERS 3A_B	166		0.0	96.3		0						
49													
50	SANFORD 3	140		0.0	95.1		0						
51													
52	SANFORD 4	964	628,946	87.7	96.3	89.6	6,991	Gas MCF ->	4,397,044	1,000,000	4,397,044	51,030,311	8.1136
53													
54	SANFORD 5	960	509,118	71.3	94.9	93.5	6,961	Gas MCF ->	3,544,265	1,000,000	3,544,265	41,035,759	8.0602
55													
56	PUTNAM 1	250		0.0	96.4		0						
57													
58	PUTNAM 2	250	4,822	2.6	96.1	77.2	9,489	Gas MCF ->	45,762	1,000,000	45,762	538,241	11.1615
59													
60	MANATEE 1	810	83,247	15.7	94.4	52.8	9,744	Heavy Oil BBLS ->	125,999	6,399,987	806,392	8,444,300	10.1437
61			11,306					Gas MCF ->	114,990	1,000,000	114,990	1,323,810	11.7093
62													

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Estimated For The Period of : Mar-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 2	810	40,842	7.4	95.0	55.4	9,703	Heavy Oil BBLS ->	61,647	6,399,955	394,538	4,131,498	10.1158
64			4,012					Gas MCF ->	40,692	1,000,000	40,692	468,442	11.6766
65													
66	MANATEE 3	1,111	722,034	87.4	96.5	87.4	6,971	Gas MCF ->	5,033,427	1,000,000	5,033,427	58,011,863	8.0345
67													
68	MARTIN 1	823	91,537	23.4	95.0	56.3	9,779	Heavy Oil BBLS ->	137,397	6,399,994	879,340	9,206,784	10.0580
69			51,700					Gas MCF ->	521,482	1,000,000	521,482	6,003,474	11.6122
70													
71	MARTIN 2	814	16,580	4.5	93.9	53.6	9,939	Heavy Oil BBLS ->	25,262	6,399,968	161,676	1,692,719	10.2094
72			10,463					Gas MCF ->	107,122	1,000,000	107,122	1,233,218	11.7869
73													
74	MARTIN 3	465	187,294	54.1	94.4	94.8	7,262	Gas MCF ->	1,360,212	1,000,000	1,360,212	15,659,139	8.3607
75													
76	MARTIN 4	466	202,899	58.5	98.6	98.1	7,170	Gas MCF ->	1,454,984	1,000,000	1,454,984	16,750,174	8.2554
77													
78	MARTIN 8	1,112	708,308	85.6	94.9	85.6	6,986	Gas MCF ->	4,948,926	1,000,000	4,948,926	56,782,374	8.0166
79													
80	FORT MYERS 1-12	627		0.0	94.7		0						
81													
82	LAUDERDALE 1-24	766		0.0	91.7		0						
83													
84	EVERGLADES 1-12	383		0.0	88.3		0						
85													
86	ST JOHNS 1O	130	15,232	15.8	18.8	97.6	9,756	Coal TONS ->	6,031	24,640,524	148,607	272,300	1.7877
87													
88	ST JOHNS 2O	130	94,459	97.7	97.0	97.7	9,650	Coal TONS ->	36,994	24,641,996	911,606	1,670,600	1.7686
89													
90	SCHERER 4	648	395,046	82.0	97.2	82.0	10,152	Coal TONS ->	229,178	17,500,004	4,010,616	7,465,000	1.8897
91													
92	TOTAL	21,734	7,412,812				8,704				64,519,885	419,563,040	5.6600

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Estimated For The Period of : Apr-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	385	100,035	36.4	95.1	75.2	9,420	Heavy Oil BBLS ->	147,193	6,399,999	942,035	9,559,717	9.5564
2			722					Gas MCF ->	7,141	1,000,000	7,141	74,928	10.3750
3													
4	TURKEY POINT 2	390	100,158	35.7	78.4	94.1	9,377	Heavy Oil BBLS ->	146,758	6,399,999	939,251	9,531,445	9.5164
5													
6	TURKEY POINT 3	693	486,491	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,563,476	1,000,000	5,563,476	1,821,500	0.3744
7													
8	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,563,476	1,000,000	5,563,476	2,119,700	0.4357
9													
10	TURKEY POINT 5	1,080		0.0	0.0		0						
11													
12	LAUDERDALE 4	426	45,675	14.9	32.5	95.7	7,880	Gas MCF ->	359,933	1,000,000	359,933	3,922,137	8.5871
13													
14	LAUDERDALE 5	426	216,648	70.6	98.4	93.8	7,817	Gas MCF ->	1,693,724	1,000,000	1,693,724	18,457,635	8.5196
15													
16	PT EVERGLADES 1	205	5,510	4.1	96.3	62.5	10,441	Heavy Oil BBLS ->	8,951	6,400,179	57,288	580,549	10.5363
17			517					Gas MCF ->	5,640	1,000,000	5,640	59,127	11.4454
18													
19	PT EVERGLADES 2	205	5,609	3.8	96.2	85.5	10,068	Heavy Oil BBLS ->	8,823	6,400,317	56,470	572,245	10.2023
20													
21	PT EVERGLADES 3	365		0.0	0.0		0						
22													
23	PT EVERGLADES 4	376	132,160	49.5	93.0	87.2	9,394	Heavy Oil BBLS ->	193,846	6,400,008	1,240,616	12,571,248	9.5121
24			1,963					Gas MCF ->	19,348	1,000,000	19,348	202,964	10.3400
25													
26	RIVIERA 3	272	98,259	58.1	94.0	66.9	9,855	Heavy Oil BBLS ->	150,298	6,399,979	961,904	9,748,415	9.9211
27			15,439					Gas MCF ->	158,700	1,000,000	158,700	1,664,783	10.7828
28													
29	RIVIERA 4	279	56,944	29.2	89.8	80.6	9,605	Heavy Oil BBLS ->	85,340	6,400,012	546,177	5,535,220	9.7205
30			1,756					Gas MCF ->	17,681	1,000,000	17,681	185,497	10.5660
31													

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Estimated For The Period of : Apr-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	19,633	3.3	3.3	97.5	11,062	Nuclear Othr ->	217,186	1,000,000	217,186	72,500	0.3693
33													
34	ST LUCIE 2	714	501,219	97.5	97.5	97.5	11,062	Nuclear Othr ->	5,544,812	1,000,000	5,544,812	1,996,700	0.3984
35													
36	CAPE CANAVERAL 1	386	86,662	31.8	82.1	83.5	9,610	Heavy Oil BBLS ->	130,022	6,399,986	832,139	8,437,028	9.7356
37			1,636					Gas MCF ->	16,489	1,000,000	16,489	172,989	10.5771
38													
39	CAPE CANAVERAL 2	386	86,483	31.4	90.4	69.1	9,599	Heavy Oil BBLS ->	129,665	6,399,977	829,853	8,413,801	9.7288
40			713					Gas MCF ->	7,186	1,000,000	7,186	75,400	10.5721
41													
42	CUTLER 5	65		0.0	98.2		0						
43													
44	CUTLER 6	110		0.0	96.0		0						
45													
46	FORT MYERS 2	1,423	922,438	90.0	92.9	90.0	7,117	Gas MCF ->	6,565,193	1,000,000	6,565,193	69,584,236	7.5435
47													
48	FORT MYERS 3A_B	160	1,268	0.6	96.3	99.1	10,462	Gas MCF ->	13,268	1,000,000	13,268	144,634	11.4056
49													
50	SANFORD 3	138	950	2.8	95.1	60.3	10,486	Heavy Oil BBLS ->	1,507	6,399,469	9,644	100,355	10.5637
51			1,798					Gas MCF ->	19,167	1,000,000	19,167	207,475	11.5411
52													
53	SANFORD 4	954	624,869	91.0	64.2	91.0	7,035	Gas MCF ->	4,396,559	1,000,000	4,396,559	47,318,452	7.5725
54													
55	SANFORD 5	950	614,511	89.8	96.5	90.9	7,053	Gas MCF ->	4,334,519	1,000,000	4,334,519	46,481,765	7.5640
56													
57	PUTNAM 1	239	96,104	55.9	96.4	95.1	9,014	Gas MCF ->	866,347	1,000,000	866,347	9,445,102	9.8280
58													
59	PUTNAM 2	239	103,148	59.9	96.1	95.1	8,977	Gas MCF ->	926,022	1,000,000	926,022	10,094,306	9.7862
60													
61	MANATEE 1	803	88,592	15.8	94.4	65.8	9,650	Heavy Oil BBLS ->	133,390	6,399,985	853,694	8,653,057	9.7673
62			2,757					Gas MCF ->	27,895	1,000,000	27,895	292,642	10.6149
63													

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Estimated For The Period of : Apr-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MANATEE 2	803	64,170	11.6	95.0	63.3	9,677	Heavy Oil BBLS ->	96,816	6,399,965	619,619	6,280,434	9.7872
65			2,978					Gas MCF ->	30,194	1,000,000	30,194	316,722	10.6350
66	------------												
67	MANATEE 3	1,087	701,806	89.7	96.5	89.7	7,043	Gas MCF ->	4,943,443	1,000,000	4,943,443	53,138,886	7.5717
68	------------												
69	MARTIN 1	813	90,548	22.6	95.0	71.9	9,749	Heavy Oil BBLS ->	135,795	6,399,993	869,087	8,807,747	9.7272
70			41,577					Gas MCF ->	419,011	1,000,000	419,011	4,395,585	10.5722
71	------------												
72	MARTIN 2	806	17,091	4.4	93.9	60.1	9,896	Heavy Oil BBLS ->	25,992	6,400,046	166,350	1,685,827	9.8638
73			8,596					Gas MCF ->	87,850	1,000,000	87,850	921,594	10.7214
74	------------												
75	MARTIN 3	449	246,070	76.1	94.4	91.5	7,392	Gas MCF ->	1,818,985	1,000,000	1,818,985	19,081,903	7.7547
76	------------												
77	MARTIN 4	450	274,423	84.7	98.6	91.2	7,342	Gas MCF ->	2,014,871	1,000,000	2,014,871	21,136,799	7.7023
78	------------												
79	MARTIN 8	1,088	713,030	91.0	96.5	91.0	6,980	Gas MCF ->	4,977,049	1,000,000	4,977,049	51,922,668	7.2820
80	------------												
81	FORT MYERS 1-12	552		0.0	91.3		0						
82	------------												
83	LAUDERDALE 1-24	684		0.0	91.7		0						
84	------------												
85	EVERGLADES 1-12	342		0.0	88.3		0						
86	------------												
87	ST JOHNS 1O	127	89,284	97.6	96.9	97.6	9,836	Coal TONS ->	35,686	24,609,146	878,202	1,502,200	1.6825
88	------------												
89	ST JOHNS 2O	127	89,302	97.7	97.0	97.7	9,723	Coal TONS ->	35,285	24,608,984	868,328	1,485,300	1.6632
90	------------												
91	SCHERER 4	641	378,698	82.0	97.2	82.0	10,198	Coal TONS ->	220,694	17,499,959	3,862,136	7,174,700	1.8946
92	------------												
93	TOTAL	21,170	7,624,728				8,544				65,147,956	465,947,917	6.1110
		=======	=======				=======				=======	=======	=======

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Estimated For The Period of : May-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	385	13,527	4.8	95.1	88.5	9,420	Heavy Oil	BBLS ->	19,904	6,400,070	127,387	1,303,131	9.6336
2			103					Gas	MCF ->	1,020	1,000,000	1,020	10,475	10.1600
3														
4	TURKEY POINT 2	390	21,252	7.5	94.1	86.8	9,427	Heavy Oil	BBLS ->	31,276	6,399,955	200,165	2,047,571	9.6347
5			410					Gas	MCF ->	4,055	1,000,000	4,055	41,760	10.1854
6														
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,435	Nuclear	Othr ->	5,748,926	1,000,000	5,748,926	1,873,600	0.3727
8														
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,435	Nuclear	Othr ->	5,748,926	1,000,000	5,748,926	2,180,600	0.4338
10														
11	TURKEY POINT 5	1,080	673,129	83.8	94.1	83.8	7,038	Gas	MCF ->	4,737,837	1,000,000	4,737,837	48,109,894	7.1472
12														
13	LAUDERDALE 4	426	246,551	77.8	97.6	77.8	8,290	Gas	MCF ->	2,044,036	1,000,000	2,044,036	21,790,996	8.8383
14														
15	LAUDERDALE 5	426	257,318	81.2	98.4	81.2	8,092	Gas	MCF ->	2,082,386	1,000,000	2,082,386	22,474,111	8.7340
16														
17	PT EVERGLADES 1	205	2,653	1.8	96.3	84.1	10,201	Heavy Oil	BBLS ->	4,221	6,400,616	27,017	275,971	10.4022
18			106					Gas	MCF ->	1,128	1,000,000	1,128	11,542	10.9403
19														
20	PT EVERGLADES 2	205	4,026	2.7	96.2	85.0	10,105	Heavy Oil	BBLS ->	6,345	6,400,473	40,611	414,844	10.3041
21			156					Gas	MCF ->	1,653	1,000,000	1,653	16,952	10.8597
22														
23	PT EVERGLADES 3	376	15,019	5.4	86.2	84.4	9,426	Heavy Oil	BBLS ->	22,108	6,399,946	141,490	1,445,224	9.6226
24			207					Gas	MCF ->	2,042	1,000,000	2,042	20,953	10.1467
25														
26	PT EVERGLADES 4	376	30,854	11.1	93.0	85.4	9,395	Heavy Oil	BBLS ->	45,271	6,400,013	289,735	2,959,566	9.5922
27			310					Gas	MCF ->	3,055	1,000,000	3,055	31,317	10.1088
28														
29	RIVIERA 3	272	2,087	1.0	15.2	95.9	9,559	Heavy Oil	BBLS ->	3,117	6,400,064	19,949	203,818	9.7661
30														

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)
31	RIVIERA 4	279	81,614	49.8	89.8	61.5	9,878	Heavy Oil BBLS ->	124,661	6,399,997	797,830	8,150,663	9.9868
32			21,806					Gas MCF ->	223,830	1,000,000	223,830	2,315,915	10.6204
33	------------												
34	ST LUCIE 1	839	490,814	78.6	78.6	97.5	11,062	Nuclear Othr ->	5,429,616	1,000,000	5,429,616	2,058,400	0.4194
35	------------												
36	ST LUCIE 2	714	517,926	97.5	97.5	97.5	11,062	Nuclear Othr ->	5,729,640	1,000,000	5,729,640	2,053,500	0.3965
37	------------												
38	CAPE CANAVERAL 1	386		0.0	17.7		0						
39	------------												
40	CAPE CANAVERAL 2	386	11,012	3.9	90.4	90.0	9,572	Heavy Oil BBLS ->	16,462	6,399,951	105,356	1,076,814	9.7786
41			102					Gas MCF ->	1,027	1,000,000	1,027	10,485	10.2593
42	------------												
43	CUTLER 5	65		0.0	98.2		0						
44	------------												
45	CUTLER 6	110		0.0	96.0		0						
46	------------												
47	FORT MYERS 2	1,423	936,045	88.4	96.1	88.4	7,156	Gas MCF ->	6,698,352	1,000,000	6,698,352	69,569,225	7.4323
48	------------												
49	FORT MYERS 3A_B	160	2,695	1.1	3.1	99.1	10,462	Gas MCF ->	28,194	1,000,000	28,194	300,834	11.1643
50	------------												
51	SANFORD 3	138	1,461	1.4	95.1	66.2	10,517	Gas MCF ->	15,367	1,000,000	15,367	169,129	11.5755
52	------------												
53	SANFORD 4	954	617,521	87.0	83.9	87.0	7,088	Gas MCF ->	4,376,998	1,000,000	4,376,998	45,949,223	7.4409
54	------------												
55	SANFORD 5	950	591,560	83.7	91.0	83.7	7,146	Gas MCF ->	4,227,523	1,000,000	4,227,523	44,231,318	7.4771
56	------------												
57	PUTNAM 1	239	29,503	16.6	96.4	96.4	8,998	Gas MCF ->	265,474	1,000,000	265,474	2,834,719	9.6082
58	------------												
59	PUTNAM 2	239	31,847	17.9	77.5	96.6	8,961	Gas MCF ->	285,389	1,000,000	285,389	3,053,169	9.5869
60	------------												

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Estimated For The Period of : May-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MANATEE 1	803	222,437	47.3	94.4	57.7	9,945	Heavy Oil BBLS ->	342,033	6,399,999	2,189,011	22,366,353	10.0551
62			60,024					Gas MCF ->	620,232	1,000,000	620,232	6,436,300	10.7229
63													
64	MANATEE 2	803	175,381	40.0	95.0	51.7	10,021	Heavy Oil BBLS ->	271,011	6,400,002	1,734,471	17,721,991	10.1049
65			63,854					Gas MCF ->	663,079	1,000,000	663,079	6,888,959	10.7886
66													
67	MANATEE 3	1,087	674,736	83.4	96.5	83.4	7,129	Gas MCF ->	4,810,314	1,000,000	4,810,314	50,639,805	7.5051
68													
69	MARTIN 1	813	174,919	50.6	95.0	60.1	10,017	Heavy Oil BBLS ->	268,035	6,400,000	1,715,424	17,524,763	10.0188
70			131,176					Gas MCF ->	1,350,757	1,000,000	1,350,757	13,895,105	10.5928
71													
72	MARTIN 2	806	89,029	33.9	93.9	44.6	10,308	Heavy Oil BBLS ->	139,476	6,400,019	892,649	9,119,324	10.2431
73			114,254					Gas MCF ->	1,202,845	1,000,000	1,202,845	12,438,412	10.8866
74													
75	MARTIN 3	449	67,002	20.1	94.4	96.9	7,323	Gas MCF ->	490,709	1,000,000	490,709	5,035,904	7.5161
76													
77	MARTIN 4	450	83,684	25.0	98.6	98.4	7,251	Gas MCF ->	606,817	1,000,000	606,817	6,227,486	7.4417
78													
79	MARTIN 8	1,088	685,412	84.7	96.5	84.7	7,065	Gas MCF ->	4,842,652	1,000,000	4,842,652	50,808,739	7.4129
80													
81	FORT MYERS 1-12	552		0.0	88.9		0						
82													
83	LAUDERDALE 1-24	684		0.0	91.7		0						
84													
85	EVERGLADES 1-12	342		0.0	88.3		0						
86													
87	ST JOHNS 1O	127	92,260	97.6	96.9	97.6	9,836	Coal TONS ->	36,926	24,575,529	907,476	1,912,100	2.0725
88													
89	ST JOHNS 2O	127	92,279	97.7	97.0	97.7	9,723	Coal TONS ->	36,510	24,576,061	897,272	1,890,600	2.0488
90													

