BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

DOCKET NO. 100001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
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PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN ART GRAHAM COMMISSIONER LISA POLAK EDGAR COMMISSIONER RONALD A. BRISÉ COMMISSIONER EDUARDO E. BALBIS COMMISSIONER JULIE I. BROWN
DATE:	Wednesday, January 26, 2011
TIME:	Commenced at 1:30 p.m. Concluded at 1:42 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

APPEARANCES:

JOHN T. BUTLER, ESQUIRE, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

CECILIA BRADLEY, ESQUIRE, Senior Assistant Attorney General, Office of Attorney General, The Capitol - PL01, Tallahassee, Florida 32399-1050, appearing on behalf of the Office of the Citizens of the State of Florida.

CHARLIE BECK, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison St., Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of Florida.

KATHERINE FLEMING, ESQUIRE and ERIK SAYLER, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

MARY ANNE HELTON, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1-23; 25-47	(Descriptions of all exhibits contained in the Comprehensive Exhibit List, Exhibit 1; Exhibit 24 withdrawn.)	8	8

P R O C E E D I N G S

CHAIRMAN GRAHAM: Let the record show that it is January 26th, and not the 12th. This is a fuel clause hearing, and we are taking up Docket Number 100001, Docket 100002, and Docket 100007. So we will call this meeting to order.

I guess that gavel means that it's official and everything I say now is going to follow me forever. I guess we will request the staff to read the notice.

MS. FLEMING: Pursuant to notice issued by the Commission Clerk, this time and place has been set for a hearing for the FPL portion of the following dockets: 100001-EI, 100002-EG, and 100007-EI.

CHAIRMAN GRAHAM: What about appearances?

MR. BUTLER: John Butler appearing on behalf of Florida Power and Light Company in all three of the dockets.

MS. BRADLEY: Cecilia Bradley, Office of the Attorney General, appearing in the 100001 docket.

MR. BECK: Charlie Beck, Office of Public Counsel, appearing on behalf of the Citizens of Florida in all three dockets.

CHAIRMAN GRAHAM: All right. Staff, are we at the point where we're ready to open Docket Number 01?

MS. BROWN: Mr. Chairman, I'm Martha Carter

Brown appearing on behalf of the Commission staff in the 07 docket.

MS. TAN: And I'm Lee Eng Tan on behalf of Commission staff appearing in the 02 docket.

MS. FLEMING: Katherine Fleming appearing in the 01 and 02 docket. I would also like to enter an appearance for Erik Sayler in the 01 docket.

MS. HELTON: And Mary Anne Helton, I'm here to advise you in all the dockets.

CHAIRMAN GRAHAM: Are you to keep me out of trouble?

MS. HELTON: That's my goal, Mr. Chairman.

CHAIRMAN GRAHAM: Good luck with that.

Okay. Then we are now ready to open the 01 docket. We will do that. Staff, are there any preliminary matters to this docket that need to be addressed?

MS. FLEMING: Chairman, Commissioners, I'm not aware of any preliminary matters. We would note for the record that the parties are proposing stipulation of all issues. We would also note for the record that FIPUG, the Florida Retail Federation, the Association for Fairness in Ratemaking, and the Federal Executive Agencies have been excused from the hearing. And Staff will also note that all witnesses have been excused from the hearing, as well.

CHAIRMAN GRAHAM: Sounds good.

Let's address the prefiled testimony.

MS. FLEMING: That being said, Commissioners, staff will ask that the prefiled testimony of all witnesses identified in Section VI of the Prehearing Order, which is contained on Page 4, be moved into the record as though read.

CHAIRMAN GRAHAM: Let it move into the record as though read. How about exhibits?

MS. FLEMING: Staff has compiled a stipulated Comprehensive Exhibit List which has been provided to all the parties, the court reporter, and the Commissioners. This exhibit list contains prefiled exhibits as well as staff composite exhibits.

The exhibit lists are identified as Exhibits 1 through 47. We ask that those exhibits be marked as contained on the list.

We would note for the record that Exhibit 24 has been withdrawn as it relates to the recovery of costs that have been spun out to a separate docket. So at this time staff would ask that Exhibits 1 through 23 and 25 through 47 be moved into the record.

CHAIRMAN GRAHAM: Let the record show that we are moving Exhibits 1 through 23 and 25 through 47 moved into the record.

(Exhibits 1 through 23 and 25 through 47 marked for identification and admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 100001-EI

APRIL 1, 2010

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 Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in the predecessors to this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present data on FPL's hedging activities, by month, for calendar year 2009. This data is required per Item 5 of the Resolution of Issues in Docket 011605-EI approved by the Commission per Order No. PSC-02-1484-FOF-EI, which states:

"5. Each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost recovery docket, the following information: (1) the volumes of each fuel the utility actually hedged using a fixed price contract or instrument; (2) the types of hedging instruments the utility used, and the volume and type of fuel associated with each type of instrument; (3) the average period of each hedge; and (4) the actual total cost (e.g. fees, commissions, options premiums, futures gains and losses, swaps settlements) associated with using each type of hedging instrument."

The requirement for this data was further clarified in Section III of the Hedging Order Clarification Guidelines that was approved by the Commission per Order No. PSC-08-0667-PAA-EI issued on October 8, 2008.

Q. Are you sponsoring an Exhibit for this proceeding?

A. Yes. I am sponsoring Exhibit GJY-1 -- 2009 Hedging Activity Final True-Up Report.

Q. Please describe FPL's hedging objectives.

A. Consistent with the guiding principles described in Section IV of the Hedging Order Clarification Guidelines, the primary objective of FPL's hedging program is to reduce the impact of fuel price volatility in the fuel adjustment charges paid by FPL's customers. FPL does not execute speculative hedging strategies aimed at "out guessing" the market in the hopes of potentially returning savings to FPL's customers. FPL has implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL's 2009 Risk Management Plan that was approved by the Commission in Order No. PSC-08-0824-FOF-EI, issued on December 22, 2008.

Q. Please summarize FPL's 2009 hedging activities.

A. Consistent with its approved 2009 Risk Management Plan, FPL hedged its fuel portfolio for 2009 utilizing fixed price transactions. A fixed price transaction allows a buyer to lock in the price of a commodity for a set volume over a set period of time.

Actual 2009 natural gas and heavy oil fuel prices declined substantially from the forward prices that were in effect when FPL was executing its hedges for 2009. As would be expected under the approved hedging approach, this large decline in natural gas and heavy oil prices resulted in reported hedging losses for the year, as shown on Exhibit GJY-1. It is important to recognize that those large declines in fuel prices resulted in FPL customers paying significantly lower overall fuel costs for 2009. This was evidenced by the 2009 net over-recovery of approximately $365 million that was returned to customers as a one-time credit in January 2010. Conversely, if fuel prices had increased sharply after FPL executed its hedges, FPL's hedging results would have shown a substantial gain for the year but FPL customers would have ended up paying higher fuel costs.

Q. Does your Exhibit GJY-1 provide the detail on FPL's 2009 hedging activities required by Item 5 of the Resolution of Issues?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 100001-EI

SEPTEMBER 1, 2010

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 Senior 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 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. I also review the interim results of FPL's 2010 hedging program and its 2011 Risk Management Plan. Lastly, I present the projected fuel savings resulting from West County Energy Center Unit 3 (WCEC 3) coming into commercial service on its projected in-service date of June 1, 2011.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-4: Appendix I
- Schedules E2 through E9 of Appendix II

FUEL PRICE FORECAST

Q. **What forecast methodologies has FPL used for the 2011 recovery period?**

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. 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 execute transactions for 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 curves 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 2, 2010 for its 2011 projection filing.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2011 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; (9) the terms of FPL's supply and fuel transportation contracts; and (10) domestic and global inventory.

With the global economy projected to continue its slow recovery from the recession, global demand for oil is expected to increase in 2011. Demand in 2011 is forecasted to be 1.8% above projected 2010 demand and 4.4% above actual 2009 demand. Consistent with this trend, crude oil and refined petroleum product prices, like heavy and light fuel oil, should continue to steadily rise over the 2010 to 2011 period. With non-OPEC production projected to be essentially the same over the 2009 through 2011 period, sufficient OPEC production capacity is expected to be available to meet this projected increase in demand and help moderate the price of oil. A greater-than-expected economic recovery resulting in higher-than-expected oil demand will put upward pressure on price. Conversely, a weaker-than-expected global economic recovery will put downward pressure on the price of oil.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2011 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 for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2011 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 for St. Johns' River Power Park (SJRPP) and Plant Scherer?

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal, delivered to the plants.

Q. Please provide FPL's projection for the dispatch cost of SJRPP and Plant Scherer for the January through December 2011 period.

A. FPL's projection for the system average dispatch cost of coal 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 2011 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.

Similar to oil, the major driver for natural gas prices during the remainder of 2010 and all of 2011 revolves around economic recovery and an associated increase in demand as well as domestic natural gas production, particularly from shale sources. Future prices reflect this expectation of economic recovery. Although natural gas prices fell dramatically in 2009 as demand dropped, particularly in the industrial sector, demand in 2010 is projected to be 2.3% over 2009 actual levels and 2011 is forecasted to be 0.6% over 2010. Although the number of working natural gas rigs is down almost 40% since August 2008, domestic production from unconventional sources has and is projected to continue to create ample supply to meet the expected increases in demand. In addition, natural gas storage is projected to continue to be at historical high levels through the 2010 injection season.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2011 period?

A. The key factors are (1) the capacity of the Florida Gas Transmission (FGT) pipeline into Florida; (2) the capacity of the Gulfstream Natural Gas System (Gulfstream) pipeline into Florida; (3) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; and (4) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is approximately 2,300,000 MMBtu/day and the current capacity of Gulfstream is approximately 1,100,000 MMBtu/day. In the spring of 2011, FGT's total capacity into the State of Florida will increase by approximately 820,000 MMBtu/day as its Phase VIII expansion is expected to be completed and put into service. FPL has acquired 400,000 MMBtu/day of additional firm natural gas transportation on FGT as part of this expansion. After the completion of the Phase VIII expansion, FPL's total transportation capacity on FGT will range from 1,150,000 to 1,274,000 MMBtu/day, depending on the month. In an effort to support the acquisition of this additional transportation capacity, FPL recently entered into a five-year agreement for 200,000 MMBtu/day of firm transportation capacity on the Transcontinental Pipe Line Gas Company, LLC (Transco) Zone 4A lateral. This firm transportation capacity will give FPL access to shale gas supply at Transco's Station 85, which will further diversify FPL's portfolio and help enhance the reliability of supply with additional on-shore sources. FPL will be able to deliver gas into FGT or Gulfstream via the Transco Zone 4A lateral. Additional upstream opportunities to support the remaining 200,000 MMBtu/day are currently being evaluated. FPL's firm transportation capacity on Gulfstream will remain at 695,000 MMBtu/day during the 2011 period. Additionally, FPL has 500,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline.

The firm transportation on the SESH and Transco pipelines does not increase transportation capacity into the state, but FPL's firm transportation rights on these pipelines provide FPL access to 700,000 MMBtu/day of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2011 period, between 115,000 and 235,000 MMBtu/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.

Q. **Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2011 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.

<u>PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY</u>

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

A. The projected Average Net 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 2011?

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 2011.

Q. Please describe the significant planned outages for the January through December 2011 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 2 is scheduled to be out of service from January 3, 2011 until March 26, 2011 or 82 days during the period. Turkey Point Unit 4 is scheduled to be out of service from March 19, 2011 until May 13, 2011 or 55 days during the period. St. Lucie Unit 1 is scheduled to be out of service from August 29, 2011 until December 17, 2011 or 110 days during the period.

Q. Please list any changes to FPL's fossil generation capacity projected to take place during the January through December 2011 period.

A. FPL projects to put West County Energy Center Unit 3 into commercial operation on June 1, 2011. This unit will add an additional 1,219 MW of summer capacity and 1,335 MW of winter capacity.

<u>WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS</u>

Q. **Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2011?**

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 on purchases and gains on sales are credited to customers 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. Additionally, FPL is a member of the Florida Cost-Based Broker System (FCBBS). The FCBBS matches hourly cost-based bids and offers to maximize savings for all participants. Currently, the FCBBS is comprised of 11 members, including FPL. 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. **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 873,500 MWh of wholesale (off-system) power sales for the period of January through December 2011. The projected fuel cost related to these sales is $40,232,035. The projected transaction revenue from these sales is $52,336,135. The projected gain for these sales is $9,692,706.

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 costs of wholesale (off-system) power purchases for the January to December 2011 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 1,400,595 MWh at a cost of $79,718,309. If FPL generated this energy, FPL estimates that it would cost $106,875,924. Therefore, these purchases are projected to result in savings of $27,157,615.

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

A. Yes. FPL purchases energy under three Unit Power Sales Agreements (UPS) with the Southern Companies. The agreements are comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 165 MW of coal generation (Scherer Unit 3). The UPS agreements have a term that runs through December 31, 2015. Additionally, FPL has a capacity agreement for 2011 with Southern Power Company (Oleander) for the output of one combustion turbine totaling 155 MW. The Southern Power Company (Oleander) agreement expires on May 31, 2012. FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units. 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 2011 period.

A. UPS energy purchases for the period are projected to be 3,106,196 MWh at an energy cost of $128,521,619. The UPS energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of SJRPP are projected to be 2,931,727 MWh for the period at an energy cost of $90,728,000. 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 352,982 MWh at a cost of $2,102,300. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 13,197 MWh from its capacity agreement with Southern Power Company (Oleander) at a cost of $1,084,274. 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 4,073,261 MWh at a cost of $153,332,683.

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 378,619 MWh of energy at a cost of $2,446,761. These projections are shown on Schedule E6 of Appendix II.

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.

HEDGING/ RISK MANAGEMENT PLAN

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program has been, and remains, the reduction of fuel price volatility. Reducing fuel price volatility helps deliver greater price certainty to FPL's customers.

FPL does not engage in speculative hedging strategies aimed at "out guessing" the market.

Q. Has FPL filed a comprehensive risk management plan for 2011, consistent with the Hedging Order Clarification Guidelines as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2011 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Estimated/Actual True/Up filing on August 2, 2010.

Q. Please provide an overview of FPL's 2011 Risk Management Plan.

A. FPL's 2011 Risk Management Plan remains consistent with FPL's overall objectives that I previously described. It addresses Items 1-9 and 13-15 of Exhibit TFB-4, which is required per the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOF-EI dated October 30, 2002. FPL's 2011 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2011 for its projected fuel requirements in 2012. FPL plans to hedge the percentages of its 2012 projected natural gas and heavy oil requirements over the time periods in 2011 that are described in the plan.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2010, consistent with the Hedging Order Clarification Guidelines, as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2010 (January through July) on August 16, 2010.

Q. Have FPL's 2010 hedging strategies been successful in achieving its hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers. Additionally, FPL's customers have been able to benefit from the decrease in natural gas prices from the unhedged portion of FPL's portfolio. At the time FPL was placing its hedges for its 2010 projected natural gas and heavy oil requirements, market prices were significantly different than the actual settlement prices that occurred in 2010.

For example, at the beginning of January 2009, the average monthly NYMEX forward price for natural gas for the January through July 2010 time period was approximately $7.247 per MMBtu. At the end of July 2009, the average monthly NYMEX forward price for the January through July 2010 time period was approximately $5.673 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $4.698 per MMBtu or $2.549 per MMBtu lower than the prices seen in January and $0.975 per MMBtu lower than the prices seen in July. Conversely, heavy oil prices climbed steadily beginning in January 2009 and are currently at nearly twice the level seen in January 2009. As described in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for natural gas results in significant lost opportunities for savings in the fuel costs paid by customers; however, this lost opportunity is a reasonable trade-off for reducing customers' exposure to fuel price increases when market conditions change in the other direction. Conversely, hedging in the type of market conditions described above for heavy oil results in savings for customers; however, as previously stated, FPL's hedging objective is to reduce fuel price volatility and deliver greater price certainty.

Q. **Does FPL's projection filing include incremental operating and maintenance expenses with respect to maintaining an expanded, non-speculative financial and/or physical hedging program for the January through December 2011 period?**

A. No. These costs are now being recovered through base rates.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE ADDITION OF WCEC 3 (IMPLEMENTATION OF STIPULATION AND SETTLEMENT)

Q. **You stated earlier in this testimony that FPL is planning on putting WCEC 3 into operation on June 1, 2011. Will the addition of WCEC 3 result in fuel savings to FPL's customers?**

A. Yes. This unit's high efficiency will create substantial fuel savings for FPL's customers once it goes into operation. For the June through December, 2011 period, the addition of WCEC 3 will save FPL's customers $98,411,000.

