BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 110001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
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VOLUME 1

Pages 1 through 167

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Tuesday, November 1, 2011

TIME: Commenced at 9:30 a.m.
Concluded at 11:45 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6734

APPEARANCES

JOHN BUTLER and MARIA MONCADA, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

JOHN T. BURNETT, R. ALEXANDER GLENN, and DIANNE TRIPLETT, ESQUIRES, Progress Energy Service Co., LLC, 299 First Avenue North, St. Petersburg, Florida 33701-3324, appearing on behalf of Progress Energy Florida, Inc.

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Public Utilities Company.

JEFFREY A. STONE, ESQUIRE, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

JAMES D. BEASLEY, and J. JEFFRY WAHLEN, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, 32302, appearing on behalf of Tampa Electric Company.

APPEARANCES (Continued):

CHARLES REHWINKEL, JOSEPH A. MCGLOTHLIN, and PATRICIA CHRISTENSEN, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Strett, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

KAREN S. WHITE, ESQUIRE, USAF Utility Law Field Support Center, 139 Barnes Drive, Tyndall AFB, Florida 32403, appearing on behalf of the Federal Executive Agencies.

JON MOYLE, JR., ESQUIRE, Keefe, Anchors, Gordon & Moyle, P.A., 118 North Gadsden Street, Tallahassee, Florida 32312, appearing on behalf of the Florida Industrial Power Users Group.

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Wiener, Wadsworth, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of the Florida Retail Federation.

JAMES W. BREW and F. ALVIN TAYLOR, ESQUIRES, Brickfield, Burchette, Ritts & Stone, P.C., 1025 Thomas Jefferson Street, N.W., Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of PCS Phosphate - White Springs.

APPEARANCES (Continued):

LISA BENNETT and MARTHA BARRERA, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of Commission Staff.

MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, and SAMANTHA CIBULA, ESQUIRE, General Counsel's Office, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing as advisors to the Commission.

I N D E X

WITNESSES

P R O C E E D I N G S

CHAIRMAN GRAHAM: I want to thank everyone involved for those first three dockets. It always works very well for everybody when we can all come to agreement on what we need to do to move forward. That being said, we are now into Docket 110001. Any preliminary matters?

MR. BEASLEY: Chairman Graham, Jim Beasley for Tampa Electric Company.

CHAIRMAN GRAHAM: Sure.

MR. BEASLEY: One very minor preliminary matter on Page 57 of the Prehearing Order in this docket. There is a chart or Table 33-4 depicted on that page, and the very bottom value on that chart, the 0.0064 is missing one zero. It should be 0.00064.

CHAIRMAN GRAHAM: 00064.

MR. BEASLEY: And that's the only input we have preliminarily.

MS. BENNETT: We will note that correction in the final order.

CHAIRMAN GRAHAM: Okay.

MS. BENNETT: And there are several stipulations in the Prehearing Order. And, in fact, the only issues remaining in this docket are Issues 1C regarding the replacement power cost for the extended outage of the Crystal River Unit 3, and the what we call fallout issues regarding Progress in both the fuel and capacity related to the replacement power costs.

Also, for Florida Public Utilities Company, FPUC, there is an Issue 3B, and the fallout issue for that related to the demand allocation cost, there was a change that FPUC is suggesting. Other than that, there are -- all of the issues are stipulated in this docket.

CHAIRMAN GRAHAM: Have all parties been able to view all the stipulations other than those two that were read? Are there any concerns?

Okay. Prefiled testimony.

MS. BENNETT: Because there are so many -- there are several issues that are subject to proposed stipulations and many of the witnesses have been excused from the proceeding, Staff will ask that the prefiled testimony of all of the witnesses identified with an asterisk on Section VI, which is page -- which are found on pages 4 and 5 of your Prehearing Order, that that testimony be inserted into the record as though read. And there's one additional witness who was excused after the Prehearing Order was issued, and that's Progress Energy's Witness McCallister. So McCallister and all of the witnesses whose names were identified with an asterisk, we ask that those, that testimony be entered into the record as though read.

CHAIRMAN GRAHAM: So we're going to enter the testimony of all the witnesses on page 4 and page 5 of the prehearing testimony that are marked with an asterisk, as well as Witness McCallister; is that correct?

MS. BENNETT: That is correct.

CHAIRMAN GRAHAM: We're entering all of those into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 110001-EI

APRIL 1, 2011

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 2010. 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 were 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 – August through December 2010 Hedging Activity 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 implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL's 2010 Risk Management Plan that was approved by the Commission in Order No. PSC-09-0795-FOF-EI, issued on December 2, 2009.

Q. Please summarize FPL's 2010 hedging activities.

A. Consistent with its approved 2010 Risk Management Plan, FPL hedged its fuel portfolio for 2010 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 2010 natural gas prices declined from the forward prices that were in effect when FPL was executing its natural gas hedges for 2010. As would be expected under the approved hedging approach, this decline in natural gas prices resulted in reported natural gas hedging costs for the year, as shown on Exhibit GJY-1. Conversely, heavy oil prices increased from the forward prices that were in effect when FPL was executing its heavy oil hedges for 2010. As shown on Exhibit GJY-1, this resulted in reported heavy oil hedging savings for the year.

Q. Does your Exhibit GJY-1 provide the detail on FPL's 2010 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. 110001-EI

SEPTEMBER 1, 2011

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 2011 hedging program and its 2012 Risk Management Plan. Lastly, I present the projected fuel savings resulting from the operation of West County Energy Center Unit 3 (WCEC 3) during 2012.

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-2: 2012 Risk Management Plan
- GJY-3: Hedging Activity Supplemental Report for 2011 (January through July)
- GJY-4: Appendix I
- Schedules E2 through E9 of Appendix II

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2012 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 1, 2011 for its 2012 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 2012 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 supply and demand for heavy oil in the domestic market; (8) the terms of FPL's supply and fuel transportation contracts; and (9) domestic and global inventory. In recent years, the price relationship between heavy oil and natural gas has been listed as one of the key factors affecting FPL's price for heavy oil. This relationship no longer appears relevant as heavy oil is primarily impacted by global forces and natural gas is primarily a domestic product with the growth in shale gas production.

With the global economy projected to continue its slow recovery from the recession, global demand for oil is expected to increase modestly in 2012. According to the latest information from the PIRA Energy Group, demand in 2012 is forecasted to be 1.7% above projected 2011 levels and 2.9% above actual 2010 demand. Consistent with this trend, crude oil and refined petroleum product prices, like heavy and light fuel oil, should continue to slowly rise over the 2011 to 2012 period. Non-OPEC production is projected to be 1.2% above forecasted 2011 levels and 0.9% above actual 2010 production. Sufficient OPEC production capacity is expected to be available to meet the balance of the projected increase in demand and will help moderate the price of oil. A greater-than-expected economic recovery resulting in higher-than-expected oil demand would put upward pressure on price. Conversely, a weaker-than-expected global economic recovery would 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 2012 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 2012 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 2012 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 2012 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; and (3) the terms of FPL's natural gas supply and transportation contracts. As mentioned previously, the price relationship between natural gas and heavy oil no longer appears to be one of the factors impacting the price FPL pays for natural gas.

Similar to oil, the major driver for natural gas prices during the remainder of 2011 and all of 2012 revolves around economic recovery and an associated increase in demand as well as domestic natural gas production, particularly from non-conventional sources. Future prices reflect this expectation of economic recovery. According to the latest information from the PIRA Energy Group, natural gas demand in 2011 is projected to be 2.3% over 2010 actual levels and 2012 is forecasted to be 1.9% over 2011. Although the number of working natural gas rigs is down about 44%

since August 2008, domestic production from non-conventional sources has created, 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 above historical average levels through the 2011 injection season.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2012 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 3,100,000 MMBtu/day (post-Phase VIII expansion) and the current capacity of Gulfstream is approximately 1,260,000 MMBtu/day. FPL's total firm transportation capacity on FGT ranges from 1,150,000 to 1,274,000 MMBtu/day, depending on the month. FPL has firm transportation capacity on Gulfstream of 695,000 MMBtu/day.

Additionally, FPL has 500,000 MMBtu/day of firm transport on the

Southeast Supply Header (SESH) pipeline and 200,000 MMBtu/day of firm transport on the Transcontinental Pipe Line Gas Company, LLC (Transco) Zone 4A lateral. 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 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 2012 period, 80,000 MMBtu/day to 200,000 MMBtu/day of non-firm natural gas transportation capacity will be available into the state, depending on the month. 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 2012 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 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 2012?

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 2012.

Q. Please describe the significant planned outages for the January through December 2012 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 1 is scheduled to be out of service from November 26, 2011 until April 1, 2012 or 91 days during the period. Turkey Point Unit 3 is scheduled to be out of service from January 30, 2012 until July 8, 2012 or 160 days during the period. St. Lucie Unit 2 is scheduled to be out of service from July 9, 2012 until October 30, 2012 or 113 days during the period. Turkey Point Unit 4 is scheduled to be out of service from November 5, 2012 until March 15, 2013 or 57 days during the period. These outages are lengthier than typical refueling outages at FPL's nuclear units because of extended power uprate (EPU) work that is scheduled during the outages. FPL's EPU projects were recently addressed in Docket No. 110009-EI.

Q. Please list any changes to FPL's fossil generation capacity projected to take place during the January through December 2012 period.

A. FPL does not project any fossil generation capacity changes during 2012.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2012?

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. Over the last two years, as the price spread between natural gas and heavy oil has widened, FPL's economy purchases have markedly increased, while economy sales have decreased. FPL's opportunities to purchase economic power during peak periods, when heavy oil becomes the marginal fuel have grown as heavy oil prices are approximately three times that of natural gas. Likewise, economy sales opportunities have diminished as FPL's cost to generate power during peak periods has increased with the price of heavy oil. While this has been the recent trend, FPL's customers continue to benefit as both purchases and sales allow 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 497,000 MWh of wholesale (off-system) power sales for the period of January through December 2012. The projected fuel cost related to these sales is $21,373,355. The projected transaction revenue from these sales is $27,984,917. The projected gain for these sales is $5,093,861.

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 2012 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 1,609,150 MWh at a cost of $78,556,181. If FPL generated this energy, FPL estimates that it would cost $124,142,358. Therefore, these purchases are projected to result in savings of $45,586,176.

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. FPL also has a capacity agreement for part of 2012 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. Additionally, FPL is currently finalizing a capacity agreement with a third-party provider for the output of two combustion turbines totaling 305 MW. This agreement will run from January 1, 2012 through December 31, 2012. The disclosure of the third-party provider is commercially sensitive information prior to the execution of a contract and, therefore, FPL has identified this provider as confidential information on Schedule E12. 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 2012 period.

A. UPS energy purchases for the period are projected to be 3,241,156 MWh at an energy cost of $128,583,465. 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 2,490,309 MWh for the period at an energy cost of $101,395,000. 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 339,326 MWh at a cost of $2,218,267. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 311,888 MWh from its capacity agreements at a cost of $20,895,108. 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 3,807,454 MWh at a cost of $182,889,430.

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

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

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

A. FPL projects to sell 455,894 MWh of energy at a cost of $3,499,579. These projections are shown on Schedule E6 of Appendix II.

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 2012, 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 2012 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up filing on August 1, 2011. The 2012 Risk Management Plant is included as Exhibit GJY-2.

Q. Please provide an overview of FPL's 2012 Risk Management Plan.

A. FPL's 2012 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 2012 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2012 for its projected fuel requirements in 2013. FPL plans to hedge the percentages of its 2013 projected natural gas and heavy oil requirements over the time periods in 2012 that are described in the plan.

Q. Has FPL filed a Hedging Activity Supplemental Report 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 Hedging Activity Supplemental Report for 2011 (January through July) on August 15, 2011. The Hedging Activity Supplemental Report is included as Exhibit GJY-3.

Q. Have FPL's 2011 hedging strategies been successful in achieving FPL's 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 2011 projected natural gas and heavy oil requirements, market prices were different than the actual settlement prices that have occurred in 2011.

For example, at the beginning of January 2010, the average monthly NYMEX forward price for natural gas for the January through July 2011 time period was approximately $6.480 per MMBtu. At the end of July 2010, the average monthly NYMEX forward price for the January through July 2011 time period was approximately $5.196 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $4.232 per MMBtu or $2.248 per MMBtu lower than the forward prices seen in January and $0.964 per MMBtu lower than the forward prices seen in July. Conversely, in January 2010, the average forward price for heavy oil for the January through July 2011 time period was approximately $77.76 per barrel. In July 2010, the average forward price for heavy oil for the January through July 2011 time period was approximately $73.26 per barrel. The actual average settlement price for heavy oil for this same time period was $98.63 per barrel or $20.87 per barrel higher than the forward prices seen in January and $25.37 per barrel higher than the forward prices seen in July. As described in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for natural gas results in 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.

<u>CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF WCEC 3</u>

Q. Will the operation of WCEC 3 during 2012 result in fuel savings to FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the January through December, 2012 period, the operation of WCEC 3 is projected to save FPL's customers $190,367,526.

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

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the operation 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 $190,367,526 lower in the case that included WCEC 3 than in the case without WCEC 3.

Q. Is your calculation of $190,367,526 in WCEC 3 fuel savings consistent with Paragraph 5(c) of the Stipulation and Settlement that was approved by the Commission in Docket No. 080677-EI?

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 RENAE B. DEATON

DOCKET NO. 110001-EI

September 1, 2011

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

A. My name is Renae B. Deaton. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Rate Development Manager in the Rates & Tariffs Department. My business address is Florida Power & Light Company, 700 Universe Blvd., Juno Beach Florida 33408.

Q. Please describe your educational and employment background.

A. I hold a Bachelor of Science in Business Administration and a Masters of Business Administration from Charleston Southern University. Since joining FPL in 1998, I have held positions in the Rates & Tariffs department and the Regulatory Affairs department. Prior to this, I was employed at South Carolina Public Service Authority (d/b/a Santee Cooper) for fourteen years, where I held a variety of positions in the Corporate Forecasting, Rates, and Marketing Departments and in generation plant operations.

Q. What are the responsibilities of your present position?

A. I am responsible for developing electric rates at both the retail and wholesale levels.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the changes to the methodology used in the calculation of FPL's Time-of-Use ("TOU") Fuel factors. FPL proposes to develop the TOU fuel factors based on marginal cost.

Additionally, I support the use of seasonally differentiated fuel factors for the TOU rates.

Q. What is meant by marginal fuel cost?

A. Marginal fuel cost is defined as the cost of fuel that a utility burns to generate the last MWh of electricity needed to serve its load. Use of marginal fuel cost for the TOU fuel factors sends customers price signals that reflect the incremental cost to FPL of their electric consumption, rather than the average cost of fuel used to serve all MWh of load during the time period in question.

Q. What is meant by seasonally differentiated fuel cost?

A. FPL's TOU on-peak periods are differentiated based on the load patterns during months of April through October and November through March. The projected cost of fuel during the on-peak periods in the November through March time period are less than the projected cost of fuel during the on-peak periods in the April through October time period. Seasonal differentiation of the TOU fuel factors for April through October and November through March would reflect this cost differential.

Q. Why Is FPL proposing to change the methodology used in the calculation of its TOU rates?

A. In Order No. PSC-11-0216-PAA-EI, issued in Docket No. 100358-EI on May 11, 2011, the Commission directed FPL to investigate whether TOU fuel factors based on marginal cost would benefit its customers and provide system benefits, and to report back its findings to the Commission in testimony in this year's proceeding. Additionally, the Commission directed FPL to investigate whether TOU fuel factors based on seasonal differentiation would benefit its customers. FPL witness Keith has provided three sets of TOU fuel factors for the period January 2012 through December 2012. Appendix II contains 2012 TOU fuel factors calculated using seasonally differentiated marginal fuel cost, Appendix III contains 2012 TOU fuel factors calculated using marginal fuel cost, and Appendix IV contains 2012 TOU fuel factors calculated using average total system fuel cost. The price differential between the on-peak and the off-peak fuel factors using average total system fuel cost is approximately 0.55 ¢/kWh. Using marginal fuel costs that are not seasonally differentiated, the price differential between the on-peak and the off-peak fuel factors is approximately 2.5 ¢/kWh. Finally, using seasonally differentiated marginal fuel cost, the on-peak and off-peak price differential is approximately 3.2 ¢/kWh during April through October and approximately 1.2 ¢/kWh during November through March.