Estimated For The Period of : May-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
91	SCHERER 4	641	463,578	97.1	97.2	97.1	10,200	Coal	TONS ->	270,222	17,500,011	4,728,888	8,768,300	1.8914
92														
93	TOTAL	21,181	8,797,052				8,760					77,058,607	518,659,860	5.8958

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Estimated For The Period of : Jun-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	385	43,137	15.6	95.1	97.4	9,389	Heavy Oil BBLS ->	63,289	6,399,959	405,047	4,154,241	9.6303
2													
3	TURKEY POINT 2	390	58,843	21.0	94.1	95.1	9,377	Heavy Oil BBLS ->	86,209	6,400,028	551,740	5,658,739	9.6167
4			101					Gas MCF ->	993	1,000,000	993	9,967	9.8683
5													
6	TURKEY POINT 3	693	486,491	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,563,476	1,000,000	5,563,476	1,804,800	0.3710
7													
8	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,563,476	1,000,000	5,563,476	2,100,800	0.4318
9													
10	TURKEY POINT 5	1,080	674,592	86.8	94.1	86.8	7,002	Gas MCF ->	4,723,734	1,000,000	4,723,734	47,564,709	7.0509
11													
12	LAUDERDALE 4	426	248,529	81.0	97.6	81.0	8,198	Gas MCF ->	2,037,634	1,000,000	2,037,634	21,412,819	8.6158
13													
14	LAUDERDALE 5	426	263,046	85.8	98.4	85.8	7,971	Gas MCF ->	2,096,970	1,000,000	2,096,970	22,133,418	8.4143
15													
16	PT EVERGLADES 1	205	4,485	3.0	96.3	91.1	10,637	Gas MCF ->	47,707	1,000,000	47,707	504,487	11.2496
17													
18	PT EVERGLADES 2	205	1,616	5.3	96.2	95.1	10,417	Heavy Oil BBLS ->	2,530	6,399,209	16,190	165,778	10.2585
19			6,186					Gas MCF ->	65,085	1,000,000	65,085	688,715	11.1336
20													
21	PT EVERGLADES 3	376	59,986	22.2	92.2	96.1	9,377	Heavy Oil BBLS ->	87,895	6,399,966	562,525	5,761,089	9.6041
22													
23	PT EVERGLADES 4	376	69,582	25.7	93.0	96.0	9,355	Heavy Oil BBLS ->	101,709	6,400,004	650,938	6,666,528	9.5808
24			104					Gas MCF ->	1,018	1,000,000	1,018	10,402	10.0309
25													
26	RIVIERA 3	272	13,510	8.0	21.9	68.9	9,844	Heavy Oil BBLS ->	20,635	6,400,048	132,065	1,352,691	10.0125
27			2,231					Gas MCF ->	22,897	1,000,000	22,897	233,027	10.4459
28													
29	RIVIERA 4	279	16,841	8.4	89.8	94.3	9,529	Heavy Oil BBLS ->	25,076	6,400,064	160,488	1,643,855	9.7610
30													

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Estimated For The Period of : Jun-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 1	839	588,980	97.5	97.5	97.5	11,062	Nuclear Othr ->	6,515,534	1,000,000	6,515,534	2,459,600	0.4176
32													
33	ST LUCIE 2	714	501,219	97.5	97.5	97.5	11,062	Nuclear Othr ->	5,544,812	1,000,000	5,544,812	1,978,400	0.3947
34													
35	CAPE CANAVERAL 1	386	29,199	10.5	91.3	94.6	9,553	Heavy Oil BBLS ->	43,587	6,399,959	278,955	2,858,549	9.7899
36													
37	CAPE CANAVERAL 2	386	41,575	15.0	90.4	94.5	9,543	Heavy Oil BBLS ->	61,993	6,400,029	396,757	4,065,643	9.7791
38													
39	CUTLER 5	65		0.0	98.2		0						
40													
41	CUTLER 6	110		0.0	96.0		0						
42													
43	FORT MYERS 2	1,423	926,094	90.4	96.1	90.4	7,124	Gas MCF ->	6,598,145	1,000,000	6,598,145	67,996,786	7.3423
44													
45	FORT MYERS 3A_B	160	10,303	4.5	96.3	99.1	10,462	Gas MCF ->	107,800	1,000,000	107,800	1,141,130	11.0757
46													
47	SANFORD 3	138		0.0	95.1		0						
48													
49	SANFORD 4	954	609,695	88.8	96.3	88.8	7,064	Gas MCF ->	4,307,427	1,000,000	4,307,427	44,929,196	7.3691
50													
51	SANFORD 5	950	605,350	88.5	96.5	88.5	7,083	Gas MCF ->	4,288,200	1,000,000	4,288,200	44,555,423	7.3603
52													
53	PUTNAM 1	239	48,712	28.3	96.4	98.0	8,980	Gas MCF ->	437,434	1,000,000	437,434	4,613,703	9.4715
54													
55	PUTNAM 2	239	20,567	12.0	3.2	97.8	8,946	Gas MCF ->	184,006	1,000,000	184,006	1,943,958	9.4520
56													
57	MANATEE 1	803	227,358	55.5	94.4	67.8	9,916	Heavy Oil BBLS ->	347,224	6,400,007	2,222,236	22,765,360	10.0130
58			93,419					Gas MCF ->	958,742	1,000,000	958,742	10,009,692	10.7149
59													
60	MANATEE 2	803	121,120	47.7	95.0	59.7	10,063	Heavy Oil BBLS ->	185,262	6,399,996	1,185,676	12,146,444	10.0284
61			154,640					Gas MCF ->	1,589,502	1,000,000	1,589,502	16,678,185	10.7852
62													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 3	1,087	673,205	86.0	96.5	86.0	7,094	Gas MCF ->	4,776,314	1,000,000	4,776,314	49,485,906	7.3508
64													
65	MARTIN 1	813	206,706	60.7	95.0	69.3	9,968	Heavy Oil BBLS ->	315,380	6,399,997	2,018,431	20,674,353	10.0018
66			148,340					Gas MCF ->	1,520,919	1,000,000	1,520,919	15,541,253	10.4768
67													
68	MARTIN 2	806	25,010	38.9	93.9	51.3	10,324	Heavy Oil BBLS ->	38,628	6,399,943	247,217	2,532,186	10.1247
69			200,932					Gas MCF ->	2,085,451	1,000,000	2,085,451	21,686,057	10.7928
70													
71	MARTIN 3	449	104,834	32.4	94.4	97.3	7,319	Gas MCF ->	767,321	1,000,000	767,321	7,809,425	7.4493
72													
73	MARTIN 4	450	120,560	37.2	98.6	98.9	7,246	Gas MCF ->	873,587	1,000,000	873,587	8,890,941	7.3747
74													
75	MARTIN 8	1,088	687,076	87.7	96.5	87.7	7,025	Gas MCF ->	4,827,260	1,000,000	4,827,260	49,667,055	7.2288
76													
77	FORT MYERS 1-12	552		0.0	98.4		0						
78													
79	LAUDERDALE 1-24	684		0.0	91.7		0						
80													
81	EVERGLADES 1-12	342		0.0	88.3		0						
82													
83	ST JOHNS 1O	127	89,284	97.6	96.9	97.6	9,836	Coal TONS ->	35,782	24,543,122	878,202	1,450,000	1.6240
84													
85	ST JOHNS 2O	127	89,302	97.7	97.0	97.7	9,723	Coal TONS ->	35,380	24,542,906	868,328	1,433,700	1.6055
86													
87	SCHERER 4	641	451,714	97.8	97.2	97.8	10,198	Coal TONS ->	263,249	17,500,032	4,606,866	8,525,900	1.8875
88													
89	TOTAL	21,181	9,210,961				8,760				80,687,104	547,704,910	5.9462

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	385	64,361	22.5	95.1	97.2	9,390	Heavy Oil BBLS ->	94,431	6,400,017	604,360	6,096,189	9.4719
2													
3	TURKEY POINT 2	390	78,508	27.1	94.1	96.3	9,371	Heavy Oil BBLS ->	114,959	6,399,995	735,737	7,421,356	9.4530
4													
5	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,748,926	1,000,000	5,748,926	1,856,300	0.3693
6													
7	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,748,926	1,000,000	5,748,926	2,161,000	0.4299
8													
9	TURKEY POINT 5	1,080	717,921	89.4	94.1	89.3	6,975	Gas MCF ->	5,007,767	1,000,000	5,007,767	50,612,494	7.0499
10													
11	LAUDERDALE 4	426	270,361	85.3	97.6	85.3	8,087	Gas MCF ->	2,186,483	1,000,000	2,186,483	23,157,058	8.5652
12													
13	LAUDERDALE 5	426	286,027	90.3	98.4	90.2	7,869	Gas MCF ->	2,250,845	1,000,000	2,250,845	23,941,634	8.3704
14													
15	PT EVERGLADES 1	205	3,287	2.4	96.3	72.3	10,354	Heavy Oil BBLS ->	5,289	6,399,887	33,849	340,923	10.3719
16			417					Gas MCF ->	4,512	1,000,000	4,512	46,122	11.0525
17													
18	PT EVERGLADES 2	205	7,509	7.5	96.2	86.6	10,246	Heavy Oil BBLS ->	11,822	6,399,848	75,659	762,099	10.1491
19			3,859					Gas MCF ->	40,828	1,000,000	40,828	431,886	11.1917
20													
21	PT EVERGLADES 3	376	89,290	31.9	92.2	96.5	9,377	Heavy Oil BBLS ->	130,834	6,399,980	837,335	8,433,726	9.4453
22													
23	PT EVERGLADES 4	376	92,653	33.1	93.0	97.0	9,351	Heavy Oil BBLS ->	135,388	6,400,013	866,485	8,727,419	9.4195
24													
25	RIVIERA 3	272	20,867	10.3	94.0	95.9	9,559	Heavy Oil BBLS ->	31,170	6,400,032	199,489	2,009,517	9.6301
26													
27	RIVIERA 4	279	119,316	63.0	89.8	75.7	9,692	Heavy Oil BBLS ->	179,913	6,399,999	1,151,443	11,599,100	9.7213
28			11,456					Gas MCF ->	116,080	1,000,000	116,080	1,185,755	10.3508
29													
30	ST LUCIE 1	839	608,613	97.5	97.5	97.5	11,062	Nuclear Othr ->	6,732,718	1,000,000	6,732,718	2,530,800	0.4158
31													

Estimated For The Period of : Jul-07

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 2	714	517,926	97.5	97.5	97.5	11,062	Nuclear Othr ->	5,729,640	1,000,000	5,729,640	2,034,600	0.3928
34	CAPE CANAVERAL 1	386	46,698	16.3	91.3	94.7	9,555	Heavy Oil BBLS ->	69,716	6,400,023	446,184	4,496,645	9.6292
35			103					Gas MCF ->	1,031	1,000,000	1,031	10,553	10.2756
37	CAPE CANAVERAL 2	386	56,786	19.8	90.4	95.5	9,541	Heavy Oil BBLS ->	84,661	6,400,031	541,833	5,460,576	9.6161
39	CUTLER 5	65		0.0	98.2		0						
41	CUTLER 6	110		0.0	96.0		0						
43	FORT MYERS 2	1,423	973,620	92.0	96.1	92.0	7,107	Gas MCF ->	6,920,392	1,000,000	6,920,392	71,679,114	7.3621
45	FORT MYERS 3A_B	160	10,779	4.5	96.3	99.1	10,462	Gas MCF ->	112,776	1,000,000	112,776	1,198,018	11.1149
47	SANFORD 3	138		0.0	95.1		0						
49	SANFORD 4	954	644,427	90.8	96.3	90.8	7,038	Gas MCF ->	4,535,538	1,000,000	4,535,538	47,537,694	7.3767
51	SANFORD 5	950	640,145	90.6	96.5	90.6	7,056	Gas MCF ->	4,517,306	1,000,000	4,517,306	47,203,364	7.3739
53	PUTNAM 1	239	63,700	35.8	96.4	98.0	8,980	Gas MCF ->	572,029	1,000,000	572,029	6,062,687	9.5176
55	PUTNAM 2	239	65,673	36.9	96.1	97.8	8,946	Gas MCF ->	587,567	1,000,000	587,567	6,236,082	9.4957
57	MANATEE 1	803	337,491	64.0	94.4	73.3	9,815	Heavy Oil BBLS ->	514,609	6,400,001	3,293,498	33,182,237	9.8320
58			44,637					Gas MCF ->	457,386	1,000,000	457,386	4,719,619	10.5733
60	MANATEE 2	803	250,847	55.0	95.0	67.2	9,866	Heavy Oil BBLS ->	382,191	6,400,004	2,446,024	24,643,844	9.8243
61			77,711					Gas MCF ->	795,649	1,000,000	795,649	8,326,289	10.7145

Estimated For The Period of : Jul-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 3	1,087	720,743	89.1	96.5	89.1	7,055	Gas MCF ->	5,085,188	1,000,000	5,085,188	52,863,609	7.3346
64													
65	MARTIN 1	813	257,417	68.2	95.0	70.7	9,953	Heavy Oil BBLS ->	392,943	6,400,002	2,514,836	25,333,298	9.8413
66			155,132					Gas MCF ->	1,591,338	1,000,000	1,591,338	16,255,532	10.4785
67													
68	MARTIN 2	806	65,412	44.6	93.9	55.3	10,194	Heavy Oil BBLS ->	100,402	6,400,022	642,575	6,472,941	9.8956
69			202,033					Gas MCF ->	2,083,918	1,000,000	2,083,918	21,708,142	10.7448
70													
71	MARTIN 3	449	141,963	42.5	94.4	97.3	7,319	Gas MCF ->	1,039,081	1,000,000	1,039,081	10,614,193	7.4768
72													
73	MARTIN 4	450	161,488	48.2	98.6	98.9	7,246	Gas MCF ->	1,170,155	1,000,000	1,170,155	11,953,129	7.4018
74													
75	MARTIN 8	1,088	734,022	90.7	96.5	90.7	6,991	Gas MCF ->	5,131,682	1,000,000	5,131,682	53,100,132	7.2341
76													
77	FORT MYERS 1-12	552		0.0	98.4		0						
78													
79	LAUDERDALE 1-24	684		0.0	91.7		0						
80													
81	EVERGLADES 1-12	342		0.0	88.3		0						
82													
83	ST JOHNS 1O	127	92,260	97.6	96.9	97.6	9,836	Coal TONS ->	37,025	24,509,818	907,476	1,565,000	1.6963
84													
85	ST JOHNS 2O	127	92,279	97.7	97.0	97.7	9,723	Coal TONS ->	36,609	24,509,601	897,272	1,547,400	1.6769
86													
87	SCHERER 4	641	466,771	97.8	97.2	97.8	10,198	Coal TONS ->	272,024	17,500,033	4,760,429	8,793,000	1.8838
88													
89	TOTAL	21,181	10,199,921				8,738				89,122,244	624,311,076	6.1207

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	385	64,241	22.4	95.1	97.0	9,389	Heavy Oil	BBLS ->	94,250	6,399,989	603,199	6,086,640	9.4747
2														
3	TURKEY POINT 2	390	67,443	23.2	94.1	96.6	9,370	Heavy Oil	BBLS ->	98,742	6,400,022	631,951	6,376,737	9.4550
4														
5	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,435	Nuclear	Othr ->	5,748,926	1,000,000	5,748,926	1,847,700	0.3676
6														
7	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,435	Nuclear	Othr ->	5,748,926	1,000,000	5,748,926	2,151,800	0.4280
8														
9	TURKEY POINT 5	1,080	713,688	88.8	94.1	88.8	6,975	Gas	MCF ->	4,978,498	1,000,000	4,978,498	50,557,182	7.0839
10														
11	LAUDERDALE 4	426	272,497	86.0	97.6	86.0	8,061	Gas	MCF ->	2,196,731	1,000,000	2,196,731	23,372,977	8.5773
12														
13	LAUDERDALE 5	426	287,522	90.7	98.4	90.7	7,853	Gas	MCF ->	2,258,053	1,000,000	2,258,053	24,128,756	8.3920
14														
15	PT EVERGLADES 1	205	10,267	8.2	96.3	95.3	10,192	Heavy Oil	BBLS ->	16,206	6,399,975	103,718	1,044,990	10.1781
16			2,241					Gas	MCF ->	23,771	1,000,000	23,771	253,422	11.3084
17														
18	PT EVERGLADES 2	205	11,704	9.2	96.2	94.9	10,104	Heavy Oil	BBLS ->	18,328	6,399,935	117,298	1,181,888	10.0982
19			2,307					Gas	MCF ->	24,281	1,000,000	24,281	258,674	11.2106
20														
21	PT EVERGLADES 3	376	71,489	25.6	92.2	97.0	9,375	Heavy Oil	BBLS ->	104,729	6,399,975	670,263	6,753,333	9.4467
22														
23	PT EVERGLADES 4	376	75,873	27.1	93.0	97.0	9,351	Heavy Oil	BBLS ->	110,869	6,400,004	709,562	7,149,329	9.4228
24														
25	RIVIERA 3	272	106,714	60.6	94.0	72.9	9,795	Heavy Oil	BBLS ->	162,290	6,399,994	1,038,655	10,466,596	9.8081
26			15,845					Gas	MCF ->	161,927	1,000,000	161,927	1,669,634	10.5376
27														
28	RIVIERA 4	279	29,453	14.2	89.8	94.3	9,529	Heavy Oil	BBLS ->	43,856	6,400,036	280,680	2,828,472	9.6033
29														
30	ST LUCIE 1	839	608,613	97.5	97.5	97.5	11,062	Nuclear	Othr ->	6,732,718	1,000,000	6,732,718	2,520,100	0.4141
31														