Q. **How did FPL calculate the fuel savings associated with the addition of WCEC 3?**

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the addition of WCEC 3. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the WCEC 3 fuel savings. In order to calculate the WCEC 3 fuel savings, FPL ran two separate production cost simulations, one without WCEC 3 and one with WCEC 3. A comparison of the total system fuel costs from POWERSYM for the two simulations showed that the fuel costs were $98,411,000 lower in the case that included WCEC 3 than in the case without WCEC 3.

Q. In the Stipulation and Settlement that FPL and the Intervening parties in Docket No. 080677-EI filed for Commission approval on August 20, 2010, Paragraph 5(c) directs FPL to calculate the fuel savings associated with WCEC 3 as follows: "FPL shall quantify the projected fuel savings associated with the addition of West County Unit 3 through the use of the same computerized simulations of its system and current assumptions and data regarding unit performance, system load, and fuel costs that it employs to project its fuel costs in the fuel cost recovery proceeding to compare the total fuel costs that FPL would incur without the addition of West County Unit 3 to the total fuel costs it will incur with the addition of West County Unit 3." Is your calculation of $98,411,000 in WCEC 3 fuel savings consistent with Paragraph 5(c)?

A. Yes, it is.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF GERARD J. YUPP

DOCKET NO. 100001-EI

OCTOBER 1, 2010

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 Senior 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 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. I also review the interim results of FPL's 2010 hedging program and its 2011 Risk Management Plan. Lastly, I present the projected fuel savings resulting from West County Energy Center Unit 3 (WCEC 3) coming into commercial service on its projected in-service date of June 1, 2011.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-4: Appendix I
- Schedules E2 through E9 of Appendix II

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2011 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. 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 execute transactions for 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 curves 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 September 21, 2010 for its 2011 projection filing.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2011 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; (9) the terms of FPL's supply and fuel transportation contracts; and (10) domestic and global inventory.

With the global economy projected to continue its slow recovery from the recession, global demand for oil is expected to increase in 2011. Demand in 2011 is forecasted to be 2.0% above projected 2010 demand and 4.4% above actual 2009 demand. Consistent with this trend, crude oil and refined petroleum product prices, like heavy and light fuel oil, should continue to steadily rise over the 2010 to 2011 period. With non-OPEC production projected to be essentially the same over the 2010 through 2011 period, sufficient OPEC production capacity is expected to be available to meet this projected increase in demand and help moderate the price of oil. A greater-than-expected economic recovery resulting in higher-than-expected oil demand will put upward pressure on price. Conversely, a weaker-than-expected global economic recovery will put downward pressure on the price of oil.

Q. **Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2011 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 for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2011 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 for St. Johns' River Power Park (SJRPP) and Plant Scherer?

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal, delivered to the plants.

Q. Please provide FPL's projection for the dispatch cost of SJRPP and Plant Scherer for the January through December 2011 period.

A. FPL's projection for the system average dispatch cost of coal 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 2011 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.

Similar to oil, the major driver for natural gas prices during the remainder of 2010 and all of 2011 revolves around economic recovery and an associated increase in demand as well as domestic natural gas production, particularly from shale sources. Future prices reflect this expectation of economic recovery. Although natural gas prices fell dramatically in 2009 as demand dropped, particularly in the industrial sector, demand in 2010 is projected to be 3.8% over 2009 actual levels and 2011 is forecasted to be 0.3% over 2010. Although the number of working natural gas rigs is down almost 40% since August 2008, domestic production from unconventional sources has and is projected to continue to create ample supply to meet the expected increases in demand. In addition, natural gas storage is projected to continue to be at historical high levels through the 2010 injection season.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2011 period?

A. The key factors are (1) the capacity of the Florida Gas Transmission (FGT) pipeline into Florida; (2) the capacity of the Gulfstream Natural Gas System (Gulfstream) pipeline into Florida; (3) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; and (4) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is approximately 2,300,000 MMBtu/day and the current capacity of Gulfstream is approximately 1,100,000 MMBtu/day. In the spring of 2011, FGT's total capacity into the State of Florida will increase by approximately 820,000 MMBtu/day as its Phase VIII expansion is expected to be completed and put into service. FPL has acquired 400,000 MMBtu/day of additional firm natural gas transportation on FGT as part of this expansion. After the completion of the Phase VIII expansion, FPL's total transportation capacity on FGT will range from 1,150,000 to 1,274,000 MMBtu/day, depending on the month. In an effort to support the acquisition of this additional transportation capacity, FPL recently entered into a five-year agreement for 200,000 MMBtu/day of firm transportation capacity on the Transcontinental Pipe Line Gas Company, LLC (Transco) Zone 4A lateral. This firm transportation capacity will give FPL access to shale gas supply at Transco's Station 85, which will further diversify FPL's portfolio and help enhance the reliability of supply with additional on-shore sources. FPL will be able to deliver gas into FGT or Gulfstream via the Transco Zone 4A lateral. Additional upstream opportunities to support the remaining 200,000 MMBtu/day are currently being evaluated. FPL's firm transportation capacity on Gulfstream will remain at 695,000 MMBtu/day during the 2011 period. Additionally, FPL has 500,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline.

The firm transportation on the SESH and Transco pipelines does not increase transportation capacity into the state, but FPL's firm transportation rights on these pipelines provide FPL access to 700,000 MMBtu/day of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2011 period, between 115,000 and 235,000 MMBtu/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.

Q. **Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2011 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 Heat Rates shown on Schedule E4 of Appendix II.**

A. The projected Average Net Heat Rates were calculated by the POWRSYM (PMAREA) 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 2011?**

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 2011.

Q. Please describe the significant planned outages for the January through December 2011 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 2 is scheduled to be out of service from January 3, 2011 until March 26, 2011 or 82 days during the period. Turkey Point Unit 4 is scheduled to be out of service from March 19, 2011 until May 13, 2011 or 55 days during the period. St. Lucie Unit 1 is scheduled to be out of service from August 29, 2011 until December 17, 2011 or 110 days during the period.

Q. Please list any changes to FPL's fossil generation capacity projected to take place during the January through December 2011 period.

A. FPL projects to put West County Energy Center Unit 3 into commercial operation on June 1, 2011. This unit will add an additional 1,219 MW of summer capacity and 1,335 MW of winter capacity.

<u>WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS</u>

Q. **Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2011?**

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 on purchases and gains on sales are credited to customers 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. Additionally, FPL is a member of the Florida Cost-Based Broker System (FCBBS). The FCBBS matches hourly cost-based bids and offers to maximize savings for all participants. Currently, the FCBBS is comprised of 11 members, including FPL. 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. **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 873,500 MWh of wholesale (off-system) power sales for the period of January through December 2011. The projected fuel cost related to these sales is $36,505,360. The projected transaction revenue from these sales is $48,654,000. The projected gain for these sales is $9,737,246.

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 costs of wholesale (off-system) power purchases for the January to December 2011 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 1,400,595 MWh at a cost of $72,133,630. If FPL generated this energy, FPL estimates that it would cost $105,335,722. Therefore, these purchases are projected to result in savings of $33,202,092.

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

A. Yes. FPL purchases energy under three Unit Power Sales Agreements (UPS) with the Southern Companies. The agreements are comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 163 MW of coal generation (Scherer Unit 3). The UPS agreements have a term that runs through December 31, 2015. Additionally, FPL has a capacity agreement for 2011 with Southern Power Company (Oleander) for the output of one combustion turbine totaling 155 MW. The Southern Power Company (Oleander) agreement expires on May 31, 2012. FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units. 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 2011 period.**

A. UPS energy purchases for the period are projected to be 3,250,099 MWh at an energy cost of $125,687,163. The UPS energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of SJRPP are projected to be 2,976,884 MWh for the period at an energy cost of $92,080,000. 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 352,982 MWh at a cost of $2,102,300. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 13,197 MWh from its capacity agreement with Southern Power Company (Oleander) at a cost of $990,274. 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 3,553,780 MWh at a cost of $147,317,000.

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 378,619 MWh of energy at a cost of $2,446,761. These projections are shown on Schedule E6 of Appendix II.

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.

<u>HEDGING/ RISK MANAGEMENT PLAN</u>

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program has been, and remains, the reduction of fuel price volatility. Reducing fuel price volatility helps deliver greater price certainty to FPL's customers.

FPL does not engage in speculative hedging strategies aimed at "out guessing" the market.

Q. Has FPL filed a comprehensive risk management plan for 2011, consistent with the Hedging Order Clarification Guidelines as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2011 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Estimated/Actual True/Up filing on August 2, 2010.

Q. Please provide an overview of FPL's 2011 Risk Management Plan.

A. FPL's 2011 Risk Management Plan remains consistent with FPL's overall objectives that I previously described. It addresses Items 1-9 and 13-15 of Exhibit TFB-4, which is required per the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOF-EI dated October 30, 2002. FPL's 2011 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2011 for its projected fuel requirements in 2012. FPL plans to hedge the percentages of its 2012 projected natural gas and heavy oil requirements over the time periods in 2011 that are described in the plan.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2010, consistent with the Hedging Order Clarification Guidelines, as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2010 (January through July) on August 16, 2010.

Q. Have FPL's 2010 hedging strategies been successful in achieving its hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers. Additionally, FPL's customers have been able to benefit from the decrease in natural gas prices from the unhedged portion of FPL's portfolio. At the time FPL was placing its hedges for its 2010 projected natural gas and heavy oil requirements, market prices were significantly different than the actual settlement prices that occurred in 2010.

For example, at the beginning of January 2009, the average monthly NYMEX forward price for natural gas for the January through July 2010 time period was approximately $7.247 per MMBtu. At the end of July 2009, the average monthly NYMEX forward price for the January through July 2010 time period was approximately $5.673 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $4.698 per MMBtu or $2.549 per MMBtu lower than the prices seen in January and $0.975 per MMBtu lower than the prices seen in July. Conversely, heavy oil prices climbed steadily beginning in January 2009 and are currently at nearly twice the level seen in January 2009. As described in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for natural gas results in significant lost opportunities for savings in the fuel costs paid by customers; however, this lost opportunity is a reasonable trade-off for reducing customers' exposure to fuel price increases when market conditions change in the other direction. Conversely, hedging in the type of market conditions described above for heavy oil results in savings for customers; however, as previously stated, FPL's hedging objective is to reduce fuel price volatility and deliver greater price certainty.

Q. Does FPL's projection filing include incremental operating and maintenance expenses with respect to maintaining an expanded, non-speculative financial and/or physical hedging program for the January through December 2011 period?

A. No. These costs are now being recovered through base rates.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE ADDITION OF WCEC 3 (IMPLEMENTATION OF STIPULATION AND SETTLEMENT)

Q. You stated earlier in this testimony that FPL is planning on putting WCEC 3 into operation on June 1, 2011. Will the addition of WCEC 3 result in fuel savings to FPL's customers?

A. Yes. This unit's high efficiency will create substantial fuel savings for FPL's customers once it goes into operation. For the June through December, 2011 period, the addition of WCEC 3 will save FPL's customers $97,296,000.

Q. How did FPL calculate the fuel savings associated with the addition of WCEC 3?

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the addition of WCEC 3. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the WCEC 3 fuel savings. In order to calculate the WCEC 3 fuel savings, FPL ran two separate production cost simulations, one without WCEC 3 and one with WCEC 3. A comparison of the total system fuel costs from POWRSYM for the two simulations showed that the fuel costs were $97,296,000 lower in the case that included WCEC 3 than in the case without WCEC 3.

Q. In the Stipulation and Settlement that FPL and the intervening parties in Docket No. 080677-EI filed for Commission approval on August 20, 2010, Paragraph 5(c) directs FPL to calculate the fuel savings associated with WCEC 3 as follows: "FPL shall quantify the projected fuel savings associated with the addition of West County Unit 3 through the use of the same computerized simulations of its system and current assumptions and data regarding unit performance, system load, and fuel costs that it employs to project its fuel costs in the fuel cost recovery proceeding to compare the total fuel costs that FPL would incur without the addition of West County Unit 3 to the total fuel costs it will incur with the addition of West County Unit 3." Is your calculation of $97,296,000 in WCEC 3 fuel savings consistent with Paragraph 5(c)?

A. Yes, it is.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KIM OUSDAHL

DOCKET NO. 100001-EI

September 1, 2010

Q. Please state your name and address.

A. My name is Kim Ousdahl, and my business address is Florida Power & Light 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" or the "Company") as Vice President, Controller and Chief Accounting Officer.

Q. Please describe your duties and responsibilities in this position.

A. I am responsible for financial accounting and internal reporting for FPL, along with the management of the Property Accounting and Regulatory Accounting functions. In these roles, I am responsible for ensuring that the Company's financial reporting complies with the requirements of Generally Accepted Accounting Principles (GAAP) and multi-jurisdictional regulatory accounting requirements.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in Docket No. 080677-EI, the Company's 2009 base rate case, and Docket No. 080009-EI, the 2008 nuclear cost recovery proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the calculation of the revenue requirement of the West County Energy Center Unit 3 (WCEC 3). Specifically, this includes the calculation of the revenue requirement for WCEC 3 for the period June, 2011 through December, 2011, the first seven months of operation of this facility.

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:

- KO-1 -- Determination of the Revenue Requirement for the West County Unit 3 (WCEC 3) Power Station
- KO-2 -- Capital Structure Calculation and Support for the Revenue Requirement of the WCEC 3 Power Station

Q. What is the purpose of the calculation of WCEC 3 revenue requirement as it relates to this proceeding?

A. FPL and the major intervenors in FPL's 2009 base rate proceeding have entered into a Stipulation and Settlement (the

"Settlement Agreement"), which was filed for Commission approval on August 20, 2010. The Settlement Agreement provides an opportunity for FPL to recover the previously approved revenue requirements for WCEC 3 through the capacity cost recovery clause starting with the first billing cycle after the unit goes into commercial service, limited to the amount of its projected fuel savings for that period of operation. While the Commission is not scheduled to rule on the Settlement Agreement until September 28, 2010, the Settlement Agreement contemplates that FPL will file for recovery of the WCEC 3 revenue requirement as part of its 2011 fuel cost recovery projection filing. I am providing a calculation of the 2011 WCEC 3 revenue requirement in support of FPL's recovery request. This request is contingent upon Commission approval of the Settlement Agreement.

Q. Please describe how the Revenue Requirement calculation was developed?

A. The development of the revenue requirement is based on the approach and assumptions utilized in the calculation of WCEC 3 revenue requirement in the need determination proceeding for that unit in Docket No. 080203-EI. The first step in the calculation of the revenue requirement was to calculate the jurisdictional average rate base represented by WCEC 3. As shown on KO-2 line 20, the beginning net plant balance as of June 2011 and the ending plant balance as of December 2011 on line 20, divided by two results in an average rate base of $861,859,229 (KO-2, line 24). The average rate base was then multiplied by the jurisdictional factor of 0.981404 (KO-2, line 25) which produces the jurisdictional average rate base of $845,832,095 (KO-2, line 26).

Next, FPL determined the required jurisdictional net operating income. This calculation was developed utilizing the jurisdictional average rate base (KO-1, line 1) multiplied by the weighted cost of capital (KO-1, line 3). As required in the Settlement Agreement, the weighted cost of capital has been adjusted to reflect a 10% ROE midpoint return on equity in lieu of the return on equity that was used in the need determination proceeding. This results in a required jurisdictional net operating income of $71,236,487 (KO-1, line 5). Because WCEC 3 is expected to go in service June 1, 2011, I calculated a partial year net operating income (KO-1, line 7). The $41,554,617 represents 7/12th of a full year of jurisdictional net operating income. The jurisdictional adjusted net operating loss of $19,413,788 (KO-1, line 9) represents operation and maintenance expenses, depreciation and taxes. The amount shown on KO-2, line 50 represents the jurisdictional net operating loss from June 2011 through December 2011.

Finally, the net operating income deficiency was determined (KO-1, line 7 minus KO-1, line 9), to arrive at a net operating income deficiency of $60,968,406 (KO-1, line 11). This amount was then grossed up for taxes, regulatory assessment fees and bad debt expense using the net operating income multiplier of 1.63411 (KO-1, line 13). The result is a jurisdictional revenue requirement in the amount of $99,629,081 (KO-1, line 15) for the seven months of 2011 during which the unit is projected to be in service.

Q. What was the basis for the determination of the jurisdictional average rate base, capital ratios, operating expenses and jurisdictional operating income?