Although FPL believes that its current methodology for calculating TOU fuel factors based on average total system fuel cost is reasonable and the methodology has also been approved by the Commission in prior annual fuel proceedings, FPL also believes that calculating TOU fuel factors based on marginal fuel cost increases the on-peak and off-peak differential and provides a stronger price signal to customers. Additionally, FPL believes that using seasonally differentiated fuel cost to develop the TOU fuel factors better tracks the cost of fuel during the months when such cost are expected to be incurred. Therefore, FPL proposes that the Commission approve FPL's 2012 TOU fuel factors based on seasonally differentiated marginal fuel cost.

Q. What impact will the use of seasonally differentiated TOU fuel factors

based on marginal cost have on FPL's customers and the system?

A. The impact will vary based on customer response to the price signals. Increasing the on-peak energy price signal should better encourage off-peak usage and reduce on-peak usage. Reducing on-peak usage may reduce the use of higher cost fuel and result in lower fuel cost for all customers. Also, current TOU customers that experience savings due to reduced on-peak energy usage may experience greater savings under the proposed fuel factors due to the lower off-peak price.

Q. Has FPL used the same on-peak and off-peak time periods for the TOU fuel factors as those used for base rates?

A. Yes. TOU customers need a clear price signal to understand when to reduce usage. Currently, TOU customers are made aware of the on-peak time periods for November through March and April through October through bill inserts and other communications. TOU customers have adjusted their processes and usage to benefit from the TOU rates. If fuel prices have differing on-peak time period than base rates, customers will not have a clear price signal to know when to shift usage and therefore, the benefits of TOU rates may not be realized. This would lead to customer confusion and complaints regarding overly-complicated TOU pricing. Also, having differing on-peak and off-peak time periods for the TOU fuel factors than those used for base rates would require significant changes to FPL's metering and billing systems.

Q. The cost of fuel varies from month to month. Should FPL use monthly TOU fuel factors?

A. No. While the actual cost of fuel is volatile and changes month to month and hour to hour, some averaging is appropriate to provide predictability for customers. The appropriate time period over which to average fuel cost is the April through October and November through March time period established in base rates. As discussed previously, TOU customers are already aware of the two seasonal changes to the on-peak and off-time periods.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 110001-EI

MARCH 1, 2011

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 2010 through December 2010. The Net True-Up for the FCR is an under-recovery, including interest, of $45,498,496. The Net True-Up for the CCR is an over-recovery, including interest, of $3,364,670. FPL is requesting Commission approval to include the FCR true-up under-recovery of $45,498,496 in the calculation of the FCR factor for the period January 2012 through December 2012. FPL is also requesting Commission approval to include the CCR true-up over-recovery of $3,364,670 in the calculation of the CCR factor for the period January 2012 through December 2012.

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 2010 through December 2010 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 2010 through December 2010, an under-recovery of $45,498,496.

The Summary of the Net True-up amount shown on Appendix I, page 3 shows the actual End-of-Period True-Up under-recovery for the period January 2010 through December 2010 of $253,467,342 on line 1. The Actual/Estimated True-Up under-recovery for the same period of $207,968,846 is shown on line 2. Line 1 less line 2 results in the Net Final True-Up for the period January 2010 through December 2010 shown on line 3, an under-recovery of $45,498,496.

The calculation of the true-up amount for the period follows the procedures established by this Commission as 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 2010 through December 2010.

Q. Have you provided a schedule showing the variances between actual and actual/estimated fuel costs and applicable revenues for 2010?

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 under-recovery of $253,467,342 to the Actual/Estimated End-of-Period True-up under-recovery of $207,968,846 resulting in the variance of $45,498,496.

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 $45,498,496 variance was due primarily to an increase in the fuel cost per MWh ($43.77/MWh vs. $43.32/MWh) that results in an increase of $47,521,719, and an increase in fuel revenues per MWh ($37.97/MWh vs. $37.96/MWh) that results in an increase of $1,423,295. The impact of the MWh variance due to consumption on the cost per MWh and the revenues per MWh virtually offset each other, netting to a decrease of $570,750. Finally, the variance reflects a decrease of $29,180 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 $42,732,104. As shown on Appendix I, page 7, this $42.7 million increase in Adjusted Total Fuel Costs and Net Power Transactions was due primarily to a $36.2 million (0.9%) increase in the Fuel Cost of System Net Generation, a $17.6 million (6.6%) increase in the Fuel Cost of Purchased Power, a $1.2 million (6.0%) variance in the Fuel Cost of Power Sold, a $2.5 million (5.0%) variance in the sales to Florida Keys Electric Cooperative (FKEC) and City of Key West Electric Cooperative (CKW) and $0.4 million (7.9%) variance in Gains from Off-System Sales. These amounts are partially offset by a $10.4 million (6.9%) decrease in Energy Cost of Economy Purchases, and a $3.5 million (2.0%) decrease in Energy Payments to Qualifying Facilities.

As shown on the December 2010 A3 Schedule, the $36.2 million (0.9%) increase in the Fuel Cost of System Net Generation was primarily due to $48.7 million (1.5%) higher than projected natural gas and $7.0 million (20.2%) higher than projected light oil, partially offset by $13.0 million (2.6%) lower than projected heavy oil, $2.6 million (1.7%) lower than projected coal, and $3.8 million (2.7%) lower than projected nuclear.

Natural gas averaged $6.36 per MMBtu, $0.07 per MMBtu (1.1%) less than projected, but 13,241,906 more MMBtus (2.6%) of natural gas were used during the period than projected. Of the $48.7 million natural gas variance, $85.1 million was due to higher consumption, partially offset by $36.4 million due to lower prices.

Light oil averaged $13.84 per MMBtu, $0.16 per MMBtu (1.2%) higher than projected, plus 473,540 more MMBtus (18.8%) of light oil were used during the period than projected. Of the $7.0 million light oil variance, $6.5 million was due to higher consumption and $0.5 million was due to higher prices.

Heavy oil averaged $11.49 per MMBtu, $0.01 per MMBtu (0.1%) higher than projected, but 1,181,273 less MMBtus (2.7%) of heavy oil were used during the period than projected. Of the $13.0 million heavy oil variance, $13.6 million was due to lower consumption, partially offset by $0.6 million due to higher prices.

Coal averaged $2.59 per MMBtu, $0.06 per MMBtu (2.4%) higher than projected, but 2,466,792 less MMBtus (4.0%) of coal were used during the period than projected. Of the $2.6 million coal variance, $6.2 million was due to lower consumption, partially offset by $3.6 million due to higher prices.

Nuclear power averaged $0.55 per MMBtu, $0.01 per MMBtu (1.0%) less than projected, and 4,387,287 less MMBtus (1.7%) of nuclear were used during the period than projected. Of the $3.8 million nuclear variance, $2.4 million was due to lower consumption and $1.4 million was due to lower prices.

The Fuel Cost of Purchased Power was $17.6 million (6.6%) higher than projected primarily due to the following:

- Fuel costs for UPS purchases were approximately $9.7 million higher than projected. Approximately 90%, or $8.7 million, of this variance was due to higher than projected purchases. FPL purchased approximately 263,000 MWh more than projected. Approximately 10%, or $1.0 million, of the variance was due to higher than projected unit costs. The average cost for UPS purchases was approximately $0.19 per MWh higher than estimated.

- Fuel costs for SJRPP purchases were approximately $4.9 million higher than projected. Approximately 57%, or $2.8 million, of the variance was due to higher than projected purchases. FPL purchased approximately 87,000 MWh more than it estimated. Approximately 43%, or $2.1 million, of the variance was due to higher than projected unit costs. The average cost for SJRPP purchases was approximately $0.72 per MWh higher than estimated.

- Fuel costs for PPA purchases were $2.6 million higher than projected. Lower unit costs were offset by increased purchase volumes. FPL paid approximately $1.60 per MWh less than projected over the period, while purchasing approximately 48,000 MWh more energy when compared to projections.

- Fuel costs of St. Lucie Reliability purchases were $304,000 higher than projected. Approximately 40% of the variance was due to increased unit costs. FPL paid approximately $0.22 per MWh more than estimated. Approximately 60% of the variance was due to higher than projected purchases. FPL purchased approximately 31,500 MWh more than projected.

The variance in the Fuel Cost of Power Sold was $1.2 million (6.0%). Approximately 49%, or $0.6 million, of the variance was due to lower than projected economy sales. FPL sold approximately 26,000 MWh less of economy power than projected. Approximately 51%, or another $0.6 million, was due to lower than projected fuel costs for power sales. The average unit cost of fuel attributable to power sales was approximately $0.72 per MWh less than projected.

The $2.5 million (5.0%) variance in sales to FKEC and CKW was primarily due to approximately 463,000 less MWh sales than anticipated.

The Energy Cost of Economy Purchases was $10.4 million (6.9%) lower than projected. This variance was primarily due to lower than projected economy purchases. Approximately $13.5 million of the variance was due to FPL purchasing approximately 218,000 MWh less than projected. This amount was offset by $3.1 million due to a slightly higher than projected unit cost for economy purchases. The average unit cost was approximately $1.42 per MWh higher than projected.

The Energy Payments to Qualifying Facilities were $3.5 million (2.0%) lower than projected. Approximately 71% of this variance was due to lower than projected unit costs paid to cogenerators. The average unit cost paid per MWh was $0.59 less than projected, resulting in an approximately $2.5 million cost reduction when compared to estimates. The remaining variance was due to lower than projected MWh purchases. FPL purchased approximately 25,000 MWh less than projected.

The variance in Gains from Off-System Sales was $377,612 (7.9%). Approximately 73%, or $276,119, of the variance was due to lower than projected economy sales. FPL sold approximately 26,000 MWh less of economy power than projected. Approximately 27%, or $101,494, was due to lower than projected gains on economy sales. The average gain on economy sales was approximately $0.23 per MWh less than projected.

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 approximately $2.6 million (0.1%) lower than the actual/estimated projection, reflecting lower than projected jurisdictional sales, a variance of 106,508,188 kWh (0.1%), partially offset by higher average revenues per kWh sold.

Q. Pursuant to Commission Order No. PSC-11-0094-FOF-EI, FPL's 2010 gains on non-separated wholesale energy sales are to be measured against a three-year average Shareholder Incentive Benchmark of $15,415,773. Did FPL exceed this benchmark?

A. No.

Q. What is the appropriate final Shareholder Incentive 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 year 2011, the three year average Shareholder Incentive Benchmark consists of actual gains for 2008, 2009 and 2010 (see below) resulting in a three year average threshold of $10,707,967.

2008	$17,001,482
2009	$10,700,431
2010	$ 4,421,987

Gains on sales in 2011 are to be measured against the three-year average Shareholder Incentive Benchmark of $10,707,967.

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 2010 through December 2010, an over-recovery of $3,364,670, which FPL is requesting to be included in the calculation of the CCR factors for the January 2012 through December 2012 period.

The actual End-of-Period under-recovery for the period January 2010 through December 2010 of $82,569,130 (shown on page 3, line 1) less the Actual/Estimated End-of-Period under-recovery for the same period of $85,933,800 (shown on page 3, line 2) that was approved by the Commission in Order No. PSC-11-0094-FOF-EI, results in the Net True-Up over-recovery for the period January 2010 through December 2010 of $3,364,670 (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 2010 through December 2010 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 actual and actual/estimated capacity charges and applicable revenues for 2010?

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to actual/estimated capacity charges and applicable revenues for the period January 2010 through December 2010.

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 $1,723,293 or 0.3%. This $1.7 million variance was primarily due to an $8.8 million (17.9%) decrease in Incremental Plant Security Costs, a $1.0 million (12.1%) decrease in Transmission of Electricity by Others and a variance of $54,273 (4.9%) associated with Transmission Revenues from Capacity Sales. These decreases were partially offset by a $3.3 million (5.5%) increase in Short Term Capacity Payments, a $2.9 million (1.8%) increase in Payments to Non-cogenerators and a $1.7

million (0.6%) increase in Payments to Cogenerators.

The $8.8 million (17.9%) decrease in Incremental Plant Security Costs was primarily due to the deferral of the Part 73 Cyber Security Critical Digital Assessment, until the NRC accepts FPL's proposed plan. FPL expects to begin the implementation of the plan in 2011. Additionally, costs associated with the Regulated Security Solutions (RSS) vacation buy-out, G&A and overtime were less than anticipated. Finally, the NERC CIP-002 estimates for 2010 associated with the Final Milestone Requirements for documentation have shifted into 2011 due to vendors not meeting critical milestones in 2010.

The $1.0 million (12.1%) decrease in Transmission of Electricity by Others was primarily due to higher than projected power purchases, resulting in lower than projected unutilized transmission costs.

The variance of $54,273 (4.9%) associated with Transmission Revenues from Capacity Sales was primarily due to lower than projected economy power sales. FPL sold approximately 26,000 MWh less economy power than projected.

Short Term Capacity Payments were $3.3 million (5.5%) higher than projected. Approximately 36%, or $1,183,287 of this variance was due to the reclassification of Change In Law payments made to Southern Company under the UPS agreements from the fuel clause to the capacity clause. This reclassification was made in September 2010, with all prior Change In Law payments being transferred to the capacity clause. Approximately 64%, or $2,139,680, of this variance was due to Capacity Availability Performance Adjustment (CAPA) payments made to Southern Company under the new UPS agreements, which were not included in prior estimates. The CAPA provisions serve to adjust FPL's monthly capacity payments (up or down) based on availability of the UPS units. FPL did not forecast any CAPA payments or credits in its Actual/Estimated filing in 2010 or in its annual FCR filing for 2011, as the new UPS agreement only began in June 2010 and there were insufficient data on how the CAPA would operate at that time to make projections for those periods. FPL believes that it will be able to include CAPA estimates beginning with its Actual/Estimated filing in 2011, as slightly over one year of historical data will be available at that time.

The Payments to Non-cogenerators are $2.9 million (1.8%) higher than projected. The primary cause of the variance was increased JEA O&M expense charges to FPL, which resulted from purchasing approximately 87,000 more MWh than originally projected. This was partially offset by approximately $109,000 due to Southern Company (1988 UPS Contract) true-ups for tax expenses, depreciation expenses, and variable O&M expenses.

The $1.7 million (0.6%) increase in Payments to Cogenerators was primarily due to better performance and, therefore, higher than projected capacity payments to both Cedar Bay and Indiantown contracts. The payments to

Cedar Bay were approximately $718,000 higher than estimated. The payments to Indiantown were approximately $905,000 higher than estimated.

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

A. As shown on page 6, line 15, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes), were $1,636,136 (0.3%) higher than the actual/estimated projection. This $1,636,136 increase in revenues, plus the $1,723,293 decrease in costs and $5,245 decrease in interest (page 6, line 17), results in the final over-recovery of $3,364,670.

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 2010 through December 2010.

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. 110001-EI

August 1, 2011

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 Actual/Estimated True-up amounts for the Fuel Cost Recovery (FCR) Clause and the Capacity Cost Recovery (CCR) Clause 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 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 2011 through December 2011. FCR Schedules A1 through A9 provide actual data for the period January 2011 through June 2011. 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 actual/estimated variances and the actual/estimated true-up amount for the period January 2011 through December 2011.