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 2	714	517,926	97.5	97.5	97.5	11,062	Nuclear Othr ->	5,729,640	1,000,000	5,729,640	2,025,400	0.3911
33	------------												
34	CAPE CANAVERAL 1	386	52,265	18.2	91.3	94.2	9,557	Heavy Oil BBLS ->	78,039	6,400,031	499,452	5,035,250	9.6341
35			103					Gas MCF ->	1,031	1,000,000	1,031	10,619	10.3398
36	------------												
37	CAPE CANAVERAL 2	386	60,372	21.0	90.4	95.4	9,541	Heavy Oil BBLS ->	90,005	6,399,989	576,031	5,807,242	9.6191
38	------------												
39	CUTLER 5	65		0.0	98.2		0						
40	------------												
41	CUTLER 6	110	426	0.5	96.0	96.9	11,388	Gas MCF ->	4,853	1,000,000	4,853	49,811	11.6872
42	------------												
43	FORT MYERS 2	1,423	970,398	91.7	96.1	91.7	7,109	Gas MCF ->	6,898,809	1,000,000	6,898,809	71,735,096	7.3923
44	------------												
45	FORT MYERS 3A_B	160	16,643	7.0	96.3	99.1	10,462	Gas MCF ->	174,139	1,000,000	174,139	1,858,263	11.1652
46	------------												
47	SANFORD 3	138	4,102	4.0	95.1	74.3	10,381	Gas MCF ->	42,580	1,000,000	42,580	466,695	11.3784
48	------------												
49	SANFORD 4	954	644,461	90.8	96.3	90.8	7,037	Gas MCF ->	4,535,112	1,000,000	4,535,112	47,726,436	7.4056
50	------------												
51	SANFORD 5	950	639,919	90.5	96.5	90.5	7,055	Gas MCF ->	4,515,191	1,000,000	4,515,191	47,345,341	7.3986
52	------------												
53	PUTNAM 1	239	55,972	31.5	96.4	98.0	8,980	Gas MCF ->	502,629	1,000,000	502,629	5,353,064	9.5639
54	------------												
55	PUTNAM 2	239	55,390	31.2	96.1	97.8	8,946	Gas MCF ->	495,564	1,000,000	495,564	5,284,222	9.5401
56	------------												
57	MANATEE 1	803	292,370	59.1	94.4	69.2	9,856	Heavy Oil BBLS ->	446,454	6,399,994	2,857,303	28,797,714	9.8497
58			60,545					Gas MCF ->	621,281	1,000,000	621,281	6,478,415	10.7002
59	------------												
60	MANATEE 2	803	191,005	49.5	95.0	60.5	9,964	Heavy Oil BBLS ->	292,205	6,400,003	1,870,113	18,848,213	9.8679
61			104,506					Gas MCF ->	1,074,373	1,000,000	1,074,373	11,312,683	10.8249
62	------------												

Date: 9/01/2006
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATEE 3	1,087	723,802	89.5	96.5	89.5	7,044	Gas MCF ->	5,098,801	1,000,000	5,098,801	53,241,646	7.3558
64	------------												
65	MARTIN 1	813	239,444	64.6	95.0	67.8	9,974	Heavy Oil BBLS ->	366,086	6,399,996	2,342,949	23,610,066	9.8604
66			151,121					Gas MCF ->	1,552,651	1,000,000	1,552,651	15,935,283	10.5447
67	------------												
68	MARTIN 2	806	60,430	42.4	93.9	51.8	10,251	Heavy Oil BBLS ->	93,239	6,400,015	596,731	6,013,340	9.9509
69			193,642					Gas MCF ->	2,007,780	1,000,000	2,007,780	20,994,157	10.8418
70	------------												
71	MARTIN 3	449	121,433	36.4	94.4	97.3	7,319	Gas MCF ->	888,814	1,000,000	888,814	9,122,204	7.5122
72	------------												
73	MARTIN 4	450	139,245	41.6	98.6	98.9	7,246	Gas MCF ->	1,008,977	1,000,000	1,008,977	10,355,388	7.4368
74	------------												
75	MARTIN 8	1,088	735,415	90.9	96.5	90.9	6,983	Gas MCF ->	5,135,703	1,000,000	5,135,703	53,370,273	7.2572
76	------------												
77	FORT MYERS 1-12	552		0.0	98.4		0						
78	------------												
79	LAUDERDALE 1-24	684		0.0	91.7		0						
80	------------												
81	EVERGLADES 1-12	342		0.0	88.3		0						
82	------------												
83	ST JOHNS 1O	127	92,260	97.6	96.9	97.6	9,836	Coal TONS ->	37,075	24,476,763	907,476	1,493,900	1.6192
84	------------												
85	ST JOHNS 2O	127	92,279	97.7	97.0	97.7	9,723	Coal TONS ->	36,658	24,476,840	897,272	1,477,100	1.6007
86	------------												
87	SCHERER 4	641	466,771	97.8	97.2	97.8	10,198	Coal TONS ->	272,024	17,500,033	4,760,429	8,776,300	1.8802
88	------------												
89	TOTAL	21,181	10,027,553				8,738				87,624,839	611,172,351	6.0949
		=======	=======				=======				=======	=======	=======

Date: 9/01/2006
Company: Florida Power & Light

Estimated For The Period of : Sep-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	385	60,016	21.7	95.1	97.4	9,389	Heavy Oil BBLS ->	88,054	6,399,982	563,544	5,687,955	9.4774
2													
3	TURKEY POINT 2	390	73,530	26.2	94.1	96.2	9,371	Heavy Oil BBLS ->	107,668	6,399,989	689,074	6,954,876	9.4586
4													
5	TURKEY POINT 3	693		0.0	0.0		0						
6													
7	TURKEY POINT 4	693	486,491	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,563,476	1,000,000	5,563,476	2,073,000	0.4261
8													
9	TURKEY POINT 5	1,080	699,452	90.0	94.1	90.0	6,966	Gas MCF ->	4,872,738	1,000,000	4,872,738	49,849,533	7.1269
10													
11	LAUDERDALE 4	426	269,598	87.9	97.6	87.9	8,017	Gas MCF ->	2,161,604	1,000,000	2,161,604	23,160,806	8.5909
12													
13	LAUDERDALE 5	426	282,343	92.1	98.4	92.1	7,828	Gas MCF ->	2,210,368	1,000,000	2,210,368	23,771,564	8.4194
14													
15	PT EVERGLADES 1	205	8,796	6.5	96.3	97.5	10,131	Heavy Oil BBLS ->	13,866	6,399,827	88,740	894,379	10.1680
16			798					Gas MCF ->	8,449	1,000,000	8,449	90,814	11.3873
17													
18	PT EVERGLADES 2	205	6,366	4.3	22.5	97.0	10,009	Heavy Oil BBLS ->	9,955	6,400,100	63,713	642,154	10.0872
19													
20	PT EVERGLADES 3	376	79,115	29.5	92.2	94.1	9,396	Heavy Oil BBLS ->	116,100	6,399,991	743,039	7,488,599	9.4655
21			828					Gas MCF ->	8,169	1,000,000	8,169	84,462	10.1958
22													
23	PT EVERGLADES 4	376	85,719	31.7	93.0	97.0	9,351	Heavy Oil BBLS ->	125,257	6,400,002	801,645	8,079,188	9.4252
24													
25	RIVIERA 3	272	20,769	10.6	94.0	95.4	9,561	Heavy Oil BBLS ->	31,028	6,399,961	198,578	2,001,610	9.6375
26													
27	RIVIERA 4	279	25,298	12.6	89.8	94.5	9,529	Heavy Oil BBLS ->	37,669	6,399,958	241,080	2,430,012	9.6055
28													
29	ST LUCIE 1	839	588,980	97.5	97.5	97.5	11,062	Nuclear Othr ->	6,515,534	1,000,000	6,515,534	2,428,300	0.4123
30													

Estimated For The Period of : Sep-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUCIE 2	714	501,219	97.5	97.5	97.5	11,062	Nuclear	Othr ->	5,544,812	1,000,000	5,544,812	1,951,200	0.3893
33	CAPE CANAVERAL 1	386	43,798	15.8	91.3	94.6	9,553	Heavy Oil	BBLS ->	65,380	6,400,000	418,432	4,219,471	9.6339
35	CAPE CANAVERAL 2	386	50,517	18.2	90.4	95.5	9,541	Heavy Oil	BBLS ->	75,316	6,399,981	482,021	4,860,726	9.6220
37	CUTLER 5	65	828	1.8	98.2	79.6	12,061	Gas	MCF ->	9,981	1,000,000	9,981	103,338	12.4865
39	CUTLER 6	110	1,705	2.2	96.0	96.9	11,388	Gas	MCF ->	19,414	1,000,000	19,414	201,887	11.8430
41	FORT MYERS 2	1,423	946,835	92.4	86.3	92.4	7,101	Gas	MCF ->	6,724,015	1,000,000	6,724,015	70,387,408	7.4340
43	FORT MYERS 3A_B	160	8,084	3.5	19.3	99.1	10,462	Gas	MCF ->	84,582	1,000,000	84,582	908,952	11.2440
45	SANFORD 3	138	4,446	4.5	95.1	80.5	10,356	Gas	MCF ->	46,039	1,000,000	46,039	508,534	11.4388
47	SANFORD 4	954	629,935	91.7	96.3	91.7	7,026	Gas	MCF ->	4,426,030	1,000,000	4,426,030	46,911,478	7.4470
49	SANFORD 5	950	625,966	91.5	96.5	91.5	7,044	Gas	MCF ->	4,409,396	1,000,000	4,409,396	46,549,384	7.4364
51	PUTNAM 1	239	56,908	33.1	96.4	98.0	8,980	Gas	MCF ->	511,041	1,000,000	511,041	5,483,369	9.6354
53	PUTNAM 2	239	54,221	31.5	96.1	97.8	8,946	Gas	MCF ->	485,109	1,000,000	485,109	5,211,394	9.6114
55	MANATEE 1	803	310,415	62.0	94.4	74.4	9,812	Heavy Oil	BBLS ->	472,748	6,399,995	3,025,585	30,501,521	9.8260
56			48,271					Gas	MCF ->	494,021	1,000,000	494,021	5,194,190	10.7604
58	MANATEE 2	803	248,458	56.0	95.0	69.9	9,868	Heavy Oil	BBLS ->	378,703	6,399,994	2,423,697	24,433,734	9.8342
59			75,405					Gas	MCF ->	772,355	1,000,000	772,355	8,187,232	10.8576

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Estimated For The Period of : Sep-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MANATEE 3	1,087	711,197	90.9	96.5	90.9	7,029	Gas MCF ->	4,999,179	1,000,000	4,999,179	52,564,869	7.3910
62	----------												
63	MARTIN 1	813	238,429	66.9	95.0	71.6	9,948	Heavy Oil BBLS ->	363,511	6,399,999	2,326,470	23,450,015	9.8352
64			152,887					Gas MCF ->	1,566,389	1,000,000	1,566,389	16,227,697	10.6141
65	----------												
66	MARTIN 2	806	74,692	44.3	93.9	56.7	10,182	Heavy Oil BBLS ->	114,767	6,399,993	734,508	7,403,558	9.9121
67			182,617					Gas MCF ->	1,885,619	1,000,000	1,885,619	19,850,815	10.8702
68	----------												
69	MARTIN 3	449	117,065	36.2	94.4	97.3	7,319	Gas MCF ->	856,842	1,000,000	856,842	8,858,465	7.5672
70	----------												
71	MARTIN 4	450	148,142	45.7	98.6	98.9	7,246	Gas MCF ->	1,073,448	1,000,000	1,073,448	11,097,866	7.4914
72	----------												
73	MARTIN 8	1,088	720,662	92.0	96.5	92.0	6,972	Gas MCF ->	5,025,014	1,000,000	5,025,014	52,626,922	7.3026
74	----------												
75	FORT MYERS 1-12	552		0.0	98.4		0						
76	----------												
77	LAUDERDALE 1-24	684		0.0	91.7		0						
78	----------												
79	EVERGLADES 1-12	342		0.0	88.3		0						
80	----------												
81	ST JOHNS 1O	127	89,284	97.6	96.9	97.6	9,836	Coal TONS ->	35,927	24,444,067	878,202	1,445,000	1.6184
82	----------												
83	ST JOHNS 2O	127	89,302	97.7	97.0	97.7	9,723	Coal TONS ->	35,523	24,444,107	868,328	1,428,700	1.5999
84	----------												
85	SCHERER 4	641	451,714	97.8	97.2	97.8	10,198	Coal TONS ->	263,249	17,500,032	4,606,866	8,477,100	1.8767
86	----------												
87	TOTAL	21,181	9,271,102				8,567				79,427,145	594,682,077	6.4144
		=======	=======				=======				=======	=======	=======

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Estimated For The Period of : Oct-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	385	66,456	23.7	95.1	90.1	9,436	Heavy Oil BBLS ->	97,875	6,400,020	626,402	6,460,571	9.7216
2			1,547					Gas MCF ->	15,303	1,000,000	15,303	161,500	10.4423
3													
4	TURKEY POINT 2	390	66,288	23.0	94.1	94.1	9,386	Heavy Oil BBLS ->	97,187	6,399,981	621,995	6,415,161	9.6777
5			518					Gas MCF ->	5,104	1,000,000	5,104	53,871	10.3978
6													
7	TURKEY POINT 3	693	502,707	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,748,926	1,000,000	5,748,926	2,308,800	0.4593
8													
9	TURKEY POINT 4	693	502,707	97.5	97.5	97.5	11,435	Nuclear Othr ->	5,748,926	1,000,000	5,748,926	2,132,300	0.4242
10													
11	TURKEY POINT 5	1,080	743,549	92.5	94.1	92.5	6,952	Gas MCF ->	5,169,466	1,000,000	5,169,466	54,477,592	7.3267
12													
13	LAUDERDALE 4	426	154,486	48.7	97.6	97.0	7,856	Gas MCF ->	1,213,766	1,000,000	1,213,766	13,331,891	8.6299
14													
15	LAUDERDALE 5	426	86,996	27.5	54.0	97.7	7,752	Gas MCF ->	674,443	1,000,000	674,443	7,496,997	8.6177
16													
17	PT EVERGLADES 1	205	3,198	2.1	96.3	97.5	10,089	Heavy Oil BBLS ->	5,041	6,399,921	32,262	332,294	10.3907
18													
19	PT EVERGLADES 2	205		0.0	0.0		0						
20													
21	PT EVERGLADES 3	376	81,502	29.7	92.2	89.1	9,421	Heavy Oil BBLS ->	119,861	6,400,022	767,113	7,900,422	9.6935
22			1,550					Gas MCF ->	15,317	1,000,000	15,317	161,319	10.4090
23													
24	PT EVERGLADES 4	376	92,437	33.5	93.0	91.9	9,382	Heavy Oil BBLS ->	135,418	6,400,013	866,677	8,925,842	9.6561
25			1,241					Gas MCF ->	12,220	1,000,000	12,220	128,671	10.3667
26													
27	RIVIERA 3	272	11,081	5.7	94.0	86.7	9,638	Heavy Oil BBLS ->	16,654	6,400,144	106,588	1,097,930	9.9082
28			469					Gas MCF ->	4,737	1,000,000	4,737	49,892	10.6380
29													
30	RIVIERA 4	279	10,572	5.1	89.8	94.7	9,528	Heavy Oil BBLS ->	15,741	6,399,848	100,740	1,037,690	9.8155
31													

Estimated For The Period of : Oct-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUCIE 1	839	608,613	97.5	97.5	97.5	11,062	Nuclear Othr ->	6,732,718	1,000,000	6,732,718	2,497,800	0.4104
33													
34	ST LUCIE 2	714		0.0	0.0		0						
35													
36	CAPE CANAVERAL 1	386	20,655	7.2	91.3	95.6	9,550	Heavy Oil BBLS ->	30,823	6,399,929	197,265	2,032,813	9.8417
37													
38	CAPE CANAVERAL 2	386	39,134	14.0	90.4	87.9	9,592	Heavy Oil BBLS ->	58,586	6,400,044	374,953	3,863,839	9.8734
39			918					Gas MCF ->	9,239	1,000,000	9,239	97,275	10.5929
40													
41	CUTLER 5	65		0.0	98.2		0						
42													
43	CUTLER 6	110	426	0.5	40.2	96.9	11,388	Gas MCF ->	4,853	1,000,000	4,853	51,143	11.9998
44													
45	FORT MYERS 2	1,423	738,186	69.7	66.6	83.3	7,253	Gas MCF ->	5,354,275	1,000,000	5,354,275	56,885,438	7.7061
46													
47	FORT MYERS 3A_B	160	2,695	1.1	96.3	99.1	10,462	Gas MCF ->	28,194	1,000,000	28,194	308,449	11.4469
48													
49	SANFORD 3	138	855	0.8	95.1	77.4	9,847	Heavy Oil BBLS ->	1,315	6,402,281	8,419	89,030	10.4129
50													
51	SANFORD 4	954	652,754	92.0	96.3	94.1	6,999	Gas MCF ->	4,569,032	1,000,000	4,569,032	49,408,525	7.5692
52													
53	SANFORD 5	950	587,489	83.1	96.5	94.4	7,011	Gas MCF ->	4,119,446	1,000,000	4,119,446	44,240,415	7.5304
54													
55	PUTNAM 1	239	60,187	33.9	96.4	98.0	8,980	Gas MCF ->	540,483	1,000,000	540,483	5,920,111	9.8362
56													
57	PUTNAM 2	239	66,374	37.3	96.1	97.8	8,946	Gas MCF ->	593,840	1,000,000	593,840	6,505,649	9.8015
58													
59	MANATEE 1	803	239,011	43.2	57.9	71.6	9,762	Heavy Oil BBLS ->	363,231	6,400,004	2,324,680	23,948,517	10.0198
60			19,120					Gas MCF ->	195,261	1,000,000	195,261	2,056,806	10.7575
61													

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Estimated For The Period of : Oct-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MANATEE 2	803	306,052	56.6	95.0	59.6	9,782	Heavy Oil BBLS ->	465,567	6,400,003	2,979,630	30,695,731	10.0296
63			32,280					Gas MCF ->	329,978	1,000,000	329,978	3,475,781	10.7677
64													
65	MANATEE 3	1,087	760,194	94.0	96.5	94.0	7,002	Gas MCF ->	5,323,481	1,000,000	5,323,481	57,202,091	7.5247
66													
67	MARTIN 1	813	286,731	73.1	95.0	74.6	9,886	Heavy Oil BBLS ->	435,282	6,400,007	2,785,808	28,694,707	10.0075
68			155,520					Gas MCF ->	1,586,545	1,000,000	1,586,545	16,711,714	10.7457
69													
70	MARTIN 2	806	34,114	8.8	15.1	58.1	9,955	Heavy Oil BBLS ->	52,141	6,399,992	333,702	3,437,284	10.0759
71			18,837					Gas MCF ->	193,472	1,000,000	193,472	2,037,868	10.8187
72													
73	MARTIN 3	449	147,150	44.1	76.1	79.2	7,469	Gas MCF ->	1,099,126	1,000,000	1,099,126	11,577,558	7.8678
74													
75	MARTIN 4	450	192,398	57.5	98.6	98.1	7,255	Gas MCF ->	1,395,898	1,000,000	1,395,898	14,703,538	7.6422
76													
77	MARTIN 8	1,088	767,037	94.8	96.5	94.8	6,952	Gas MCF ->	5,332,966	1,000,000	5,332,966	58,262,086	7.5957
78													
79	FORT MYERS 1-12	552		0.0	98.4		0						
80													
81	LAUDERDALE 1-24	684		0.0	91.7		0						
82													
83	EVERGLADES 1-12	342		0.0	88.3		0						
84													
85	ST JOHNS 1O	127	92,260	97.6	96.9	97.6	9,836	Coal TONS ->	37,174	24,411,578	907,476	1,561,200	1.6922
86													
87	ST JOHNS 2O	127	92,279	97.7	97.0	97.7	9,723	Coal TONS ->	36,756	24,411,579	897,272	1,543,700	1.6729
88													
89	SCHERER 4	641	466,771	97.8	97.2	97.8	10,198	Coal TONS ->	272,024	17,500,033	4,760,429	8,742,500	1.8730
90													
91	TOTAL	21,181	8,715,343				8,572				74,708,424	549,024,311	6.2995