A. All of the calculations shown on my exhibits KO-1 and KO-2 were developed using the need determination supporting data as filed in Docket No 080203-EI. The only exceptions are that FPL has used the 10% cost of common equity and the net operating income multiplier approved by the Commission in Docket No 080677-EI, Order No PSC-10-0153-FOF-EI.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 100001-EI

MARCH 12, 2010

Q. Please state your name, business address, employer and position.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company ("FPL"or the "Company") as the Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery (FCR) Clause and Capacity Cost Recovery (CCR) Clause Net True-Up amounts for the period January 2009 through December 2009. The Net True-Up for the FCR is an under-recovery, including interest, of $8,771,414. The Net True-Up for the CCR is an over-recovery, including interest, of $20,891,498. FPL is requesting Commission approval to include the FCR true-up under-recovery of $8,771,414 in the calculation of the FCR factor for the period January 2011 through December

2011. FPL is also requesting Commission approval to include the CCR true-up over-recovery of $20,891,498 in the calculation of the CCR factor for the period January 2011 through December 2011.

Q. **Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?**

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. In addition, FCR Schedules A-1 through A-12 for the January 2009 through December 2009 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. **What is the source of the data that you will present in this proceeding?**

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE (FCR)

Q. **Please explain the calculation of the Net True-up Amount.**

A. Appendix I, page 3, entitled "Summary of Net True-Up," shows the calculation of the Net True-Up for the period January 2009 through December 2009, an under-recovery of $8,771,414.

The Summary of the Net True-up amount shown on Appendix I, page 3 shows the actual End-of-Period True-Up over-recovery for the period January 2009 through December 2009 of $435,392,807 on line 1. The Estimated/Actual True-Up over-recovery for the same period of $444,164,222 is shown on line 2. Line 1 less line 2 results in the Net Final True-Up for the period January 2009 through December 2009 shown on line 3, an under-recovery of $8,771,414.

The calculation of the true-up amount for the period follows the procedures established by this Commission set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision."

Q. **Have you provided a schedule showing the calculation of the actual true-up by month?**

A. Yes. Appendix I, pages 4 and 5, entitled "Calculation of Actual True-up Amount," show the calculation of the FCR actual true-up by month for January 2009 through December 2009.

Q. **Have you provided a schedule showing the variances between actuals and estimated/actuals for 2009?**

A. Yes. Appendix I, page 6 provides a comparison of jurisdictional fuel revenues and costs on a dollar per MWh basis. Appendix I, page 7 compares the actual End-of-Period True-up over-recovery of $435,392,807 to the Estimated/Actual End-of-Period True-up over-recovery of $444,164,222 resulting in the variance of $8,771,414.

Q. Please describe the variance analysis on page 6 of Appendix I.

A. Appendix I, page 6 provides a comparison of Jurisdictional Total Fuel Revenues and Jurisdictional Total Fuel Costs and Net Power Transactions on a dollar per MWh basis. The $8,771,414 variance is due primarily to an increase in the fuel cost per MWh ($51.12/MWh vs. $50.90/MWh) that results in a positive variance of $23,334,535, and an increase in fuel revenues per MWh ($57.12/MWh vs. $57.07/MWh) that results in a positive variance of $5,641,226. The increase in consumption results in a positive variance in fuel revenues of $83,584,126 and a positive variance in fuel costs of $74,546,264. The total variance due to cost is $17,693,838 and the total variance due to consumption is $9,037,861. Finally, the variance reflects a decrease of $115,437 in interest primarily due to lower than expected commercial paper rates.

Q. What was the variance in Adjusted Total Fuel Costs and Net Power Transactions?

A. The variance in Adjusted Total Fuel Costs and Net Power Transactions was $100,382,923. As shown on Appendix I, page 7, this $100.4 million increase in Adjusted Total Fuel Costs and Net Power Transactions is due primarily to a $94.4 million (2.0%) increase in the Fuel Cost of System Net Generation, and an $8.6 million (18.7%) increase in the Energy Cost of Economy Purchases. These amounts are partially offset by a $0.076 million (11.8%) decrease in Incremental Hedging Costs, a $7.0 million (18.3%) decrease in Fuel Cost of Power Sold, a $2.1 million (16.2%) decrease in Gains from Off-System Sales, a $10.6 million (3.6%) decrease in Fuel cost of Purchased Power, a $4.6 million (2.8%) decrease in Energy Payments to Qualifying Facilities, and a $4.3 million (7.1%) decrease in sales to the Florida Keys Electric Cooperative (FKEC) and City of Key West Electric Cooperative (CKW) contracts.

As shown on the December 2009 A3 Schedule, the $94.4 million (2.0%) increase in the Fuel Cost of System Net Generation is primarily due to $93.1 million (22.3%) higher than projected heavy oil and $13.6 million (0.3%) higher than projected natural gas, offset by $1.7 million (29.4%) lower than projected light oil, $6.0 million (3.6%) lower than projected coal, and $4.6 million (3.4%) lower than projected nuclear.

Heavy oil averaged $10.65 per MMBtu, $0.09 per MMBtu (0.9%) lower than projected, but 9,080,158 more MMBtus (23.3%) of heavy oil were used during the period than projected. Of the $93.1 million heavy oil variance, $97.5 million is due to higher consumption, partially offset by $4.5 million due to lower prices.

Natural gas averaged $8.19 per MMBtu, $0.32 per MMBtu (3.8%) less than projected, but 20,319,045 higher MMBtus (4.3%) of natural gas were used during the period than projected. Of the $13.6 million natural gas variance, $172.9 million is due to higher consumption, partially offset by $159.3 million due to lower prices.

Light oil averaged $14.06 per MMBtu, $0.23 per MMBtu (1.62%) less than projected, and 116,168 less MMBtus (28.3%) of light oil were used during the period than projected. Of the $1.7 million light oil variance, 96.1% is due to lower consumption and the remainder due to lower prices.

Coal averaged $2.44 per MMBtu, $0.06 per MMBtu (2.46%) more than projected, but 4,127,058 less MMBtus (5.89%) of coal were used during the period than projected. Of the $6.0 million coal variance, $9.8 million is due to lower consumption, partially offset by $3.9 million due to higher prices.

Nuclear power averaged $0.51 per MMBtu, $0.01 per MMBtu (2.23%) less than projected, and 3,115,025 less MMBtus (1.23%) of nuclear were used during the period than projected. Of the approximate $4.6 million nuclear variance, $1.6 million is due to lower consumption and $2.9 million is due to lower prices.

The $8.6 million increase in the Energy Cost of Economy Purchases is primarily due to higher than projected purchases of approximately 177,000 MWh. The higher than projected purchases resulted in a variance of approximately $9.2 million, or 107% of the total variance. This variance was slightly offset by lower than projected costs for economy purchases of approximately $0.61/MWh or $0.6 million, yielding a net variance of $ 8.6 million.

The $0.076 million (11.8%) decrease in Incremental Hedging Costs is primarily due to lower than projected expenses for salaries and employee-related expenses for personnel supporting FPL's hedging program. Additionally, the costs for FPL's volume forecasting software was lower than projected.

The $7.02 million (18.3%) decrease in the Fuel Cost of Power Sold is primarily due to lower than projected off-system sales (107,000 MWh) and lower than expected fuel costs attributable to off-system sales (approximately $4.00/MWh). Of the $7.02 million variance, approximately 50% was due to lower than projected sales and 50% was due to lower than projected fuel costs.

The $2.1 million (16.2%) decrease in Gains from Off-System Sales is primarily due to lower than projected sales. Approximately 63% of the total variance is due to lower than projected sales and the remaining 37% is due to lower than projected margins on sales.

The $10.6 million (3.6%) decrease in Fuel Cost of Purchased Power is primarily due to $16.4 million lower than projected energy purchases from UPS, partially offset by $7.2 million higher than projected fuel costs on PPAs. The variance resulting from lower than projected energy purchases from UPS is due to a lower anticipated energy rate from Southern Company and less than anticipated energy deliveries from UPS and SJRPP. The variance resulting from higher than projected fuel costs on PPAs is primarily due to greater than expected utilization of the purchased power agreements, somewhat offset by lower than projected energy costs.

The $4.6 million (2.8%) decrease in Energy Payments to Qualifying Facilities is primarily due to lower than projected energy purchases from ICL.

The $4.3 million (7.1%) decrease in sales to FKEC and CKW is primarily due to lower than anticipated MWh sales (960,306,477 vs. 1,011,973,000).

Q. What was the variance in retail (jurisdictional) Fuel Cost Recovery revenues?

A. As shown on Appendix I, page 7, line C3, actual jurisdictional FCR revenues, net of revenue taxes, were $89.2 million (1.6%) higher than the estimated/actual projection, reflecting higher than projected jurisdictional sales of 1,464,683,918 kWh (1.4%).

Q. Pursuant to Commission Order No. PSC-09-0795-FOF-EI, FPL's 2009 gains on non-separated wholesale energy sales are to be measured against a three-year average Shareholder Incentive Benchmark of $18,328,381. Did FPL exceed this benchmark?

A. No.

Q. What is the appropriate final Shareholder Incentive Benchmark level for calendar year 2010 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI in Docket No. 991779-EI?

A. For the year 2010, the three year average Shareholder Incentive Benchmark consists of actual gains for 2007, 2008 and 2009 (see below) resulting in a three year average threshold of $15,415,773.

2007	$18,545,406
2008	$17,001,482
2009	$ 10,700,431

Gains on sales in 2010 are to be measured against the three-year average Shareholder Incentive Benchmark of $15,415,773.

CAPACITY COST RECOVERY CLAUSE (CCR)

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix II, page 3, entitled "Summary of Net True-Up" shows the calculation of the Net True-Up for the period January 2009 through December 2009, an over-recovery of $20,891,498, which FPL is requesting to be included in the calculation of the CCR factors for the January 2011 through December 2011 period.

The actual End-of-Period under-recovery for the period January 2009 through December 2009 of $35,096,648 (shown on page 3 line 1) less the estimated/actual End-of-Period under-recovery for the same period of $55,988,146 (shown on page 3, line 2) that was approved by the Commission in Order No. PSC-09-0795-FOF-EI, results in the Net True-Up over-recovery for the period January 2009 through December 2009 of $20,891,498 (shown on page 3, line 3).

Q. Have you provided a schedule showing the calculation of the actual true-up by month?

A. Yes. Appendix II, pages 4 and 5, entitled "Calculation of Final True-up Amount," shows the calculation of the CCR End-of-Period true-up for the period January 2009 through December 2009 by month.

Q. Is this true-up calculation consistent with the true-up methodology used

for the fuel cost recovery clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. **Have you provided a schedule showing the variances between actuals and estimated/actuals?**

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period January 2009 through December 2009.

Q. **What was the variance in net capacity charges?**

A. Appendix II, Page 6, Line 13 provides the variance in Jurisdictional Capacity Charges, which is a decrease of $12,531,582 or 1.6%. This $12.5 million variance was primarily due to a $2.8 million (1.3%) decrease in Payments to Non-cogenerators, an $11.5 million (26.0%) decrease in Incremental Plant Security Costs, and a $0.300 million (15.2%) decrease in Transmission Revenues from Capacity Sales. These decreases were partially offset by a $1.2 (0.4%) increase in Payments to Cogenerators, and a $0.425 million (19.7%) increase in costs associated with the SJRPP Suspension Accrual.

The $2.8 million (1.3%) decrease in Payments to Non-cogenerators is primarily due to lower than projected capacity payments to Southern Company for UPS, somewhat offset by higher than projected capacity charges for SJRPP.

The $11.5 million (26.0%) decrease in Incremental Plant Security Costs is primarily due to lower than projected Part 73 expenses. Some costs have been delayed into 2010 and a fully developed job scope revealed lower costs than originally anticipated. Turkey Point force-on-force upgrades were less than originally estimated. Part 26 expenses were $1.1 million lower than projected because security officers were not fully staffed until later in 2009.

The $0.300 million (15.2%) decrease in Transmission Revenues from Capacity Sales is due to lower than projected off-system sales. Off-system sales were approximately 107,000 MWh lower than projected.

The $1.2 million (0.4%) increase in Payments to Cogenerators is primarily due to higher than projected capacity payments for ICL and Cedar Bay contracts. The $0.425 million (19.7%) variance in the SJRPP Suspension Accrual is primarily due to legal fees incurred by FPL in its successful defense of the suspension of energy dispute with SJRPP.

Q. **What was the variance in Capacity Cost Recovery revenues?**

A. As shown on page 6, line 16, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes), were $8,326,520 (1.1%) higher than the estimated/actual projection. This $8,326,520 increase in revenues and the $12,531,582 decrease in costs and increase in interest of $33,396 (page 6, line 18), results in the final over-recovery of $20,891,498.

Q. Have you provided Schedule A12 showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Appendix II as pages 7 and 8. Page 7 shows the actual capacity payments for Qualifying Facilities, the Southern Company UPS contract and the SJRPP contract. Page 8 provides the Short Term Capacity payments for the period January 2009 through December 2009.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 100001-EI

August 2, 2010

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Director, Cost Recovery Clauses 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. The purpose of my testimony is to present for Commission review and approval the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery (FCR) Clause and the Capacity Cost Recovery (CCR) Clause for the period January 2010 through December 2010.

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

A. Yes, I have. It consists of various schedules included in Appendices I and II. Appendix I contains the FCR related schedules and Appendix

II contains the CCR related schedules.

The FCR Schedules contained in Appendix I include Schedules E3 through E9 that provide revised estimates for the period July 2010 through December 2010. FCR Schedules A1 through A9 provide actual data for the period January 2010 through June 2010. They are filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

The CCR Schedules contained in Appendix II provide the calculation of estimated/actual variances and the estimated/actual true-up amount for the period January 2010 through December 2010.

Q. **What is the source of the actual data that you will present by way of testimony or exhibits in this proceeding?**

A. Unless otherwise indicated, the actual data is taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, as well as the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. **Please describe what data FPL has used as a comparison when calculating the FCR and CCR true-ups that are presented in your testimony.**

A. The FCR true-up calculation compares estimated/actual data consisting of actuals for January 2010 through June 2010, and revised estimates for July 2010 through December 2010, with the original 2010 projections filed on August 20, 2009. The CCR true-up calculation compares estimated/actual data consisting of actuals for January 2010 through June 2010, and revised estimates for July 2010 through December 2010 with the original estimates for January 2010 through December 2010 filed on August 20, 2009.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-ups.

A. The calculation of the interest provision follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount times the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the 30-day commercial paper rates as published in the Wall Street Journal on the first business day of the current and the subsequent month. The average interest rate for the projected months is the actual rate as of the first business day in July 2010.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the FCR End of Period Net True-up and Estimated/Actual True-up amounts you are requesting this Commission to approve.

A. Appendix I, Pages 2 and 3, show the calculation of the FCR End of Period Net True-up and Estimated/Actual True-up amounts. The End of Period Net True-up amount to be carried forward to the 2011 fuel factor is an under-recovery of $277,584,308 (Appendix I, Page 3, Column 13, Line C11). This $277,584,308 under-recovery includes the 2009 Final True-up under-recovery of $8,771,414 (Appendix I, Page 3, Column 13, Line C9b), filed with the Commission on March 12, 2010, and the Estimated/Actual True-up under-recovery, including interest, of $268,812,894 (Appendix I, Page 3, Column 13, Lines C7 plus C8) for the period January 2010 through December 2010.

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

A. Yes, they were.

Q. Have you provided a schedule showing the calculation of the estimated/actual true-up by month?

A. Yes. Appendix I, Pages 2 and 3, entitled "Calculation of True-Up Amount," show the calculation of the FCR Estimated/Actual True-up by month for January 2010 through December 2010.

Q. Have you provided a schedule showing the variances between estimated/actuals and original projections for 2010?

A. Yes. Appendix I, Page 4 provides a comparison of jurisdictional revenues and costs on a dollar per MWh basis. Appendix I, Page 5 provides a variance calculation that compares the Estimated/Actual period data to the data from the original projections filing for the January 2010 through December 2010 period.

Q. Please describe the variance analysis on Page 4 of Appendix I.

A. Appendix I, Page 4 provides a comparison of Jurisdictional Total Revenues and Jurisdictional Total Fuel Costs and Net Power Transactions on a dollar per MWh basis. The $277,584,308 variance is primarily due to an increase in fuel costs per MWh of $43.80/MWh vs. $41.60/MWh that results in a cost variance of $227,646,554, and a decrease in fuel revenues per MWh of $41.32/MWh vs. $41.71/MWh that results in a cost variance of ($40,832,839), for a total variance due to cost of ($268,479,393). The impact of the variance due to consumption is mostly offset between costs per MWh and revenues per MWh, netting to a variance due to consumption of $268,679. When the interest amount of $602,180 associated with the 2010 estimated/actual true-up amount and the 2009 Final True-up under-recovery amount of $8,771,414 are added to the calculation, the total amount of the variance results in the $277,584,308.