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

A. Unless otherwise indicated, the actuals data are 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 and CCR true-up calculations compare actual/estimated data consisting of actuals for January 2011 through June 2011, and revised estimates for July 2011 through December 2011.

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 2011.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the FCR End-of-Period Net True-up and Actual/Estimated 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 Actual/Estimated True-up amounts. The End-of-Period Net True-up amount to be carried forward to the 2012 fuel factor is an under-recovery of $168,290,077 (Appendix I, Page 3, Column 13, Line C11). This $168,290,077 under-recovery includes the 2010 Final True-up under-recovery of $45,498,494 (Appendix I, Page 3, Column 13, Line C9b), filed with the Commission on March 1, 2011, and the Actual/Estimated True-up under-recovery, including interest, of $122,791,583 (Appendix I, Page 3, Column 13, Lines C7 plus C8) for the period January 2011 through December 2011.

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 actual/estimated true-up by month?

A. Yes. Appendix I, Pages 2 and 3 entitled "Calculation of True-Up Amount," show the calculation of the FCR Actual/Estimated True-up by month for the period January 2011 through December 2011.

Q. Have you provided a schedule showing the variances between actual/estimated and original projections for 2011?

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 actual/estimated period data to the data from the original projections filing for the January 2011 through December 2011 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 ($168,290,077) variance is primarily due to an increase in fuel costs per MWh of $40.66/MWh vs. $39.60/MWh that results in a cost variance of $110,344,204, and a decrease in fuel revenues per MWh of $41.65/MWh vs. $41.80/MWh that results in a cost variance of ($15,099,020), for a total variance due to cost of ($125,443,225). 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 $3,074,093. When the interest amount of ($422,452) associated with the 2011 actual/estimated true-up amount and the 2010 Final True-up under-recovery amount of ($45,498,494) are added to the calculation, the total amount of the variance results in the ($168,290,077).

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

A. FPL's original projections filed on December 2, 2010 projected Jurisdictional Total Fuel and Net Power Transactions to be $4.042 billion for 2011 (Appendix I, Page 5, Column 2, line C6). The Actual/Estimated Jurisdictional Total Fuel Costs and Net Power Transactions are now projected to be $ 4.207 billion for that period (actual data for January 2011 through June 2011 and revised estimates for July 2011 through December 2011) (Appendix I, Page 5, Column 1, Line C6). Therefore, Jurisdictional Total Fuel Costs and Net Power Transactions are $165,599,651, or 4.1% higher than the original projections filing (Appendix I, Page 5, Column 3, Line C6). Jurisdictional Fuel Revenues for 2011 are projected to be $43,230,520, or 1.1% 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 $165,599,651 million is a 4.1% increase from original projections. The primary reasons for this variance are higher than projected Energy Cost of Economy Purchases ($44.1 million), higher than projected Fuel Cost of Purchased Power ($37.1 million), higher than projected Fuel Cost of System Net Generation ($25.6 million), higher than projected Energy Payments to Qualifying Facilities ($18.3), lower than projected Fuel Cost of Power Sold ($17.9 million), and lower than projected Gains from Off-System Sales ($4.7 million).

The $25.6 million or 0.7 % increase in the Fuel Cost of System Net Generation is primarily due to higher than projected nuclear generation costs, light oil costs, natural gas costs and coal costs, partially offset by lower than projected heavy oil costs.

Nuclear generation costs are currently projected to be $20.3 million (13.8%) higher than the original projection. The unit cost of nuclear generation in the actual/estimated period is $0.70 per MMBTU, which is 10.4% higher than the $0.63 per MMBTU included in the original projection. Additionally, nuclear consumption in the actual/estimated period is projected to be 240,852,841 MMBTUs, which is 3.0% higher than the 233,788,606 MMBTUs included in the original projection.

Light oil costs are currently projected to be $18.1 million (221.5%) higher than the original projection. The unit cost of light oil in the actual/estimated is $18.88 per MMBTU, or 14.4% higher than the $16.50 per MMBTU included in the original projection. Additionally, light oil burn in the actual/estimated period is projected to be 1,393,926 MMBTUs, which is 181.1% higher than the 495,918 MMBTUs included in the original projection.

Natural gas is currently projected to be $12.2 million (0.4%) higher than the original projection. The unit cost of natural gas in the actual/estimated period is $6.08 per MMBTU, which is 2.7% lower than the $6.24 per MMBTU included in the original projection. Consumption of natural gas in the actual/estimated period is projected to be 533,032,777 MMBTUs, which is 3.2% higher than the 516,692,886 included in the original projection.

Coal is currently projected to be $4.7 million (2.7%) higher than the original projection. The unit cost of coal in the actual/estimated period is $2.79 per MMBTU, which is 10.9% higher than the $2.51 per MMBTU included in the original projection and coal consumption decreased by 7.4% compared to the original projection.

Heavy oil is currently projected to be $30.0 million (16.6%) lower than the original projection. The unit cost of heavy oil in the actual/estimated period is $13.63 per MMBTU, which is 10.3% higher than the $12.37 per MMBTU included in the original projection. Additionally, heavy oil burn in the actual/estimated period is projected to be 11,006,979 MMBTUs, which is 24.3% lower than the 14,546,814 MMBTUs included in the original projection. Projections for Generation by Fuel Type for the period July 2011 through December 2011 are included in Appendix I, Schedule E3.

The $44.1 million, or 61.1% increase in Energy Cost of Economy Purchases is primarily due to higher than projected economy purchases. FPL projects that it will purchase approximately 520,000 MWh more of economy energy than its original projections. Higher economy purchases result in a volume variance of approximately $26.8 million, or 61% of the total variance. FPL also projects that the cost of economy purchases will be $8.97/MWh higher than originally projected. Higher costs for economy purchases result in a variance of approximately $17.2 million, or 39% of the total variance.

The $37.1 million or 16.8% increase in Fuel Cost of Purchased Power is primarily due to higher than projected fuel costs related to UPS and SJRPP purchases. FPL projects that the unit cost of UPS and SJRPP will be $2.78/MWh higher and $12.42/MWh higher than its original projections, respectively. Higher than projected fuel costs resulted in a variance of approximately $46.2 million (124%) which is slightly off-set by approximately $9 million (-24%) due to lower than projected overall purchases. SJRPP is the primary cause of the volume variance with approximately 582,000 MWh less in purchases than the original projections. The combination of higher fuel costs and lower volume results in a total variance of $37,148,322.

The $18.3 million, or 12.4% increase in Energy Payments to Qualifying Facilities (QF) is primarily due to higher than projected fuel costs related QF purchases. FPL projects that the unit cost of QF purchases will be $5.36/MWh higher than its original projections. Higher than projected fuel costs resulted in a variance of approximately $18.9 million (103%) which is slightly off-set by approximately $0.60 million (-3%) due to lower than projected QF purchases. FPL now projects to purchase approximately 15,200 MWh less from QF's than its original projections. The combination of higher fuel costs and lower volume results in a total variance of $18,322,651.

The $17.9 million, or 46.1% decrease in Fuel Cost of Power Sold is primarily due to lower than projected economy sales and lower than projected fuel costs for economy sales. FPL currently projects that it will sell approximately 393,000 MWh less of economy power than originally projected. Additionally, FPL projects that its average fuel cost attributable to economy sales will be $35.79/MWh as compared to an original estimate of $41.79/MWh. The total variance related to fuel costs of economy sales is approximately $19.3 million lower than projected. Of this total, approximately 85% is due to lower than projected economy sales and the remaining 15% is due to lower than projected fuel costs for economy sales. The $19.3 million variance is slightly off-set by higher than projected sales and costs related to the St. Lucie Reliability Exchange. Overall, the total variance of $17,940,393 for Fuel Cost of Power Sold is 48% attributable to lower than projected sales and 52% attributable to lower than projected fuel costs.

The $4.7 million, or 48.8% decrease in Gains from Off-System Sales is primarily due to lower than projected economy sales. While FPL currently projects that its average margin on economy sales will be slightly lower than originally projected (approximately $0.76/MWh lower), the major cause for the variance is that FPL now projects to sell approximately 393,000 MWh less in economy sales than its original projections. Approximately 92% of the total variance of

$4,748,320 is attributable to lower than projected economy sales. The remaining 8% is attributable to lower than projected average margins on economy sales.

Q. What is the appropriate estimated benchmark level for calendar year 2012 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 2012, the three-year average threshold consists of actual gains for 2009, 2010 and January 2011 through June 2011, and estimates for July 2011 through December 2011. Gains on sales in 2012 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 2012) to include all actual data for the year 2011.

2009	$10,700,431
2010	$4,421,987
2011	$4,988,926
Average threshold	$6,703,781

CAPACITY COST RECOVERY CLAUSE

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

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

Actual/Estimated True-up amount. The calculation of the Actual/Estimated True-up for the period January 2011 through December 2011 is an over-recovery of $28,750,824 including interest (Appendix II, Page 3, Column 13, Lines 15 plus 16).

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 actual/estimated and the original projections?**

A. Yes. Appendix II, Page 4 shows the actual/estimated capacity charges and applicable revenues (January 2011 through June 2011 reflects actual data and the data for July 2011 through December 2011 is based on updated estimates) compared to the original projections for the January 2011 through December 2011 period, filed on October 1, 2010.

Q. **Please explain the variances related to capacity charges.**

A. As shown in Appendix II, Page 4, Column 3, Line 11, the variance related to jurisdictional capacity charges is $31,888,608 million, a 5.9% increase. The primary reason for this variance is a $32.5 million increase in total system capacity costs (Page 4, Column 3, and Line 8).

The $32.5 million, or 6.3% increase in total capacity charges is due to a $26.5 million increase in Capacity Payments to Non-cogenerators, a $2.6 million increase in Payments to Cogenerators, a $2.7 million increase in Incremental Plant Security Costs, and a $0.9 million decrease in Transmission Revenues from Capacity sales.

The $26.5 million or 14% increase in Payments to Non-Cogenerators is primarily due to the addition of Capacity Availability Performance Adjustment (CAPA) payments and Change In Law (CIL) payments related to the UPS agreements. These costs were not included in prior estimates and account for approximately $16.1 million or 61% of the total variance. The CAPA provisions serve to adjust FPL's monthly capacity payments (up or down) based on availability of the UPS units, so that FPL's payments reflect the extent to which the UPS units are actually available for FPL's benefit. The CIL provisions serve to increase FPL's monthly capacity payments to offset increases in the seller's cost of providing capacity to FPL due to changes in law such as increased environmental regulatory requirements. FPL did not forecast CAPA or CIL payments or credits in its 2011 Projection filing, as the new UPS agreements only began in June 2010 and there was insufficient data at that time to make projections for this period. FPL now has sufficient data to include both CAPA and CIL estimates in the 2011 Actual/Estimated filing. Approximately $7.3 million, or 28% of the variance was due to higher payments to SJRPP for Cumulative Capital Recovery Amount (CCRA) costs than were originally projected. Higher than projected JEA O&M expense charges to FPL, for SJRPP, resulted in an 11%, or approximately $3 million, variance from original estimates.

The $2.6 million or 0.9% increase in Payments to Co-generators is primarily due to better availability performance and, therefore, higher than projected capacity payments to Indiantown (ICL), which is approximately 98% or $2.52 million, of the $2.57 million variance. Additionally, payments to Cedar Bay were approximately $320,000 higher than estimated, offset by payments to Broward-North which were approximately $270,000 lower than estimated.

The $2.7 million or 5.5% increase in Incremental Plant Security Costs is primarily due to additional Nuclear Regulatory Commission requirements associated with Part 73 Cyber Security implementation of critical key cyber components and a revision to the implementation date of these requirements to 2012 from 2014. Force on Force upgrades increased to reflect updated engineering estimates. Additionally, approximately $0.6 million of the 2011 variance was attributed to delays with milestone payments for the NERC CIP requirements that were originally scheduled for 2010.

The $0.9 million or 39.1% decrease in Transmission Revenues from Capacity Sales is primarily due to lower than projected economy power sales. FPL sold approximately 243,000 MWh less economy power than projected during the first six months of 2011. For the full year, FPL now projects to sell approximately 393,000 MWh less economy power than originally projected.

In addition to the cost variances, Appendix II, Page 4, Column 3, Line 12 shows that CCR Revenues Net of Revenue Taxes, are $60.7 million higher than originally projected. The $31.9 million higher costs (Appendix II, Page 4, Column 3, Line11) adjusted by the $60.7 million increase in revenues (Appendix II, Page 4, Column 3, Line 14) results in an actual/estimated 2011 True-up over-recovery amount of $28.8 million, including interest (Appendix II, Page 4, Column 3, Lines 15 plus 16). This over-recovery of $28.8 million including interest, plus the Final 2010 True-up over-recovery of $3.4 million filed on March 1, 2011 results in a net over-recovery of $32.1 million to be carried forward to the 2012 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. 110001-EI

September 1, 2011

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 2011 Fuel Cost Recovery (FCR) actual/estimated true-up amount, which has been updated to include July 2011 actual data and which is incorporated into the calculation of the 2012 FCR Factors.
- I present FCR factors for the period January 2012 through December 2012, which include time-of-use (TOU) factors that are calculated based on seasonally differentiated marginal fuel costs. I also present non-seasonally differentiated TOU factors for the

period January 2012 through December 2012, which are calculated based on marginal fuel costs and non-seasonally differentiated TOU factors for the period January 2012 through December 2012 based on average total system fuel costs.

- I present a revised 2011 Capacity Cost Recovery (CCR) actual/estimated true-up amount, which has been updated to include July 2011 actual data and which is incorporated into the calculation of the 2012 CCR Factors.
- I present the CCR factors for the period January 2012 through December 2012 including an adjustment to recover the projected non-fuel revenue requirement associated with West County Energy Center Unit 3 (WCEC-3) for the period January 2012 through December 2012, which is lower than the projected fuel savings for the same period.
- I present FPL's proposed Nuclear Power Plant Cost Recovery amount to be recovered through the CCR Clause in 2012, which FPL will update if necessary once the Commission has approved the recoverable amount at its October 24, 2011 special agenda conference.
- I present the WCEC-3 revenue requirement calculation for the period January 2012 through December 2012.
- Finally, I provide on pages 59-60 of Appendix II FPL's proposed COG tariff sheets, which reflect 2012 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. TJK-5 also includes Schedule H1 (page 58), 2010 actual energy losses by rate class (pages 13-15) and cogeneration tariff sheets (pages 59-60). 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
- TJK-9 -- the entire Appendix VI

Appendix II contains the FCR related schedules with TOU factors calculated using seasonally differentiated marginal fuel costs. Appendix III contains the FCR related schedules with TOU factors calculated using marginal fuel costs. Appendix IV contains the FCR related schedules with TOU factors calculated using average total system fuel costs. Appendix V contains the CCR related schedules, including the calculation of the CCR factors recovering the projected non-fuel revenue requirement associated with WCEC-3 for the period January 2012 through December 2012, which is lower than the projected fuel savings for the same period. Appendix VI contains the calculation of the WCEC-3 non-fuel revenue requirement for the period January 2012 through December 2012.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2011 FCR Actual/Estimated True-up amount that was filed on August 1, 2011 to reflect July 2011 actual data?

A. Yes. The 2011 FCR actual/estimated true-up amount has been revised to an under-recovery of $109,641,629, reflecting July 2011 actual data, plus interest. This $109,641,629 under-recovery, plus the 2010 final true-up under-recovery of $45,498,494 results in a net under-recovery of $155,140,123 (see Schedule E1-b, Pages 5 and 6 of Appendix II). This $155,140,123 under-recovery is to be included in the FCR factor for the January 2012 through December 2012 period.

Q What adjustments are included in the calculation of the levelized FCR factors shown on Schedule E1?