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	388	44,677	17.8	95.1	54.9	9,579	Heavy Oil BBLS ->	66,540	6,399,985	425,855	4,573,692	10.2372
2			4,956					Gas MCF ->	49,601	1,000,000	49,601	542,287	10.9416
3													
4	TURKEY POINT 2	393	61,257	23.5	94.1	66.6	9,579	Heavy Oil BBLS ->	91,328	6,399,976	584,497	6,277,511	10.2478
5			5,222					Gas MCF ->	52,321	1,000,000	52,321	572,159	10.9563
6													
7	TURKEY POINT 3	717	503,332	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,628,865	1,000,000	5,628,865	2,251,000	0.4472
8													
9	TURKEY POINT 4	717	503,332	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,628,865	1,000,000	5,628,865	2,078,700	0.4130
10													
11	TURKEY POINT 5	1,104	696,649	87.6	94.1	87.6	6,925	Gas MCF ->	4,824,535	1,000,000	4,824,535	53,117,633	7.6247
12													
13	LAUDERDALE 4	443	134,224	42.1	97.6	88.6	7,896	Gas MCF ->	1,059,838	1,000,000	1,059,838	11,906,465	8.8706
14													
15	LAUDERDALE 5	443	140,056	43.9	98.4	91.9	7,743	Gas MCF ->	1,084,551	1,000,000	1,084,551	12,213,726	8.7206
16													
17	PT EVERGLADES 1	206	1,401	1.3	96.3	37.1	11,116	Heavy Oil BBLS ->	2,399	6,399,333	15,352	164,605	11.7491
18			586					Gas MCF ->	6,736	1,000,000	6,736	73,768	12.5970
19													
20	PT EVERGLADES 2	206		0.0	44.9		0						
21													
22	PT EVERGLADES 3	381	57,633	23.9	92.2	62.0	9,627	Heavy Oil BBLS ->	86,170	6,400,035	551,491	5,914,811	10.2629
23			7,998					Gas MCF ->	80,356	1,000,000	80,356	879,361	10.9953
24													
25	PT EVERGLADES 4	381	47,807	21.6	93.0	56.2	9,760	Heavy Oil BBLS ->	72,222	6,399,975	462,219	4,957,374	10.3696
26			11,305					Gas MCF ->	114,770	1,000,000	114,770	1,255,992	11.1098
27													
28	RIVIERA 3	274	22,440	12.7	94.0	66.3	9,805	Heavy Oil BBLS ->	34,204	6,400,012	218,906	2,348,097	10.4639
29			2,613					Gas MCF ->	26,762	1,000,000	26,762	292,898	11.2105
30													

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Estimated For The Period of : Nov-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	RIVIERA 4	281	22,626	12.4	89.8	63.8	9,741	Heavy Oil BBLS ->	34,270	6,399,912	219,325	2,352,632	10.3979
32			2,485					Gas MCF ->	25,289	1,000,000	25,289	276,706	11.1364
33													
34	ST LUCIE 1	853	598,803	97.5	97.5	97.5	10,880	Nuclear Othr ->	6,515,158	1,000,000	6,515,158	2,407,400	0.4020
35													
36	ST LUCIE 2	726		0.0	0.0		0						
37													
38	CAPE CANAVERAL 1	390	35,948	14.4	91.3	55.6	9,852	Heavy Oil BBLS ->	55,030	6,399,964	352,190	3,779,402	10.5135
39			4,578					Gas MCF ->	47,096	1,000,000	47,096	515,420	11.2581
40													
41	CAPE CANAVERAL 2	390	38,067	15.2	90.4	48.5	9,809	Heavy Oil BBLS ->	58,032	6,399,952	371,402	3,985,571	10.4699
42			4,675					Gas MCF ->	47,889	1,000,000	47,889	524,069	11.2110
43													
44	CUTLER 5	67		0.0	98.2		0						
45													
46	CUTLER 6	110		0.0	0.0		0						
47													
48	FORT MYERS 2	1,451	512,331	49.0	66.7	67.6	7,260	Gas MCF ->	3,719,944	1,000,000	3,719,944	40,792,762	7.9622
49													
50	FORT MYERS 3A_B	166	1,316	0.6	96.3	99.1	10,256	Gas MCF ->	13,494	1,000,000	13,494	151,056	11.4819
51													
52	SANFORD 3	140	1,294	1.7	95.1	48.7	10,534	Heavy Oil BBLS ->	2,105	6,399,050	13,470	148,150	11.4490
53			412					Gas MCF ->	4,500	1,000,000	4,500	49,254	11.9636
54													
55	SANFORD 4	964	568,100	81.9	90.7	88.0	7,003	Gas MCF ->	3,978,525	1,000,000	3,978,525	43,729,000	7.6974
56													
57	SANFORD 5	960	559,400	80.9	96.5	92.2	6,973	Gas MCF ->	3,901,090	1,000,000	3,901,090	42,834,800	7.6573
58													
59	PUTNAM 1	250	62,046	34.5	96.4	84.4	9,081	Gas MCF ->	563,445	1,000,000	563,445	6,302,225	10.1574
60													

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Estimated For The Period of : Nov-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	PUTNAM 2	250	64,388	35.8	96.1	85.6	9,004	Gas	MCF ->	579,755	1,000,000	579,755	6,501,642	10.0976
62														
63	MANATEE 1	810	9,358	1.8	44.1	52.4	9,737	Heavy Oil	BBLS ->	14,154	6,400,028	90,586	971,773	10.3844
64			1,257					Gas	MCF ->	12,777	1,000,000	12,777	139,778	11.1200
65														
66	MANATEE 2	810	48,291	9.4	95.0	52.7	9,759	Heavy Oil	BBLS ->	73,216	6,399,981	468,581	5,026,940	10.4097
67			6,306					Gas	MCF ->	64,251	1,000,000	64,251	703,136	11.1497
68														
69	MANATEE 3	1,111	728,717	91.1	96.5	91.1	6,907	Gas	MCF ->	5,033,479	1,000,000	5,033,479	55,321,248	7.5916
70														
71	MARTIN 1	823	40,531	10.6	95.0	60.7	9,769	Heavy Oil	BBLS ->	60,787	6,399,970	389,035	4,173,054	10.2960
72			22,447					Gas	MCF ->	226,230	1,000,000	226,230	2,475,755	11.0292
73														
74	MARTIN 2	814		0.0	0.0		0							
75														
76	MARTIN 3	465	165,462	49.4	94.4	93.4	7,278	Gas	MCF ->	1,204,284	1,000,000	1,204,284	13,179,310	7.9651
77														
78	MARTIN 4	466	181,015	54.0	98.6	96.4	7,188	Gas	MCF ->	1,301,313	1,000,000	1,301,313	14,241,131	7.8674
79														
80	MARTIN 8	1,112	716,684	89.5	96.5	89.5	6,918	Gas	MCF ->	4,958,656	1,000,000	4,958,656	55,206,117	7.7030
81														
82	FORT MYERS 1-12	627		0.0	98.4		0							
83														
84	LAUDERDALE 1-24	766		0.0	91.7		0							
85														
86	EVERGLADES 1-12	383		0.0	88.3		0							
87														
88	ST JOHNS 1O	130	91,393	97.6	96.9	97.6	9,756	Coal	TONS ->	36,574	24,379,258	891,647	1,575,500	1.7239
89														
90	ST JOHNS 2O	130	91,412	97.7	97.0	97.7	9,650	Coal	TONS ->	36,187	24,378,921	882,200	1,558,800	1.7052
91														

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Estimated For The Period of : Nov-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	SCHERER 4	648	456,019	97.8	97.2	97.8	10,152	Coal	TONS ->	264,547	17,500,002	4,629,573	8,486,000	1.8609
93														
94	TOTAL	21,745	7,280,846				8,422					61,320,701	426,828,710	5.8624

Estimated For The Period of : Dec-07

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	388	66,826	25.6	95.1	50.6	9,647	Heavy Oil BBLS ->	100,259	6,399,974	641,655	6,772,339	10.1343
2			6,989					Gas MCF ->	70,457	1,000,000	70,457	794,257	11.3649
3													
4	TURKEY POINT 2	393	79,273	31.6	94.1	55.7	9,737	Heavy Oil BBLS ->	119,771	6,400,005	766,535	8,090,293	10.2056
5			13,031					Gas MCF ->	132,303	1,000,000	132,303	1,491,844	11.4482
6													
7	TURKEY POINT 3	717	520,110	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,816,494	1,000,000	5,816,494	2,315,500	0.4452
8													
9	TURKEY POINT 4	717	520,110	97.5	97.5	97.5	11,183	Nuclear Othr ->	5,816,494	1,000,000	5,816,494	2,138,100	0.4111
10													
11	TURKEY POINT 5	1,104	723,462	88.1	94.1	88.1	6,928	Gas MCF ->	5,012,717	1,000,000	5,012,717	56,906,215	7.8658
12													
13	LAUDERDALE 4	443	161,781	49.1	97.6	88.4	7,898	Gas MCF ->	1,277,855	1,000,000	1,277,855	14,805,440	9.1515
14													
15	LAUDERDALE 5	443	169,541	51.4	98.4	91.6	7,744	Gas MCF ->	1,313,080	1,000,000	1,313,080	15,310,867	9.0308
16													
17	PT EVERGLADES 1	206		0.0	31.1		0						
18													
19	PT EVERGLADES 2	206	5,537	5.0	96.2	40.4	10,856	Heavy Oil BBLS ->	9,261	6,399,957	59,270	624,732	11.2829
20			2,195					Gas MCF ->	24,676	1,000,000	24,676	277,987	12.6622
21													
22	PT EVERGLADES 3	381	75,543	30.0	92.2	56.7	9,655	Heavy Oil BBLS ->	113,349	6,399,986	725,432	7,645,689	10.1210
23			9,382					Gas MCF ->	94,597	1,000,000	94,597	1,065,502	11.3571
24													
25	PT EVERGLADES 4	381	72,393	31.1	93.0	51.9	9,789	Heavy Oil BBLS ->	109,744	6,400,022	702,364	7,402,577	10.2255
26			15,852					Gas MCF ->	161,491	1,000,000	161,491	1,818,958	11.4743
27													
28	RIVIERA 3	274	23,236	12.9	94.0	66.2	9,806	Heavy Oil BBLS ->	35,396	6,399,960	226,533	2,387,850	10.2765
29			3,076					Gas MCF ->	31,484	1,000,000	31,484	354,646	11.5306
30													

Estimated For The Period of : Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	RIVIERA 4	281	31,209	16.7	89.8	60.0	9,769	Heavy Oil BBLS ->	47,390	6,400,000	303,296	3,197,020	10.2439
32			3,680					Gas MCF ->	37,550	1,000,000	37,550	422,971	11.4944
33													
34	ST LUCIE 1	853	618,763	97.5	97.5	97.5	10,880	Nuclear Othr ->	6,732,330	1,000,000	6,732,330	2,476,200	0.4002
35													
36	ST LUCIE 2	726	118,903	22.0	22.0	97.5	10,880	Nuclear Othr ->	1,293,695	1,000,000	1,293,695	453,100	0.3811
37													
38	CAPE CANAVERAL 1	390	58,175	22.9	91.3	52.5	9,900	Heavy Oil BBLS ->	89,437	6,399,980	572,395	6,036,087	10.3757
39			8,324					Gas MCF ->	86,001	1,000,000	86,001	968,640	11.6362
40													
41	CAPE CANAVERAL 2	390	57,763	22.9	90.4	46.4	9,892	Heavy Oil BBLS ->	88,705	6,400,000	567,712	5,986,765	10.3644
42			8,689					Gas MCF ->	89,664	1,000,000	89,664	1,009,886	11.6231
43													
44	CUTLER 5	70	380	0.7	98.2	45.2	12,613	Gas MCF ->	4,788	1,000,000	4,788	53,951	14.2126
45													
46	CUTLER 6	130		0.0	27.9		0						
47													
48	FORT MYERS 2	1,451	443,532	41.1	47.8	68.4	7,184	Gas MCF ->	3,186,389	1,000,000	3,186,389	35,999,344	8.1165
49													
50	FORT MYERS 3A_B	166	8,716	3.5	96.3	99.1	10,256	Gas MCF ->	89,397	1,000,000	89,397	1,030,966	11.8286
51													
52	SANFORD 3	140	5,385	6.4	95.1	44.2	10,613	Heavy Oil BBLS ->	8,844	6,399,932	56,601	611,978	11.3645
53			1,297					Gas MCF ->	14,318	1,000,000	14,318	161,233	12.4284
54													
55	SANFORD 4	964	538,819	75.1	80.0	78.5	7,123	Gas MCF ->	3,838,402	1,000,000	3,838,402	43,415,794	8.0576
56													
57	SANFORD 5	960	544,228	76.2	96.5	93.1	6,963	Gas MCF ->	3,789,504	1,000,000	3,789,504	42,818,123	7.8677
58													
59	PUTNAM 1	250	90,580	48.7	96.4	84.3	9,075	Gas MCF ->	822,068	1,000,000	822,068	9,497,555	10.4853
60													

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Estimated For The Period of : Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	PUTNAM 2	250	87,060	46.8	96.1	85.1	9,009	Gas	MCF ->	784,389	1,000,000	784,389	9,064,625	10.4119
63	MANATEE 1	810	81,106	14.6	94.4	53.9	9,694	Heavy Oil	BBLS ->	122,390	6,400,000	783,296	8,257,924	10.1816
64			6,720					Gas	MCF ->	68,142	1,000,000	68,142	767,516	11.4217
66	MANATEE 2	810	53,701	10.1	95.0	52.0	9,776	Heavy Oil	BBLS ->	81,567	6,399,990	522,028	5,503,469	10.2484
67			6,924					Gas	MCF ->	70,676	1,000,000	70,676	796,055	11.4967
69	MANATEE 3	1,111	758,522	91.8	96.5	91.8	6,906	Gas	MCF ->	5,238,700	1,000,000	5,238,700	59,396,647	7.8306
71	MARTIN 1	823	82,201	21.5	95.0	51.5	9,862	Heavy Oil	BBLS ->	124,331	6,400,013	795,720	8,387,632	10.2038
72			49,491					Gas	MCF ->	503,040	1,000,000	503,040	5,666,016	11.4485
74	MARTIN 2	814		0.0	51.5		0							
76	MARTIN 3	465	186,831	54.0	94.4	90.1	7,318	Gas	MCF ->	1,367,391	1,000,000	1,367,391	15,401,769	8.2437
78	MARTIN 4	466	205,770	59.4	98.6	93.4	7,222	Gas	MCF ->	1,486,187	1,000,000	1,486,187	16,739,844	8.1352
80	MARTIN 8	1,112	745,912	90.2	96.5	90.2	6,917	Gas	MCF ->	5,160,204	1,000,000	5,160,204	59,197,980	7.9363
82	FORT MYERS 1-12	627		0.0	98.4		0							
84	LAUDERDALE 1-24	766		0.0	91.7		0							
86	EVERGLADES 1-12	383		0.0	88.3		0							
88	ST JOHNS 1O	130	94,440	97.6	96.9	97.6	9,756	Coal	TONS ->	37,844	24,346,501	921,369	1,511,900	1.6009
90	ST JOHNS 2O	130	94,459	97.7	97.0	97.7	9,650	Coal	TONS ->	37,443	24,346,527	911,607	1,495,900	1.5837

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Estimated For The Period of : Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	SCHERER 4	648	471,220	97.8	97.2	97.8	10,152	Coal TONS ->	273,366	17,499,971	4,783,897	8,752,100	1.8573
93	----------												
94	TOTAL	21,768	7,931,136				8,543				67,754,191	485,281,786	6.1187

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Company: Florida Power & Light

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Estimated For The Period of : Jan-07 Thru Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	386	683,601	21.1	95.1	69.4	9,490	Heavy Oil BBLS ->	1,010,969	6,399,996	6,470,198	67,010,557	9.8026
2			31,202					Gas MCF ->	313,110	1,000,000	313,110	3,548,165	11.3715
3													
4	TURKEY POINT 2	391	646,561	19.7	76.0	79.0	9,481	Heavy Oil BBLS ->	954,847	6,399,996	6,111,017	62,975,287	9.7400
5			28,911					Gas MCF ->	293,344	1,000,000	293,344	3,311,063	11.4526
6			0						0		0	0	0.0000
7													
8	TURKEY POINT 3	703	5,517,249	89.6	89.5	97.6	11,320	Nuclear Othr ->	62,454,611	1,000,000	62,454,611	21,656,300	0.3925
9													
10													
11	TURKEY POINT 4	703	6,003,740	97.5	97.5	97.5	11,329	Nuclear Othr ->	68,018,087	1,000,000	68,018,087	25,623,800	0.4268
12													
13	TURKEY POINT 5	1,090	5,642,441	59.1	63.2	88.0	6,970	Gas MCF ->	39,327,292	1,000,000	39,327,292	411,195,252	7.2875
14													
15	LAUDERDALE 4	433	2,094,771	55.2	84.5	85.1	8,044	Gas MCF ->	16,851,083	1,000,000	16,851,083	184,237,114	8.7951
16													
17	LAUDERDALE 5	433	2,455,519	64.7	94.6	88.9	7,861	Gas MCF ->	19,302,478	1,000,000	19,302,478	213,021,717	8.6752
18													
19	PT EVERGLADES 1	205	38,895	2.7	90.7	78.1	10,328	Heavy Oil BBLS ->	62,143	6,400,013	397,716	4,058,939	10.4356
20			10,019					Gas MCF ->	107,486	1,000,000	107,486	1,149,970	11.4782
21			0						0		0	0	0.0000
22													
23	PT EVERGLADES 2	205	47,890	3.6	77.8	73.8	10,292	Heavy Oil BBLS ->	76,053	6,400,037	486,742	4,978,480	10.3957
24			16,101					Gas MCF ->	171,877	1,000,000	171,877	1,851,892	11.5019
25			0						0		0	0	0.0000
26													
27	PT EVERGLADES 3	374	633,045	20.4	76.3	75.0	9,507	Heavy Oil BBLS ->	937,064	6,399,995	5,997,205	62,100,264	9.8098
28			36,923					Gas MCF ->	372,382	1,000,000	372,382	4,206,645	11.3931
29			0						0		0	0	0.0000
30													