Q. Please summarize the variance schedule on Page 5 of Appendix I.

A. FPL's original projections filed on August 20, 2009 projected Jurisdictional Total Fuel and Net Power Transactions to be $4.202 billion for 2010 (Appendix I, Page 5, Column 2, line C6). The Estimated/Actual Jurisdictional Total Fuel Costs and Net Power

Transactions are now projected to be $ 4.529 billion for that period (actual data for January 2010 through June 2010 and revised estimates for July 2010 through December 2010) (Appendix I, Page 5, Column 1, Line C6). Therefore, Jurisdictional Total Fuel Costs and Net Power Transactions are $326,206,940, or 7.8% higher than the original projections filing (Appendix I, Page 5, Column 3, Line C6). Jurisdictional Fuel Revenues for 2010 are projected to be $57,996,226, or 1.4% higher than the original projections filing (Appendix I, Page 5, Column 3, Line C3).

Q. Please explain the variances in Jurisdictional Total Fuel Costs and Net Power Transactions.

A. As shown on Appendix I, Page 5 Line C6, the variance in Jurisdictional Total Fuel Costs and Net Power Transactions of $326.2 million is a 7.8% increase from original projections. The primary reasons for this variance are higher than projected Fuel Cost of System Net Generation ($257.8 million), higher than projected Energy Cost of Economy Purchases ($58.0 million), lower than projected Fuel Cost of Power Sold ($28.3 million) and lower than projected Gains from Off-System Sales ($8.4 million), partially offset by lower than projected Incremental Hedging Costs ($0.628 million) and lower than projected Fuel Cost of Purchased Power ($22.8 million).

The $257.8 million or 6.7 % increase in the Fuel Cost of System Net

Generation is primarily due to higher than projected heavy and light oil costs partially offset by lower than projected natural gas costs. Heavy oil is currently projected to be $409.0 million (369.9%) higher than the original projection. Heavy oil burn in the estimated/actual period is projected to be 45,275,515 MMBTUs, which is 343.0% higher than the 10,221,287 MMBTUs included in the original projection. Additionally, the unit cost of heavy oil in the estimated/actual period is $11.48 per MMBTU, which is 6.09% higher than the $10.82 per MMBTU included in the original projection. Light oil costs are currently projected to be $26.2 million (234.4%) higher than the original projection. The unit cost of light oil in the estimated/actual is $14.03 per MMBTU, or 12.3% lower than the $16.01 per MMBTU included in the original projection and light oil burn in the estimated/actual period is projected to be 2,665,241 MMBTUs, which is 281.5% higher than the 698,657 MMBTUs included in the original projection. The increases in heavy oil and light oil costs are partially offset by lower than projected natural gas costs. Natural gas is currently projected to be $159.3 million, or 4.7% lower than the original projection. The unit cost of natural gas in the estimated/actual period is $6.58 per MMBTU, which is 6.6% lower than the $7.05 per MMBTU included in the original projection. Additionally, consumption of natural gas increased by 2.0% compared to the original projection. Projections for Generation by Fuel Type for the period July 2010 through December 2010 are included in Appendix I, Schedule E3.

The $58.0 million, or 149.4% increase in Energy Cost of Economy Purchases is primarily due to higher than projected economy purchases. Approximately 61% or slightly less than $35.2 million of the variance is due to higher than projected economy purchases. FPL is currently estimating that it will purchase approximately 760,000 MWh more of economy power than originally projected. Approximately 39% or slightly more than $22.8 million is due to higher than projected unit costs for economy purchases. FPL is currently estimating that the average cost of its economy purchases will be approximately $14.30/MWh higher than originally projected.

The $28.3 million, or 50.4% decrease in Fuel Cost of Power Sold is primarily due to lower than projected economy sales. Approximately 83% or slightly more than $23.6 million of the variance is due to lower than projected economy sales. FPL is currently estimating that it will sell approximately 683,000 MWh less of economy power than originally projected. Approximately 17% or slightly less than $4.7 million is due to lower than projected fuel costs for power sales. FPL is currently estimating that the average unit cost of fuel attributable to power sales will be approximately $4.60/MWh less than originally projected.

The $8.4 million or 56.0% decrease in Gains from Off-System Sales is primarily due to lower than projected economy sales. FPL is currently estimating that it will sell approximately 683,000 MWh less of economy power than originally projected. Approximately 5% or slightly less than $0.45 million is due to lower than projected gains on economy sales. FPL is currently estimating that the average gain on its economy sales will be approximately $0.74/MWh less than originally projected.

The $0.628 million, or 87.8% decrease in Incremental Hedging Costs is the result of the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI related to the recovery of incremental hedging costs. In these dockets, FPL requested to move recovery of incremental hedging costs from the FCR to base rates. In Order No. PSC-10-0153-FOF-EI, the Commission states:

> "Consistent with our prior orders, we move incremental hedging costs into base rates. The incremental hedging costs are administrative costs and properly belong in base rates, not in fuel factors."

This change became effective on March 1, 2010.

The $22.8 million, or 7.8% decrease in the Fuel Cost of Purchased

Power is primarily due to lower than projected energy purchases from UPS ($26.5 million) and SJRPP ($3.5 million), slightly offset by higher than projected energy purchases from Purchased Power Agreements ($6.3 million) and St. Lucie Unit 2 ($0.8 million).

Q. What is the appropriate estimated benchmark level for calendar year 2011 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI?

A. For the forecast year 2011, the three-year average threshold consists of actual gains for 2008, 2009 and January 2010 through June 2010, and estimates for July 2010 through December 2010. Gains on sales in 2011 are to be measured against this three-year average threshold, after it has been adjusted with the true-up filing (scheduled to be filed in March 2011) to include all actual data for the year 2010.

2008	$17,001,482
2009	$10,700,431
2010	6,581,695
Average threshold	$11,427,869

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the CCR Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Appendix II, Pages 2 and 3 show the calculation of the CCR

Estimated/Actual True-up amount. The calculation of the Estimated/Actual True-up for the period January 2010 through December 2010 is an under-recovery of $94,409,910, including interest (Appendix II, Page 3, Column 13, Lines 17 plus 18).

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes, it is.

Q. Have you provided a schedule showing the variances between the Estimated/Actuals and the Original Projections?

A. Yes. Appendix II, Page 4 shows the Estimated/Actual capacity charges and applicable revenues (January 2010 through June 2010 reflects actual data and the data for July 2010 through December 2010 is based on updated estimates) compared to the original projections for the January 2010 through December 2010 period, filed on August 20, 2010.

Q. Please explain the variances related to capacity charges.

A. As shown in Appendix II, Page 4, Column 3, Line 13, the variance related to jurisdictional capacity charges is $115.5 million, a 22.9% increase. The primary reasons for this variance are a $74.8 million increase in total system capacity costs (Page 4, Column 3, and Line 9) and a $47.5 million increase in capacity related amounts previously included in base rates, per the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos.

080677-EI and 090130-EI (Page 4, Column 3, Line 12), partially offset by a $6.8 million decrease in costs associated with the use of a revised jurisdictional separation factor.

The $74.8 million, or 14.8% increase in total capacity charges is due to a $2.0 million increase in Capacity Payments to Non-cogenerators, a $53.5 million increase in Short Term Capacity Payments, a $2.8 million increase in Payments to Cogenerators, a $0.693 million decrease in return requirements on the SJRPP Suspension Liability, a $7.3 million increase in Incremental Plant Security Costs, an $8.1 million increase in Transmission of Electricity by Others and a $0.996 million decrease in Transmission Revenues from Capacity Sales, slightly offset by a $0.543 million decrease in the SJRPP Suspension Accrual amount.

The $2.0 million, or 1.3% increase in Payments to Non-cogenerators is primarily due to higher than projected fixed monthly O&M costs from SJRPP and UPS production adjustments issued during the first five months of 2010.

The $53.5 million, or 653.7% increase in Short Term Capacity Payments is due to the addition of the capacity payments associated with FPL's new Unit Power Sales Agreement (UPS) with Southern Company. FPL has moved these capacity payments from the

Payments to Non-cogenerators line (also from Schedule A12, Page 1 of 2) to the Short-Term Capacity Payments line to facilitate the confidential treatment of these payments in a single location (i.e., Schedule A12, Page 2 of 2). Please note that $69.7 million associated with FPL's new UPS agreement with Southern Company were inadvertently excluded from the Payments to Non-cogenerators line (Line 1) in the 2010 original projection filing dated August 20, 2010. Additionally, in the 2010 projection filing, the data reflected on the Payments to Non-cogenerators line (Line 1) and the Payments to Cogenerators line (Line 3) were inadvertently reversed. These changes have been made and are properly reflected in this filing. Because of these changes, the variances I am reporting for those line items are not representative of actual changes in FPL's 2010 capacity payments.

The $2.8 million or 0.9% increase in Payments to Cogenerators is primarily due to higher than projected capacity payments of approximately $2.8 million for the first six months of 2010. Cedar Bay's performance in the first six months of 2010 exceeded estimates by approximately $2.4 million. The remaining variance is due to ICL performing better than anticipated by approximately $0.672 million in the first half of 2010 from what was originally anticipated.

The $0.693 million, or 11.7% decrease in return requirements on the

SJRPP Suspension Liability is primarily due to the change in capital structure (debt/equity) used to calculate the return on investment resulting from the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI.

The $7.3 million, or 15.9% increase in Incremental Plant Security Costs is primarily attributable to an increase of $5.5 million from the original projection associated with activities identified by the Risk-Based Methodology annual assessment performed in March 2010. NERC CIP-002 requires FPL to maintain a documented Risk-Based Methodology, perform an annual assessment of applicable facilities and identify and address all generation resources that support the reliability of the Bulk Electric System. The March 2010 assessment identified a new critical asset (i.e., generation facility). Per NERC CIP-002, FPL is required to make modifications within a 12-month period to the physical and electronic security perimeters of the identified asset. Planned activities include the implementation of physical security boundaries and an electronic security perimeter, upgrading existing control systems and installing security appliances.

Additionally, there is an increase of $1.8 million due to expenses associated with the Force on Force upgrades planned at St. Lucie, which were not included in the original projection. In February 2009, the NRC updated the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). These enhancements are now being utilized during the triennial Force on Force inspections performed at the nuclear stations. FPL could not estimate the impact of these changes for St. Lucie until a comprehensive review was completed in late 2009 after the 2010 projection was submitted. This increase was somewhat offset by a $0.6 million decrease in security payroll projections due to vacant positions.

The $8.1 million increase in Transmission of Electricity by Others is due to projected costs for "unutilized transmission" associated with FPL's new UPS agreement with Southern Company, which were inadvertently omitted from the original projections. In the previous UPS agreement, transmission costs were bundled with energy costs. The new agreement provides a separate transmission charge that is paid directly to the transmission provider, in this case Southern Company Transmission. Because this is a reservation charge, FPL pays for this transmission whether or not it is utilized. Utilized transmission dollars are recovered through the FCR on Schedule A7. The portion of transmission dollars that is unutilized is now being recovered through the CCR under the Transmission of Electricity by Others line.

The $0.996 million, or 40.0% decrease in Transmission Revenues from Capacity Sales is primarily due to lower than projected economy power sales. Through June 2010, FPL sold approximately 542,000 MWh less than projected. FPL now projects a total of approximately 683,000 MWh less economy sales by the end of 2010 versus the original projection resulting in a variance in transmission revenues of $996,111.

The $0.543 million or 25.2% decrease in the SJRPP Suspension Accrual is due to a reduction in the suspension accrual rate resulting from revised calculations reflecting current performance and an updated debt maturity schedule.

The $47.5 million or 83.3% increase in Capacity related amounts included in base rates is a result of the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI related to capacity charges. In these dockets, FPL requested to transfer $56.9 million associated with St. John's River Power Park (SJRPP) from base rates to the capacity clause. In Order No. PSC-10-0153-FOF-EI, the Commission states:

> "We find that capacity charges associated with SJRPP shall be treated consistently with other capacity arrangements and shall be included in the capacity clause. This is the first general rate case in which we have had the opportunity to

transfer these charges from base rates to the capacity clause. Accordingly, the adjustments made by FPL for the St. Johns River Power Park (SJRPP) from base rates to the capacity clause are approved."

This change became effective on March 1, 2010.

Additionally, there is a $6.8 million decrease in CCR costs associated with the use of a revised jurisdictional separation factor. Order No. PSC-09-0795-FOF-EI issued in Docket No. 090001-EI on December 2, 2009 approved a jurisdictional separation factor for FPL of 99.09578%, which was used in determining the amount of CCR costs to be recovered from retail customers during the period January 2010 through December 2010. This jurisdictional separation factor was based on 2008 actual data, which was the most current 12-month period of actual data available at the time of FPL's 2010 projection filing on August 20, 2009. FPL's contract with Lee County Electric Cooperative (LCEC) became effective on January 1, 2010, which serves to reduce FPL's jurisdictional separation factor and the amount of CCR costs to be recovered from retail customers. As a result, FPL has revised the jurisdictional separation factor used in the calculation of the 2010 Estimated/Actual True-up amount to account for the additional load required to serve the LCEC contract thereby reducing the amount of CCR costs recovered from retail customers.

FPL is using the 2010 jurisdictional separation factor for demand of 98.03105% approved by the Commission in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI.

In addition to the cost variances, Appendix II, Page 4, Column 3, Line 14 shows that CCR Revenues Net of Revenue Taxes, are $21.2 million higher than originally projected. The $115.5 million higher costs (Appendix II, Page 4, Column 3, Line 13) adjusted by the $21.2 million increase in revenues (Appendix II, Page 4, Column 3, Line 14) results in an Estimated/Actual 2010 True-up under-recovery amount of $94.4 million, including interest (Appendix II, Page 4, Column 3, Lines 17 plus 18). This under-recovery of $94.4 million including interest, plus the Final 2009 True-up over-recovery of $20.9 million filed on March 12, 2010 results in a net under-recovery of $73.5 million to be carried forward to the 2011 capacity factor.

Q. **Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 100001-EI

September 1, 2010

Q. Please state your name and address.

A. My name is Terry J. Keith 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 Director, Cost Recovery Clauses 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 a revised 2010 Fuel Cost Recovery (FCR) estimated/actual true-up amount, which has been updated to include July 2010 actual data and which is incorporated into the calculation of the 2011 FCR Factors.
- I present FCR factors for the period January 2011 through December 2011 based on the traditional factor calculation methodology, which spreads the fuel savings associated with West County Energy Center Unit 3 (WCEC-3) over the entire

calendar year, as well as FCR factors that reflect all of the WCEC-3 fuel savings in the period after WCEC-3 goes into service (projected to be June 1, 2011).

- I present a new activity for possible recovery through the FCR – the Scherer Unit 4 steam turbine upgrade - and associated FCR factors based on both the traditional factor calculation methodology and the calculation methodology based on the Stipulation and Settlement Agreement (the Settlement Agreement) dated August 20, 2010.
- I present a revised 2010 Capacity Cost Recovery (CCR) estimated/actual true-up amount, which has been updated to include July 2010 actual data and which is incorporated into the calculation of the 2011 CCR Factors.
- I present the CCR factors for the period January 2011 through December 2011.
- I present FPL's Nuclear Power Plant Cost Recovery costs to be recovered through the CCR Clause in 2011.
- I present CCR factors for the period June 2011 through December 2011 including an adjustment to recover the portion of the non-fuel revenue requirements equaling the projected fuel savings associated with WCEC-3.
- Finally, I provide on pages 58-59 of Appendix II FPL's proposed COG tariff sheets, which reflect 2011 projections of avoided energy costs for purchases from small power producers and

cogenerators and an updated ten-year projection of FPL'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:

- TJK-5 -- Schedules E1, E1-A, E1-B, E1-C, E1-D, E1-E, E2 and E10 based on the traditional factor calculation methodology. TJK-5 also includes Schedule H1, and pages 12-14 and 58-59. These schedules are included in Appendix II.
- TJK-6 -- the entire Appendix III
- TJK-7 -- the entire Appendix IV
- TJK-8 – the entire Appendix V

Appendix II contains the FCR related schedules based on the traditional factor calculation methodology, with and without the costs associated with the Scherer Unit 4 steam turbine upgrade. Appendix III contains the CCR related schedules, including the calculation of the CCR factors recovering the portion of the non-fuel revenue requirements equaling the projected fuel savings associated with WCEC-3. Appendix IV contains the FCR schedules based on the Settlement Agreement methodology excluding the costs associated with the Scherer Unit 4 steam turbine upgrade. Appendix V contains the FCR schedules based on the Settlement Agreement methodology including the costs associated with the Scherer Unit 4 steam turbine upgrade.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2010 FCR Estimated/Actual True-up amount that was filed on August 2, 2010 to reflect July actual data?