A. The total net true-up to be included in the 2012 FCR factors is an under-recovery of $155,140,123. This amount, divided by the projected retail sales of 102,458,681 MWh for January 2012 through December 2012, results in an increase of 0.1514¢ 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 March 15, 2011 and adopted by FPL Witness J. Carine Bullock on September 1, 2011, calculated a reward of $6,571,449 for the period ending December 2010, which is being applied to the January 2012 through December 2012 period. This $6,571,449 reward, divided by the projected retail sales of 102,458,681 MWh during the projected period, results in an increase of .0064¢ per kWh, as shown on line 30 of Schedule E1, Page 3 of Appendix II.

Q. What is the proposed levelized FCR factor for the period January 2012 through December 2012?

A. 4.131¢ per kWh. Schedule E1, Page 3 of Appendix II shows the calculation of this twelve-month levelized FCR factor. Schedule E2, Pages 16 and 17 of Appendix II shows the monthly fuel factors for January 2012 through December 2012 and also the twelve-month levelized FCR factor for the period.

Q. Is FPL proposing any changes to the methodology used in the calculation of its TOU rates?

A. Yes. As discussed in the direct testimony of FPL witness Renae B. Deaton, FPL proposes to base its TOU fuel factors on seasonally differentiated marginal fuel costs. This is in response to Order No. PSC-11-0216-PAA-EI, issued in Docket No. 100358-EI on May 11, 2011, where the Commission directed FPL to investigate both the use of marginal costs and seasonal differentiation in determining its TOU fuel factors.

In order to provide the Commission with complete information on the available alternatives for calculating the TOU fuel factors, FPL has provided three sets of TOU fuel factors for the period January 2012 through December 2012. Appendix II contains 2012 TOU fuel factors calculated using seasonally differentiated marginal fuel costs. Appendix III contains 2012 TOU factors calculated using only marginal fuel costs. Appendix IV contains 2012 TOU fuel factors calculated using only average total system fuel costs.

Q. How has FPL calculated its proposed levelized FCR factors for its TOU rates?

A. Schedule E1-D located on Page 8 of Appendix II, provides the calculation of the TOU multipliers of 1.204 for on-peak and 0.925 for off-peak for the period January through March and November through December. Schedule E1-D also provides the calculation of the TOU multipliers of 1.592 for on-peak and 0.824 for off-peak for the period April through October. These multipliers are then applied to the levelized FCR factor of 4.131 cents per kWh, which is further adjusted by the FCR loss multiplier for each rate class, resulting in the final fuel TOU factors for each of FPL's TOU rates for the periods January through March and November through December, and April through October. FPL's proposed 2012 TOU fuel factors for these periods are presented on Schedule E1-E.

FPL is also proposing SDTR rates based on marginal fuel costs. FPL's proposed 2012 SDTR rates calculated using marginal fuel costs are provided on Schedules E-1D and E-1E, Pages 9 and 12 of Appendix II.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2011 CCR Actual/Estimated True-up amount that was filed on August 1, 2011 to reflect July 2011 actual data?

A. Yes. The 2011 CCR actual/estimated true-up amount has been revised to an over-recovery of $25,243,602, reflecting July 2011 actual data plus interest. This $25,243,602 over-recovery, plus the 2010 final true-up over-recovery of $3,364,670 results in a net over-recovery of $28,608,272 (see Pages 3 and 4 of Appendix V). This $28,608,272 net over-recovery is to be included for recovery in the CCR factor for the January 2012 through December 2012 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2012 through December 2012?

A. Yes. Page 5 of Appendix V provides this summary, excluding the 2012 jurisdictionalized WCEC-3 revenue requirement. Total Recoverable Capacity Payments are $714,889,978 (line 15) and include payments of $212,267,891 to non-cogenerators (line 1), payments of $290,874,574 to cogenerators (line 2), $1,637,100 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 3), $43,151,276 in Incremental Power Plant Security Costs (line 5) and $16,964,769 in costs associated with Transmission of Electricity by Others (line 6). These amounts are partially offset by $5,405,019 of Return Requirements on SJRPP Suspension Payments (line 4) and by Transmission Revenues from Capacity Sales of $1,517,701 (line 7). The resulting amount is then reduced by the net over-recovery for 2010 and 2011 of $28,608,272 (line 11) and increased by the Nuclear Power Plant Cost Recovery Clause amount of $196,092,631 (line 12).

Q. What does line 12 - Nuclear Power Plant Cost Recovery (NPPCR) represent?

A. FPL has included in the calculation of its CCR Factors $196,092,631 as reflected in Exhibit WP-10 contained in the NPPCR testimony and exhibits of Winnie Powers filed on June 10, 2011. FPL will update this calculation if necessary, once the Commission has approved the recoverable amount at its October 24, 2011 special agenda conference. 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. Has FPL included any other adjustments to the calculation of its CCR factors for the period January 2012 through December 2012?

A. Yes. Per the Stipulation and Settlement that was filed in Docket Nos. 080677-EI and 090130-EI on August 20, 2010, FPL has included in the calculation of its CCR factors for the period January 2012 through December 2012 an amount of $166,860,714. As shown below, this is the lesser of the projected 2012 WCEC-3 jurisdictional non-fuel revenue requirement and the projected 2012 WCEC-3 jurisdictional fuel savings.

Q. What is the projected WCEC-3 jurisdictional non-fuel revenue

requirement for the January 2012 through December 2012 period?

A. The projected jurisdictional non-fuel revenue requirement for January 2012 through December 2012 is $166,860,714. The calculation of this amount is shown on Page 2 of my Exhibit TJK-9, Appendix VI. As contemplated by the Settlement Agreement, this amount 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 the higher ROE that was used for the need determination. Page 3 of Exhibit TJK-9 provides the capital structure calculation and support for the projected WCEC-3 jurisdictional non-fuel revenue requirement of $166,860,714.

Q. What are the projected WCEC-3 jurisdictional fuel savings for the January 2012 through December 2012 period?

A. As explained in the testimony of FPL witness Yupp, the projected total system fuel savings for the period above is $190,367,526. 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 $190,367,526 lower in the case that included WCEC-3 than in the case without WCEC-3. The jurisdictional portion of those fuel savings is $186,895,413. The calculation of this amount is shown on Schedule EI, Appendix II.

Q. Has FPL included a true-up to its prior GBRA recovery of non-fuel

revenue requirements for West County Energy Centers (WCEC) Units 1 and 2 in its 2012 CCR factors?

A. No, pursuant to Order No. PSC-05-0902-S-EI, FPL is to reflect in the CCR as a one-time credit the difference between the actual capital costs of the units and the projected costs approved in its need determination, if the actual cost is lower. WCEC Units 1 and 2 were placed in service during 2009. While the actual capital cost for each unit has not yet been finally determined because there are limited commissioning activities still ongoing, those commissioning activities are not expected to affect the overall combined capital costs for the two units. FPL expects the total capital costs of the two units will equal the capital cost estimates that were approved by the Commission in the need determination for the units. Thus, there is no need for a GBRA true-up adjustment.

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

A. Yes. Page 6 of Appendix V 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 2012 CCR factors by rate class?

A. Yes. Page 7 of Appendix V presents the calculation of the proposed CCR factors, excluding the projected 2012 WCEC-3 jurisdictional non-fuel revenue requirement. Pages 10 through 12 of Appendix V provide the calculation of the CCR factor for the recovery of the projected 2012 WCEC-3 jurisdictional non-fuel revenue requirement. Pages 13 and 14 provide FPL's proposed 2012 CCR factors including recovery of the projected 2012 WCEC-3 jurisdictional non-fuel revenue requirement.

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 2012 (cycle day 1) and that they remain effective until cycle day 21 of December 2012, or until they are modified by the Commission. This will provide for at least 12 months of billing on the FCR and CCR factors for all our customers.

Q. What is FPL's preliminary Residential 1,000 kWh bill for the period beginning January, 2012?

A. FPL's preliminary Residential 1,000 kWh bill beginning January, 2012 is \$99.10. Of this amount, the base rate charges are \$43.03, the FCR charge is \$37.96, the CCR charge is \$9.69, the Environmental charge is \$2.00 and the amount of Gross Receipts Tax is \$2.48. The Conservation charge of \$2.85 is based on FPL's current estimates of its Conservation clause factors; however, they are subject to change when FPL files its 2012 projections on September 13, 2011. The Storm charge of \$1.09 is based on FPL's September 1, 2011 Storm factors. FPL does not have an estimate at this time of the Storm charge that will be in effect in January, 2012. FPL's preliminary Residential 1,000 kWh bill is provided on

Schedule E-10, which is page 57 of Exhibit TJK-5, Appendix II.

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. 110001-EI

October 26, 2011

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. The purpose of my testimony is to present for Commission review and approval revised Capacity Cost Recovery (CCR) cost projections for the period January 2012 through December 2012 that reflect the Nuclear Power Plant Cost Recovery (NPPCR) amount approved by the Commission on October 24, 2011 in Docket No. 110009-EI.

Q. Have you prepared or caused to be prepared under your

direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. TJK-10 provides the two pages in the CCR schedules for the period January 2012 through December 2012 that reflect the NPPCR amount approved by the Commission.

Q. What is the NPPCR amount that the Commission approved for recovery through the CCR during the January 2012 through December 2012 period?

A. At the October 24, 2011 agenda conference the Commission authorized FPL to recover $196,088,824 through the CCR during the January 2012 through December 2012 period.

Q. Is this the same amount that FPL included in the 2012 CCR factors at the time of FPL's September 1, 2011 projection filing?

A. No. In its September 1, 2011 filing in this docket, FPL included $196,092,631 for the NPPCR in the calculation of its 2012 CCR factors reflected in Exhibit WP-10 contained in the NPPCR testimony and exhibits of Winnie Powers filed on June 10, 2011 in Docket No. 110009-EI. At the October 24, 2011 agenda conference, the Commission reduced overall recovery by $3,807, from $196,092,631 to $196,088,824.

Q. Does this revision change the CCR factors filed on September 1, 2011?

A. No. Due to the minor change in the approved NPPCR amount, the CCR factors based on this revised amount do not change from those filed in my testimony on September 1, 2011.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GENE ST. PIERRE

DOCKET NO. 110001-EI

September 1, 2011

Q. Please state your name and address.

A. My name is Gene 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. Have you previously testified in the predecessor to this docket?

A. Yes, I have.

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 2012 through December 2012.

Nuclear Fuel Costs

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

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and current operating schedules, for the period January 2012 through December 2012.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2012 through December 2012.

A. FPL projects the nuclear units will produce 215,120,531 MMBtu of energy at a cost of $0.6987 per MMBtu, excluding spent fuel disposal costs, for the period January 2012 through December 2012. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 22.

Spent Nuclear Fuel Disposal Costs

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2012 through December 2012 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $18.3 million are provided in Appendix II, on Schedule E-2, starting on page 15. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9349 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, petitions for review were filed by the Nuclear Energy Institute (NEI) and several utilities including FPL and by the National Association of Regulatory Utility Commissioners (NARUC) against the DOE in the U.S. Court of Appeals for the District of Columbia (D.C.) 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. On December 13, 2010, the D.C. Circuit dismissed the NEI and NARUC petitions for review, ruling that a November 1, 2010 DOE fee assessment mooted the NEI and NARUC requests in their petitions for review that DOE conduct an annual assessment and that it suspend the 1 mill fee until that assessment is completed. NEI and NARUC then filed new petitions for review with the D.C. Circuit in March 2011, seeking the same relief as in the 2010 petitions. This matter should be decided by the Court in late 2011 or 2012.

<u>Nuclear Plant Security Costs</u>

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2012 through December 2012?

A. FPL projects that it will incur $41.8 million in incremental nuclear power plant security costs in 2012.

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. Are there new impacts from the NRC's recent revisions to the security-related Orders that affect FPL's 2012 security cost projections?

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 impose significant requirements for monitoring, hardening and responding to cyber intrusions. Full regulatory implementation for this new Part 73.54 is scheduled for completion in 2014. The protection of key critical cyber components must be implemented by the end of 2012. The NRC Cyber Security rulemaking costs for 2012 are estimated to be $6.0 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. Turkey Point is currently performing modifications to the site in preparation for the NRC triennial FoF inspection expected in late 2012. The Turkey Point FoF modifications are estimated to be $2.0 million for 2012.

<u>2011 Outage Events</u>

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2011?

A. Yes. In March 2011, a manual reactor trip on Unit 3 was initiated due to high sodium levels in the Condenser Hotwells. Prior to the reactor trip, a sodium spike was detected in the Unit 3 South Condenser. A rapid down power was initiated to identify and isolate the leaking tube(s). Approximately four hours later, another sodium spike was detected in the South Condenser. The unit was subsequently taken offline due to exceeding sodium/chloride limits in the steam generators as directed by Plant Off-Normal Operating Procedures.

Q. What caused the high sodium levels in the steam generators?

A. The high sodium level was caused by a leak in one condenser tube located within the 3 B South Condenser tube bundle.

Q. How many days was the Turkey Point Unit 3 outage due to this issue?

A. The Unit 3 outage was approximately 8 days.

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

A. As an interim response, FPL identified and plugged the one leaking condenser tube, several surrounding tubes were plugged as a preventive measure, and contaminants were removed from the steam generators to return secondary water chemistry parameters to acceptable limits. FPL will replace all condenser tube bundles during the refueling outage scheduled in early 2012.

Q. Has FPL experienced any unplanned outages at Turkey Point Unit 4 in 2011?

A. Yes. In May 2011, during start up of Unit 4 from the refueling outage, the 4A Reactor Cooling Pump (RCP) #1 seal leak-off increased abnormally. The seal leak-off must be maintained within the vendor recommended band to avoid damage to the seal. The unit was shut down to replace the seal.

Q. What caused the increased seal leak-off?

A. The new seal provided by AREVA did not operate as expected after the 4A RCP was started. When the 4A RCP seal was disassembled, it was determined to have a damaged #1 seal runner O-ring. The damaged O-ring appeared to have been "pinched" or extruded, which led to its degradation following the start of the 4A RCP. FPL determined AREVA had incorrectly installed the seal runner O-ring while assembling the #1 4A RCP seal.

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

A. The Unit 4 refueling outage was delayed approximately 2 days.

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

A. FPL and AREVA replaced the seal. Analysis of the failed seal was performed to ensure the cause of failure was properly identified and resolved. Additionally, FPL revised the RCP seal maintenance and assembly procedure to incorporate additional steps that verify correct installation.

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2011?

A. Yes. In April 2011, while Unit 2 was shut down to perform a scheduled refueling outage the following events delayed the restart of the unit:

1. The Extended Power Uprate (EPU) scope of work took longer than originally planned, largely as a result of an error by Siemens, the vendor who performed the turbine generator upgrade work.
2. During pre-start up testing, FPL identified an issue with Control Element Assembly (CEA) #89 and determined the CEA was not latched to its extension shaft. All CEAs must be latched to their extension shafts before the unit can return to service.

Consequently, FPL was required to cool the unit down in order to latch CEA #89.

Q. Please describe the circumstances related to the delay in the EPU scope of work.

A. The required post-reassembly Loop testing of the upgraded turbine generator failed and FPL was required to disassemble the generator to determine the cause. It was determined that a small tool - an alignment pin - had been left inside the generator stator core by Siemens personnel during the generator rebuild. Inspection of the area surrounding the tool revealed damage requiring some of the stator core iron to be replaced.

Q. What corrective actions were initiated to avoid this problem in the future?

A. Siemens has revised several procedures to provide additional guidance for stator core testing. Although the upcoming Unit 1 scope of work is different than Unit 2 where the entire Main Generator core iron is being replaced in the refueling outage for Unit 1, FPL has added an additional measure to validate the work package(s) for the St. Lucie Unit 1 refueling outage scheduled for November 2011, to include a generator visual inspection prior to Loop testing.