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Estimated For The Period of : Jan-07 Thru Dec-07

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	PT EVERGLADES 4	378	889,558	28.7	93.0	73.2	9,510	Heavy Oil	BBLS ->	1,315,687	6,400,005	8,420,403	86,902,069	9.7691
32			60,510					Gas	MCF ->	614,570	1,000,000	614,570	6,953,977	11.4923
33														
34	RIVIERA 3	273	389,551	19.0	81.4	65.6	9,866	Heavy Oil	BBLS ->	595,161	6,399,996	3,809,028	39,177,576	10.0571
35			65,101					Gas	MCF ->	676,483	1,000,000	676,483	7,403,951	11.3731
36														
37	RIVIERA 4	280	517,508	24.9	89.8	61.7	9,831	Heavy Oil	BBLS ->	786,478	6,399,990	5,033,451	51,831,736	10.0156
38			91,916					Gas	MCF ->	957,622	1,000,000	957,622	10,596,346	11.5283
39														
40	ST LUCIE 1	845	6,528,221	88.2	88.2	97.6	10,978	Nuclear	Othr ->	71,668,986	1,000,000	71,668,986	25,862,000	0.3962
41														
42	ST LUCIE 2	719	4,705,095	74.7	74.8	97.4	10,999	Nuclear	Othr ->	51,750,432	1,000,000	51,750,432	18,534,700	0.3939
43			0							0		0	0	0.0000
44														
45	CAPE CANAVERAL 1	388	533,873	16.8	84.3	68.2	9,724	Heavy Oil	BBLS ->	807,827	6,399,988	5,170,083	53,641,753	10.0477
46			37,200					Gas	MCF ->	383,032	1,000,000	383,032	4,356,402	11.7109
47														
48														
49	CAPE CANAVERAL 2	388	584,815	18.2	90.4	64.0	9,684	Heavy Oil	BBLS ->	881,937	6,399,995	5,644,392	58,427,056	9.9907
50			32,340					Gas	MCF ->	332,293	1,000,000	332,293	3,771,634	11.6625
51														
52	CUTLER 5	66	1,207	0.2	98.2	65.2	12,234	Gas	MCF ->	14,769	1,000,000	14,769	157,289	13.0292
53			0							0		0	0	0.0000
54														
55	CUTLER 6	112	2,557	0.3	77.6	95.4	11,388	Gas	MCF ->	29,120	1,000,000	29,120	302,841	11.8431
56			0							0		0	0	0.0000
57														
58	FORT MYERS 2	1,435	10,033,462	79.8	84.4	85.9	7,129	Gas	MCF ->	71,530,365	1,000,000	71,530,365	773,361,439	7.7078
59														
60	FORT MYERS 3A_B	163	63,813	4.5	82.0	100.0	10,426	Gas	MCF ->	665,337	1,000,000	665,337	7,205,799	11.2920
61			0							0		0	0	0.0000
62														

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Estimated For The Period of : Jan-07 Thru Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	SANFORD 3	139	9,982	1.9	95.1	58.5	10,441	Heavy Oil BBLS ->	16,144	6,399,777	103,318	1,117,243	11.1926
64			13,668					Gas MCF ->	143,608	1,000,000	143,608	1,581,271	11.5696
65			0						0		0	0	0.0000
66													
67	SANFORD 4	958	7,334,390	87.4	90.8	89.2	7,030	Gas MCF ->	51,561,273	1,000,000	51,561,273	563,592,816	7.6842
68													
69	SANFORD 5	954	6,808,884	81.5	94.6	90.0	7,039	Gas MCF ->	47,925,561	1,000,000	47,925,561	520,353,254	7.6423
70													
71	PUTNAM 1	244	566,024	26.5	96.4	92.7	9,014	Gas MCF ->	5,102,131	1,000,000	5,102,131	55,769,083	9.8528
72			0						0		0	0	0.0000
73													
74	PUTNAM 2	244	555,876	26.1	86.9	92.7	8,975	Gas MCF ->	4,989,083	1,000,000	4,989,083	54,695,943	9.8396
75													
76													
77	MANATEE 1	806	1,967,946	32.9	87.2	66.2	9,830	Heavy Oil BBLS ->	2,998,653	6,399,999	19,191,375	195,916,003	9.9554
78			356,387					Gas MCF ->	3,655,905	1,000,000	3,655,905	38,406,899	10.7767
79													
80	MANATEE 2	806	1,525,100	29.1	95.0	60.5	9,894	Heavy Oil BBLS ->	2,326,316	6,399,997	14,888,416	152,060,461	9.9705
81			529,879					Gas MCF ->	5,443,597	1,000,000	5,443,597	57,302,343	10.8142
82													
83	MANATEE 3	1,097	8,307,675	86.5	95.6	87.5	7,012	Gas MCF ->	58,254,392	1,000,000	58,254,392	634,262,250	7.6347
84													
85	MARTIN 1	817	1,828,085	41.5	95.0	65.2	9,928	Heavy Oil BBLS ->	2,781,771	6,400,001	17,803,337	182,434,081	9.9795
86			1,142,679					Gas MCF ->	11,691,472	1,000,000	11,691,472	123,016,347	10.7656
87													
88	MARTIN 2	809	397,978	18.9	75.9	52.2	10,217	Heavy Oil BBLS ->	613,735	6,400,013	3,927,912	39,999,188	10.0506
89			939,953					Gas MCF ->	9,742,015	1,000,000	9,742,015	101,890,050	10.8399
90			0						0		0	0	0.0000
91													
92	MARTIN 3	456	1,836,089	46.0	92.8	92.0	7,334	Gas MCF ->	13,465,966	1,000,000	13,465,966	146,215,546	7.9634
93													

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Estimated For The Period of : Jan-07 Thru Dec-07

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	MARTIN 4	457	2,096,907	52.4	98.6	95.6	7,245	Gas MCF ->	15,192,632	1,000,000	15,192,632	164,680,858	7.8535
95	-----------												
96	MARTIN 8	1,098	8,552,076	88.9	95.6	88.9	6,974	Gas MCF ->	59,643,237	1,000,000	59,643,237	648,578,931	7.5839
97	-----------												
98	FORT MYERS 1-12	583	0	0.0	95.4	0.0	0		0		0	0	0.0000
99	-----------												
100	LAUDERDALE 1-24	718	0	0.0	91.7	0.0	0		0		0	0	0.0000
101	-----------												
102	EVERGLADES 1-12	359	0	0.0	88.3	0.0	0		0		0	0	0.0000
103	-----------												
104	ST JOHNS 1O	128	1,002,465	89.2	88.9	97.5	9,807	Coal TONS ->	401,037	24,514,192	9,831,098	17,143,900	1.7102
105	-----------												
106	ST JOHNS 2O	128	1,097,129	97.7	97.0	97.7	9,693	Coal TONS ->	433,608	24,525,558	10,634,478	18,612,900	1.6965
107	-----------												
108	SCHERER 4	644	5,217,671	92.5	97.2	92.5	10,181	Coal TONS ->	3,035,369	17,500,013	53,118,996	98,163,900	1.8814
109	-----------												
110	TOTAL	21,415	100,510,435				8,653				869,684,796	6,035,205,280	6.0046
		=======	=======				=======				=======	=======	=======

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System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2007 thru June 2007

Line			January 2007	February 2007	March 2007	April 2007	May 2007	June 2007
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	680,244	684,693	1,192,843	1,639,395	1,720,920	1,779,415
3	Unit Cost	($/BBLS)	61.3059	62.3608	62.2488	61.7484	62.6764	63.6378
4	Amount	($)	41,703,000	42,698,000	74,253,000	101,230,000	107,861,000	113,238,000
5								
6	Burned:							
7	Units	(BBLS)	670,243	644,694	922,842	1,394,395	1,293,921	1,379,416
8	Unit Cost	($/BBLS)	68.8759	69.0941	67.0251	64.8865	65.3897	65.5675
9	Amount	($)	46,163,575	44,544,527	61,853,617	90,477,391	84,609,059	90,444,901
10								
11	Ending Inventory:							
12	Units	(BBLS)	3,120,000	3,160,000	3,430,000	3,675,001	4,102,001	4,502,000
13	Unit Cost	($/BBLS)	60.1045	60.1538	60.3262	60.4277	60.6779	60.9402
14	Amount	($)	187,526,000	190,086,000	206,919,000	222,072,000	248,901,000	274,353,000
15								
16	Light Oil							
17								
18								
19	Purchases:							
20	Units	(BBLS)	93,381	0	0	0	0	0
21	Unit Cost	($/BBLS)	99.1529	0.0000	0.0000	0.0000	0.0000	0.0000
22	Amount	($)	9,259,000	0	0	0	0	0
23								
24	Burned:							
25	Units	(BBLS)	0	0	0	0	0	0
26	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
27	Amount	($)	0	0	0	0	0	0
28								
29	Ending Inventory:							
30	Units	(BBLS)	756,762	756,762	756,762	756,762	756,762	756,762
31	Unit Cost	($/BBLS)	99.8028	99.8028	99.8028	99.8028	99.8028	99.8028
32	Amount	($)	75,527,000	75,527,000	75,527,000	75,527,000	75,527,000	75,527,000
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	74,182	61,071	43,024	70,972	73,437	71,164
39	Unit Cost	($/Tons)	44.5795	43.0483	45.1608	42.0870	51.7859	40.5261
40	Amount	($)	3,307,000	2,629,000	1,943,000	2,987,000	3,803,000	2,884,000
41								
42	Burned:							
43	Units	(Tons)	74,182	61,071	43,024	70,972	73,437	71,164
44	Unit Cost	($/Tons)	44.5795	43.0483	45.1608	42.0870	51.7859	40.5261
45	Amount	($)	3,307,000	2,629,000	1,943,000	2,987,000	3,803,000	2,884,000
46								
47	Ending Inventory:							
48	Units	(Tons)	57,499	57,499	57,500	57,501	57,501	57,501
49	Unit Cost	($/Tons)	43.0964	43.0964	43.0957	43.0949	43.0949	43.0949
50	Amount	($)	2,478,000	2,478,000	2,478,000	2,478,000	2,478,000	2,478,000
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	4,009,093	3,599,768	4,010,615	3,862,145	4,728,885	4,606,858
57	Unit Cost	($/MBTU)	1.8683	1.8648	1.8613	1.8578	1.8541	1.8507
58	Amount	($)	7,490,000	6,713,000	7,465,000	7,175,000	8,768,000	8,526,000
59								
60	Burned:							
61	Units	(MBTU)	4,009,093	3,599,768	4,010,615	3,862,145	4,728,885	4,606,858
62	Unit Cost	($/MBTU)	1.8683	1.8648	1.8613	1.8578	1.8541	1.8507
63	Amount	($)	7,490,000	6,713,000	7,465,000	7,175,000	8,768,000	8,526,000
64								
65	Ending Inventory:							
66	Units	(MBTU)	4,629,433	4,629,433	4,629,433	4,629,398	4,629,450	4,629,450
67	Unit Cost	($/MBTU)	1.8082	1.8082	1.8082	1.8082	1.8082	1.8082
68	Amount	($)	8,371,000	8,371,000	8,371,000	8,371,000	8,371,000	8,371,000
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	29,657,615	27,434,208	29,448,272	33,726,212	39,586,420	42,318,136
75	Unit Cost	($/MCF)	11.6181	11.6827	11.5421	10.6534	10.4407	10.3386
76	Amount	($)	344,565,764	320,506,897	339,895,252	359,298,897	413,311,215	437,508,247
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	24,094,594	21,762,856	24,094,594	16,888,950	22,657,106	23,187,296
83	Unit Cost	($/MBTU)	0.3521	0.3505	0.3489	0.3559	0.3604	0.3599
84	Amount	($)	8,483,000	7,628,000	8,407,000	6,010,000	8,166,000	8,344,000

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System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2007 thru December 2007

			July 2007	August 2007	September 2007	October 2007	November 2007	December 2007	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	2,248,322	2,015,294	1,700,014	1,271,601	520,153	841,601	16,294,495
3	Unit Cost	($/BBLS)	64.4414	64.5067	64.5689	64.4731	65.0943	65.6808	63.6262
4	Amount	($)	144,885,000	130,000,000	109,768,000	81,984,000	33,859,000	55,277,000	1,036,756,000
5									
6	Burned:								
7	Units	(BBLS)	2,248,329	2,015,298	2,000,020	1,894,724	650,455	1,050,443	16,164,780
8	Unit Cost	($/BBLS)	64.4832	64.5064	64.5229	65.9366	68.6799	67.4998	65.7373
9	Amount	($)	144,979,411	129,999,676	129,047,165	124,931,722	44,673,172	70,904,684	1,062,628,900
10									
11	Ending Inventory:								
12	Units	(BBLS)	4,501,996	4,501,998	4,201,999	3,578,881	3,448,580	3,239,736	3,239,736
13	Unit Cost	($/BBLS)	60.9403	60.9403	60.6816	60.0230	59.8313	59.4508	59.4508
14	Amount	($)	274,353,000	274,353,000	254,984,000	214,815,000	206,333,000	192,605,000	192,605,000
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	0	0	0	0	0	0	0
21	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
22	Amount	($)	0	0	0	0	0	0	0
23									
24	Burned:								
25	Units	(BBLS)	0	0	0	0	0	0	0
26	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
27	Amount	($)	0	0	0	0	0	0	0
28									
29	Ending Inventory:								
30	Units	(BBLS)	756,762	756,762	756,762	756,762	756,762	756,762	756,762
31	Unit Cost	($/BBLS)	99.8028	99.8028	99.8028	99.8028	99.8028	99.8028	99.8028
32	Amount	($)	75,527,000	75,527,000	75,527,000	75,527,000	75,527,000	75,527,000	75,527,000
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	73,635	73,733	71,450	73,931	72,759	75,285	834,643
39	Unit Cost	($/Tons)	42.2761	40.2940	40.2239	41.9986	43.0737	39.9548	42.8423
40	Amount	($)	3,113,000	2,971,000	2,874,000	3,105,000	3,134,000	3,008,000	35,758,000
41									
42	Burned:								
43	Units	(Tons)	73,635	73,733	71,450	73,931	72,759	75,285	834,643
44	Unit Cost	($/Tons)	42.2761	40.2940	40.2239	41.9986	43.0737	39.9548	42.8423
45	Amount	($)	3,113,000	2,971,000	2,874,000	3,105,000	3,134,000	3,008,000	35,758,000
46									
47	Ending Inventory:								
48	Units	(Tons)	57,501	57,501	57,501	57,501	57,499	57,499	57,499
49	Unit Cost	($/Tons)	43.0949	43.0949	43.0949	43.0949	43.0964	43.0964	43.0964
50	Amount	($)	2,478,000	2,478,000	2,478,000	2,478,000	2,478,000	2,478,000	2,478,000
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	4,760,420	4,760,420	4,606,858	4,760,420	4,629,573	4,783,905	53,118,958
57	Unit Cost	($/MBTU)	1.8471	1.8435	1.8401	1.8366	1.8330	1.8295	1.8480
58	Amount	($)	8,793,000	8,776,000	8,477,000	8,743,000	8,486,000	8,752,000	98,164,000
59									
60	Burned:								
61	Units	(MBTU)	4,760,420	4,760,420	4,606,858	4,760,420	4,629,573	4,783,905	53,118,958
62	Unit Cost	($/MBTU)	1.8471	1.8435	1.8401	1.8366	1.8330	1.8295	1.8480
63	Amount	($)	8,793,000	8,776,000	8,477,000	8,743,000	8,486,000	8,752,000	98,164,000
64									
65	Ending Inventory:								
66	Units	(MBTU)	4,629,450	4,629,450	4,629,450	4,629,450	4,629,433	4,629,450	4,629,450
67	Unit Cost	($/MBTU)	1.8082	1.8082	1.8082	1.8082	1.8082	1.8082	1.8082
68	Amount	($)	8,371,000	8,371,000	8,371,000	8,371,000	8,371,000	8,371,000	8,371,000
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	44,207,556	44,201,556	42,649,809	37,786,308	32,981,290	34,755,366	438,752,748
75	Unit Cost	($/MCF)	10.3793	10.4268	10.5002	10.7262	11.0304	11.3719	10.8192
76	Amount	($)	458,845,438	460,878,593	447,830,722	405,303,745	363,797,567	395,233,109	4,746,975,444
77			10.3793	10.4268	10.5002	10.7262	11.0304	11.3719	10.8192
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	23,960,208	23,960,208	17,623,820	18,230,568	17,772,888	19,659,014	253,892,102
83	Unit Cost	($/MBTU)	0.3582	0.3566	0.3662	0.3806	0.3791	0.3756	0.3611
84	Amount	($)	8,583,000	8,545,000	6,453,000	6,939,000	6,737,000	7,383,000	91,678,000

POWER SOLD

Estimated for the Period of : January 2007 thru December 2007

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
January		OS	301,344		301,344	7.402	8.782	22,306,515	26,464,750	3,562,601
2007	St.Lucie Rel.		6,863		6,863	2.269	2.269	155,700	155,700	0
Total			308,207	0	308,207	7.288	8.637	22,462,215	26,620,450	3,562,601
February		OS	265,772		265,772	6.792	7.915	18,051,330	21,036,048	2,460,808
2007	St.Lucie Rel.		6,199		6,199	2.258	2.258	140,000	140,000	0
Total			271,971	0	271,971	6.689	7.786	18,191,330	21,176,048	2,460,808
March		OS	218,523		218,523	7.299	8.302	15,949,855	18,142,621	1,759,868
2007	St.Lucie Rel.		6,863		6,863	2.248	2.248	154,300	154,300	0
Total			225,386	0	225,386	7.145	8.118	16,104,155	18,296,921	1,759,868
April		OS	151,763		151,763	7.640	8.608	11,593,970	13,063,714	1,154,571
2007	St.Lucie Rel.		0		0	0.000	0.000	148,700	148,700	0
Total			151,763	0	151,763	7.738	8.706	11,742,670	13,212,414	1,154,571
May		OS	87,172		87,172	7.310	8.435	6,371,901	7,352,682	794,342
2007	St.Lucie Rel.		0		0	0.000	0.000	152,900	152,900	0
Total			87,172	0	87,172	7.485	8.610	6,524,801	7,505,582	794,342
June		OS	97,395		97,395	7.719	8.608	7,518,358	8,384,159	657,886
2007	St.Lucie Rel.		6,537		6,537	2.253	2.253	147,300	147,300	0
Total			103,932	0	103,932	7.376	8.209	7,665,658	8,531,459	657,886
			1,121,969	0	1,121,969			81,791,930	94,443,973	10,390,076
			26,462	0	26,462			898,900	898,900	0