A. Yes. The 2010 FCR estimated/actual true-up amount has been revised to an under-recovery of $286,129,908, reflecting July 2010 actual data, plus interest. This $286,129,908 under-recovery, plus the 2009 final true-up under-recovery of $8,771,414 results in a net under-recovery of $294,901,322 (see Schedule E1-b, Pages 5 and 6 of Appendix II). This $294,901,322 under-recovery is to be included in the FCR factor for the January 2011 through December 2011 period.

Q What adjustments are included in the calculation of the levelized FCR factors shown on Schedules E1 included in Appendices II, IV and V?

A. The total net true-up to be included in the 2011 FCR factors is an under-recovery of $294,901,322. This amount, divided by the projected retail sales of 102,071,219 MWh for January 2011 through December 2011, results in an increase of 0.2889¢ per kWh before applicable revenue taxes, as shown on Line 26 of Schedule E1, Page 3 of Appendix II. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Carmine A. Priore III, filed on April 1, 2010, calculated a reward of $8,948,495 for the period ending December 2009. In his September 1, 2010 testimony, Mr. Priore presents a refinement that FPL has implemented for calculation of the 2011 GPIF AHNOR targets and recalculation of prior year targets. Implementing this refinement for prior years results in a credit to customers of $832,595 including interest, which is being applied to reduce the 2009 GPIF reward of $8,948,495. The resulting revised 2009 GPIF reward, which is being applied to the January 2011 through December 2011 period is $8,115,900. This $8,115,900 reward, divided by the projected retail sales of 102,071,219 MWh during the projected period, results in an increase of .0080¢ per kWh, as shown on line 30 of Schedule E1, Page 3 Appendix II.

Q. **What is the proposed levelized FCR factor based on the traditional factor calculation methodology?**

A. 4.464¢ per kWh. Schedule E1, Page 3 of Appendix II shows the calculation of this twelve-month levelized FCR factor based on the traditional factor calculation methodology. Schedule E2, Pages 15 and 16 of Appendix II shows the monthly fuel factors for January 2011 through December 2011 and also the twelve-month levelized FCR factor for the period.

Q. **Has the Company developed levelized FCR factors for its Time of Use rates based on the traditional factor calculation methodology?**

A. Yes. Schedule E1-D Page 1 of 2, located on Page 8 of Appendix II, provides a twelve-month levelized FCR factor of 5.084¢ per kWh on-peak and 4.179¢ per kWh off-peak for our Time of Use rate schedules based on the traditional factor calculation methodology. The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are 5.241¢ (on-peak) and 4.214¢ (off-peak) and are provided on Schedule E-1D, Page 2 of 2, located on Page 9 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 period January 2011 through December 2011 are presented on Schedule E1-E, Page 1 of 2, located on Page 10 of Appendix II. FCR factors by rate group for the SDTR are provided on Schedule E-1E, Page 2 of 2, located on Page 11 of Appendix II.

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

A. Yes.

FCR RECOVERY OF SCHERER UNIT 4 STEAM TURBINE UPGRADE COSTS

Q. Are you presenting a new activity for possible recovery through the FCR ?

A. Yes. In the testimony of FPL witness Randall LaBauve filed in Docket No. 100007-EI on August 27, 2010, FPL presented an update to its CAIR and CAMR Compliance Project, which is currently being recovered through the Environmental Cost Recovery Clause (ECRC). The update consists of the upgrade of the steam turbine at Plant Scherer Unit 4, in order to offset the loss in unit output resulting from the installation of required pollution control equipment at the generating unit.

Q. Does FPL believe that the Scherer Unit 4 steam turbine upgrade is eligible for cost recovery through the ECRC?

A. Yes. As explained in Mr. LaBauve's testimony, the turbine upgrade is an integral part of the most cost-effective compliance strategy for the CAIR and CAMR Compliance Project and its costs should be recovered through the ECRC. FPL believes that the turbine upgrade is directly analogous to Progress Energy Florida's modular cooling tower project, which the Commission approved for ECRC recovery in Order No. PSC-07-0722-FOF-EI issued in Docket No. 060162-EI on September 5, 2007.

Q. Why is FPL also presenting the Scherer Unit 4 steam turbine upgrade for recovery through the FCR Clause?

A. In an informal meeting held on August 19, 2010 with Staff and the parties to the ECRC and FCR dockets, Staff expressed the view that the turbine upgrade might not qualify for ECRC recovery. FPL disagrees and believes that the turbine upgrade costs should be recovered through the ECRC for the reasons discussed in Mr. LaBauve's testimony. However, FPL also believes that the turbine upgrade would qualify for cost recovery through the FCR Clause in the event that the Commission does not permit ECRC recovery.

Q. Why does FPL believe that the steam turbine upgrade at the Scherer Plant qualifies for recovery through the FCR Clause?

A. In Order No. 14546 issued in Docket No. 850001-EI-B on July 8, 1985, the Commission approved recovery through the FCR Clause of "fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine base rates and which, if expended, will result in fuel savings to customers".

The steam Unit 4 turbine upgrade consists of installing a new high-pressure rotor that is projected to allow the unit to generate approximately 35 MW of additional electric output. FPL, with the assistance of Georgia Power Company, identified the opportunity to implement this upgrade in conjunction with the installation of pollution control equipment on Unit 4 as part of the CAIR and CAMR Compliance Project and thus avoid the imposition of additional environmental compliance requirements that would ordinarily accompany a major modification such as a turbine upgrade. FPL is scheduled to implement the turbine upgrade in early 2012, at the same time that the final installation work is performed for the pollution control equipment, or else in June 2011 if necessary to avoid the application of the US Environmental Protection Agency's new "Tailoring Rule" for greenhouse gasses.

In the absence of the turbine upgrade, the new pollution control equipment at Scherer Unit 4 is projected to reduce the net output of the unit that is available to serve customers by about 35 MW. Because of Scherer Unit 4's low fuel cost, that loss of net output would result in FPL and its customers being subjected to substantial additional fuel costs to generate the equivalent amount of energy from other, more-expensive sources. The 35 MW of additional Unit 4 output that will result from the turbine upgrade will essentially offset the parasitic load of the pollution control equipment and thus will result in substantial fuel savings to FPL's customers compared to operating the unit without the turbine upgrade. In addition, the turbine upgrade will result in an improvement in Unit 4's heat rate of more than 400 Btu/kWh, meaning that the unit will be able to generate electricity more efficiently as well as increasing its output. FPL's economic analysis indicates that the turbine upgrade will result in fuel savings to FPL's customers of approximately $240 million on a net present value (NPV) basis, compared to a cost to FPL for the upgrade of about $7 million.

Q. Order No. 14546 refers specifically to recovery of "fossil fuel-related costs." Why does FPL believe that a turbine upgrade at a coal-fired plant would qualify for such recovery?

A. The order does not define "fossil fuel," but standard dictionary definitions commonly include coal as a fossil fuel. For example, the American Heritage Dictionary of the English Language defines "fossil fuel" to be "a hydrocarbon deposit, such as petroleum, *coal*, or natural gas, derived from living matter of a previous geologic time and used for fuel." (Emphasis added). The efficiency improvement associated with the turbine upgrade will result in lower coal costs for a given level of output, thus directly reducing FPL's costs for fossil fuels.

Furthermore, the Commission has previously interpreted Order No. 14546 to permit recovery of costs incurred at generating units with low fuel costs -- regardless of fuel type -- that increase the output of those units and thus reduce the amount of energy that must be generated from units with higher fuel costs. For example, in Order No. PSC-96-1172-FOF-EI issued in Docket No. 960001-EI on September 19, 1996, the Commission approved recovery of costs associated with the thermal power uprate at FPL's Turkey Point nuclear-powered Units 3 and 4 through the FCR Clause. The Commission approved recovery of that project through the FCR because the estimated fuel savings related to the thermal power uprate at Turkey Point Units 3 and 4 had a NPV of $98 million at a cost of approximately $10 million. In that case, the savings were due to the low cost nuclear fuel replacing higher cost fossil fuel.

In FPL's current request, the turbine upgrade at Scherer Unit 4 will also result in a power uprate and is projected to result in fuel savings of approximately $240 million on an NPV basis at a cost of about $7 million. This is even more cost-effective than the Turkey Point thermal uprate. In the case of the turbine upgrade, the savings are due to the difference between the ability to burn lower cost coal versus higher cost fossil fuel or purchased power, which is precisely analogous to the Commission's rationale for permitting FCR Clause recovery of the Turkey Point thermal uprate costs.

Q. Order No. 14546 requires that costs for which FCR Clause recovery is sought "were not recognized or anticipated in the cost levels used

to determine base rates." Was FPL aware of the potential for implementing the Scherer Unit 4 steam turbine upgrade when it prepared its forecasted test year in Docket No. 080677-EI?

A. No. FPL prepared its test year MFRs in late 2008. FPL learned of the potential to pursue the turbine upgrade from discussions with Georgia Power Company in the summer of 2009, applied for a permit from the Georgia Environmental Protection Division in late December 2009, and received the permit in February 2010. FPL could not have reasonably anticipated the turbine upgrade as part of the rate case in Docket No. 080677-EI.

Q. How does FPL propose to recover the 2011 costs of the Scherer Unit 4 steam turbine upgrade through the FCR Clause?

A. FPL proposes to recover the depreciation and return on investment associated with the cost of the Scherer Plant Unit 4 steam turbine upgrade through the FCR. For 2011, this amount is $342,418. The calculation of depreciation and return on investment for the Scherer Unit 4 steam turbine upgrade is included in Appendix II, Pages 61 and 62..

Q. What is the levelized FCR factor for January 2011 through December 2011 based on the traditional methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade?

A. Due to the relatively small dollar amount to be recovered in 2011 of $342,418, the levelized FCR factor for 2011 did not change from the FCR factor excluding upgrade costs. Therefore, the levelized FCR factor for January 2011 through December 2011 based on the traditional methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade is 4.464¢ per kWh. Schedule El, Page 60 of Appendix II shows the calculation of this twelve-month levelized FCR factor. Schedule E2, Pages 67 and 68 of Appendix II shows the monthly fuel factors for January 2011 through December 2011 and also the twelve-month levelized FCR factor for the period including the $342,418.

Q. **Has the Company developed levelized FCR factors for its Time of Use rates based on the traditional factor calculation methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade?**

A. Yes. Schedule E1-D Page 1 of 2, located on Page 63 of Appendix II, provides a twelve-month levelized FCR factor of 5.085¢ per kWh on-peak and 4.179¢ per kWh off-peak for our Time of Use rate schedules based on the traditional factor calculation methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade. The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are 5.242¢ (on-peak) and 4.215¢ (off-peak) and are provided on Schedule E-1D, Page 2 of 2, located on Page 64 of Appendix II.

FCR factors by rate group for the period January 2011 through December 2011 based on the traditional factor calculation methodology, including costs associated with the Scherer Unit 4 steam turbine upgrade are presented on Schedule E1-E, Page 1 of 2, located on Page 65 of Appendix II. FCR factors by rate group for the SDTR are provided on

Schedule E-1E, Page 2 of 2, located on Page 66 of Appendix II.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2010 CCR Estimated/Actual True-up amount that was filed on August 2, 2010 to reflect July 2010 actual data?

A. Yes. The 2010 CCR estimated/actual true-up amount has been revised to an under-recovery of $88,494,367, reflecting July 2010 actual data plus interest. This $88,494,367 under-recovery, plus the 2009 final true-up over-recovery of $20,891,498 results in a net under-recovery of $67,602,870 (see Pages 3 and 4 of Appendix III). This $67,602,870 net under-recovery is to be included for recovery in the CCR factor for the January 2011 through December 2011 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2011 through December 2011?

A. Yes. Page 5 of Appendix III provides this summary. Total Recoverable Capacity Payments are $609,681,261 (line 15) and include payments of $188,421,452 to non-cogenerators (line1), payments of $272,104,074 to cogenerators (line 2), $1,613,943 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 3), $49,351,038 in Incremental Power Plant Security Costs (line 5) and $16,769,276 in Transmission of Electricity by Others (line 6). These amounts are partially offset by $5,246,711 of Return Requirements on SJRPP Suspension Payments (line 4) and by Transmission Revenues from Capacity Sales of $2,411,394 (line 7). The resulting amount is then increased by the net under-recovery for 2009 and 2010 of $67,602,870 (line 11) and the Nuclear Power Plant Cost Recovery Clause amount of $31,288,445 (line 12).

Q. What does line 14 - Nuclear Power Plant Cost Recovery (NPPCR) represent?

A. FPL has included in the calculation of its CCR Factors $31,288,445 as reflected in Exhibit WP-7 contained in the supplemental NPPCR testimony and exhibits of Winnie Powers filed on August 17, 2010. Per Order No. PSC-07-0240-FOF-EI, issued on March 20, 2007, the Commission adopted Rule 25-6.0423 to implement Section 366.93, Florida Statutes, which was enacted by the Florida Legislature in 2006. The Rule provides the mechanism to determine recoverable costs and provides for annual recovery of those costs through the CCR.

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

A. Yes. Page 6 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 class contributes to total kWh sales, as adjusted for losses.

Q. Have you prepared a calculation of the proposed 2011 CCR factors by rate class?

A. Yes. Page 7 of Appendix III presents this calculation.

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

CCR factors?

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2011 (cycle day 1) through December 2011 (cycle day 21). This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

IMPLEMENTATION OF STIPULATION AND SETTLEMENT AGREEMENT FOR FCR AND CCR CLAUSES

Q. If approved by the Commission, how will the Stipulation and Settlement that was filed in Docket Nos. 080677-EI and 090130-EI on August 20, 2010 (the "Settlement Agreement") impact the FCR and CCR clauses?

A. The Settlement Agreement states that beginning with the first billing cycle on or after the date on which WCEC-3 enters commercial service, FPL shall be authorized to recover during the remainder of the calendar year the lesser of the projected WCEC-3 non-fuel revenue requirements for the balance of the calendar year and the projected WCEC-3 fuel savings for the balance of the calendar year, via FPL's CCR clause. The Settlement Agreement also provides that FPL shall simultaneously implement revised FCR factors that reflect the projected WCEC-3 fuel savings.

Q. When does FPL project WCEC-3 to enter commercial operation?

A. FPL projects WCEC-3 to enter commercial operation on approximately

June 1, 2011.

Q. What are the projected WCEC-3 jurisdictional non-fuel revenue requirements from June 1, 2011 through the balance of 2011?

A. As explained in the testimony of FPL witness Ousdahl, the jurisdictional non-fuel revenue requirements for June 1, 2011 through December 31, 2011 are projected to be $99,629,081. As contemplated by the Settlement Agreement, this calculation reflects the projected Plant in Service balance and operating expenses for WCEC-3 that were used in the determination of need for the unit in Docket No. 080203-EI, with the 10% return on equity (ROE) approved by the Commission in Order No. PSC-10-0153-FOF-EI substituted for higher ROE that was used for the need determination.

Q. What are the projected WCEC-3 jurisdictional fuel savings from June 1, 2011 through the balance of 2011?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings for the period above is $98,411,000. In order to calculate the WCEC 3 fuel savings, FPL ran two separate production cost simulations, one without WCEC 3 and one with WCEC 3. A comparison of the total system fuel costs from the production model for the two simulations showed that the fuel costs were $98,411,000 lower in the case that included WCEC 3 than in the case without WCEC 3. The jurisdictional portion of those fuel savings is $97,277,315. The calculation of this amount is shown on Schedule E1, in both Appendices IV and V.

Q. How does FPL propose to revise the 2011 CCR factors to reflect

recovery of WCEC-3 costs consistent with the Settlement Agreement?

A. As I explained earlier, the Settlement Agreement provides for FPL to recover the lesser of the non-fuel revenue requirements or the fuel savings associated with WCEC-3 for the portion of 2011 after it goes into service. Based on the information provided by Ms. Ousdahl and Mr. Yupp, the WCEC-3 fuel savings are less than its non-fuel revenue requirements for that period. Therefore, I have developed WCEC-3 Recovery Components that are designed to recover $97,277,315 in projected jurisdictional fuel savings from FPL's retail customers, based on the assumed in-service date of June 1, 2011. The $97,277,315 was allocated to customer classes utilizing the same cost of service and rate design methodology that was approved in FPL's recent rate case, Docket No. 080677-EI.

Page 12 of Appendix III provides the calculation of the WCEC-3 CCR components by rate class based on these revenue requirements. Pages 13-14 of Appendix III provide the total CCR factors, including the WCEC-3 CCR components that would apply during the period from when WCEC-3 goes into service through December 31, 2011.