Q. What caused the unlatched CEA?

A. As part of the work scope in the refueling outage, the Incore Instrumentation (ICI) Thimbles were being replaced. In order for the ICI work to be completed, the CEAs were attached to their extension shafts and temporarily stored. While in temporary storage, the CEA #89 extension shaft was damaged when a refueling machine operated by Westinghouse inadvertently made contact with the CEA. The extension shaft was subsequently replaced by Westinghouse but was re-latched using the standard process for five-finger latching mechanisms instead of the separate process for four-finger latching mechanisms that was appropriate for this extension shaft. It was determined that Westinghouse failed to identify and apply the applicable technical manual guidance for the CEA process. In addition, if not for the damage caused by Westinghouse to the CEA while it was in temporary storage, the latching issue would never have arisen.

Q. What corrective actions were initiated to avoid this problem in the future?

A. Westinghouse is revising its field services program to incorporate lessons learned. FPL plans to permanently remove the four finger CEAs after the completion of the extended power uprate project, but in the interim is issuing a procedure that specifically applies to latching four finger CEAs.

Q. How many days was the St. Lucie Unit 2 refueling outage delayed due to these issues?

A. The Unit 2 refueling outage was delayed approximately 43 days.

Q. Has FPL initiated claims with Siemens and Westinghouse for the reimbursement of costs incurred as a result of these events?

A. Yes. FPL is currently in ongoing negotiations with Siemens over costs associated with the stator core event. FPL is currently in negotiation with Westinghouse to structure a settlement whereby FPL is not responsible for the additional costs incurred by Westinghouse related to the CEA event. Additionally, FPL has notified Nuclear Electric Insurance Limited (NEIL) of its intent to file an insurance claim for the costs associated with damages resulting from the CEA event.

As with any major nuclear outage work contract, however, there are limits to the vendor's liability, and recovery of replacement generation and fuel costs on FPL's system is not provided in either the Siemens or Westinghouse contracts. FPL has insurance with

NEIL for extra costs resulting from extended outages, but that coverage is subject to a 12 week deductible that is substantially longer than the outage extension resulting from the stator core and CEA events.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 2 in 2011?

A. Yes. In May 2011, Unit 2 initiated a manual shut down due to a leak in a steam vent line in one of the main steam headers.

Q. What caused the leak in the steam vent line?

A. Vent valves had experienced vibrations which resulted in a vent line that severed. This created a steam leak that could not be controlled without closing the Main Steam Isolation Valves which results in a unit shutdown.

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

A. FPL replaced the failed vent line. Additionally, a walk down of the Unit 1 and Unit 2 Main Steam system was performed to identify and correct any similar issues.

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

A. The Unit 2 outage was approximately 3 days.

Q. Did St. Lucie Unit 2 experience any other outages?

A. Yes. In June 2011, Unit 2 experienced an automatic shut down during the performance of Reactor Protection System (RPS) testing.

Q. What caused the Unit 2 automatic shut down?

A. While performing RPS Logic Matrix Testing, the relay test selector switch was inadvertently mispositioned, causing several reactor trip circuit breakers to open.

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

A. The Unit 2 outage was approximately 1 day.

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

A. FPL revised the RPS testing procedures to provide additional guidance in testing methodology. Additionally, FPL will be replacing the Matrix Relay Hold pushbuttons with rotary switches.

Q. Has St. Lucie Unit 1 experienced any unplanned outages in 2011?

A. Yes. In August, 2011 Unit 1 initiated a manual shut down due to a heavy influx of jellyfish in the unit intake.

Q. How did the jellyfish influx affect plant operations?

A. A heavy influx of jellyfish entered into the unit intake that caused high traveling screen differential pressures (D/P). The traveling screen D/P exceeded 40" H_20 causing the operators to shut down the 1A2 Circulating water pump to prevent damage to the traveling screen system. Due to the loss of the 1A2 Circulating water pump and its cooling flow, the condenser backpressure increased to a level that required a manual shutdown per plant operating procedures.

Q. How long was the St. Lucie Unit 1 outage due to this issue?

A. The Unit 1 outage was approximately 3 days.

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

A. FPL is using divers, nets, and floating booms to remove the jellyfish before they reach the cooling water systems. In addition, jellyfish that reach the intake traveling screens are being removed by Operations and Maintenance personnel prior to challenging the intake cooling water systems. Traveling screens and debris filter removal systems are operating in a continuous mode to aid in the jellyfish removal. Vacuum trucks have been used to remove jellyfish from the intake canal and intake system weir pits. Additional corrective measures are being evaluated to determine if other long term actions are necessary.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF J. CARINE BULLOCK

DOCKET NO. 110001-EI

SEPTEMBER 1, 2011

Q. Please state your name and business address.

A. My name is J. Carine Bullock, 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's degree in Mechanical Engineering from the Georgia Institute of Technology. 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 NextEra Energy for over 20 years. From 1991 to 2003, I held various roles at the Martin Plant in support of construction, startup, and production management of FPL's first General Electric (GE) 7FA advanced combined cycle plant. In 2003, I moved into a General Manager role for the Turbine Fleet Team, providing technical support for NextEra Energy's fleet of combustion and steam turbines and providing CT parts management services. In 2006, I moved into NextEra Energy's unregulated side for two years as General Manager for the Marcus Hook Plant, a 750 MW merchant combined cycle plant in Philadelphia, Pennsylvania. After returning to Florida in 2008, I managed the Ft. Myers Plant site, a 2,395 MW combined cycle and simple cycle plant site. Later in 2010, I assumed management responsibility for the West County Energy Center (West County), a 3,657 MW three unit state-of-the-art combined cycle plant. For each of these plants, I was responsible for all production activities and budget management. While at West County, I also completed the commissioning of Units 1 and 2 and the startup and commissioning of Unit 3. I returned to the Corporate office in 2011 and assumed my present role.

Q. Ms. Bullock, are you adopting the testimony and exhibits of FPL witness Carmine A. Priore III entitled "Generating Performance Incentive Factor, Performance Results for January through December 2010" as your own?

A. Yes, I am.

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, 2012.

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 Exhibit JCB-1. This exhibit supports the development of the 2012 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.

Q. Please summarize the 2012 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, 2012, FPL projects a weighted system equivalent planned outage factor of 15.5% and a weighted system equivalent unplanned outage factor of 6.1%, which yield a weighted system equivalent availability target of 78.4%. The targets for this period reflect planned refueling and Extended Power Uprates (EPU) outages for all four nuclear units. FPL also projects a weighted system ANOHR target of 8,315 Btu/kWh for the period January through December, 2012. 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 individual target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit JCB-1, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for 10 generating units that FPL proposes to be considered as GPIF units for the period January through

December, 2012. 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 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 10 units which FPL proposes to use for the period January through December, 2012 represent the top 81.6% 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 2012 EAF and ANOHR performance targets represent reasonable level of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 110001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2010

DIRECT TESTIMONY OF
JOSEPH MCCALLISTER

April 1, 2011

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 100 E. Davie Street, Raleigh, North Carolina 27601.

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

A. I am employed by Progress Energy Carolinas in the capacity of Director of Gas, Oil and Power.

Q. Have your duties and responsibilities remained the same since you last testified in this proceeding?

A. Yes. My responsibilities for the Gas, Oil and Power section activities within the Fuels and Power Optimization Department have remained the same.

Q. Please briefly describe your work experience.

A. I joined Progress Energy Service Company in 2003. Prior to my current position, I served as the Director of Portfolio and Market Risk Assessment in the Treasury and Enterprise Risk Management Department through mid 2006, and the Director of Gas and Oil Trading from mid 2006 through early 2009. Prior to joining Progress Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies supporting and managing commercial activities. Summary experience over this time period includes gas and power scheduling and real time trading, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets, wholesale power agreements, fuel agreements, and corporate planning.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August-December 2010 Hedging True-up data and summarize the results of PEF's hedging activity for calendar year 2010 as required by Commission Order No. PSC-02-1484-FOF-EI and further clarified by Commission Order No. PSC-08-0667-PPA-EI issued in October 2008.

Q. Have you prepared exhibits to your testimony?

A. Yes. I have attached Exhibit No. ___ (JM-1T) which summarizes the hedging information for calendar year 2010 and cumulative results from 2002 to 2010.

Q. What are the objectives of PEF's hedging strategy?

A. The objectives of PEF's hedging strategy are to reduce the impacts of fuel price volatility over time and provide a greater degree of fuel price certainty to PEF's customers.

Q. What hedging activities did PEF undertake for 2010 and what were results?

A. PEF utilized approved physical and financial agreements to hedge a portion of its projected natural gas, heavy oil and light oil burns fuel burns, and a portion of the estimated fuel surcharge exposure embedded in PEF's coal river barge and railroad transportation agreements. These activities resulted in a net hedge cost for 2010 of $281.9 million.

Q. Did PEF execute its hedging activities consistent with its approved Risk Management Plan?

A. Yes. The hedging activities executed by PEF were consistent with those outlined in its 2010 Risk Management Plan ("Plan"). In the Plan filed in August 2009, the hedging target ranges established for calendar year 2010 were [redacted] to [redacted] for forecasted 2010 calendar year natural gas and heavy oil burns, and at least [redacted] of forecasted 2010 calendar year burns for light oil. In addition, PEF outlined that it expected to begin executing oil product financial hedges to hedge a portion of the oil related fuel surcharge embedded in PEF's coal railroad and barge agreements in 2010. This activity was approved by Commission Order No. PSC-09-0349-CO-E1. PEF did not establish formal hedging target ranges for these activities for calendar year 2010 for two reasons. First, 2010 was the first year PEF began hedging a portion of the estimated 2010 fuel related coal transportation surcharges and PEF wanted to implement associated reporting processes before setting formal target hedging ranges in its Risk Management Plan. Secondly, at the time of filing its Plan, PEF had yet to finalize the negotiation of all the terms and conditions of the CSX railroad agreement for periods after 2009 and wanted to wait until the new agreement was executed before setting formal target hedging percentage ranges in the Plan to ensure the hedging activities were consistent with the surcharge exposure in this agreement. By mid-2010, PEF had implemented the hedging activities for established fuel surcharge exposures in the coal and river barge transportation agreements and has set formal targets in its 2011 Risk Management Plan.

REDACTED

With that background, PEF's estimated hedging percentages for 2010 based on forecasted calendar year burns as of December 2009 for natural gas, heavy oil and light oil fuel oil burns were approximately [redacted], [redacted] and [redacted], respectively. All of these percentages were within the targets established as part of the Plan. As outlined in the Plan, actual hedge percentages can come in higher or lower than targets as a result of actual versus forecasted fuel burns. For calendar year 2010, PEF's actual hedge percentages based on actual burns for natural gas, heavy oil and light oil were approximately [redacted], [redacted] and [redacted], respectively. The actual hedge percentages for natural gas and light oil were within the targets of the Risk Management Plan. The primary driver of the lower actual heavy oil hedge percentage versus the targeted hedge percentage range was due primarily to significantly higher heavy oil burns to support PEF's energy requirements for the months of January 2010, June 2010 and December 2010. In aggregate, the higher heavy oil burns were due primarily to higher energy loads as a result of colder than normal weather in January and December 2010 and warmer than normal weather in June 2010. For illustrative purposes, in its November 2009 Fuel and Operation Forecast for 2010, January 2010, June 2010 and December 2010 had forecasted heavy oil burns of 19,847 barrels, 123,897 barrels and 15,626 barrels. Actual heavy oil burns for January 2010, June 2010 and December 2010 were 349,900 barrels, 246,400 barrels and 133,500 barrels. PEF estimated hedge percentages for the fuel surcharges embedded in PEF's coal railroad and river barge agreements in 2010 were [redacted] and [redacted], respectively.

Q. What were the results of PEF economic purchase and sales activities for 2010?

A. With respect to economic purchases and sales, during 2010 PEF's economic energy wholesale purchases and power sales resulted in savings of approximately $24.5 million and $1.1 million, respectively.

Q. Did PEF hedging activities meet the stated objective and are the activities consistent with the Commission's Orders for hedging?

A. Yes. PEF's hedging activity met the stated objective which is to reduce price volatility and provide a greater degree of price certainty for its customers. The hedging activities are consistent with Commission Orders No. PSC-02-1484-FOF-EI and No. PSC-08-0667-PPA-EI. PEF's hedging activities are conducted in an environment of strong internal controls and executed in a structured manner. PEF's hedging activities do not attempt to outguess the market and may or may not result in net fuel cost savings, but have achieved the objectives.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 110001-EI

Fuel and Capacity Cost Recovery
January through December 2012

DIRECT TESTIMONY OF JOSEPH McCALLISTER

September 1, 2011

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 100 E. Davie Street, Raleigh, North Carolina 27601.

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

A. I am employed by Progress Energy Carolinas as the Director of Gas, Oil and Power.

Q. Have you previously filed testimony before this Commission?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last testified in this proceeding?

A. Yes. My responsibilities for the Gas, Oil and Power section activities within the Fuels and Power Optimization Department have remained the same.

Q. Please briefly describe your work experience.

A. I joined Progress Energy Service Company in 2003. Prior to my current position, I served as the Director of Portfolio and Market Risk Assessment through mid 2006, and the Director of Gas and Oil Trading from mid 2006 through early 2009. Prior to joining Progress Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies supporting and managing commercial activities. Summary experience over this time period includes gas and power scheduling,, real time power trading, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets, wholesale power agreements, fuel agreements, and corporate planning.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to outline PEF's hedging objectives and activities for 2012, outline PEF's hedging results for January 2011 through July 2011, and summarize PEF's economy purchase and sales savings for the period January 2011 through July 2011.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits:

- Exhibit No. ___ (JM-1P) – 2012 Risk Management Plan *(originally filed on August 1, 2011)*; and

- Exhibit No. ___ (JM-2P) - Hedging Results for January 2011 through July 2011 *(originally filed on August 15, 2011).*

Q. What are the objectives of PEF's hedging activities?

A. The objectives of PEF's hedging strategy are to reduce price risk and provide greater cost certainty for PEF's customers.

Q. Describe PEF's hedging activities that the company will execute for 2012.

A. PEF will hedge a percentage of its projected natural gas, heavy oil and light oil burns fuel burns, and a portion of the estimated fuel surcharge exposure embedded in PEF's coal river barge and railroad transportation agreements. PEF will utilize approved physical and financial agreements. With respect to to hedging activity, natural gas represents the largest component of PEF's overall hedging activity given its the largest fuel cost component. PEF's target hedging percentage ranges are between [redacted] to [redacted] of its current 2012 forecasted calendar annual burns. The current expectation is for PEF to hedge at least [redacted] of its forecasted natural gas burn projections for 2012. Hedging in this range will allow PEF to monitor actual fuel burns, updated fuel forecasts and make any adjustments if needed. With respect to heavy oil and light oil, PEF will target to hedge at least [redacted] and [redacted], respectively, of the current forecasted annual heavy and light oil burns for 2012. With respect to coal river and rail transportation estimated fuel surcharges, for calendar year 2012 PEF will target to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposure in the coal rail and river barge transportation agreements.

PEF's hedging activities do not involve price speculation or trying to "out-guess" the market. All hedging transactions are executed at the prevailing market price for any given period that exists at the time the hedging transactions are executed. The results of hedging activities may or may not result in net fuel cost savings due to differences between the monthly settlement prices and the actual hedge price of the transactions that were executed over time. The volumes hedged over time are based on periodic updated fuel forecasts and the actual hedge percentages for any month, rolling period or calendar annual period may come in higher or lower than the target minimum hedge percentages and hedging ranges because of actual fuel burns versus forecasted fuel burns. Actual burns can deviate from forecasted burns because of variables such as weather, unforeseen unit outages, actual load and changing fuel prices. PEF's approach to executing fixed price transactions over time is a reasonable and prudent approach to reduce price risk and providing greater cost certainty for PEF's customers.