Company: Florida Power & Light
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Schedule: E6
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POWER SOLD

Estimated for the Period of : January 2007 thru December 2007

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	82,424		82,424	8.019	9.041	6,609,263	7,451,883	671,043
2007	St.Lucie Rel.		6,755		6,755	2.243	2.243	151,500	151,500	0
Total			89,179	0	89,179	7.581	8.526	6,760,763	7,603,383	671,043
August		OS	109,919		109,919	7.887	9.063	8,669,078	9,962,231	1,057,241
2007	St.Lucie Rel.		6,755		6,755	2.232	2.232	150,800	150,800	0
Total			116,674	0	116,674	7.559	8.668	8,819,878	10,113,031	1,057,241
September		OS	31,007		31,007	8.924	10.266	2,767,043	3,183,087	346,946
2007	St.Lucie Rel.		6,537		6,537	2.223	2.223	145,300	145,300	0
Total			37,544	0	37,544	7.757	8.865	2,912,343	3,328,387	346,946
October		OS	51,424		51,424	8.755	9.883	4,502,294	5,082,329	467,277
2007	St.Lucie Rel.		0		0	0.000	0.100	0	0	0
Total			51,424	0	51,424	8.755	9.883	4,502,294	5,082,329	467,277
November		OS	148,970		148,970	7.578	8.637	11,288,800	12,867,032	1,267,006
2007	St.Lucie Rel.		0		0	0.100	0.100	0	0	0
Total			148,970	0	148,970	7.578	8.637	11,288,800	12,867,032	1,267,006
December		OS	385,196		385,196	7.878	9.377	30,343,836	36,121,256	4,998,371
2007	St.Lucie Rel.		37,229		37,229	0.091	0.091	33,700	33,700	0
Total			422,425	0	422,425	7.191	8.559	30,377,536	36,154,956	4,998,371
Period		OS	1,930,909	0	1,930,909	7.560	8.758	145,972,243	169,111,791	19,197,960
	St.Lucie Rel.		83,738	0	83,738	1.648	1.648	1,380,200	1,380,200	0
Total			2,014,647	0	2,014,647	7.314	8.463	147,352,443	170,491,991	19,197,960

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2007 thru December 2007

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2007 January	Sou. Co. (UPS + R)		688,984			688,984	1.903		13,111,000
	St. Lucie Rel.		39,221			39,221	0.397		155,700
	SJRPP		283,348			283,348	1.750		4,959,000
	PPAs		3,681			3,681	12.921		475,624
Total			1,015,234			1,015,234	1.842		18,701,324
2007 February	Sou. Co. (UPS + R)		612,260			612,260	1.903		11,651,000
	St. Lucie Rel.		35,426			35,426	0.395		140,000
	SJRPP		233,065			233,065	1.691		3,942,000
	PPAs		0			0	0.100		0
Total			880,751			880,751	1.786		15,733,000
2007 March	Sou. Co. (UPS + R)		682,855			682,855	1.903		12,994,000
	St. Lucie Rel.		39,221			39,221	0.393		154,300
	SJRPP		164,538			164,538	1.770		2,913,000
	PPAs		0			0	0.100		0
Total			886,614			886,614	1.812		16,061,300
2007 April	Sou. Co. (UPS + R)		669,595			669,595	1.903		12,742,000
	St. Lucie Rel.		37,333			37,333	0.398		148,700
	SJRPP		267,879			267,879	1.672		4,480,000
	PPAs		55,510			55,510	8.060		4,474,183
Total			1,030,317			1,030,317	2.120		21,844,883
2007 May	Sou. Co. (UPS + R)		669,728			669,728	1.903		12,744,000
	St. Lucie Rel.		38,577			38,577	0.396		152,900
	SJRPP		276,787			276,787	2.060		5,702,000
	PPAs		39,503			39,503	8.394		3,316,050
Total			1,024,595			1,024,595	2.139		21,914,950
2007 June	Sou. Co. (UPS + R)		667,917			667,917	1.903		12,710,000
	St. Lucie Rel.		37,333			37,333	0.395		147,300
	SJRPP		267,879			267,879	1.615		4,325,000
	PPAs		39,008			39,008	7.823		3,051,712
Total			1,012,137			1,012,137	1.999		20,234,012
Period Total	Sou. Co. (UPS + R)		3,991,339			3,991,339	1.903		75,952,000
	St. Lucie Rel.		227,111			227,111	0.396		898,900
	SJRPP		1,493,496			1,493,496	1.762		26,321,000
	PPAs		137,702			137,702	8.219		11,317,569
Total			5,849,648			5,849,648	1.957		114,489,469

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2007 thru December 2007

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2007 July	Sou. Co. (UPS + R)		691,915			691,915	1.903		13,167,000
	St. Lucie Rel.		38,577			38,577	0.393		151,500
	SJRPP		276,808			276,808	1.686		4,668,000
	PPAs		50,864			50,864	7.987		4,062,482
Total			1,058,164			1,058,164	2.084		22,048,982
2007 August	Sou. Co. (UPS + R)		691,269			691,269	1.903		13,154,000
	St. Lucie Rel.		38,577			38,577	0.391		150,800
	SJRPP		276,808			276,808	1.609		4,455,000
	PPAs		44,080			44,080	8.069		3,556,648
Total			1,050,734			1,050,734	2.029		21,316,448
2007 September	Sou. Co. (UPS + R)		669,595			669,595	1.903		12,742,000
	St. Lucie Rel.		37,333			37,333	0.389		145,300
	SJRPP		267,879			267,879	1.609		4,310,000
	PPAs		67,283			67,283	9.559		6,431,833
Total			1,042,090			1,042,090	2.267		23,629,133
2007 October	Sou. Co. (UPS + R)		691,735			691,735	1.903		13,163,000
	St. Lucie Rel.		0			0	0.100		0
	SJRPP		276,808			276,808	1.682		4,656,000
	PPAs		60,740			60,740	9.019		5,477,893
Total			1,029,283			1,029,283	2.263		23,296,893
2007 November	Sou. Co. (UPS + R)		669,321			669,321	1.903		12,737,000
	St. Lucie Rel.		0			0	0.100		0
	SJRPP		274,207			274,207	1.714		4,701,000
	PPAs		52,751			52,751	9.342		4,927,782
Total			996,279			996,279	2.245		22,365,782
2007 December	Sou. Co. (UPS + R)		691,510			691,510	1.903		13,159,000
	St. Lucie Rel.		8,856			8,856	0.381		33,700
	SJRPP		283,348			283,348	1.592		4,510,000
	PPAs		15,574			15,574	12.647		1,969,700
Total			999,288			999,288	1.969		19,672,400
Period Total	Sou. Co. (UPS + R)		8,096,684			8,096,684	1.903		154,074,000
	St. Lucie Rel.		350,454			350,454	0.394		1,380,200
	SJRPP		3,149,354			3,149,354	1.703		53,621,000
	PPAs		428,994			428,994	8.798		37,743,907
Total			12,025,486			12,025,486	2.052		246,819,107

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2007 thru December 2007

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2007 January	Qual. Facilities		547,591			547,591	2.825	2.825	15,469,000
Total			547,591			547,591	2.825	2.825	15,469,000
2007 February	Qual. Facilities		498,930			498,930	2.848	2.848	14,209,000
Total			498,930			498,930	2.848	2.848	14,209,000
2007 March	Qual. Facilities		538,961			538,961	2.835	2.835	15,277,000
Total			538,961			538,961	2.835	2.835	15,277,000
2007 April	Qual. Facilities		253,048			253,048	3.472	3.472	8,786,000
Total			253,048			253,048	3.472	3.472	8,786,000
2007 May	Qual. Facilities		504,034			504,034	2.859	2.859	14,412,000
Total			504,034			504,034	2.859	2.859	14,412,000
2007 June	Qual. Facilities		533,694			533,694	2.864	2.864	15,286,000
Total			533,694			533,694	2.864	2.864	15,286,000
Period Total	Qual. Facilities		2,876,258			2,876,258	2.901	2.901	83,439,000
Total			2,876,258			2,876,258	2.901	2.901	83,439,000

9/1/2006
Company: Florida Power & Light

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2007 thru December 2007

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2007 July	Qual. Facilities		550,005			550,005	2.886	2.886	15,875,000
Total			550,005			550,005	2.886	2.886	15,875,000
2007 August	Qual. Facilities		549,373			549,373	2.877	2.877	15,803,000
Total			549,373			549,373	2.877	2.877	15,803,000
2007 September	Qual. Facilities		537,078			537,078	2.903	2.903	15,593,000
Total			537,078			537,078	2.903	2.903	15,593,000
2007 October	Qual. Facilities		437,696			437,696	2.897	2.897	12,682,000
Total			437,696			437,696	2.897	2.897	12,682,000
2007 November	Qual. Facilities		451,165			451,165	3.049	3.049	13,758,000
Total			451,165			451,165	3.049	3.049	13,758,000
2007 December	Qual. Facilities		549,458			549,458	2.861	2.861	15,720,000
Total			549,458			549,458	2.861	2.861	15,720,000
Period Total	Qual. Facilities		5,951,033			5,951,033	2.905	2.905	172,870,000
Total			5,951,033			5,951,033	2.905	2.905	172,870,000

Economy Energy Purchases

Estimated For the Period of : January 2007 Thru December 2007

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
January	Florida	OS	21,027	6.893	1,449,421	8.087	1,700,495	251,074
2007	Non-Florida	OS	63,831	7.216	4,606,360	8.067	5,149,451	512,801
Total			84,858	7.136	6,055,781	8.072	6,849,946	763,875
February	Florida	OS	13,623	7.634	1,040,010	8.496	1,157,473	117,463
2007	Non-Florida	OS	69,989	7.784	5,447,942	8.491	5,942,961	480,444
Total			83,612	7.760	6,487,952	8.492	7,100,434	597,907
March	Florida	OS	25,267	7.801	1,970,985	8.876	2,242,595	271,610
2007	Non-Florida	OS	87,364	7.690	6,718,410	8.825	7,709,513	957,208
Total			112,631	7.715	8,689,396	8.836	9,952,108	1,228,818
April	Florida	OS	25,049	7.707	1,930,527	8.768	2,196,394	265,866
2007	Non-Florida	OS	108,671	7.761	8,433,743	8.687	9,440,402	970,223
Total			133,720	7.751	10,364,270	8.702	11,636,796	1,236,089
May	Florida	OS	37,444	7.882	2,951,480	8.543	3,198,759	247,279
2007	Non-Florida	OS	163,487	7.375	12,056,764	8.517	13,923,503	1,815,032
Total			200,931	7.469	15,008,245	8.521	17,122,262	2,062,311
June	Florida	OS	31,329	7.348	2,302,010	8.530	2,672,284	370,273
2007	Non-Florida	OS	80,803	7.677	6,203,356	8.639	6,980,553	730,131
Total			112,132	7.585	8,505,366	8.608	9,652,837	1,100,404
Period	Florida	OS	153,739	7.574	11,644,435	8.565	13,168,000	1,523,565
Total	Non-Florida	OS	574,145	7.571	43,466,575	8.560	49,146,384	5,465,839
Total			727,884	7.571	55,111,010	8.561	62,314,383	6,989,404

9/1/2006
Company: Florida Power & Light

Economy Energy Purchases

Estimated For the Period of : January 2007 Thru December 2007

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
July	Florida	OS	33,656	6.817	2,294,431	9.128	3,072,278	777,848
2007	Non-Florida	OS	96,577	7.952	7,680,097	8.969	8,661,992	915,008
Total			130,233	7.659	9,974,528	9.010	11,734,270	1,692,856
August	Florida	OS	29,251	6.849	2,003,378	9.151	2,676,846	673,467
2007	Non-Florida	OS	84,243	7.787	6,559,870	8.771	7,388,820	762,907
Total			113,494	7.545	8,563,248	8.869	10,065,666	1,436,374
September	Florida	OS	35,542	7.641	2,715,819	9.383	3,334,756	618,937
2007	Non-Florida	OS	106,214	7.984	8,480,029	9.072	9,635,514	1,081,928
Total			141,756	7.898	11,195,847	9.150	12,970,270	1,700,865
October	Florida	OS	161,857	8.278	13,398,317	9.794	15,852,902	2,454,585
2007	Non-Florida	OS	118,559	7.874	9,334,975	9.429	11,179,204	1,773,414
Total			280,416	8.107	22,733,292	9.640	27,032,106	4,227,999
November	Florida	OS	94,035	7.852	7,383,307	8.838	8,310,351	927,043
2007	Non-Florida	OS	125,254	7.805	9,775,929	8.819	11,046,360	1,210,135
Total			219,289	7.825	17,159,236	8.827	19,356,711	2,137,178
December	Florida	OS	49,331	7.017	3,461,798	8.744	4,313,636	851,838
2007	Non-Florida	OS	65,276	7.877	5,141,954	8.831	5,764,429	589,189
Total			114,607	7.507	8,603,752	8.794	10,078,065	1,441,027
Period	Florida	OS	557,411	7.697	42,901,485	9.101	50,728,768	7,827,284
Total	Non-Florida	OS	1,170,268	7.728	90,439,427	8.786	102,822,704	11,798,420
Total			1,727,679	7.718	133,340,912	8.888	153,551,472	19,625,703

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	JAN 06 - DEC 06	JAN 07 - APR 07	DIFFERENCE $	DIFFERENCE %	MAY 07 - DEC 07	DIFFERENCE $	DIFFERENCE %
BASE	$38.12	$38.12	$0.00	0.00%	$39.37	$1.25	3.28%
FUEL	$58.41	$57.29	($1.12)	-1.92%	$56.04	($1.25)	-2.18%
CONSERVATION	$1.42	$1.69	$0.27	19.01%	$1.69	$0.00	0.00%
CAPACITY PAYMENT	$6.03	$5.57	($0.46)	-7.63%	$5.57	$0.00	0.00%
ENVIRONMENTAL	$0.26	$0.24	($0.02)	-7.69%	$0.24	$0.00	0.00%
STORM SURCHARGE	$1.65	$1.10 *	($0.55)	-33.33%	$1.10 *	$0.00	0.00%
SUBTOTAL	$105.89	$104.01	($1.33)	-1.26%	$104.01	$0.00	0.00%
GROSS RECEIPTS TAX	$2.72	$2.67	($0.05)	-1.84%	$2.67	$0.00	0.00%
TOTAL	**$108.61**	**$106.68**	**($1.93)**	**-1.78%**	**$106.68**	**$0.00**	**0.00%**

* Preliminary estimate subject to market conditions.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ACTUAL	PROJECTED			
		JAN - DEC 2004 - 2004 (COLUMN 1)	JAN - DEC 2005 - 2005 (COLUMN 2)	JAN - DEC 2006 - 2006 (COLUMN 3)	JAN - DEC 2007 - 2007 (COLUMN 4)	(COLUMN 2) / (COLUMN 1)	(COLUMN 3) / (COLUMN 2)	(COLUMN 4) / (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	880,989,788	1,189,534,130	561,148,468	1,062,628,900	35.0	(52.8)	89.4
2	LIGHT OIL	18,481,297	21,649,472	2,120,616	0	17.1	(90.2)	(100.0)
3	COAL	106,401,206	101,261,934	117,361,464	133,920,000	(4.8)	15.9	14.1
4	GAS	2,053,469,036	3,104,658,880	4,222,422,416	4,746,975,444	51.2	36.0	12.4
5	NUCLEAR	69,760,680	75,683,285	91,738,442	91,678,000	8.5	21.2	(0.1)
6	OTHER	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	3,129,102,007	4,492,787,701	4,994,791,406	6,035,202,344	43.6	11.2	20.8
	SYSTEM NET GENERATION							
8	HEAVY OIL	19,708,832	19,069,057	6,980,349	10,694,382	(3.3)	(63.4)	53.2
9	LIGHT OIL	198,926	186,425	21,148	0	(6.3)	(88.7)	(100.0)
10	COAL	6,315,303	5,765,059	6,135,127	7,317,267	(8.7)	6.4	19.3
11	GAS	40,969,969	47,113,904	60,151,759	59,744,397	15.0	27.7	(0.7)
12	NUCLEAR	23,012,886	21,405,553	23,432,921	22,754,302	(7.0)	9.5	(2.9)
13	OTHER	0		0	0	0.0	0.0	0.0
14	TOTAL (MWH)	90,205,916	93,539,998	96,721,304	100,510,348	3.7	3.4	3.9
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	31,250,093	30,217,452	10,996,435	16,164,780	(3.3)	(63.6)	47.0
16	LIGHT OIL (Bbl)	406,123	344,163	28,050	0	(15.3)	(91.9)	(100.0)
17	COAL (TON)	731,272	695,245	1,976,280	3,870,014	(4.9)	184.3	95.8
18	GAS (MCF)	311,056,697	345,850,962	462,850,117	438,752,748	11.2	33.8	(5.2)
19	NUCLEAR (MMBTU)	252,278,261	235,447,135	256,669,817	253,892,102	(6.7)	9.0	(1.1)
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	198,910,244	192,970,149	69,977,975	103,454,590	(3.0)	(63.7)	47.8
22	LIGHT OIL	2,322,003	1,790,210	160,355	0	(22.9)	(91.0)	(100.0)
23	COAL	63,111,557	58,749,974	62,489,602	73,584,573	(6.9)	6.4	17.8
24	GAS	322,377,181	363,861,486	473,130,736	438,752,748	12.9	30.0	(7.3)
25	NUCLEAR	252,278,261	235,447,135	256,669,817	253,892,102	(6.7)	9.0	(1.1)
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	838,999,246	852,818,954	862,428,485	869,684,013	1.7	1.1	0.8
	GENERATION MIX (%MWH)							
28	HEAVY OIL	21.85	20.39	7.22	10.64	-	-	-
29	LIGHT OIL	0.22	0.20	0.02	0.00	-	-	-
30	COAL	7.00	6.16	6.34	7.28			
31	GAS	45.42	50.37	62.19	59.44	-	-	-
32	NUCLEAR	25.51	22.88	24.23	22.64	-	-	-
33	*OTHER*	*0.00*	*0.00*	*0.00*	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	28.1916	39.3658	51.0300	65.7373	39.6	29.6	28.8
36	LIGHT OIL ($/Bbl)	45.5066	62.9047	75.6013	0.0000	38.2	20.2	(100.0)
37	COAL ($/TON)	40.5611	44.4710	17.7347	34.6045	9.6	(60.1)	95.1
38	GAS ($/MCF)	6.6016	8.9769	9.1227	10.8192	36.0	1.6	18.6
39	NUCLEAR ($/MMBTU)	0.2765	0.3214	0.3574	0.3611	16.2	11.2	1.0
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	4.4291	6.1643	8.0189	10.2715	39.2	30.1	28.1
42	LIGHT OIL	7.9592	12.0933	13.2245	0.0000	51.9	9.4	(100.0)
43	COAL	1.6859	1.7236	1.8781	1.8199	2.2	9.0	(3.1)
44	GAS	6.3698	8.5325	8.9244	10.8192	34.0	4.6	21.2
45	NUCLEAR	0.2765	0.3214	0.3574	0.3611	16.2	11.2	1.0
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	3.7296	5.2682	5.7915	6.9395	41.3	9.9	19.8
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,092	10,120	10,025	9,674	0.3	(0.9)	(3.5)
49	LIGHT OIL	11,673	9,603	7,583	0	(17.7)	(21.0)	(100.0)
50	COAL	9,993	10,191	10,188	10,056	2.0	(0.1)	(1.3)
51	GAS	7,869	7,723	7,866	7,344	(1.9)	1.9	(6.6)
52	NUCLEAR	10,962	10,999	10,953	11,158	0.3	(0.4)	1.9
53	OTHER	*0*	*0*	*0*	*0*	*0.0*	*0.0*	0.0
54	TOTAL (BTU/KWH)	9,301	9,117	8,917	8,653	(2.0)	(2.2)	(3.0)
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	4.4700	6.2380	8.0390	9.9363	39.6	28.9	23.6
56	LIGHT OIL	9.2906	11.6130	10.0275	0.0000	25.0	(13.7)	(100.0)
57	COAL	1.6848	1.7565	1.9129	1.8302	4.3	8.9	(4.3)
58	GAS	5.0121	6.5897	7.0196	7.9455	31.5	6.5	13.2
59	NUCLEAR	0.3031	0.3536	0.3915	0.4029	16.7	10.7	2.9
60	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (c/KWH)	3.4688	4.8031	5.1641	6.0046	38.5	7.5	16.3