Q. How has FPL calculated the 2011 FCR factors to address the provision of the Settlement Agreement for WCEC-3 fuel savings to be reflected in the FCR factors commencing with the unit's in-service date?

A. Per the methodology provided in the Settlement Agreement, FPL proposes to revise the 2011 fuel factor to include the fuel savings associated with its WCEC-3 beginning with the commercial operation date of WCEC-3, which is projected to be June 1, 2011.

To calculate the 2011 fuel factors per the Settlement Agreement, FPL has prepared two E-1 Schedules to calculate average "Step 1" fuel factors to be applied during the period before WCEC-3 goes into service (assumed to be January 2011 through May 2011) (Page 2 of Appendix IV) and separate average "Step 2" fuel factors to be applied during the period after WCEC-3 goes into service (assumed to be June 2011 through December 2011) (Page 9 of Appendix IV). FPL first calculates the Step 1 fuel factors assuming WCEC-3 is not operating in 2011, meaning that the total jurisdictional fuel savings are excluded from the calculation of the levelized fuel factor on both E-1 Schedules. This adjustment is shown on Line 1a.

Next, FPL adjusts the Step 2 fuel factors for the period June 2011 through December 2011 by crediting the fuel savings associated with WCEC-3 during this period. The total jurisdictional fuel savings of $97,277,315, divided by the projected sales for June 2011 through December 2011 of 63,929,494 mWh results in a downward adjustment of 0.1523 cents per kWh (including revenue taxes) (Schedule E-1, Line 33a, Page 9 of Appendix IV). This downward adjustments results in a lower levelized FCR factor of 4.407 cents per kWh. This represents $40.62 on a

Residential 1,000 kWh bill, which is $1.52 less than the $42.14 charge in January 2011.

Q. **Has FPL also calculated the Step 1 and Step 2 FCR factors, including the costs associated with the Scherer Unit 4 Steam Turbine Upgrade?**

A. Yes. FCR factors for the period January 2011 through December 2011 including the costs associated with the Scherer Unit 4 steam turbine upgrade are included in Appendix V of my testimony.

Q. **Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF TERRY J. KEITH

DOCKET NO. 100001-EI

OCTOBER 1, 2010

Q. Please state your name and address.

A. My name is Terry J. Keith 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 Director, Cost Recovery Clauses 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 a revised 2010 Fuel Cost Recovery (FCR) estimated/actual true-up amount, which has been updated to include actual data through August 2010 and which is incorporated into the calculation of the 2011 FCR Factors.
- I present the levelized FCR factors for the period January 2011 through December 2011, which spreads the fuel savings associated with West County Energy Center Unit 3 (WCEC-3) over the entire calendar year, as well as FCR factors that reflect all

of the WCEC-3 fuel savings in the period after WCEC-3 goes into service (projected to be June 1, 2011).

- I present a revised 2010 Capacity Cost Recovery (CCR) estimated/actual true-up amount, which has been updated to include actual data through August 2010 and which is incorporated into the calculation of the 2011 CCR Factors.
- I present the CCR factors for the period January 2011 through December 2011.
- I present FPL's Nuclear Power Plant Cost Recovery costs to be recovered through the CCR Clause in 2011.
- I present CCR factors for the period June 2011 through December 2011 including an adjustment to recover the portion of the non-fuel revenue requirements equaling the projected fuel savings associated with WCEC-3.
- Finally, I provide on pages 58-59 of Appendix II FPL's proposed COG tariff sheets, which reflect 2011 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten-year projection of FPL'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:

- TJK-5 -- Schedules E1, E1-A, E1-B, E1-C, E1-D, E1-E, E2 and E10 based on the traditional factor calculation methodology. TJK-5 also includes Schedule H1, and pages 12-14 and 58-59. These schedules are included in Appendix II.

- TJK-6 -- the entire Appendix III
- TJK-7 -- the entire Appendix IV

Appendix II contains the levelized FCR related schedules. Appendix III contains the CCR related schedules, including the calculation of the CCR factors recovering the portion of the non-fuel revenue requirements equaling the projected fuel savings associated with WCEC-3. Appendix IV contains the FCR schedules based on the Settlement Agreement.

FUEL COST RECOVERY CLAUSE

Q. **Has FPL revised its 2010 FCR Estimated/Actual True-up amount that was filed on August 2, 2010 to reflect actual data through August 2010?**

A. Yes. The 2010 FCR estimated/actual true-up amount has been revised to an under-recovery of $221,691,239, reflecting actual data through August 2010, plus interest. This $221,691,239 under-recovery, plus the 2009 final true-up under-recovery of $8,771,414 results in a net under-recovery of $230,462,653 (see Schedule E1-b, Pages 5 and 6 of Appendix II). This $230,462,653 under-recovery is to be included in the FCR factor for the January 2011 through December 2011 period.

Q **What adjustments are included in the calculation of the levelized**

FCR factors shown on Schedules E1 included in Appendices II and IV?

A. The total net true-up to be included in the 2011 FCR factors is an under-recovery of $230,462,653. This amount, divided by the projected retail sales of 102,071,219 MWh for January 2011 through December 2011, results in an increase of 0.2258¢ per kWh before applicable revenue taxes, as shown on Line 26 of Schedule E1, Page 3 of Appendix II. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Carmine A. Priore III, filed on April 1, 2010, calculated a reward of $8,948,495 for the period ending December 2009. In his October 1, 2010 testimony, Mr. Priore presents a refinement that FPL has implemented for calculation of the 2011 GPIF AHNOR targets and recalculation of prior year targets. Implementing this refinement for prior years results in a credit to customers of $832,595 including interest, which is being applied to reduce the 2009 GPIF reward of $8,948,495. The resulting revised 2009 GPIF reward, which is being applied to the January 2011 through December 2011 period is $8,115,900. This $8,115,900 reward, divided by the projected retail sales of 102,071,219 MWh during the projected period, results in an increase of .0080¢ per kWh, as shown on line 30 of Schedule E1, Page 3 Appendix II.

Q. **What is the proposed levelized FCR factor for the period January 2011 through December 2011?**

A. 4.214¢ per kWh. Schedule E1, Page 3 of Appendix II shows the calculation of this twelve-month levelized FCR factor for January 2011 through December 2011. Schedule E2, Pages 15 and 16 of Appendix II shows the monthly fuel factors for January 2011 through December 2011 and also the twelve-month levelized FCR factor for the period.

Q. Has the Company developed levelized FCR factors for its Time of Use rates for January 2011 through December 2011?

A. Yes. Schedule E1-D Page 1 of 2, located on Page 8 of Appendix II, provides a twelve-month levelized FCR factor of 4.836¢ per kWh on-peak and 3.929¢ per kWh off-peak for our Time of Use rate schedules for January 2011 through December 2011. The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are 4.996¢ (on-peak) and 3.964¢ (off-peak) and are provided on Schedule E-1D, Page 2 of 2, located on Page 9 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 period January 2011 through December 2011 are presented on Schedule E1-E, Page 1 of 2, located on Page 10 of Appendix II. FCR factors by rate group for the SDTR are provided on Schedule E-1E, Page 2 of 2, located on Page 11 of Appendix II.

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

A. Yes.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2010 CCR Estimated/Actual True-up amount that was filed on August 2, 2010 to reflect actual data through August 2010?

A. Yes. The 2010 CCR estimated/actual true-up amount has been revised to an under-recovery of $85,933,800, reflecting actual data through August 2010 plus interest. This $85,933,800 under-recovery, plus the 2009 final true-up over-recovery of $20,891,498 results in a net under-recovery of $65,042,302 (see Pages 3 and 4 of Appendix III). This $65,042,302 net under-recovery is to be included for recovery in the CCR factor for the January 2011 through December 2011 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2011 through December 2011?

A. Yes. Page 5 of Appendix III provides this summary. Total Recoverable Capacity Payments are $606,646,448 (line 15) and include payments of $188,421,452 to non-cogenerators (line1), payments of $272,104,074 to cogenerators (line 2), $1,613,943 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 3), $49,351,038 in Incremental Power Plant Security Costs (line 5) and $16,287,732 in Transmission of Electricity by Others (line 6). These amounts are partially offset by $5,246,711 of Return Requirements on SJRPP Suspension Payments (line 4) and by Transmission Revenues from Capacity Sales of $2,411,394 (line 7). The resulting amount is then increased by the net under-recovery for 2009 and 2010 of $65,042,302 (line 11) and the Nuclear Power Plant Cost Recovery Clause amount of $31,288,445 (line 12).

Q. What does line 12 – Nuclear Cost Recovery Clause represent?

A. FPL has included in the calculation of its CCR Factors $31,288,445 as reflected in Exhibit WP-7 contained in the supplemental Nuclear Power Plant Cost Recovery (NPPCR) testimony and exhibits of Winnie Powers filed on August 17, 2010. Per Order No. PSC-07-0240-FOF-EI, issued on March 20, 2007, the Commission adopted Rule 25-6.0423 to implement Section 366.93, Florida Statutes, which was enacted by the Florida Legislature in 2006. The Rule provides the mechanism to determine recoverable costs and provides for annual recovery of those costs through the CCR.

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

A. Yes. Page 6 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 class contributes to total kWh sales, as adjusted for losses.

Q. Have you prepared a calculation of the proposed 2011 CCR factors by rate class?

A. Yes. Page 7 of Appendix III presents this calculation.

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

CCR factors?

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2011 (cycle day 1) through December 2011 (cycle day 21). This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

IMPLEMENTATION OF STIPULATION AND SETTLEMENT AGREEMENT FOR FCR AND CCR CLAUSES

Q. **If approved by the Commission, how will the Stipulation and Settlement that was filed in Docket Nos. 080677-EI and 090130-EI on August 20, 2010 (the "Settlement Agreement") impact the FCR and CCR clauses?**

A. The Settlement Agreement states that beginning with the first billing cycle on or after the date on which WCEC-3 enters commercial service, FPL shall be authorized to recover during the remainder of the calendar year the lesser of the projected WCEC-3 non-fuel revenue requirements for the balance of the calendar year and the projected WCEC-3 fuel savings for the balance of the calendar year, via FPL's CCR clause. The Settlement Agreement also provides that FPL shall simultaneously implement revised FCR factors that reflect the projected WCEC-3 fuel savings.

Q. **When does FPL project WCEC-3 to enter commercial operation?**

A. FPL projects WCEC-3 to enter commercial operation on approximately

June 1, 2011.

Q. What are the projected WCEC-3 jurisdictional non-fuel revenue requirements from June 1, 2011 through the balance of 2011?

A. As explained in the testimony of FPL witness Ousdahl, the jurisdictional non-fuel revenue requirements for June 1, 2011 through December 31, 2011 are projected to be $99,629,081. As contemplated by the Settlement Agreement, this calculation reflects the projected Plant in Service balance and operating expenses for WCEC-3 that were used in the determination of need for the unit in Docket No. 080203-EI, with the 10% return on equity (ROE) approved by the Commission in Order No. PSC-10-0153-FOF-EI substituted for higher ROE that was used for the need determination.

Q. What are the projected WCEC-3 jurisdictional fuel savings from June 1, 2011 through the balance of 2011?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings for the period above is $97,296,000. In order to calculate the WCEC-3 fuel savings, FPL ran two separate production cost simulations, one without WCEC-3 and one with WCEC-3. A comparison of the total system fuel costs from the production model for the two simulations showed that the fuel costs were $97,296,000 lower in the case that included WCEC-3 than in the case without WCEC-3. The jurisdictional portion of those fuel savings is $96,175,160. The calculation of this amount is shown on Schedule E1, which is Page 9 of Appendix IV.

Q. How does FPL propose to revise the 2011 CCR factors to reflect

recovery of WCEC-3 costs consistent with the Settlement Agreement?

A. As I explained earlier, the Settlement Agreement provides for FPL to recover the lesser of the non-fuel revenue requirements or the fuel savings associated with WCEC-3 for the portion of 2011 after it goes into service. Based on the information provided by Ms. Ousdahl and Mr. Yupp, the WCEC-3 fuel savings are less than its non-fuel revenue requirements for that period. Therefore, I have developed WCEC-3 Recovery Components that are designed to recover $96,175,160 in projected jurisdictional fuel savings from FPL's retail customers, based on the assumed in-service date of June 1, 2011. The $96,175,160 was allocated to customer classes utilizing the same cost of service and rate design methodology that was approved in FPL's recent rate case, Docket No. 080677-EI.

Page 12 of Appendix III provides the calculation of the WCEC-3 CCR components by rate class based on these revenue requirements. Pages 13-14 of Appendix III provide the total CCR factors, including the WCEC-3 CCR components that would apply during the period from when WCEC-3 goes into service through the balance of the year.

Q. **How has FPL calculated the 2011 FCR factors to address the provision of the Settlement Agreement for WCEC-3 fuel savings to be reflected in the FCR factors commencing with the unit's in-service date?**

A. Per the methodology provided in the Settlement Agreement, FPL proposes to revise the 2011 fuel factor to include the fuel savings associated with its WCEC-3 beginning with the commercial operation date of WCEC-3, which is projected to be June 1, 2011.

To calculate the 2011 fuel factors per the Settlement Agreement, FPL has prepared two E-1 Schedules to calculate average "Step 1" fuel factors to be applied during the period before WCEC-3 goes into service (assumed to be January 2011 through May 2011) (Page 2 of Appendix IV) and separate average "Step 2" fuel factors to be applied during the period after WCEC-3 goes into service (assumed to be June 2011 through December 2011) (Page 9 of Appendix IV). FPL first calculates the Step 1 fuel factors assuming WCEC-3 is not operating in 2011, meaning that the total amount of fuel savings are excluded from the calculation of the levelized fuel factor on both E-1 Schedules. This adjustment is shown on Line 1a.

Next, FPL adjusts the Step 2 fuel factors for the period June 2011 through December 2011 by crediting the fuel savings associated with WCEC-3 during this period. The total jurisdictional fuel savings of $96,175,160, divided by the projected sales for June 2011 through December 2011 of 63,929,494 MWh results in a downward adjustment of 0.1505 cents per kWh (including revenue taxes) (Schedule E-1, Line 31, Page 9 of Appendix IV). This downward adjustment results in a lower levelized FCR factor of 4.158 cents per kWh. This represents $38.13 on a Residential 1,000 kWh bill, which is $1.51 less than the $39.64 charge in January 2011.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GENE F. ST. PIERRE

DOCKET NO. 100001-EI

September 1, 2010

Q. Please state your name and address.

A. My name is Gene F. St. Pierre. 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 in the Nuclear Business Unit as Vice President of Fleet Support.

Q. Please describe your educational background and business experience in the nuclear industry.

A. I received my technical training in the U.S. Navy Nuclear Power Program, serving for six years. I received my Bachelor of Science degree in general studies from the University State of New York and my Masters in Management from Emmanuel College. I also completed the Program for Management Development at Harvard Business School. In 1977, I joined Yankee Atomic Power Station as an Operator, where I remained until 1979 when I joined Public Service Company of New Hampshire at the Seabrook Nuclear

Power Plant (owned by NextEra Energy since 2002). I served in various roles of increasing responsibility at Seabrook until early 2010. My positions included Control Room Operator, Shift Supervisor, Assistant Operations Manager, Station Director and Site Vice President. In February 2010, I was appointed Vice President of Fleet Support. I have accountability for Emergency Preparedness, Nuclear Fuels, Licensing, Performance Improvement, Security and Fleet Training.

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 and the costs of disposal of spent nuclear fuel. I am also updating the status of certain litigation that affects FPL's nuclear fuel costs; plant security costs and new NRC security initiatives; and outage events. 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 2011 through December 2011.

<u>Nuclear Fuel Costs</u>

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 2011 through December 2011.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2011 through December 2011.

A. FPL projects the nuclear units will produce 233,788,606 MMBtu of energy at a cost of $0.6326 per MMBtu, excluding spent fuel disposal costs, for the period January 2011 through December 2011. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 22.

<u>Spent Nuclear Fuel Disposal Costs</u>

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2011 through December 2011 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $19.5 million are provided in Appendix II, on Schedule E-2, starting on page 15 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 0.9321 mills per net kWh generated, including transmission and distribution line losses.

Litigation Status Update

Q. Is there currently an unresolved dispute relating to the spent fuel disposal fee?

A. Yes. On April 5, 2010, FPL along with several other utilities and with the Nuclear Energy Institute filed a petition for review against the DOE in the U.S. Court of Appeals for the District of Columbia Circuit to suspend collection of the spent nuclear fuel disposal fee in light of the DOE's decision to terminate the Yucca Mountain spent nuclear fuel disposal project. FPL expects the Court to rule on the petition sometime in 2011.