As of August 15, 2011, for 2012 PEF has hedged approximately [redacted] of its forecasted natural gas burns, [redacted] of its forecasted heavy oil burns and [redacted] of its forecasted light oil burns. In addition, as of August 15, 2011, for 2012 PEF has hedged approximately [redacted] and [redacted] of its estimated fuel surcharge exposure based on the contractual provisions in the coal rail and river barge transportation agreements, respectively. PEF will continue to execute additional hedges for 2012 throughout the remainder of 2011 and during 2012 consistent with its on-going strategy.

Q. What were the results of PEF's hedging activities for January through July 2011?

A. The Company's natural gas hedging activities for January through July 2011 have resulted in hedges being above the closing natural gas settlement prices for the periods of January 2011 through July 2011 by approximately $125.8 million. The Company's overall fuel oil hedging activities have resulted in hedges being below the closing settlement prices for the periods of January 2011 through July 2011 by approximately $6.7 million. This overall hedge results were driven primarily as a result of continued declines in natural gas prices after the execution of PEF's 2011 hedging transactions. The hedging activities were executed consistent with its Risk Management Plan. Although PEF's hedging activity did not result in net fuel cost savings, the activities did achieve the objective to reduce the impacts of fuel price risk and provide greater cost certainty for PEF's customers.

Q. What are the results of the economy purchase and sales power activity for January 2011 through July 2011?

A. During the period January 2011 through July 2011, PEF has made economic energy purchases and wholesale power sales to third parties that resulted in net savings of approximately $14.9 million and $0.3 million, respectively.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 110001-EI
Fuel and Purchased Power Cost Recovery Clause
Revised 5/16/2011
2010 Final True-Up Testimony of
Curtis D. Young
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis D. Young, 401 South Dixie Highway, West Palm Beach, Florida 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Accountant for Florida Public Utilities Company. I have performed various accounting functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period Jan. 2010 through Dec. 2010.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. Exhibit________ (CDY-1) consists of Schedules M1 , F1 and E1-B for the Northwest Florida (Marianna) and Northeast Florida (Fernandina Beach) Divisions. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period Jan. - Dec. 2010?

A. For Northwest Florida the final remaining true-up amount is an over recovery of $885,786. For Northeast Florida the calculation is an over recovery of $856,166.

Q. How were these amounts calculated?

A. They are the sum of the actual end of period true-up amounts for the Jan. - Dec. 2010 period and the total true-up amounts to be collected or refunded during the Jan. - Dec. 2011 period.

Q. What was the actual end of period true-up amount for Jan. - Dec. 2010?

A. For Northwest Florida it was $577,267 under recovery and for Northeast Florida it was $2,603,285 over recovery.

Q. What have you calculated to be the total true-up amount to be collected or refunded during the Jan. - Dec. 2011 period?

A. Using six months actual and six months estimated amounts, we calculated an under recovery for Northwest Florida of $1,463,053 and an over recovery of $1,747,119 for Northeast Florida.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

Fuel and Purchasd Power Cost Recovery Clause
Actual/Estimated True-Up
REVISED Direct Testimony of
Curtis D. Young
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis D. Young, 401 South Dixie Highway, West Palm Beach, FL 33401.

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

A. I am employed by Florida Public Utilities Company as the Regulatory Analyst.

Q. Have you previously testified in this Docket?

A. Yes.

Q. What is the purpose of your revised testimony at this time?

A. I will briefly describe the basis for the Company's revised computations that were made in preparation of the various schedules that have submitted to support the calculation of the levelized fuel adjustment factor for January 2012 - December 2012.

Q. What is the primary reason for the revised true-up schedules in the Northwest Division and Northeast Division for the January 2011 through December 2011 time period?

A. The Company is now reflecting the actual 2011 unbilled revenues associated with fuel revenues in the net over/under recovery amount. The unbilled fuel revenue recognition is appropriate for accounting purposes and properly matches the recognition of fuel revenues and cost of fuel.

Q. Should the unbilled fuel revenues be considered in the computation of the net over/under recovery of fuel costs?

A. Yes, it is appropriate to include the unbilled fuel revenues in the net over/under recovery of fuel. Fuel costs are generally recognized for a calendar month. Since revenues are billed on a cycle method, there is a portion of revenues at the end of a calendar month that has not been billed, unbilled revenues. Unbilled revenues reflect the difference between what has been billed for that calendar month and what remains to be billed for that same calendar month. The actual unbilled recognized in the Northwest Division and Northeast Division is an estimate for the amount of unbilled that will remain for December of 2011. The Company used the actual unbilled at July 2011 for the Northwest Division, and the actual unbilled at June 2011 for the Northeast Division.

Q. Were the schedules filed by the Company completed by you or under your direction?

A. Yes.

Q. Which of the Staff's set of schedules has the Company completed and filed?

A. The Company has filed revised Schedules E1-A, E1-B, and E1-B1 for the Northwest Division and E1-A, E1-B, and E1-B1 for the Northeast Division. They are included in Composite Prehearing Identification Number CDY-3. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2011 - December 2011 based on 6 Months Actual and 6 Months Estimated data.

Q. What are the final remaining true-up amounts for the period January 2010 - December 2010 for both divisions?

A. In the Northwest Division, the final remaining true-up amount was an over-recovery of $885,786. The final remaining true-up amount for the Northeast Division was an over-recovery of $856,166.

Q. What are the estimated true-up amounts for the period January 2011 - December 2011?

A. In the Northwest Division, there is an estimated over-recovery of $682,002. The Northeast Division has an estimated over-recovery of $2,292,856.

Q. What are the total true-up amounts to be collected or refunded during January 2012 - December 2012?

A. The Company has determined that at the end of December 2011, based on six months actual and six months estimated, the Company will over-recover $1,567,788 in purchased power costs in the Northwest Division. In the Northeast Division, the Company will have over-recovered $3,149,022 in purchased power costs.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony and Exhibits of

H. R. Ball

Docket No. 110001-EI

Date of Filing: March 1, 2011

Q. Please state your name, business address, and occupation.

A. My name is Herbert Russell Ball. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in 1978 with a Bachelor of Science Degree (Chemistry major) and again in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power Company (MPC) at Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Corporate Office and worked in the Fuel Department as a Fuel Business Analyst. In 1987 I was promoted and returned to Plant Daniel as the Supervisor of Chemistry and Regulatory Compliance. In 1998 I transferred to Southern Company Services, Inc. in Birmingham, Alabama and took the position of Supervisor of Coal Logistics. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the

Southern Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's participation in the Intercompany Interchange Contract (IIC) between Gulf and the other operating companies in the Southern Electric System (SES).

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses, net power transaction expense, and purchased power capacity costs, and to certify that these expenses were properly incurred during the period January 1, 2010 through December 31, 2010. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Mr. Ball's exhibit consisting of thirteen schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January 2010 through December 2010, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $639,924,986, which is $42,887,016 or 7.18% above the projected amount of $597,037,970. Actual net power transaction energy was 12,496,074,414 KWH compared to the projected net energy of 12,209,710,000 KWH or 2.35% above projections. The resulting actual average cost of 5.1210 cents per KWH was 4.73% above the projected cost of 4.8899 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2010 included in Appendix 1 of Witness Dodd's exhibit. The higher total fuel and net power transaction expense is attributed to a higher quantity of available energy (KWH) than projected. The actual total cost of available energy was above projections by $54,724,706, or 7.93% and the total available quantity of energy was above projections by 2,408,238,286 KWH or 16.71%. The actual cost per KWH of available energy was 4.4275 cents per KWH which is lower than the projected cost of 4.7877 cents per KWH. A combination of higher jurisdictional customer demand and 96.46% increase in power sales drove the higher quantity of fuel and net power transaction energy for the period. The higher cost per KWH for total fuel and net power transaction expense is primarily due to lower revenue per KWH from fuel cost and gains of power sales at a higher than projected percentage of sales occurred during off peak periods when fuel reimbursement rates were lower.

Q. During the period January 2010 through December 2010, how did Gulf Power Company's recoverable fuel cost of net generation compare with the projected expenses?

A. Gulf's recoverable fuel cost of system net generation was $606,009,955 or 6.73% below the projected amount of $649,707,594. Actual generation was 12,211,483,000 KWH compared to the projected generation of 13,308,786,000 KWH, or 8.24% below projections. The resulting actual average fuel cost of 4.96 cents per KWH was 1.64% above the projected fuel cost of 4.88 cents per KWH. The lower total fuel expense is attributed to a lower quantity of fuel burned than projected for the period. The actual quantity of fuel consumed was 120,128,038 MMBTU which is 10.41% below the projected quantity of 134,092,206 MMBTU. The generation mix was more heavily weighted to natural gas fired generation than projected due to efforts to utilize available natural gas fired generation which was lower in cost. The percentage of energy generated from natural gas fired resources was 23.77%, which was 40.24% higher than the projected percentage of 16.95%. The weighted average fuel cost for natural gas was 3.84 cents per KWH, which is 6.57% below the projected cost of 4.11 cents per KWH. The weighted average fuel cost for coal, plus lighter fuel, was 5.31cents per KWH, which is 5.36% higher than the projected cost of 5.04 cents per KWH. This information is found on Schedule A-3, period-to-date, for the month of December 2010 included in Appendix 1 of Witness Dodd's exhibit.

Q. How did the total projected cost of coal purchased compare with the actual cost?

A. The total actual cost of coal purchased was $491,262,529 (line 17 of Schedule A-5, period-to-date, for December 2010) compared to the projected cost of $569,099,182 or 13.68% below the projected amount. The lower coal cost was due to a 16.70% lower quantity of coal purchased for the period than projected. The actual weighted average price of coal purchased was $113.92 per ton which is 3.63% above the projected price of $109.93 per ton. The higher weighted average price of coal for the period was due to a change in the mix of coal purchases during the period. Gulf deferred some planned contract coal shipments to future periods and purchased no spot coal during the current period.

Q How did the total projected cost of coal burned compare to the actual cost?

A. The total cost of coal burned was $490,869,562 (line 21 of Schedule A-5, period-to-date, for December 2010). This is 11.76% lower than the projection of $556,260,106. The lower total coal cost was due to the quantity of coal burned being 14.45% below projections. This was offset somewhat by the weighted average coal burn cost being 3.15% above projections for the period.

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total actual cost of natural gas burned for generation was $110,792,592 (line 47 of Schedule A-5, period-to-date, for December 2010). This is 25.30% above the projection of $88,422,329. The increase can be attributed to a higher quantity of gas burned (28.78% higher) due to natural gas fired units being more economic to operate than coal fired generation on a cents per KWH basis. The actual weighted average gas burn cost was $5.36 per MMBTU, which is 2.72% lower than the projected burn cost of $5.51 per MMBTU.

Q. Did fuel procurement activity during the period in question follow Gulf Power's Risk Management Plan for Fuel Procurement?

A. Yes. Gulf Power's fuel strategy in 2010 complied with the Risk Management Plan filed on September 2, 2009.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of coal being delivered to Gulf's coal-fired generating units during the period?

A. Yes. The supply of coal and associated transportation to Gulf's generating plants is generally secured through a combination of long-term contracts and spot agreements as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These early purchase commitments and the planned diversity of fuel suppliers are designed to provide a more reliable source of coal to the generating plants. The result was that Gulf's coal-fired generating units had an adequate supply of fuel available at all times at a reasonable cost to meet the electric generation demands of its customers.

Q. For coal shipments during the period, what percentage was purchased on the spot market and what percentage was purchased using longer-term contracts?

A. Total coal shipments for the period amounted to 4,316,443 tons. Gulf purchased none of this coal on the spot market. Spot purchases are classified as coal purchase agreements with terms of one year of less. Spot coal purchases are typically needed to allow a portion of the purchase quantity commitments to be adjusted in response to changes in coal burn that may occur during the year. There were no spot coal purchases for the period due to coal burn (tons) being 14.45% lower than projected during 2010 and a carry over of contract coal tons from the previous year. Natural gas prices were lower than projected and the low cost of gas fired generation allowed Gulf to shift generation from coal fired units to natural gas fired units. Gas fired generation was 28.64% above projections and coal fired generation was 15.74% below projections for the period. Gulf shipped all of its 2010 coal purchases under longer-term contracts. Longer-term contracts provide a reliable base quantity of coal to Gulf's generating units with firm pricing terms. This limits price volatility and increases coal supply consistency over the term of the agreements. Schedule 1 of my exhibit consists of a list of contract and spot coal purchases for the period.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in stable coal prices for the period?

A. Yes. Coal cost volatility was mitigated through compliance with the Risk Management Plan. Gulf uses physical hedges to reduce price volatility in its coal procurement program. Gulf purchases coal and associated transportation at market price through the process of either issuing formal requests for proposals to market participants or occasionally for small quantity spot purchases through informal proposals. Once these confidential bids are received, they are evaluated against other similar proposals using standard contract terms and conditions. The least cost acceptable alternatives are selected and firm purchase agreements are negotiated with the successful bidders. Gulf purchased coal and coal transportation using a combination of firm price contracts and purchase orders that either fix the price for the period or escalate the price using a combination of government published economic indices. Schedule 2 of my exhibit provides a list of the contract and spot coal purchases for the period and the weighted average price of shipments under each purchase agreement in \$/MMBTU. Because of the fixed price nature of longer term contract coal purchase agreements and the substantial amount of coal under firm commitments prior to the beginning of the period, there was only a small variance between the estimated purchase price of coal and the actual price for the period (3.63% as reported on line 16 of Schedule A-5, period to date, for the month of December 2010).

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of natural gas being delivered to Gulf's gas-fired generating units at a reasonable price during the period?

A. Yes. The supply of natural gas and associated transportation to Gulf's generating plants was secured through a combination of long-term purchase contracts and daily gas purchases as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These natural gas purchase agreements price the supply of gas at market price as defined by published market indices. Schedule 3 of my exhibit compares the actual monthly weighted average purchase price of natural gas delivered to Gulf's generating units to a market price based on the daily Florida Gas Transmission Zone 3 published market price plus an estimated gas storage and transportation rate based on the actual cost of gas storage and transportation Gulf paid during the period. The purpose of early natural gas procurement commitments, the planned diversity of natural gas suppliers, and providing gas suppliers with market pricing is to provide a more reliable source of gas to Gulf's generating units. The result was that Gulf's gas-fired generating units had an adequate supply of fuel available at all times at a reasonable price to meet the electric generation demands of its customers.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in lower volatility of natural gas prices for the period?

A. Yes. Gulf purchases physical natural gas requirements at market prices and swaps the market price on a percentage of these purchases for firm prices using financial hedges. The objective of the financial hedging program is to reduce upside price risk to Gulf's customers in a volatile price market for natural gas. In 2010, Gulf's weighted average cost of natural gas purchases for generation was $5.33 per MMBTU. This was 3.27% lower than the projection of $5.51 per MMBTU (line 42 of Schedule A-5, period-to-date, for December 2010). Gulf was able to hold per unit fuel costs to very reasonable levels for its customers by following its Fuel Risk Management Plan. The volatility of Gulf's natural gas cost has been reduced by utilizing financial hedging as described in the Fuel Risk Management Plan. As shown on Schedule 4 of my exhibit, the volatility of Gulf's delivered cost of natural gas over the past four-year period as measured by standard deviation was 2.68. The volatility of Gulf's hedged delivered cost of natural gas over the same four-year period as measured by standard deviation was 2.17. Therefore, the financial hedging program is achieving the goal of reducing the volatility of natural gas cost to the customer.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power hedged 6,750,000 MMBTU of natural gas in 2010 using fixed-price financial hedges. This represents 42% of Gulf's 16,058,585 MMBTU of projected natural gas burn for generation during the period and 33% of Gulf's 20,679,489 MMBTU of actual gas burn for generation during the period.