Note: Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM QUALIFYING COGENERATION AND SMALL POWER PRODUCTION FACILITIES (QUALIFYING FACILITIES)

SCHEDULE

COG-1, As-Available Energy

AVAILABLE

The Company will purchase energy offered by any Qualifying Facility located within the State of Florida under the provisions of this schedule or at contract negotiated rates as approved by the Florida Public Service Commission.

APPLICABLE

To any cogeneration or small power production Qualifying Facility located within the State of Florida producing energy for sale to the Company on an As-Available basis. As-Available Energy is described by Florida Public Service Commission (FPSC) Rule 25-17.0825, F.A.C. and is energy produced and sold by a Qualifying Facility on an hour-by-hour basis for which contractual commitments as to the time, quantity, or reliability of delivery are not required.

CHARACTER OF SERVICE

Purchase shall be, at the option of the Company, single or three phase, 60 hertz, alternating current at any available standard Company voltage.

LIMITATION:

All service pursuant to this schedule is subject to FPSC Rules 25-17.082 through 25-17.091, F.A.C.

RATE FOR PURCHASES BY THE COMPANY

A. Capacity Rates

Capacity payments to Qualifying Facilities will not be paid under this Rate Schedule. Capacity payments to Qualifying Facilities may be obtained under other applicable tariffs, or pursuant to a negotiated contract.

B. Energy Rates

As-Available Energy is purchased at a unit cost, in cents per kilowatt-hour, based on the Company's actual hourly avoided energy costs, before the sale of interchange energy, which is calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C. Customer charges directly attributable to the purchase of As-Available Energy from the Qualifying Facility are deducted from the Qualifying Facility's total monthly energy payment.

Avoided energy costs shall be all costs which the Company avoided due to the purchase of As-Available Energy, including incremental fuel, identifiable variable operation and maintenance expense and identifiable variable utility power purchases. Demonstrable Company administrative costs required to calculate As-Available Energy cost may be deducted from As-Available Energy payments. The calculation of the Company's As-Available Energy cost reflects the delivery of energy from the region of the Company in which the Qualifying Facility is located. Energy payments to Qualifying Facilities located outside the Company's service area shall reflect the region in which the interchange point for the delivery of As-Available Energy is located. All sales shall be adjusted for losses from the point of metering to the point of interconnection. Appendix A provides a description methodology to be used in the calculation of As-Available Energy cost.

C. Negotiated Rates

Upon agreement by both the Company and the Qualifying Facility, an alternate contract rate for the purchase of As-Available Energy may be separately negotiated.

(Continued on Sheet No. 10.101)

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next four periods are as follows. In addition, As-Available Energy cost payments will include .0024¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 2006 – March 31, 2007	8.50	7.14	7.54
April 1, 2007 – September 30, 2007	8.69	7.87	8.11
October 1, 2007 – March 31, 2008	8.35	7.23	7.56
April 1, 2008 – September 30, 2008	8.26	7.42	7.67

A MW block size ranging from 50 MW to 56 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0216
Secondary Voltage Delivery	1.0476

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)					Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Nuclear	Oil	Gas	Coal
2007	20	12	49	6	13	.41	9.06	9.87	1.82
2008	20	10	51	6	13	.42	7.89	7.94	1.82
2009	19	5	57	6	13	.41	7.76	7.25	1.83
2010	18	3	62	5	11	.43	6.95	6.32	1.86
2011	18	3	63	6	10	.43	7.40	6.35	1.89
2012	18	3	62	8	10	.44	7.83	6.59	2.05
2013	17	2	59	13	9	.44	8.23	6.81	2.18
2014	17	2	57	14	9	.44	8.62	7.04	2.24
2015	16	2	59	14	9	.45	9.05	7.32	2.28
2016	16	4	63	14	3	.45	9.89	7.81	2.32

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revisions. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	8.24	CST-1	100.74
GST-1	11.27	GSLD-2	155.68
GSD-1	32.05	GSLDT-2	155.68
GSDT-1	38.00	CS-2	155.68
RS-1	5.17	CST-2	155.68
RST-1	8.20	GSLD-3	366.30
GSLD-1	37.55	CS-3	366.30
GSLDT-1	37.55	CST-3	366.30
CS-1	100.74	GSLDT-3	366.30

B. Interconnection Charge for Non-Variable Utility Expenses:

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. Interconnection Charge for Variable Utility Expenses:

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.151%
Distribution Equipment	0.211%
Transmission Equipment	0.115%

D. Taxes and Assessments

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III

CAPACITY COST RECOVERY

KMD-6
DOCKET NO. 060001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT__________
PAGES 1-7
SEPTEMBER 1, 2006

APPENDIX III
CAPACITY COST RECOVERY

TABLE OF CONTENTS

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2007 THROUGH DECEMBER 2007

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$16,265,473	$195,185,676
2. SHORT TERM CAPACITY PAYMENTS	$6,287,300	$6,287,300	$3,514,572	$3,419,712	$3,619,352	$4,545,090	$4,545,090	$4,545,090	$4,545,090	$3,585,714	$3,585,714	$3,919,410	$52,399,434
3. CAPACITY PAYMENTS TO COGENERATORS	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$26,345,816	$316,149,792
4a. SJRPP SUSPENSION ACCRUAL	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$294,744	$3,536,928
4b. RETURN REQUIREMENTS ON SJRPP SUSPENSION LIABILITY	($434,028)	($436,918)	($439,807)	($442,697)	($445,587)	($448,477)	($451,367)	($454,257)	($457,146)	($460,036)	($462,926)	($465,816)	($5,399,062)
5b. OKEELANTA SETTLEMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6. INCREMENTAL PLANT SECURITY COSTS	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$2,536,866	$30,442,387
7. TRANSMISSION OF ELECTRICITY BY OTHERS	$566,831	$579,471	$52,732	$50,685	$270,983	$273,957	$260,221	$260,818	$250,315	$26,555	$33,608	$53,163	$2,679,339
8. TRANSMISSION REVENUES FROM CAPACITY SALES	($595,634)	($523,910)	($432,898)	($315,172)	($186,438)	($207,915)	($171,578)	($235,912)	($69,098)	($112,758)	($311,226)	($779,049)	($3,941,588)
9. SYSTEM TOTAL	$51,267,368	$51,348,842	$48,137,498	$48,155,427	$48,701,209	$49,605,554	$49,625,265	$49,558,638	$49,712,060	$48,482,374	$48,288,069	$48,170,607	$591,052,906
10. JURISDICTIONAL % *													98.68536%
11. JURISDICTIONALIZED CAPACITY PAYMENTS													$583,282,688
12. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
13. FINAL TRUE-UP -- overrecovery/(underrecovery) JANUARY 2005 - DECEMBER 2005 $3,305,688			EST \ ACT TRUE-UP -- overrecovery/(underrecovery) JANUARY 2006 - DECEMBER 2006 ($18,215,446)										($14,909,758)
14. TOTAL (Lines 10+11+12)													$541,246,854
15. REVENUE TAX MULTIPLIER													1.00072
16. TOTAL RECOVERABLE CAPACITY PAYMENTS													$541,636,552

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	18,541	98.68536%
FERC	247	1.31464%
TOTAL	18,788	100.00000%

* BASED ON 2005 ACTUAL DATA

3a

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER 2005

LINE NO.		(1) ACTUAL JAN 2006	(2) ACTUAL FEB 2006	(3) ACTUAL MAR 2006	(4) ACTUAL APR 2006	(5) ACTUAL MAY 2006	(6) ACTUAL JUN 2006
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,328,586	$17,039,174	$16,424,843	$17,022,006	$16,137,875	$16,258,337
2.	Short Term Capacity Purchases CCR	5,567,800	5,760,442	3,714,452	3,604,238	6,904,812	13,741,290
3.	QF Capacity Charges	25,941,162	25,351,277	25,824,354	25,694,198	26,100,635	25,963,653
4a.	SJRPP Suspension Accrual	354,568	354,568	354,568	354,568	354,568	354,568
4b.	Return on SJRPP Suspension Liability	(392,604)	(396,081)	(399,557)	(403,033)	(406,510)	(409,986)
5.	Okeelanta Settlement (Capacity)	3,053,254	3,045,448	3,037,545	3,030,642	3,020,858	3,011,307
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	2,947,315	2,278,720	1,710,423	2,413,005	2,137,310	2,208,967
7.	Transmission of Electricity by Others	637,042	684,247	589,986	569,737	982,560	919,270
8.	Transmission Revenues from Capacity Sales	(612,573)	(510,704)	(448,830)	(147,753)	(152,625)	(149,806)
9.	Total (Lines 1 through 8)	$ 53,824,549	$ 53,607,091	$ 50,807,784	$ 52,137,607	$ 55,079,483	$ 61,897,599
10.	Jurisdictional Separation Factor (a)	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%
11.	Jurisdictional Capacity Charges	53,082,976	52,868,514	50,107,775	51,419,276	54,320,620	61,044,799
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	$ 48,337,510	$ 48,123,048	$ 45,362,309	$ 46,673,810	$ 49,575,154	$ 56,299,333
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 45,391,676	$ 41,857,250	$ 41,260,600	$ 43,401,265	$ 47,773,199	$ 53,178,080
15.	Prior Period True-up Provision	(593,148)	(593,148)	(593,148)	(593,148)	(593,148)	(593,148)
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 44,798,528	$ 41,264,102	$ 40,667,452	$ 42,808,117	$ 47,180,051	$ 52,584,932
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(3,538,982)	(6,858,946)	(4,694,857)	(3,865,693)	(2,395,103)	(3,714,400)
18.	Interest Provision for Month	(19,400)	(37,328)	(58,697)	(76,610)	(89,277)	(103,180)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(7,117,775)	(10,083,009)	(16,386,136)	(20,546,541)	(23,895,696)	(25,786,928)
20.	Deferred True-up - Over/(Under) Recovery	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	593,148	593,148	593,148	593,148	593,148	593,148
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (6,777,321)	$ (13,080,448)	$ (17,240,853)	$ (20,590,008)	$ (22,481,240)	$ (25,705,672)

Notes:
(a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 9, 2005.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE ESTIMATED/ACTUAL PERIOD JANUARY THROUGH DECEMBER 2005

LINE NO.		(7) ACTUAL JUL 2006	(8) ESTIMATED AUG 2006	(9) ESTIMATED SEP 2006	(10) ESTIMATED OCT 2006	(11) ESTIMATED NOV 2006	(12) ESTIMATED DEC 2006	(13) TOTAL	LINE NO.
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,684,681	$16,047,667	$16,047,667	$16,047,667	$16,047,667	$16,047,667	$196,133,840	1.
2.	Short Term Capacity Purchases CCR	13,796,520	13,477,050	7,844,530	3,481,572	3,776,072	5,910,820	87,579,598	2.
3.	QF Capacity Charges	26,187,808	25,681,825	25,681,825	25,681,825	25,681,825	25,681,825	309,472,210	3.
4a.	SJRPP Suspension Accrual	354,568	354,568	354,568	354,568	354,568	354,568	4,254,816	4a.
4b.	Return on SJRPP Suspension Liability	(413,463)	(416,939)	(420,415)	(423,892)	(427,368)	(430,845)	(4,940,692)	4b.
5.	Okeelanta Settlement (Capacity)	3,001,083	2,984,623	2,972,392	2,960,161	2,947,930	2,935,699	36,000,942	6b.
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	2,172,622	2,180,424	2,172,833	2,188,015	2,233,559	2,218,378	26,861,570	6c.
7.	Transmission of Electricity by Others	942,138	909,146	952,552	579,277	603,722	566,505	8,936,181	7.
8.	Transmission Revenues from Capacity Sales	(158,354)	(235,912)	(69,098)	(112,758)	(311,226)	(779,049)	(3,688,689)	8.
9.	Total (Lines 1 through 8)	$ 62,567,605	$ 60,982,452	$ 55,536,854	$ 50,756,435	$ 50,906,749	$ 52,505,568	$ 660,609,775	9.
10.	Jurisdictional Separation Factor (a)	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	N/A	10.
11.	Jurisdictional Capacity Charges	61,705,574	60,142,260	54,771,690	50,057,133	50,205,376	51,782,167	651,508,158	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 56,960,108	$ 55,396,794	$ 50,026,224	$ 45,311,667	$ 45,459,910	$ 47,036,701	$ 594,562,566	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 55,273,079	$ 56,705,872	$ 55,166,973	$ 53,280,233	$ 44,121,091	$ 46,985,330	$ 584,394,648	14.
15.	Prior Period True-up Provision	(593,148)	(593,148)	(593,148)	(593,148)	(593,148)	(593,144)	(7,117,772)	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 54,679,931	$ 56,112,724	$ 54,573,825	$ 52,687,085	$ 43,527,943	$ 46,392,186	$ 577,276,876	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(2,280,177)	715,930	4,547,601	7,375,418	(1,931,967)	(644,515)	(17,285,690)	17.
18.	Interest Provision for Month	(117,812)	(119,173)	(104,699)	(76,265)	(61,989)	(65,326)	(929,756)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(29,011,360)	(30,816,200)	(29,626,295)	(24,590,245)	(16,697,945)	(18,098,752)	(7,117,775)	19.
20.	Deferred True-up - Over/(Under) Recovery	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	3,305,688	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	593,148	593,148	593,148	593,148	593,148	593,147	7,117,775	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (27,510,512)	$ (26,320,607)	$ (21,284,557)	$ (13,392,257)	$ (14,793,064)	$ (14,909,759)	$ (14,909,759)	22.

Notes: Notes:

(a) Per K. M. Dubin's Testimony Appen (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 9, 2005.

(b) Per FPSC Order No. PSC-94-1092-I (b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, f Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2007 THROUGH DECEMBER 2007

Rate Schedule	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1/RST1	61.793%	57,179,067,367	10,563,156	1.09570432	1.07456355	61,442,541,616	11,574,096	53.16632%	59.30190%
GS1/GST1	66.413%	6,316,475,854	1,085,719	1.09570432	1.07456355	6,787,454,717	1,189,627	5.87319%	6.09526%
GSD1/GSDT1/HLTF(21-499 kW)	79.105%	24,498,272,505	3,535,309	1.09561301	1.07449290	26,323,219,869	3,873,331	22.77752%	19.84569%
OS2	106.320%	19,483,307	2,092	1.06073265	1.04795283	20,417,587	2,219	0.01767%	0.01137%
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 kW)	76.791%	11,427,338,776	1,698,755	1.09405261	1.07330852	12,265,060,069	1,858,527	10.61297%	9.52249%
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ kW)	89.753%	1,942,208,130	247,026	1.08669203	1.06788421	2,074,053,394	268,441	1.79468%	1.37540%
GSLD3/GSLDT3/CS3/CST3	90.772%	241,266,419	30,342	1.03182865	1.02576275	247,482,106	31,308	0.21415%	0.16041%
ISST1D	81.269%	0	0	1.09570432	1.07456355	0	0	0.00000%	0.00000%
ISST1T	210.328%	0	0	1.03182865	1.02576275	0	0	0.00000%	0.00000%
SST1T	210.328%	107,481,831	5,834	1.03182865	1.02576275	110,250,858	6,020	0.09540%	0.03084%
SST1D1/SST1D2/SST1D3	81.269%	11,250,053	1,580	1.07508322	1.06930736	12,029,764	1,699	0.01041%	0.00871%
CILC D/CILC G	92.614%	3,576,500,862	440,837	1.08368374	1.06553660	3,810,892,569	477,728	3.29757%	2.44772%
CILC T	96.744%	1,633,058,243	192,696	1.03182865	1.02576275	1,675,130,315	198,829	1.44949%	1.01874%
MET	70.341%	99,513,255	16,150	1.06073265	1.04795283	104,285,197	17,131	0.09024%	0.08777%
OL1/SL1/PL1	696.444%	583,398,330	9,563	1.09570432	1.07456355	626,898,580	10,478	0.54246%	0.05369%
SL2, GSCU1	99.794%	62,308,069	7,127	1.09570432	1.07456355	66,953,980	7,809	0.05794%	0.04001%
TOTAL		107,697,623,000	17,836,186			115,566,670,621	19,517,243	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2007 through December 2007.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2005 demand losses.
(5) Based on 2005 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2007 THROUGH DECEMBER 2007

Rate Schedule	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1/RST1	53.16632%	59.30190%	$22,151,400	$296,493,017	$318,644,417	57,179,067,367	-	-	-	0.00557
GS1/GST1	5.87319%	6.09526%	$2,447,028	$30,474,613	$32,921,641	6,316,475,854	-	-	-	0.00521
GSD1/GSDT1/HLTF(21-499 kW)	22.77752%	19.84569%	$9,490,105	$99,222,919	$108,713,024	24,498,272,505	48.77603%	68,802,806	1.58	-
OS2	0.01767%	0.01137%	$7,361	$56,844	$64,205	19,483,307	-	-	-	0.00330
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 kW)	10.61297%	9.52249%	$4,421,826	$47,609,790	$52,031,616	11,427,338,776	58.89580%	26,578,956	1.96	-
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ kW)	1.79468%	1.37540%	$747,742	$6,876,639	$7,624,381	1,942,208,130	66.75988%	3,985,266	1.91	-
GSLD3/GSLDT3/CS3/CST3	0.21415%	0.16041%	$89,223	$802,015	$891,238	241,266,419	70.44910%	469,136	1.90	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
ISST1T	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
SST1T	0.09540%	0.03084%	$39,748	$154,214	$193,962	107,481,831	12.69501%	1,159,789	**	-
SST1D1/SST1D2/SST1D3	0.01041%	0.00871%	$4,337	$43,523	$47,860	11,250,053	58.59008%	26,303	**	-
CILC D/CILC G	3.29757%	2.44772%	$1,373,911	$12,237,933	$13,611,844	3,576,500,862	75.31837%	6,504,809	2.09	-
CILC T	1.44949%	1.01874%	$603,922	$5,093,392	$5,697,314	1,633,058,243	78.91615%	2,834,738	2.01	-
MET	0.09024%	0.08777%	$37,597	$438,844	$476,441	99,513,255	57.23052%	238,194	2.00	-
OL1/SL1/PL1	0.54246%	0.05369%	$226,011	$268,414	$494,425	583,398,330	-	-	-	0.00085
SL2, GSCU1	0.05794%	0.04001%	$24,138	$200,043	$224,181	62,308,069	-	-	-	0.00360
TOTAL			$41,664,349	$499,972,203	$541,636,552	107,697,623,000		110,599,997		

Note:There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period January 2007 through December 2007
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730)
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding.