Nuclear Plant Security Costs

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2011 through December 2011?

A. FPL presently projects that it will incur $47.4 million in incremental nuclear power plant security costs in 2011.

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

A. The projection includes maintaining a security force as a result of implementing NRC's fitness for duty rule under Part 26, which strictly limits the number of hours security personnel may work; additional personnel training; maintaining the physical upgrades resulting from implementing NRC's physical security rule under Part 73; and impacts of implementing NRC's rule under Part 73 for Cyber Security. It also includes Force on Force (FoF) modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force (CAF) as required by NRC inspection procedures.

Q. Has the NRC issued any revisions to the security-related Orders that affect FPL's projection?

A. Yes. On March 27, 2009 the NRC issued a new rule under Part 73.54 of the Code of Federal Regulations that involves the protection of station digital computer, communications systems and networks which would impose significant requirements for monitoring, hardening and responding to cyber intrusions. FPL provided a plan to the NRC in November 2009 that outlined when full implementation will be completed. Full implementation for this new Part 73.54 is scheduled for completion in 2014. Additionally, the Federal Regulatory Energy Commission (FERC) issued an order on March 18, 2010, imposing similar Cyber Security requirements for implementation at additional plant systems that could impact the reliability of the bulk electric system within eighteen months unless an outage is required for items specifically under FERC jurisdiction. The NRC Cyber Security rulemaking and FERC Order costs for 2011 are estimated to be $8.0 million for the St. Lucie and Turkey Point nuclear sites.

Also, in February 2009, the NRC updated the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). These enhancements are now being utilized during the triennial FoF inspections performed at the nuclear stations. The DBT is the measure that all nuclear stations are designed to defend against. Some examples of changes are: enhanced intrusion detection, adversary delay barriers, and additional vehicle barriers.

FoF inspections are scheduled on a repeating three year cycle. Consequently, St. Lucie and Turkey Point will receive third round FoF inspections in the 2011-2013 cycle and FPL sites may require additional modifications to ensure successful regulatory inspection conclusions. Adversary Characteristics are constantly being reviewed by the NRC due to the potential change in adversary capabilities. Consequently, future enhancements of nuclear facilities may be required. St. Lucie is currently performing modifications to the site for preparation of the NRC triennial FoF inspection expected in early 2011. The St. Lucie FoF modifications are estimated to be $3.0 million for 2011.

<u>2010 Outage Events</u>

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2010?

A. Yes. In January 2010, a manual reactor trip on Unit 4 was initiated due to Steam Generator level being greater than 75%.

Q. What caused the manual trip on Unit 4?

A. Prior to the reactor trip, both Unit 4 Heater Drain Pumps (HDPs) tripped. Power was stabilized at 93% and the HDPs were restored. However, following the restoration of the HDPs, a Plant Operator observed that the 4A Steam Generator Feed Pump (SGFP) was leaking oil and water from the pump outboard bearing housing and the oil reservoir level was lowering. In response, Control Room Operators manually secured the 4A SGFP, initiating an automatic reactor power reduction. The power reduction caused elevated water levels in the Steam Generators, an expected result of the normal response of the Steam Generator level control system to the automatic power reduction. Level in the 4B Steam Generator exceeded the administrative set point of 75%, prompting the

Reactor Operator to manually trip the Unit 4 reactor. Two root causes were identified while investigating the 4A SGFP oil leak, 1) unresponsive control of seal water injection to the pump outboard bearing caused by a degraded hand-auto controller, and 2) blockage of the 4A SGFP outboard bearing cavity drain.

Q. **How many days was the Turkey Point Unit 4 outage due to this issue?**

A. The Unit 4 outage was approximately 3 days.

Q. **What corrective actions has FPL initiated to avoid this problem in the future?**

A. FPL intends to replace SGFP seal water hand-auto controllers later this year for Unit 4 and as a preventative measure in Unit 3. Additionally, a preventative maintenance activity was established to verify the bearing seal cavity drains are clear on a periodic basis.

St. Lucie

Q. **Has FPL experienced any unplanned outages at its St. Lucie plant in 2010?**

A. Yes. In April 2010, Unit 2 was manually shut down due to the malfunction of the 2B moisture separator reheater (MSR) safety valve.

Q. **What caused the 2B MSR safety valve malfunction?**

A. The pilot valve spring on the 2B MSR safety valve had broken which caused the valve to lift at normal operating pressure.

Q. How many days was the St. Lucie Unit 2 outage due to this issue?

A. The Unit 2 outage was approximately 7 days.

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

A. The affected safety valve pilot valve spring was replaced. As a preventative measure, the three remaining Unit 2 MSR safety valve pilot valve springs were also replaced.

Q. Has FPL experienced any unplanned outages at St. Lucie Unit 1 in 2010?

A. Yes. In April, 2010 while Unit 1 was shut down to perform a scheduled refueling outage, there were several events that delayed the restart of the unit. The events were primarily related to addressing equipment conditions that were discovered during the course of the outage, including:

1. Scheduled activities for replacement of the Fuel Transfer system wheels and subsequent post maintenance testing revealed high running loads. Extensive troubleshooting resulted in replacement of the defective Load Cell to permit off-load of

fuel from the Reactor to support planned scope later into the outage.

2. Reactor Coolant system Alloy 600 mitigation scope was extended due to discovery of additional defective metal during the machining and welding activities. Inspection and removal of these locations was necessary to meet the intent of the NRC commitment for the repair scope planned.
3. During Reactor assembly following the load of new fuel into the Reactor, the #1 Control Rod (CEA) Extension Shaft was damaged and required replacement.
4. Inspection activities following Main Generator bearing replacement discovered a hydrogen leak in the Radial Leads. Safe operation of the Unit necessitated disassembly and replacement of the defective seals before the Generator could be placed in service.
5. During the return of the Feedwater system for Unit restart, a large seawater leak into the Main Condenser occurred. This resulted in extended activities to isolate and repair the source of leakage before Unit restart. Additionally, this event impacted the ability to increase unit power until all contaminants could be removed from the feedwater system.

Q. How many days was the St. Lucie Unit 1 outage extended due to these issues?

A. The Unit 1 refueling outage was extended approximately 25 days.

Q. Did St. Lucie Unit 1 experience an additional unplanned outage as it was returning to service from the refueling outage?

A. Yes. In June 2010, while Unit 1 was in power ascension from the refueling outage, the Unit was shut down when the control element assembly (CEA) controls malfunctioned and released two control rods into a safe position

Q. What caused the control element assembly to malfunction?

A. The malfunction was caused by a fault in the control system. Subsequent inspection and troubleshooting scope identified defective circuitry components.

Q. How many days was the St. Lucie Unit 1 outage due to these issues?

A. The Unit 1 outage was approximately 11 days.

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

A. The affected circuitry components were replaced to ensure operational reliability for Unit operation.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CARMINE A. PRIORE III

DOCKET NO. 100001-EI

APRIL 1, 2010

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

A. My name is Carmine A. Priore III, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. **By whom are you currently employed and in what capacity?**

A. I am employed by Florida Power & Light Company ("FPL") and I am the Vice President of Production Assurance and Business Services in the Power Generation Division of FPL where I am responsible for providing production standardization and commercial management of FPL's fossil generating assets.

Q. **Please describe your educational background.**

A. I earned a Bachelor of Science degree in Electrical Engineering from the University of Florida and a Master of Science in Engineering Management, which is a Business Administration and Industrial Engineering combination with focus in Operations Management, from the University of South Florida. I also completed the Executive Program "Driving Corporate Performance" at the Harvard Business School. Additionally, I am a licensed and registered Professional Engineer (PE) in the State of Florida.

Q. **Please briefly summarize your work experience at FPL.**

A. I have held various power plant engineering, design, operation, maintenance, and business roles with FPL for over 20 years. I joined FPL's Power Plant Engineering Department in 1989, where I held increasing levels of responsibility from project engineering to project management. From 1993 through 1994, I was involved in the design, construction, and startup of FPL's new advanced Martin combined cycle plant. Additionally, I had plant budget and engineering responsibilities at FPL's conventional and combined cycle plants involving operational procedures, work identification and maintenance activities. In 2000, I became the Startup Manager for FPL's Martin Units 8A and 8B advanced combustion turbines where I was responsible for assuring systems and equipment were ready to be safely started and operated. In 2001, I became Production Manager for FPL's Lauderdale combined cycle plant. In this role, I had operations and maintenance responsibilities, including environmental and regulatory compliance. In 2002, I was named General Manager of Electrical and Instrumentation & Controls for all FPL fossil plant assets. This role included the accountability for business planning recommendations as well as managing the development and review of standard operational procedures. In 2006, just prior to my current role, I was named Plant General Manager of FPL's new West County Energy Center, a clean, highly efficient state-of-the-art combined cycle plant with nearly 3,800 MW of generating capacity.

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

A. The purpose of my testimony is to report actual 2009 performance for Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the twelve (12) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets approved in Commission Order No. PSC-08-0824-FOF-EI issued December 22, 2008, for the period January through December 2009, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $56,657,635 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $8,948,495.

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

A. Yes, I have one. It is identified as Exhibit CP-1 and it shows the reward/penalty calculations prescribed by the GPIF Manual. Page 1 of Exhibit CP-1 is an index to the contents of the exhibit.

Q. **What is the GPIF reward/penalty amount calculated for the period January through December, 2009?**

A. The GPIF reward is $8,948,495.

Q. **Please explain how the GPIF reward amount is calculated.**

A. The steps involved in making this calculation are provided in Exhibit CP-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +2.71, corresponding to a $56,657,635 fuel savings and a GPIF reward of $8,948,495. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's performance indicators (EAF and ANOHR), the weighting factors, and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the twelve (12) GPIF units, the actual outage factors and the actual EAF, in columns 1 through 5. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 19. These tables are based on the targets and target ranges submitted to, and approved by, the Commission prior to the start of the period.

Continuing with Exhibit CP-1, Page 7 shows the adjustments to ANOHR. For each of the twelve (12) units, it shows, in columns 2 through 4, the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 19. These tables are based on the targets and target ranges submitted to, and approved by, the Commission prior to the start of the period.

Q. Please explain the primary reason or reasons why FPL will receive a reward under the GPIF for the January through December, 2009 period.

A. The primary reason that FPL will receive a reward for the period was that adjusted actual availabilities for St. Lucie Unit 1, Turkey Point Units 3 and 4, Ft. Myers Unit 2, Manatee Unit 3 and Sanford Unit 5 were each better than target, and Manatee Unit 3 adjusted actual heat rate was better than target.

Q. Please summarize each nuclear unit performance as it relates to the EAF of the units.

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 99.5%, compared to its target of 93.6%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $3,344,491.

St. Lucie Unit 2 operated at an adjusted actual EAF of 75.1%, compared to its target of 81.8%. This results in a -10.0 point penalty, which corresponds to a GPIF penalty of $2,548,026.

Turkey Point Unit 3 operated at an adjusted actual EAF of 84.7% compared to its target of 82.7%. This results in a +6.67 point reward, which corresponds to a GPIF reward of $1,714,878.

Turkey Point Unit 4 operated at an adjusted actual EAF of 88.8% compared to its target of 81.3%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $2,481,929.

In total, the combined nuclear units' EAF performance results in a net GPIF reward of $4,993,272.

Q. Please summarize each nuclear unit performance as it relates to the ANOHR of the units.

A. St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,980 Btu/kWh compared to its target of 11,006 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 11,029 Btu/kWh compared to its target of 11,272 Btu/kWh. This ANOHR results in a GPIF reward of $624,613.

Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,474 Btu/kWh compared to its target of 11,476 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 11,428 Btu/kWh compared to its target of 11,488 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

In total, the combined nuclear units' heat rate performance results in a GPIF reward of $624,613.

Q. What is the total GPIF reward for FPL's nuclear units?

A. $5,617,885.

Q. Please summarize the performance of FPL's fossil units.

A. Regarding EAF performance, five (5) of the eight (8) fossil generating units performed better than their availability targets resulting in a reward of $4,620,156, while the remaining three (3) units performed worse than their targets resulting in a penalty of $2,079,070. Thus, the combined fossil units' availability performance results in a net GPIF reward of $2,541,086.

Regarding ANOHR, two (2) out of the eight (8) fossil units operated with an ANOHR that was below the ± 75 Btu/kWh dead band resulting in a reward of $2,167,970, while two (2) out of the eight (8) fossil units operated with an ANOHR that was above the ± 75 Btu/kWh dead band resulting in a penalty of $1,378,446. The remaining four (4) fossil units operated with ANOHRs that were within the ± 75 Btu/kWh dead band, and receive no incentive reward or penalty. Thus, the combined fossil units' heat rate performance results in a net GPIF reward of $789,524.

Q. What is the total GPIF reward for FPL's fossil units?

A. $3,330,610.

Q. To recap, what is the total GPIF result for the period January through December 2009?

A. The total GPIF result for the period January through December 2009 is a \$56,657,635 fuel savings to FPL's customers and a GPIF reward of \$8,948,495.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CARMINE A. PRIORE III

DOCKET NO. 100001-EI

SEPTEMBER 1, 2010

Q. Please state your name and business address.

A. My name is Carmine A. Priore III and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Please state your present position with Florida Power and Light Company (FPL).

A. I am Vice President of Production Assurance and Business Services in the Power Generation Division of FPL.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor (EAF) targets and average net operating heat rate (ANOHR) targets used in determining the Generating Performance Incentive Factor (GPIF) for the period January through December, 2011. In addition, I will explain a refinement that FPL has implemented for calculation of the 2011 GPIF ANOHR targets for combined cycle units, which will also be applied to recalculate the 2010 targets and to adjust the prior years' reward/penalty calculations. Implementing this refinement for prior years results in a credit to customers of $832,595 including interest, which FPL proposes to apply as a reduction to the 2009 GPIF reward of $8,948,495 that was presented in my April 1, 2010 testimony. FPL has included the revised 2009 reward of $8,115,900 in the calculation of its 2011 fuel cost recovery factors.

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

A. Yes, I am sponsoring the following three exhibits:

- Exhibit CP-2: This exhibit supports the development of the 2011 GPIF targets (EAF and ANOHR). The first page of this exhibit is an index to the contents of the exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.
- Exhibit CP-3: This exhibit supports the development of the revised 2010 GPIF ANOHR targets for combined cycle units.
- Exhibit CP-4: This exhibit provides an annual breakdown of the $832,595 credit resulting from the GPIF ANOHR calculation refinement.

Q. Please explain the nature of FPL's calculation refinement.

A. FPL has identified and applied a refinement to its calculation of the combined cycle units' ANOHR. At the inception of the GPIF, FPL's fossil system generation was primarily fueled by oil. Accordingly, FPL applied a gas adjustment factor (GAF) to adjust the heat rates for units that are potentially dual-fuel (oil and gas) fired to an equivalent 100% oil-based ANOHR. This practice of using a GAF ensured consistent and comparative unit efficiency reporting relative to the primary fuel (as unit fuel mix varies year to year or when comparing actual to projected heat rates). Over time, however, the system-level GAF outlived its usefulness because it is not required for FPL's newer combined cycle units that are fired almost exclusively with gas, and that now are the primary fossil-fueled GPIF units. When adding Turkey Point Unit 5 as a new 2011 GPIF unit, FPL realized that the GAF was still being applied as new combined cycle units came into service, even though there was no longer a reason to do so. Therefore, the GAF was discontinued for the newer combined cycle units, and removed when calculating their ANOHR heat rates. This refinement updates combined cycle unit ANOHR heat rate calculations (both actual and target), for consistency with the current primary fuel (i.e. gas) at FPL's modern fossil power plants.

Q. Does this change affect the 2010 approved GPIF ANOHR targets for combined cycle units?

A. Yes. This change will be addressed later in my testimony.

Q. Is FPL also proposing to adjust the combined cycle units' ANOHR rewards in prior years?

A. Yes. While the GAF was applied consistently to both targets and actual results in the prior years, FPL believes it is proper and in the customers' interest to adjust the prior years' ANOHR rewards related to combined cycle units. This adjustment will be addressed later in my testimony.