Q. What types of hedging instruments were used by Gulf Power Company, and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged primarily using financial swaps that fixed the price of gas to a certain price. The total volume of gas hedged using financial swaps was 6,750,000 MMBTU. These swaps settled against either a NYMEX Last Day price or Gas Daily price.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2010 through December 2010?

A. No fees, commissions, or premiums were paid by Gulf on the financial swap hedge transactions during this period. Gulf's 2010 hedging program resulted in a net financial loss of $19,667,161 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2010 included in Appendix 1 of Witness Dodd's exhibit.

Q. Was Gulf Power prudent in commencing and continuing litigation against Coalsales II, LLC for breach of contract?

A. Yes. Gulf Power prudently initiated and pursued litigation against Coalsales II, LLC (Coalsales) to remedy Coalsales' default under its coal supply agreement with Gulf based on the reasonable expectation that this litigation would result in reduced fuel costs for Gulf's retail customers. After informal efforts to negotiate a reasonable settlement of the coal supply contract dispute with Coalsales failed, Gulf filed a complaint with the U.S. District Court for the Northern District of Florida on June 22, 2006, (Schedule 5) against Coalsales for breach of contract. On October 30, 2008, Gulf filed a motion for partial summary judgment on the issue of liability with the court (Schedule 6). Coalsales alternately filed a motion for summary judgment on the ground that its obligations under the contract were excused by a force majeure event. On September 30, 2009, the court issued its order granting Gulf's motion for partial summary judgment and denying Coalsales' motion for summary judgment (Schedule 7). Court ordered mediation between the parties failed to result in a settlement between the parties. Gulf filed its Memorandum Opinion on Damages (Schedule 8) and Memorandum Concerning Disputed Issues of Law (Schedule 9) with the court on January 25, 2010. The issue of Gulf's damages was tried to the court without a jury from February 9, 2010, to February 17, 2010. On September 30, 2010, the court issued its order ruling in favor of Coalsales, regarding damages (Schedule 10). On October 28, 2010, Gulf Power filed a Motion to Alter or Amend Judgment, or Alternatively, for Relief from Judgment (Schedule 11). By this motion, Gulf Power has asked the Court to reconsider its September 30, 2010, order on the ground that the order is the product of errors, both in the application of the law and an in the understanding of the facts. Coalsales filed a response to Gulf's motion on November 15, 2010, (Schedule 12) and Gulf filed a reply to Coalsales' response on December 7, 2010 (Schedule 13). This motion is still pending. Consequently, the Court's September 30, 2010, order is not yet final. Gulf is continuing to evaluate its options in light of the decision.

The Commission has a long standing policy of encouraging all reasonable litigation that can reasonably be expected to result in reduced fuel costs for retail customers. See e.g., Order No. PSC-87-18136-EI, issued in

Docket No. 870001-EI on September 10, 1987; and Order No. PSC-93-0443-FOF-EI, issued in Docket No. 930001-EI on March 23, 1993. Any damage recovery against Coalsales will be credited to Gulf's retail customers through the fuel cost recovery clause and will necessarily result in reduced fuel costs for those customers. As evidenced by the filings referenced above, Gulf Power has acted reasonably and prudently in commencing litigation and continuing to litigate against Coalsales for the benefit of its retail customers.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. During the period January 2010 through December 2010 how did Gulf Power Company's recoverable fuel cost of power sold compare with the projection?

A. Gulf's recoverable fuel cost of power sold for the period is ($104,679,690) or 12.75% above the projected amount of ($92,842,000). Total kilowatt hours of power sales were (4,321,560,872) KWH compared to estimated sales of (2,199,687,000) KWH, or 96.46% above projections. The resulting average fuel cost of power sold was 2.4223 cents per KWH or 42.61% below the projected amount of 4.2207 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2010 included in Appendix 1 of Witness Dodd's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of power sold and the projection?

A. The lower total credit to fuel expense from power sales is attributed to the lower average fuel reimbursement rate than originally projected. Below budget prices for natural gas reduced the fuel reimbursement rate (cents per KWH) paid to Gulf for typical power sales. Also, the timing of sales occurred during off peak (lower demand) periods a greater percentage of time than projected. During off peak periods, fuel reimbursement rates for energy sales are lower than for sales during other load demand periods.

Q. During the period January 2010 through December 2010, how did Gulf Power Company's recoverable fuel cost of purchased power compare to projected cost?

A. Gulf's recoverable fuel cost of purchased power for the period was \$119,483,119 or 276.03% above the estimated amount of \$31,774,516. Total kilowatt hours of purchased power were 4,606,152,286 KWH compared to the estimate of 1,100,611,000 KWH or 318.51% above projections. The resulting average fuel cost of purchased power was 2.5940 cents per KWH or 10.15% below the estimated amount of 2.8870 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2010 included in Appendix 1 of Witness Dodd's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of purchased power and the projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of KWH at attractive prices to supplement its own generation to meet load demands. This includes energy supplied to Gulf through purchase power agreements. The average fuel cost of energy purchases per KWH was lower than projected as a result of lower-cost energy being made available to Gulf for purchase during the period. In general the actual price of marginal fuel, primarily natural gas, used to generate market energy was lower than projected for the period.

Q. Should Gulf's recoverable fuel and purchased power cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is otherwise curtailed or unavailable. Gulf's lighter oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf adhered to its Risk Management Plan for Fuel Procurement and accomplished the objectives established by the plan. Through its participation in the integrated Southern Electric System, Gulf is able to purchase affordable energy from pool participants and other sellers of energy when needed to meet load and during times when the cost of purchased power is lower than energy that could be generated internally. Gulf is also able to sell energy to the pool when excess generation is available and return the benefits of these sales to the customer. These energy purchases and sales are governed by the IIC which is approved by the Federal Energy Regulatory Commission (FERC). Gulf also purchases power when economically attractive under the terms of several external purchase power agreements which have been reviewed and approved by the Commission.

Q. During the period January 2010 through December 2010, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual net capacity cost for the January 2010 through December 2010 recovery period, as shown on line 4 of Schedule CCA-2 of Witness Dodd's exhibit, was $47,456,303. Gulf's total projected net purchased power capacity cost for the same period was $48,729,557, as indicated on line 4 of Schedule CCE-1 of Witness Dodd's exhibit filed October 30, 2009. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $1,273,254 or 2.61% lower than originally projected. This lower actual cost is due to Gulf's lower IIC reserve sharing costs. Gulf's actual reserves (MW) were higher than originally projected due to less generating unit load outages on Gulf's system. Also, Gulf received capacity payment credits during certain months of the year as a result of the economic dispatch of one of Gulf's purchase power agreements. Therefore, Gulf's reserve purchases were lower and its associated reserve sharing costs were lower than projected for the 2010 recovery period.

Q. Was Gulf's actual 2010 IIC capacity cost prudently incurred and properly allocated to Gulf?

A. Yes. Gulf's capacity costs were incurred in accordance with the reserve sharing provisions of the IIC in which Gulf has been a participant for many years. Gulf's participation in the integrated SES that is governed by the IIC has produced and continues to produce substantial benefits for Gulf's customers and has been recognized as being prudent by the Florida Public Service Commission in previous proceedings and reviews.

Per contractual agreement in the IIC, Gulf and the other SES operating companies are obligated to provide for the continued operation of their electric facilities in the most economical manner that achieves the highest possible service reliability. The coordinated planning of future SES generation resource additions that produce adequate reserve margins for the benefit of all SES operating companies' customers facilitates this "continued operation" in the most economical manner. The IIC provides for mechanisms to facilitate the equitable sharing of the costs associated with the operation of facilities that exist for the mutual benefit of all the operating companies. In 2010, Gulf's reserve sharing cost represents the equitable sharing of the costs that the SES operating companies incurred to ensure that adequate generation reserve levels are available to provide reliable electric service to customers. This cost has been properly allocated to Gulf pursuant to the terms of the IIC.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110001-EI

BEFORE me, the undersigned authority, personally appeared Herbert R. Ball, who being first duly sworn, deposes and says that he is the Fuel Manager for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Herbert R. Ball
Herbert R. Ball
Fuel Manager

Sworn to and subscribed before me
this 28th day of February, 2011.

Vickie L. Marchman
Notary Public, State of Florida at Large

(SEAL)

NOTARY PUBLIC STATE OF FLORIDA
Vickie L. Marchman
COMMISSION # DD866249
EXPIRES: JUN. 26, 2013
WWW.AARONNOTARY.com

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony of

H. R. Ball

Docket No. 110001-EI

Date of Filing: August 1, 2011

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama in 1998. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January 2011 through December 2011 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2011 through June 2011 and projected fuel and net power transaction costs for July 2011 through December 2011. Projected capacity costs for July 2011 through December 2011 were reduced slightly to account for changes in capacity payments under Gulf's purchase power agreements. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses, and purchased power capacity costs.

Q. During the period January 2011 through December 2011 how will Gulf Power Company's recoverable total fuel and net power transactions cost compare with the original cost projection?

A. Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $597,743,941 which is $23,340,144 or 4.06% above the original projected amount of $574,403,797. The resulting average fuel cost is projected to be 4.7620 cents per kWh or 2.07% above the original projection of 4.6655 cents per kWh. The higher total fuel expense for the period is attributed to a combination of higher than projected fuel cost of purchased power and lower fuel revenue from power sales. The higher average per unit fuel cost (cents per kWh) is attributed to a higher fuel cost of generated power for the period. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 21.

Q. During the period January 2011 through December 2011 how will Gulf Power Company's recoverable fuel cost of generated power compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable fuel cost of generated power for the period is $550,128,748 which is $74,372,049 or 11.91% below the original projected amount of $624,500,797. Total generation is expected to be 11,205,515,000 kWh compared to the original projected generation of

13,345,854,000 kWh or 16.04% below original projections. The resulting average fuel cost is expected to be 4.9094 cents per kWh or 4.92% above the original projected amount of 4.6794 cents per kWh. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 6.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of generated power and the current projection?

A. The lower total fuel expense is due to lower than originally projected quantity of generated power (kWh) offset somewhat by higher average per unit fuel costs (cents/kWh). Delivered coal prices per MMBtu are projected to be above original projections for the period due to a higher percentage of contract coal in the coal supply mix and natural gas prices per MMBtu are projected to be below original projections for the period due to changes in market fuel prices. The quantity of contract coal in the supply mix for the period is expected to be above original projections due to a reduction in the quantity of coal burned which has eliminated the need for market priced spot purchases for the period. Coal burn is lower due to reduced economic dispatch of coal fired units relative to other sources of generation. Market prices for natural gas for the period are expected to be lower than original projections. A higher projected supply of natural gas in the market has driven the projected price lower and prices are expected to remain lower for the rest of the period. The quantity of natural gas burn is expected to be above original projections in response to the lower market prices for natural gas increasing economic dispatch of gas fired generation. The ability to change the mix of generating units operating to meet customer demand to a more heavily weighted natural gas mix has allowed Gulf to take advantage of lower natural gas prices.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2011?

A. The total fuel cost of system net generation for the first six months of 2011 was $254,583,875 which is $35,079,035 or 12.11% lower than the projection of $289,662,910. On a fuel cost per kWh basis, the actual cost was 4.86 cents per kWh, which is 0.83% higher than the projected cost of 4.82 cents per kWh. This higher cost of system generation on a cents per kWh basis is due to a combination of fuel cost in $/MMBtu being 0.79% higher than projected and heat rate (Btu/kWh) of the generating units operating being 0.04% lower than projected. This information is found on Schedule A-3 Period to Date of the June 2011 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2011?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2011 was $186,689,942 which is $33,848,731 or 15.35% lower than the projection of $220,538,673. On a fuel cost per kWh basis, the actual cost was 5.49 cents per kWh which is 7.23% higher than the projected cost of 5.12 cents per kWh. The lower than projected total cost of coal burned (including boiler lighter) is due to total MMBtu of coal burn being 19.27% below the estimated burn for the period. The higher per kWh cost of coal fired generation is due to actual coal prices (including boiler lighter) being 4.99% higher than projected on a $/MMBtu basis and the weighted average heat rate (Btu/kWh) of the coal fired generating units operating being 2.20% higher than projected. This information is found on Schedule A-3 Period to Date of the June 2011 Monthly Fuel Filing. Gulf has fixed price coal contracts in place for the period to limit price volatility and ensure reliability of supply. Actual average prices for coal purchased during the period are higher due to a change in the timing of contract shipments to Gulf's coal fired generating plants in response to lower coal burn for the period. Another factor contributing to the higher cost of coal fired generation (cents/kWh) is that weighted average coal unit heat rates are higher than projected for the period. Generating unit heat rates have been impacted by the percentage of time these units operated at lower than projected loads. When generating units operate at lower loads, unit efficiency is reduced.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2011?

A. The total cost of natural gas burned for generation for the first six months of 2011 was $67,484,255 which is $1,325,207 or 1.93% lower than Gulf's projection of $68,809,462. The total cost of natural gas burned for generation is lower than projected due to the market price of natural gas being lower than projected. Market prices for natural gas are lower due to increased supply of natural gas in the market. On a cost per unit basis, the actual cost of gas fired generation was 3.70 cents per kWh which is 9.31% lower than the projected cost of 4.08 cents per kWh. Actual natural gas prices were $5.19 per MMBtu or 12.48% lower than the projected cost of $5.93 per MMBtu. This information is found on Schedule A-3 Period to Date of the June 2011 Monthly Fuel Filing.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 6,890,000 MMBtu of natural gas for the period January 2011 through June 2011 using a combination of fixed price financial swaps and options. This equates to 54.5% of the actual natural gas burn for generation during the period of 12,646,305 MMBtu.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price and options (collars) that established both a price ceiling and price floor for each deal. The swaps settled against either a NYMEX Last Day price or Gas Daily price. The options settled if the NYMEX Last Day price was outside the bounds of the collar. Only a small amount of the option deals were settled during the period. The amount of gas hedged for the period using financial swaps was 5,600,000 MMBtu and the amount of gas hedged using options was 1,290,000 MMBtu.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were incurred. Gulf's gas hedging program generated a hedging expense related to settlements of $6,833,824 for the period January through June 2011. This information is found on Schedule A-1, Period to Date, line 2 of the June 2011 Monthly Fuel Filing.

Q. During the period January 2011 through December 2011 how will Gulf Power Company's recoverable fuel cost of power sold compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost and gains on power sales for the period are $(41,062,801) or 51.54% below the original projected amount of $(84,732,000). Total megawatt hours of power sales is expected to be (1,691,312,815) kWh compared to the original projection of (1,963,232,000) kWh or 13.85% below projections. The resulting average fuel cost and gains on power sales is expected to be 2.4279 cents per kWh or 43.75% below the original projected amount of 4.3159 cents per kWh. This current projection of fuel cost of power sold is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 18.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost and gains on power sales and the current projection?

A. The lower total credit to fuel expense from power sales is attributed to a lower quantity and lower price of power sales made than originally projected. Lower marginal market prices for natural gas combined with a higher percentage of natural gas fired generation in the generation fuel mix during the period have decreased the fuel reimbursement rate (cents/kWh) for power sales.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2011?

A. The total fuel cost of power sold for the first six months of 2011 was $26,413,801 which is $4,545,199 or 14.68% lower than our projection of $30,959,000. On a fuel cost per kWh basis, the actual cost was 1.9392 cents per kWh which is 52.05% below the projected cost of 4.0443 cents per kWh. This information is found on Schedule A-1, Period to Date, line 17 of the June 2011 Monthly Fuel Filing.