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.25	$0.12
ISST1T	$0.24	$0.11
SST1T	$0.24	$0.11
SST1D1/SST1D2/SST1D3	$0.25	$0.12

Florida Power & Light Company
Schedule E12 - Capacity Costs

Projected 2007

Contract	Capacity MW	Term Start	Term End	Contract Type
Cedar Bay	250	1/25/1994	12/31/2024	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Palm Beach Solid Waste Authority	47.5	4/1/1992	3/31/2010	QF
Broward North - 1987 Agreement	45	4/1/1992	12/31/2010	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1987 Agreement	50.6	4/1/1991	8/1/2009	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
Southern Co. - UPS	930	7/20/1988	5/31/2010	UPS
JEA - SJRPP	381	4/2/1982	9/30/2021	JEA

QF = Qualifying Facility
UPS= Unit Power Sales Agreement with Southern Company
JEA = SJRPP Purchased Power Agreements

2007 Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	9,751,529	117,018,350
ICL	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	10,397,388	124,768,653
SWAPBC	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	1,966,144	23,593,725
BN-SOC	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	1,816,538	21,798,450
BN-NEG	281,930	281,930	281,930	281,930	281,930	281,930	281,930	281,930	281,930	281,930	281,930	281,930	3,383,160
BS-SOC	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	2,042,583	24,510,994
BS-NEG	89,705	89,705	89,705	89,705	89,705	89,705	89,705	89,705	89,705	89,705	89,705	89,705	1,076,460
SoCo	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	10,294,309	123,531,703
SJRPP	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	5,971,165	71,653,975
Total	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	42,611,289	511,335,469

Florida Power & Light Company
Docket No. 060001-EI
Schedule E12
Page 2 of 2

Contract	Counterparty	Identification	Contract End Date
1	Southern Power Company (Desoto)	Other Entity	May 31, 2007
2	Reliant Energy Services (Shady Hills)	Other Entity	February 28, 2007
3	Southern Power Company (Oleander)	Other Entity	May 31, 2012
4	Reliant Energy Services (Indian River)	Other Entity	December 31, 2009
5	Williams Power Company	Other Entity	December 31, 2009
6	Progress Ventures, Inc.	Other Entity	April 30, 2009

Capacity in MW

Contract	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
1	373	373	373	322	322	-	-	-	-	-	-	-
2	468	468	-	-	-	-	-	-	-	-	-	-
3	156	156	156	156	156	158	158	158	158	158	158	158
4	576	576	576	576	576	576	576	576	576	576	576	576
5	106	106	106	106	106	106	106	106	106	106	106	106
6	105	105	105	105	105	105	105	105	105	105	105	105
Total	1,784	1,784	1,316	1,265	1,265	945	945	945	945	945	945	945

Capacity in Dollars

Contract	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
1	[redacted]											
2												
3												
4												
5												
6												
Total	6,287,300	6,287,300	3,514,572	3,419,712	3,619,352	4,545,090	4,545,090	4,545,090	4,545,090	3,585,714	3,585,714	3,919,410

Total Short Term Capacity Payments for 2007	52,399,434	(1)

(1) September 1, 2006 Projection Filing, Appendix III, page 3, line 2

APPENDIX IV

FUEL COST RECOVERY – NON-LEVELIZED BILL

E SCHEDULES

KMD-7
DOCKET NO. 060001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT ________
PAGES 1-8
SEPTEMBER 1, 2006

APPENDIX IV

**FUEL COST RECOVERY –
NON-LEVELIZED BILL**

**E SCHEDULES
January 2007 – December 2007**

TABLE OF CONTENTS

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2007 - DECEMBER 2007

		(a)		(b)	(c)
		DOLLARS		MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$6,035,202,342		100,510,348	6.0046
1a	Adjustment for fuel savings due to TP5	0			0.0000
2	Nuclear Fuel Disposal Costs (E2)	21,188,807		22,754,302	0.0931
3	Fuel Related Transactions (E2)	3,265,273		0	0.0000
3a	Incremental Hedging Costs (E2)	570,098		0	
4	Fuel Cost of Sales to FKEC / CKW (E2)	(67,227,136)		(1,006,871)	6.6768
5	TOTAL COST OF GENERATED POWER	$5,992,999,384		99,503,477	6.0229
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	246,819,107		12,025,486	2.0525
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	42,901,485		557,411	7.6966
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	90,439,427		1,170,268	7.7281
9		0		0	0.0000
10		0		0	0.0000
11	Okeelanta/Osceola Settlement (E2)	$0		0	0.0000
12	Payments to Qualifying Facilities (E8)	172,870,000		5,951,033	2.9049
13	TOTAL COST OF PURCHASED POWER	$553,030,019		19,704,198	2.8067
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			119,207,675	
15	*Fuel Cost of Economy Sales (E6)*	(145,972,243)		(1,930,909)	7.5598
16	Gain on Economy Sales (E6A)	0		0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,380,200)		(83,738)	1.6482
18	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
18a	Revenues from Off-System Sales	(19,197,960)		(2,014,647)	0.9529
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($166,550,403)		(2,014,647)	8.2670
19a	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$6,379,479,000		117,193,028	5.4436
21	Net Unbilled Sales	56,118,214	**	1,030,909	0.0519
22	Company Use	19,138,437	**	351,579	0.0177
23	T & D Losses	414,666,135	**	7,617,547	0.3833
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$6,379,479,000		108,192,993	5.8964
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$29,209,082		495,370	5.8964
26	Jurisdictional MWH Sales	$6,350,269,918		107,697,623	5.8964
27	Jurisdictional Loss Multiplier	-		-	1.00054
28	Jurisdictional MWH Sales Adjusted for Line Losses	$6,353,699,064		107,697,623	5.8996
29	FINAL TRUE-UP JAN 05 - DEC 05 $307,437,600 underrecovery; EST/ACT TRUE-UP JAN 06 - DEC 06 $230,603,338 overrecovery	76,834,262		107,697,623	0.0713
30	TOTAL JURISDICTIONAL FUEL COST	$6,430,533,326		107,697,623	5.9709
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes	6,435,163,310			5.9752
33	GPIF ***	$8,478,098		107,697,623	0.0079
34	Fuel Factor including GPIF (Line 32 + Line 33)	6,443,641,408		107,697,623	5.9831
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				5.983

** For Informational Purposes Only

*** *Calculation Based on Jurisdictional KWH Sales*

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2007 - DECEMBER 2007

	NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK	30.93	34.47
OFF PEAK	69.07	65.53
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$6,379,479,000	$2,199,006,411	$4,180,472,589
2	MWH SALES	108,192,993	33,464,093	74,728,900
3	COST PER KWH SOLD	5.8964	6.5712	5.5942
4	JURISDICTIONAL LOSS FACTOR	1.00054	1.00054	1.00054
5	JURISDICTIONAL FUEL FACTOR	5.8996	6.5748	5.5972
6	TRUE-UP	0.0713	0.0713	0.0713
7				
8	TOTAL	5.9709	6.6461	5.6685
9	REVENUE TAX FACTOR	1.00072	1.00072	1.00072
10	RECOVERY FACTOR	5.9752	6.6509	5.6726
11	GPIF	0.0079	0.0079	0.0079
11A				
12	RECOVERY FACTOR including GPIF	5.9831	6.6588	5.6805
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	5.983	6.659	5.681

HOURS:	ON-PEAK	24.73 %
	OFF-PEAK	75.27 %

FLORIDA POWER & LIGHT COMPANY

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

JANUARY 2007 - DECEMBER 2007

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1 first 1,000 kWh		5.983	1.00194	5.641
	all additional kWh		5.983	1.00194	6.641
A	GS-1, SL-2, GSCU-1		5.983	1.00194	5.995
A-1*	SL-1, OL-1, PL-1		5.837	1.00194	5.848
B	GSD-1		5.983	1.00187	5.994
C	GSLD-1 & CS-1		5.983	1.00077	5.988
D	GSLD-2, CS-2, OS-2 & MET		5.983	0.99464	5.951
E	GSLD-3 & CS-3		5.983	0.95644	5.722
A	RST-1, GST-1	ON-PEAK	6.659	1.00194	6.672
		OFF-PEAK	5.681	1.00194	5.692
B	GSDT-1, CILC-1(G),	ON-PEAK	6.659	1.00187	6.671
	HLFT (21-499 kW)	OFF-PEAK	5.681	1.00187	5.691
C	GSLDT-1, CST-1,	ON-PEAK	6.659	1.00077	6.664
	HLFT (500-1,999 kW)	OFF-PEAK	5.681	1.00077	5.685
D	GSLDT-2, CST-2,	ON-PEAK	6.659	0.99571	6.630
	HLFT (2,000+)	OFF-PEAK	5.681	0.99571	5.656
E	GSLDT-3,CST-3,	ON-PEAK	6.659	0.95644	6.369
	CILC -1(T)	OFF-PEAK	5.681	0.95644	5.433
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	6.659	0.99298	6.612
	ISST-1(D)	OFF-PEAK	5.681	0.99298	5.641

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$410,009,339	$382,021,424	$419,563,868	$465,948,288	$518,657,274	$547,707,147	$2,743,907,340	A1
1a	NUCLEAR FUEL DISPOSAL	2,035,188	1,838,234	2,035,188	1,391,057	1,875,581	1,921,233	11,096,481	1a
1b	COAL CAR INVESTMENT	282,966	280,992	279,017	277,043	275,068	273,093	1,668,179	1b
1c	NUCLEAR SLEEVING	0	0	0	0	0	0	0	1c
1d	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1d
1e	INCREMENTAL HEDGING COSTS	43,967	43,967	44,658	62,450	44,658	44,658	284,358	1e
2	FUEL COST OF POWER SOLD	(22,462,215)	(18,191,330)	(16,104,155)	(11,742,670)	(6,524,801)	(7,665,658)	(82,690,829)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(3,562,601)	(2,460,808)	(1,759,868)	(1,154,571)	(794,342)	(657,886)	(10,390,076)	2a
3	FUEL COST OF PURCHASED POWER	18,701,324	15,733,000	16,061,300	21,844,883	21,914,950	20,234,012	114,489,469	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	0	0	0	0	0	0	0	3b
3c	QUALIFYING FACILITIES	15,469,000	14,209,000	15,277,000	8,786,000	14,412,000	15,286,000	83,439,000	3c
4	ENERGY COST OF ECONOMY PURCHASES	6,055,781	6,487,952	8,689,396	10,364,270	15,008,245	8,505,366	55,111,010	4
4a	FUEL COST OF SALES TO FKEC / CKW	(4,905,120)	(4,902,312)	(4,809,096)	(5,237,849)	(5,445,445)	(5,783,586)	(31,083,408)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$421,667,629	$395,060,119	$439,277,308	$490,538,901	$559,423,188	$579,864,379	$2,885,831,524	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,521,049	7,794,503	7,884,492	7,796,021	8,497,229	9,661,031	50,154,325	6
7	COST PER KWH SOLD (¢/KWH)	4.9485	5.0684	5.5714	6.2922	6.5836	6.0021	5.7539	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	7a
7b	JURISDICTIONAL COST (¢/KWH)	4.9512	5.0712	5.5744	6.2956	6.5872	6.0053	5.7570	7b
9	TRUE-UP (¢/KWH)	0.0755	0.0826	0.0817	0.0826	0.0758	0.0666	0.0770	9
10	TOTAL	5.0267	5.1538	5.6561	6.3782	6.6630	6.0719	5.8340	10
11	REVENUE TAX FACTOR 0.00072	0.0036	0.0037	0.0041	0.0046	0.0048	0.0044	0.0042	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	5.0303	5.1575	5.6602	6.3828	6.6678	6.0763	5.8382	12
13	GPIF (¢/KWH)	0.0083	0.0091	0.0090	0.0091	0.0084	0.0073	0.0085	13
14	RECOVERY FACTOR including GPIF	5.0386	5.1666	5.6692	6.3919	6.6762	6.0836	5.8467	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	5.039	5.167	5.669	6.392	6.676	6.084	5.847	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2007 - DECEMBER 2007

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$624,312,849	$611,170,268	$594,681,887	$549,021,467	$426,827,738	$485,280,793	$6,035,202,342	A1
1a	NUCLEAR FUEL DISPOSAL	1,985,276	1,985,276	1,468,214	1,502,983	1,495,010	1,655,567	$21,188,807	1a
1b	COAL CAR INVESTMENT	271,119	269,144	267,170	265,195	263,220	261,246	$3,265,273	1b
1c	NUCLEAR SLEEVING	0	0	0	0	0	0	$0	1c
1d	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	$0 $0	1d
1e	INCREMENTAL HEDGING COSTS	44,658	44,658	44,658	62,450	44,658	44,658	$570,098	1e
2	FUEL COST OF POWER SOLD	(6,760,763)	(8,819,878)	(2,912,343)	(4,502,294)	(11,288,800)	(30,377,536)	($147,352,443)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(671,043)	(1,057,241)	(346,946)	(467,277)	(1,267,006)	(4,998,371)	($19,197,960)	2a
3	FUEL COST OF PURCHASED POWER	22,048,982	21,316,448	23,629,133	23,296,893	22,365,782	19,672,400	$246,819,107	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	0	0	0	0	0	0	$0	3b
3c	QUALIFYING FACILITIES	15,875,000	15,803,000	15,593,000	12,682,000	13,758,000	15,720,000	$172,870,000	3c
4	ENERGY COST OF ECONOMY PURCHASES	9,974,528	8,563,248	11,195,847	22,733,292	17,159,236	8,603,752	$133,340,912	4
4a	FUEL COST OF SALES TO FKEC / CKW	(6,135,492)	(6,381,854)	(6,501,714)	(6,243,297)	(5,750,367)	(5,131,003)	($67,227,136)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$660,945,114	$642,893,069	$637,118,906	$598,351,412	$463,607,471	$490,731,506	$6,379,479,000	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	10,312,762	10,381,920	10,314,403	9,690,394	8,658,475	8,680,716	108,192,995	6
7	COST PER KWH SOLD (¢/KWH)	6.4090	6.1924	6.1770	6.1747	5.3544	5.6531	5.8964	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	1.00054	7a
7b	JURISDICTIONAL COST (¢/KWH)	6.4125	6.1958	6.1803	6.1780	5.3573	5.6562	5.8996	7b
9	TRUE-UP (¢/KWH)	0.0623	0.0620	0.0623	0.0664	0.0744	0.0738	0.0713	9
10	TOTAL	6.4748	6.2578	6.2426	6.2444	5.4317	5.7300	5.9709	10
11	REVENUE TAX FACTOR 0.00072	0.0047	0.0045	0.0045	0.0045	0.0039	0.0041	0.0043	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	6.4795	6.2623	6.2471	6.2489	5.4356	5.7341	5.9752	12
13	GPIF (¢/KWH)	0.0069	0.0068	0.0069	0.0073	0.0082	0.0081	0.0079	13
14	RECOVERY FACTOR including GPIF	6.4864	6.2691	6.2540	6.2562	5.4438	5.7422	5.9831	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	6.486	6.269	6.254	6.256	5.444	5.742	5.983	15

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	JAN 06 - DEC 06	JAN 07 - APR 07	DIFFERENCE $	DIFFERENCE %	MAY 07 - DEC 07	DIFFERENCE $	DIFFERENCE %
BASE	$38.12	$38.12	$0.00	0.00%	$39.37	$1.25	3.28%
FUEL	$58.41	$56.41	($2.00)	-3.42%	$56.41	$0.00	0.00%
CONSERVATION	$1.42	$1.69	$0.27	19.01%	$1.69	$0.00	0.00%
CAPACITY PAYMENT	$6.03	$5.57	($0.46)	-7.63%	$5.57	$0.00	0.00%
ENVIRONMENTAL	$0.26	$0.24	($0.02)	-7.69%	$0.24	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.65	$1.10 *	($0.55)	-33.33%	$1.10 *	$0.00	0.00%
SUBTOTAL	$105.89	$103.13	($2.21)	-2.09%	$104.38	$1.25	1.21%
GROSS RECEIPTS TAX	$2.72	$2.64	($0.08)	-2.94%	$2.68	$0.04	1.52%
TOTAL	**$108.61**	**$105.77**	**($2.84)**	**-2.61%**	**$107.06**	**$1.29**	**1.22%**

* Preliminary estimate subject to market conditions.