Q. Please summarize the 2011 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December, 2011, FPL projects a weighted system equivalent planned outage factor of 12.3% and a weighted system equivalent unplanned outage factor of 6.6%, which yield a weighted system equivalent availability target of 81.1%. The targets for this period reflect planned refueling outages for three nuclear units. FPL also projects a weighted system ANOHR target of 8,541 Btu/kWh for the period January through December, 2011. As discussed later in my testimony, these targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit CP-2, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for 11 generating units that FPL proposes to be considered as GPIF units for the period of January through December, 2011. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining equivalent availability targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the equivalent planned outage factor (EPOF) and the equivalent unplanned outage factor (EUOF). The EPOF for each unit is determined by the length of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor (EFOF) and the equivalent maintenance outage factor (EMOF). The EUOF is then adjusted to reflect recent unit performance and known unit modifications or equipment changes.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, historic ANOHR vs. unit net output factor curves are developed for each GPIF unit. The historic data is analyzed for any unusual operating conditions and changes in equipment that affect the predicted heat rate. A regression equation is calculated and a statistical analysis of the historic ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor from the production costing simulation program, POWERSYM. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. In accordance with the GPIF Manual, the GPIF units selected typically represent no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the POWRSYM model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the 11 units which FPL proposes to use for the period of January through December 2011 represent the top 83.7% of the total forecasted system net generation for this period excluding the new West County Energy Center units. These three units are new for 2009 and 2011 and were excluded from the GPIF calculation because there is insufficient historical data to include them. Therefore, consistent with the GPIF Manual, the West County Energy Center units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2011 EAF and ANOHR performance targets represent reasonable level of generation availability and efficiency?

A. Yes, they do.

Q. Please explain what effect the refinement discussed earlier has on the 2010 approved GPIF ANOHR targets for combined cycle units.

A. On page 13 of Order No. PSC-09-0795-FOF-EI, the Commission approved the following 2010 GPIF ANOHR targets (in Btu/kWh) for five combined cycle units with a system gas adjustment factor applied: Ft. Myers 2 (6,952), Sanford 4 (6,968), Sanford 5 (6,969), Manatee 3 (6,750), and Martin 8 (6,826). The effect of removing the system GAF slightly increases the target values of the combined cycle units, as follows: Ft. Myers 2 (7,230), Sanford 4 (7,247), Sanford 5 (7,247), Manatee 3 (7,020), and Martin 8 (7,099) Exhibit CP-3 supports the development of the revised 2010 GPIF ANOHR targets for combined cycle units. When calculating the true-up for 2010, these revised targets will be compared to actual heat rates with the system GAF also removed. Thus, target and actual heat rate performance will continue to be compared on an equivalent basis.

Q. How does this refinement affect combined cycle units' ANOHR rewards in prior years?

A. The ANOHR targets that are calculated in the GPIF are based upon regression curves–over a range of net output factors (NOF) in order to compare target and actual performance at the same NOF. When the GAF was removed, the ANOHR targets and actual results changed, which has some impact on the true-up calculation. My Exhibit CP-4 quantifies the impact of this refinement back to October 1994, when FPL's combined cycle units at Lauderdale Plant first entered the GPIF program.

Q. If this change has affected combined cycle unit ANOHR heat rates in GPIF since 1994, why was it not brought forward until this time?

A. Because the GAF was applied to both the setting of targets and the determination of rewards and penalties, its continued use appeared to remain consistent and appropriate. However, when FPL began calculating the ANOHR targets for Turkey Point Unit 5 as it became a new GPIF unit, we did not apply the GAF and realized that the unit's heat rate appeared inconsistent with similar combined cycle units already in the GPIF calculation. After further review, FPL concluded that the GAF adjustment was not required in the case of either Turkey Point Unit 5 or the earlier predominantly gas-fired combined cycle units.

Q. What is the effect of this ANOHR calculation refinement on FPL's prior GPIF rewards received during this timeframe?

A. While the refinement occasionally results in an increase in FPL's GPIF reward, in the majority of years it results in a decrease. For the affected timeframe of October

1994 through December 2009, FPL has calculated that the refinement results in a net credit to customers in the amount of $694,824, excluding interest.

Q. How did FPL calculate the $694,824 credit excluding interest for the period October 1994 through December 2009?

A. For the period 2000 through 2009, the GAF was removed from the GPIF unit heat rate data and new ANOHR targets were developed utilizing the same methodology that had been applied in those years to develop the original ANOHR targets and to calculate rewards and penalties from actual results. For this ten year period, a credit of $455,623 excluding interest was calculated. From October 1994 through December 1999, the original unit heat rate curves were not available to calculate new ANOHR targets or the resulting rewards/penalties. As a proxy, FPL determined that the average (mean) annual credit for the recent ten year (2000-2009) period was $45,562 and used this amount as the annual credit, excluding interest, for calendar years 1995 through 1999. For the last quarter of 1994, FPL applied 25% of the annual $45,562 credit or $11,391 excluding interest. Using the mean value of the credit for 2000-2009 is conservative. The median credit for that ten-year period is $37,205, and the mean for the six-year period 2000 through 2005 (when the same four combined cycle units were in the GPIF mix as during the 1994-1999 period) was $26,953.

Q. Has FPL applied interest to these annual credits that it is proposing to refund to customers?

A. Yes.

Q. How has FPL calculated the interest to be applied to those credits?

A. FPL has calculated interest at the same commercial paper interest rates that were used in our annual true-up filings for each of the years where customers received a credit. For the two periods where FPL under-recovered its GPIF rewards, no interest was applied. This resulted in total interest for the period 1994-2009 of $137,771. Adding this interest to the total credit of $694,824 results in a total amount to be refunded to customers of $832,595 (Exhibit CP-4 provides an annual breakdown of the calculated customer credit both with and without interest). This refund amount is in addition to the GPIF fuel cost savings already provided to customers over the years.

Q. How is FPL planning to refund the $832,595 credit to customers?

A. FPL plans to refund the full amount of the $832,595 credit as a reduction to the 2009 reward, from the $8,948,495 that was identified in my April 1, 2010 testimony to a revised 2009 reward of $8,115,900. FPL has included the revised 2009 reward in the calculation of its 2011 fuel cost recovery factors that will be approved in this docket, thus ensuring that customers are promptly and fully reimbursed.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF CARMINE A. PRIORE III

DOCKET NO. 100001-EI

OCTOBER 1, 2010

Q. Please state your name and business address.

A. My name is Carmine A. Priore III and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Please state your present position with Florida Power and Light Company (FPL).

A. I am Vice President of Production Assurance and Business Services in the Power Generation Division of FPL.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor (EAF) targets and average net operating heat rate (ANOHR) targets used in determining the Generating Performance Incentive Factor (GPIF) for the period January through December, 2011. In addition, I will explain a refinement that FPL has implemented for calculation of the 2011 GPIF ANOHR targets for combined cycle units, which will also be applied to recalculate the 2010 targets and to adjust the prior years' reward/penalty calculations. Implementing this refinement for prior years results in a credit to customers of $832,595 including interest, which FPL proposes to apply as a reduction to the 2009 GPIF reward of $8,948,495 that was presented in my April 1, 2010 testimony. FPL has included the revised 2009 reward of $8,115,900 in the calculation of its 2011 fuel cost recovery factors.

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

A. Yes, I am sponsoring the following three exhibits:

- Exhibit CP-2: This exhibit supports the development of the 2011 GPIF targets (EAF and ANOHR). The first page of this exhibit is an index to the contents of the exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.
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Q. **Please explain the nature of FPL's calculation refinement.**

A. FPL has identified and applied a refinement to its calculation of the combined cycle units' ANOHR. At the inception of the GPIF, FPL's fossil system generation was primarily fueled by oil. Accordingly, FPL applied a gas adjustment factor (GAF) to adjust the heat rates for units that are potentially dual-fuel (oil and gas) fired to an equivalent 100% oil-based ANOHR. This practice of using a GAF ensured consistent and comparative unit efficiency reporting relative to the primary fuel (as unit fuel mix varies year to year or when comparing actual to projected heat rates). Over time, however, the system-level GAF outlived its usefulness because it is not required for FPL's newer combined cycle units that are fired almost exclusively with gas, and that now are the primary fossil-fueled GPIF units. When adding Turkey Point Unit 5 as a new 2011 GPIF unit, FPL realized that the GAF was still being applied as new combined cycle units came into service, even though there was no longer a reason to do so. Therefore, the GAF was discontinued for the newer combined cycle units, and removed when calculating their ANOHR heat rates. This refinement updates combined cycle unit ANOHR heat rate calculations (both actual and target), for consistency with the current primary fuel (i.e. gas) at FPL's modern fossil power plants.

Q. Does this change affect the 2010 approved GPIF ANOHR targets for combined cycle units?

A. Yes. This change will be addressed later in my testimony.

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Q. **Has FPL applied interest to these annual credits that it is proposing to refund to customers?**

A. Yes.

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Q. How is FPL planning to refund the $832,595 credit to customers?

A. FPL plans to refund the full amount of the $832,595 credit as a reduction to the 2009 reward, from the $8,948,495 that was identified in my April 1, 2010 testimony to a revised 2009 reward of $8,115,900. FPL has included the revised 2009 reward in the calculation of its 2011 fuel cost recovery factors that will be approved in this docket, thus ensuring that customers are promptly and fully reimbursed.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF KATHY L. WELCH

Q. Please state your name and business address.

A. My name is Kathy L. Welch and my business address is 3625 N.W. 82nd Ave., Suite 400, Miami, Florida, 33166.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Public Utilities Supervisor in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since June, 1979.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Business Administration degree with a major in accounting from Florida Atlantic University and a Masters of Adult Education and Human Resource Development from Florida International University. I have a Certified Public Manager certificate from Florida State University. I am also a Certified Public Accountant licensed in the State of Florida, and I am a member of the American and Florida Institutes of Certified Public Accountants. I was hired as a Public Utilities Analyst I by the Florida Public Service Commission in June of 1979. I was promoted to Public Utilities Supervisor on June 1, 2001.

Q. Please describe your current responsibilities.

A. Currently, I am a Public Utilities Supervisor with the responsibilities of administering the District Office and reviewing work load and allocating resources to complete field work and issue audit reports when due. I also supervise, plan, and conduct utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you presented testimony before this Commission or any other regulatory agency?

A. Yes. I have testified in several cases before the Florida Public Service Commission. Exhibit KLW-1 lists these cases.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Power & Light Company (FPL or Utility) which addresses the Utility's August 1, 2009 through July 31, 2010 hedging activities. This audit report is filed with my testimony and is identified as Exhibit KLW-2.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in these audits.

A. We obtained a summary schedule of all financial futures, options and swaps that were executed by the Utility for the 12-month period ended July 31, 2010. We reconciled the monthly gain or loss to the Company's filing. We traced these gains and losses to the calculation of the average unit cost of gas and oil and to FPL's books and records. FPL's accounting treatment of hedging gains and losses was verified to be in compliance with Commission Order PSC-02-1484-FOF-EI, issued October 30, 2002.

We reviewed the Company's external auditor's reports and workpapers on derivative activity for the 12-month period ended July 31, 2010. We confirmed that FPL's accounting treatment is consistent with applicable FASB statements.

We obtained the monthly level of hedging gains and losses and verified that they are consistent with the requirements of Commission orders and FPL's Hedging Plans. We traced the monthly hedging gains and losses to the supporting documents that were used to prepare FPL's filing. FPL provided the "Derivative Settlements-All Instruments" report that shows the calculation of all gains and losses by deal options and swaps made by each counter party. This report was traced to the filing. A sample of the September 2009 natural gas and heavy oil transactions were selected for testing. The deals sampled were traced to confirmation letters, bank invoices, deal forms, and purchase statements. In addition, the settle price was traced to Platts and NYMEX market data. In order to trace the September 2009 gains and losses to the general ledger, account 151 Fuel Inventory, we first reconciled the gains and losses to the "Monthly Gas Closing Report" and "Allocation of Oil Financing Instrument" report, which, in turn, were reconciled to the general ledger.

We obtained the 2009 Risk Management and the Planned Position Strategy (PPS) procedures, which show the hedged targets by months. The natural gas and the heavy oil actual percentage hedged were compared to the target hedged and verified to the specified tolerance bands. If the actual percent hedged of a particular month was not within the tolerance band, then a rebalance would be required. The rebalancing was implemented by either purchasing or selling the swaps to meet the established targets. We verified and recalculated the percent of hedge amounts and the rebalancing by month. No exceptions were noted.

We verified that the Value at Risk Activities were within the transaction limits and authorization as stated in the Risk Management Plans.

We reviewed all of the invoices related to commission costs. No exceptions were noted.

We obtained an organizational chart and identified new employees since August 1, 2009. We obtained FPL's procedures related to the separation of duties and determined the change in the procedures from August 1, 2009 to July 31, 2010. We also compared the procedures and the employees to the prior audit to determine if any changes had been made.

We obtained a detail report from FPL's general ledger detailing the source of the transactions. A sample of the various charges was reviewed to determine if the charges were incremental in nature compared to prior years. We also reconciled the charges to invoices, expense reports and payroll reports. No exceptions were noted.

Q. Does the staff audit report of Florida Power & Light Company which addresses the Utility's annual Hedging Information Report and marked as Exhibit DDB-1 contain any findings noting any errors or exceptions taken by staff?

A. No it does not.

Q. Does this conclude your testimony?

A. Yes it does.

CHAIRMAN GRAHAM: All right. So where does that put us now?

MS. FLEMING: That brings us to the stipulations, Commissioners. Since the parties are proposing stipulations on all issues in this case, staff suggests that the Commission could make a bench decision in this proceeding. And if you would like, staff can go through and just address the stipulations because we do have different types of stipulations.

CHAIRMAN GRAHAM: Give us a preview -- I mean, give us an overview from the 50,000-foot level of the stipulations.

MS. FLEMING: I can give you an overview of the types of stipulations that we have, and for a more technical analysis, I would turn to the technical staff.

CHAIRMAN GRAHAM: Sounds good.

MS. FLEMING: There are proposed stipulations on all issues. We have two types of stipulations, Type B and Type C.

Type B Stipulations reflect an agreement between the IOU, FPL, and staff, with all other parties not objecting to the agreement.

Type C Stipulations are similar to Type B, but indicate that while FIPUG has concerns about FPL's hedging practices, it takes no position on those issues because it is FIPUG's understanding that the Commission will address hedging issues on a separate track and FIPUG will participate in that proceeding.

There are no type A stipulations.

In particular, the Type C stipulations are for Issues 2A, 2B, 8, 9, and 10. All remaining issues are Type B Stipulations.

And with that, if you'd like an overview for the technical portion, I can turn to our technical staff.

CHAIRMAN GRAHAM: Does anybody on the board need any more technical information on this? Nobody is swinging their hand, so let's crank on.

MS. FLEMING: Okay.

Commissioners, as we stated previously, a bench decision is appropriate if the Commissioners choose to vote on those issues today. If so, staff would recommend that the Commission approve the proposed stipulations as contained in the Prehearing Order on Pages 10 through 23.

CHAIRMAN GRAHAM: Do we need to make a motion to move these things as stipulated? Can I get a motion?

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

At this time I would move that we approve all of the stipulated issues as they are listed and described in Section X of the Prehearing Order.

CHAIRMAN GRAHAM: It has been moved and seconded. Any further discussion?

Commissioner Balbis.

COMMISSIONER BALBIS: Yes. I would just like -- staff, if you could just give a quick summary that this is culmination of months and months worth of work and negotiations with all the parties. And at least for the benefit of the public, it looks as if things are happening quickly, but it is really a culmination of a lot of hard work and a lot of material that I know we have all reviewed and staff have worked hard on, so if you could just give a real brief summary of those activities, that would be great.

MR. BARRETT: Yes, I can, Commissioner.

Michael Barrett of technical staff. As you know, the fuel cost-recovery docket is a continuous docket, and in the review cycle there are three distinct sets of testimony and exhibits that are filed, and staff reviews those. In addition to that, we have monthly filings of various types that come in. We review those on a continuous basis. And, you know, as a result of all of that review, some of the numeric stuff is audited, and staff reviews all of those things to verify that everything is in line, and that's the case with our stipulations today.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: All right.

Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Mr. Chairman.

I just wanted to second the motion.

CHAIRMAN GRAHAM: Gotcha. Sounds good.

All right. It has been moved and seconded to move Docket 02 as stipulated. Any further discussion?

COMMISSIONER BROWN: 01.

CHAIRMAN GRAHAM: 01; sorry. Typo. To move Docket 01 as stipulated; any further discussion? Seeing none, all in favor say aye.

(Vote taken.)

CHAIRMAN GRAHAM: Any opposed?

Seeing none, you have moved Docket 01 as stipulated. Are there any other matters to be addressed in Docket 01?

MS. FLEMING: We would just note, for the record, that since the Commission has made a bench decision, no post-hearing filings are necessary and the order will be issued by February 1st.

CHAIRMAN GRAHAM: Sounds good. All right. So we will adjourn Docket 01, and proceed on to Docket 02.

* * * * * * * * * *

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 28th day of January, 2011.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732