Q. During the period January 2011 through December 2011 how will Gulf Power Company's recoverable fuel cost of purchased power compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of purchased power for the period is $88,677,993 or 156.04% above the original projected amount of $34,635,000. The total amount of purchased power is expected to be 3,038,104,851 kWh compared to the original projection of 929,227,000 kWh or 226.95% above projections. The resulting average fuel cost of purchased power is expected to be 2.9189 cents per kWh or 21.69% below the original projected amount of 3.7273 cents per kWh. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 13.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of energy to supplement its own generation to meet load demands. The lower projected price per kWh for purchased power is due to Gulf's ability to obtain power from a lower cost gas fired combined cycle unit under existing purchase power agreements.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2011?

A. The total fuel cost of purchased power for the first six months of 2011 was $52,444,994 which is $34,101,994 or 185.91% higher than our projection of $18,343,000. The higher than anticipated purchased power expense is due to the actual quantity of purchases being 285.49% higher than projected. Purchase power quantity is higher due to the lower price of available power relative to Gulf's fuel cost of generated power making it the economic choice for providing energy to the customer during certain periods of time. On a fuel cost per kWh basis, the actual cost was 2.5579 cents per kWh which is 25.83% lower than the projected cost of 3.4487 cents per kWh. This information is found on Schedule A-1, Period to Date, line 12 of the June 2011 Monthly Fuel Filing.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Were Gulf Power's actions through June 30, 2011 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

A. Yes. Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices. Over the long term, Gulf anticipates less volatile future fuel costs than would have otherwise occurred if these programs had not been utilized.

Q. Should Gulf's fuel and net power transactions cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf has followed its Risk Management Plan for Fuel Procurement in securing the fuel supply for its electric generating plants. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that natural gas is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery clause so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

Q. During the period January 2011 through December 2011, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 4 of Schedule CCE-1b in the exhibit to Witness Dodd's testimony, Gulf's total current net capacity payment projection for the January 2011 through December 2011 recovery period is $48,294,769. Gulf's original projection for the period was $50,039,244 and is shown on Line 4 of Schedule CCE-1 filed September 1, 2010. The difference between these projections is $1,744,475 or 3.49% less than the original projection of net capacity payments.

Q. How did the total projected net capacity transactions cost compare to the actual cost for the first six months of 2011?

A. Actual net capacity payments during the first six months of 2011 were $16,976,271 which is $1,746,446 or 9.33% lower than projected for the period. The variance is due to timing differences between actual payments and projected payments under Gulf's purchase power agreements for the period.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110001-EI

BEFORE me, the undersigned authority, personally appeared Herbert R. Ball, who being first duly sworn, deposes and says that he is the Fuel Manager for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Herbert R. Ball
Herbert R. Ball
Fuel Manager

Sworn to and subscribed before me
this 29th day of July, 2011.

Natalie Milstead
Notary Public, State of Florida at Large

(SEAL)

NATALIE MILSTEAD
MY COMMISSION # EE091117
EXPIRES May 08, 2015
(407) 398-0153 FloridaNotaryService.com

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 110001-EI
Date of Filing: September 1, 2011

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern electric system. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 1, 2012 through December 31, 2012. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I have three separate exhibits I am sponsoring as part of this testimony. My first exhibit (HRB–2) consists of a schedule filed as an attachment to my pre-filed testimony that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short-term fuel expense projections. The second exhibit (HRB-3) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 15, 2011 and assigned Document Number DN 05777-11 (redacted) and 05772-11 (confidential information). The purpose of this second exhibit is to comply with Order No. PSC-08-0316-PAA-EI and details Gulf Power's natural gas hedging transactions for January through July 2011. The third exhibit (HRB-4) I am sponsoring is Gulf Power Company's "Risk Management Plan for Fuel Procurement" filed with the Commission Clerk pursuant to a separate request for confidential classification on August 1, 2011 and assigned Document Number DN 05355-11 (redacted) and 05354-11 (confidential information). The risk management plan sets forth Gulf Power's fuel procurement strategy and related hedging plan for the upcoming calendar year. Through its petition in this docket, Gulf Power is seeking the Commission's approval of the Company's "Risk Management Plan for Fuel Procurement" as part of this proceeding.

Counsel: We ask that Mr. Ball's three exhibits as just described be marked for identification as Exhibit Nos. _____ (HRB-2), ______ (HRB-3), and______ (HRB-4) respectively.

Q. Has Gulf Power Company made any significant changes to its methods for projecting fuel expenses, net power transaction expense, and purchased power capacity costs for this period?

A. No. Gulf has been consistent in how it projects annual fuel expenses, net power transactions, and capacity costs.

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2012 through December 2012 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $587,773,168. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 19.

Q. How does the total projected fuel and net power transactions cost for the 2012 period compare to the updated projection of fuel cost for the same period in 2011?

A. The total updated cost of fuel and net power transactions for 2011, reflected on Schedule E-1B-1 line 21 of Witness Dodd's testimony filed in this docket on August 1, 2011, is projected to be $597,743,941. The projected total cost of fuel and net power transactions for the 2012 period reflects a decrease of $9,970,773 or 1.67% less that the same period in 2011. On a fuel cost per kWh basis, the 2011 projected cost is 4.7620 cents per kWh and the 2012 projected fuel cost is 4.5524 cents per kWh, a decrease of 0.2096 cents per kWh or 4.40%.

Q. What is Gulf's projected recoverable total fuel cost of generated power for the period?

A. The projected total cost of fuel to meet system generated power needs in 2012 is $546,783,168. The projection of fuel cost of system generated power for 2012 is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 5.

Q. How does the total projected total fuel cost of generated power for the 2012 period compare to the updated projection of fuel cost for the same period in 2011?

A. The total updated cost of fuel to meet 2011 system generated power needs, reflected on Schedule E-1B-1, line 6 of Witness Dodd's testimony filed in this docket on August 1, 2011, is projected to be $550,128,748. The projected total cost of fuel to meet system net generation needs for the 2012 period reflects a decrease of $3,345,580 or 0.61% over the same period in 2011. Total system net generation in 2012 is projected to be 11,923,813,000 kWh, which is 718,298,000 kWh or 6.41% higher than is currently projected for 2011. On a fuel cost per kWh basis, the 2011 projected cost is 4.9094 cents per kWh and the 2012 projected fuel cost is 4.5856 cents per kWh, a decrease of 0.3238 cents per kWh or 6.60%. This lower projected total fuel expense and average per unit fuel cost is the result of a lower cost of coal for the period. Weighted average coal price including boiler lighter fuel for 2011 as reflected on Schedule E-3, line 32 of Witness Dodd's testimony filed in this docket on August 1, 2011, is projected to be 4.94 $/MMBtu. Weighted average coal price including boiler lighter fuel for 2012, as reflected on Schedule E-3, line 32 of the exhibit to Witness Dodd's testimony, is projected to be 4.51 $/MMBTU. This reflects a cost decrease of 0.43 $/MMBtu or 8.70%. Several of Gulf's coal supply agreements will expire at the end of 2011 and these are being replaced with lower priced coal supply agreements that have two year terms expiring at the end of 2012. Gulf's coal supply agreements have firm price and quantity commitments with the contract coal suppliers and these agreements will cover the majority of Gulf's 2012 projected coal burn needs. The remaining coal supply needs will be purchased on the spot market. Weighted average natural gas price for 2011, as reflected on Schedule E-3, line 33 of the exhibit to Witness Dodd's testimony filed in this docket on August 1, 2011, is projected to be 5.28 $/MMBtu. Weighted average natural gas price for 2012, as reflected on Schedule E-3, line 33 of the exhibit to Witness Dodd's testimony, is projected to be 5.41 $/MMBtu. This is an increase in price of 0.13 $/MMBtu or 2.46% and reflects forecasted higher market prices for natural gas in 2012. The projected cost of landfill gas to supply the Perdido Landfill Gas to Energy Facility in the 2011 projection period is $680,971 and the rate as reflected on Schedule E-3, line 42 of the exhibit to Witness Dodd's testimony filed in this docket on August 1, 2011, is projected to be 2.61 cents per kWh. The total projected cost for landfill gas in 2012 is $685,856 and the total facility generation is projected to be 26,440,000 kWh. The average rate, as reflected on Schedule E-3, line 42 of the exhibit to Witness Dodd's testimony, is projected to be 2.59 cents per kWh.

Q. Does the 2012 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. No. As in the past, Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years by Southern Company Services - Fuel Services as agent for Gulf. Coal will be delivered under both existing and new negotiated coal transportation contracts. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements. Details of Gulf's fuel procurement strategy are included in the "Risk Management Plan for Fuel Procurement" filed as exhibit _____ (HRB-4) to this testimony.

Q. What actions does Gulf take to procure natural gas and natural gas transportation for its units at competitive prices for both long-term and short-term deliveries?

A. Gulf procures natural gas using both long and short-term agreements for gas supply at market-based prices. Gulf secures gas transportation for non-peaking units using long-term agreements for firm transportation capacity and for peaking units using interruptible transportation, released seasonal firm transportation, or delivered natural gas agreements.

Q. What fuel price hedging programs will be utilized by Gulf to protect the customer from fuel price volatility?

A. As detailed in Gulf's "Risk Management Plan for Fuel Procurement", natural gas prices will be hedged financially using instruments that conform to Gulf's established guidelines for hedging activity. Coal supply and transportation prices will be hedged physically using term agreements with either fixed pricing or term pricing with escalation terms tied to various published market price indexes. Gulf's "Risk Management Plan for Fuel Procurement" is a reasonable and appropriate strategy for protecting the customer from fuel price volatility while maintaining a reliable supply of fuel for the operation of its electric generating resources.

Q. What are the results of Gulf's fuel price hedging program for the period January 2011 through July 2011?

A. Gulf's coal price hedging program has successfully managed the price it pays for coal under its coal supply agreements for this period. Gulf has also had financial hedges in place during the period to hedge the price of natural gas. These financial hedges have been effective in fixing the price of a percentage of Gulf's gas burn during the period. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed a "Hedging Information Report" with the Commission on August 15, 2011 detailing its natural gas hedging transactions for January 2011 through July 2011. As noted earlier, I am sponsoring this report as exhibit ______ (HRB-3) to my testimony in this docket.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2011 through 2012?

A. Gulf has adequate natural gas financial hedges in place for 2011 to mitigate price risk. Gulf currently has natural gas hedges in place for 2012 and continues to look for opportunities to enter into financial hedges that we believe will provide price stability to the customer and protect against unanticipated dramatic price increases in the natural gas market.

Q. Should recent changes in the market price for natural gas impact the percentage of Gulf's natural gas requirements that Gulf plans to hedge?

A. Gulf has a disciplined process in place to evaluate the benefits of gas hedging transactions prior to entering into financial hedges that consider both market price and anticipated burn. The focus of this process is to mitigate the price volatility and risk of natural gas purchases for the customer and not to attempt to speculate in the natural gas market. Gulf's current strategy is to have gas hedges in place that do not exceed the anticipated gas burn at its Smith Unit 3 combined cycle plant. Gas burn requirements change as the market price of natural gas changes due to the economic dispatch process utilized by the Southern System generation pool in accordance with the IIC. Typically, as gas prices increase, anticipated gas burn decreases and the percentage of gas requirements that are currently hedged financially increases. Gulf will continue to evaluate the performance of this hedging strategy and will make adjustments within the guidelines of the currently approved hedging program when needed.

Q. What is Gulf's projected recoverable fuel cost of power sold for the period?

A. Gulf's projected recoverable fuel cost of power sold is $34,092,000. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 17.

Q. How does the total projected recoverable fuel cost of power sold for the 2012 period compare to the projected recoverable fuel cost of power sold for the same period in 2011?

A. The total projected recoverable fuel cost of power sold in 2011, reflected on Schedule E-1B-1, line 18 of Witness Dodd's testimony filed in this docket on August 1, 2011, is projected to be $41,062,801. The projected recoverable fuel cost of power sold in 2012 represents a decreased credit of $6,970,801 or 16.98%. Total quantity of power sales in 2012 is projected to be 806,174,000 kWh, which is 885,138,815 kWh or 52.33% less than currently projected for 2011. On a fuel cost per kWh basis, the 2011 projected cost is 2.4279 cents per kWh and the 2012 projected fuel cost is 4.2289 cents per kWh, which is an increase of 1.8010 cents per kWh or 74.18%. The lower total credit to fuel expense from power sales is attributed to a reduced quantity of energy sales for the period offset somewhat by a higher fuel reimbursement rate (cents per kWh) for power sales as a result of higher marginal fuel prices. Higher marginal fuel costs to operate Gulf's generating fleet are passed on to the purchasers of power and are reflected in the higher rate ($/kWh) for the fuel cost and gains on power sales.

Q. What is Gulf's projected total cost of purchased power for the period?

A. Gulf's projected recoverable cost for energy purchases is $75,082,000. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 12.

Q. How does the total projected purchased power cost for the 2012 period compare to the projected purchased power cost for the same period in 2011?

A. The total updated cost of purchased power to meet 2011 system needs, reflected on Schedule E-1B-1, line 13 of Witness Dodd's testimony filed in this docket on August 1, 2011, is projected to be $88,677,993. The projected cost of purchased power to meet system needs in 2012 is $13,595,993 or 15.33% less than is currently projected for 2011. The total quantity of purchased power in 2012 is projected to be 1,793,621,000 kWh, which is 1,244,483,851 kWh or 40.96% lower than is currently projected for 2011. On a fuel cost per kWh basis, the 2011 projected cost is 2.9189 cents per kWh and the 2012 projected fuel cost is 4.1861 cents per kWh, which represents an increase of 1.2672 cents per kWh or 43.41%.

Q. What is Gulf's projected recoverable capacity payments for the period?

A. The total recoverable capacity payments for the period are $38,027,046. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 10. Schedule CCE-4 of Mr. Dodd's testimony shows the Southern Company Interchange projected capacity costs of

$10,712,687 and lists the long-term power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting capacity dollar amounts. Also included in Gulf's 2012 projection of capacity cost is revenue produced by a market-based service agreement between the Southern electric system operating companies and South Carolina PSA. The total capacity cost of $48,384,587 is shown on Schedule CCE-4, line 34 in the exhibit to Witness Dodd's testimony. The total capacity cost included on Schedule CCE-4 line 34 is the sum of lines 1 and 2 of Schedule CCE-1.

Q. Have there been any new purchased power agreements entered into by Gulf that impact the total recoverable capacity payments?

A. No.

Q. What are the other projected revenues that Gulf has included in its capacity cost recovery clause for the period?

A. Gulf has included an estimate of transmission revenues in the amount of $278,000 in its capacity cost recovery projection. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 3.

Q. How does the total projected net jurisdictional capacity payments for the 2012 period compare to the current estimated net jurisdictional capacity payments for the same period in 2011?

A. Gulf's 2012 Projected Jurisdictional Capacity Payments, found in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 6, is

$46,396,792. This amount is $181,495 or 0.39% less than the current estimate of $46,578,287 (Schedule CCE-1B, line 6) for 2011 that was filed in Mr. Dodd's estimated/actual true-up testimony in this docket on August 1, 2011. The projected capacity payment decrease is the result of a decrease in Gulf's estimated IIC reserve sharing payments and a projected increase in transmission revenues for the period.

Q. Mr. Ball, does this complete your testimony?
A. Yes, it does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110001-EI

BEFORE me, the undersigned authority, personally appeared Herbert R. Ball, who being first duly sworn, deposes and says that he is the Fuel Manager for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Herbert R. Ball
Herbert R. Ball
Fuel Manager

Sworn to and subscribed before me this 30th day of August, 2011.

Candace Klinglesmith
Notary Public, State of Florida at Large

(SEAL)

CANDACE KLINGLESMITH
Notary Public - State of Florida
My Comm. Expires May 18, 2015
Commission # EE 79408
Bonded Through National Notary Assn.

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, 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' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 2nd day of November, 2011.

Linda Boles

LINDA BOLES, RPR, CRR
FPSC Official Commission Reporter
(850) 413-6734