BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140001-EI

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

Pages 1 through 233

PROCEEDINGS: HEARING

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

DATE: Wednesday, October 22, 2014

TIME: Commenced at 9:50 a.m.
Concluded at 9:56 a.m.

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

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

APPEARANCES:

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

JOHN T. BURNETT, DIANE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, 106 East College Avenue, Tallahassee, Florida 32301-7740, appearing on behalf of Duke Energy Florida, Inc.

BETH KEATING, ESQUIRE, Gunster Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1839, appearing on behalf of Florida Public Utilities Company.

JEFFREY A. STONE, RUSSELL A. BADDERS, and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

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

APPEARANCES (Continued):

J.R. KELLY, PUBLIC COUNSEL; PATRICIA A. CHRISTENSEN, ASSOCIATE PUBLIC COUNSEL, and CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of Florida.

JON C. MOYLE, JR., and VICKI GORDON KAUFMAN, ESQUIRES, The Moyle Law Firm, 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, Florida Retail Federation, The Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of Walmart Stores East, LP, and Sam's East, Inc.

MARTHA BARRERA, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

APPEARANCES (Continued):

CURT KISER, GENERAL COUNSEL, and MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisors to the Florida Public Service Commission.

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.

*****NO EXHIBITS IN THIS VOLUME*****

P R O C E E D I N G S

CHAIRMAN GRAHAM: Okay. Now I think it's time to convene the 2014 clause hearing. If I can get the staff to read the order.

MS. TAN: By notice issued September 17th, 2014, this time and place is set for a hearing conference in the following dockets: 140001-EI, 140002-EG, 140003-GU, 140004-GU, and 140007-EI. The purpose of the hearing conference is set out in the notice.

CHAIRMAN GRAHAM: Okay. Let's take appearances.

MR. BUTLER: Good morning, Mr. Chairman. John Butler and Ken Rubin appearing on behalf of FPL in the 02 docket, and John Butler and Maria Moncada appearing on behalf of FPL in the 01 and 07 dockets. Thank you.

MS. DANIELS: Good morning, Chairman. Ashley Daniels appearing with James Beasley and Jeffry Wahlen with Ausley McMullen appearing on behalf of Tampa Electric Company in the 01, 02, and 07 dockets. Thank you.

MR. BERNIER: Good morning, Commissioners. Matt Bernier with Duke Energy appearing in the 01, 02, and 07 dockets, along with John Burnett and Dianne Triplett. I'd also like to enter an appearance for Gary

Perko in the 07 docket. Thank you.

MR. BADDERS: Good morning, Chairman. Russell Badders on behalf of Gulf Power Company. I'd like to enter an appearance for myself, Jeffrey A. Stone, Steven R. Griffin in the 01, 02, and 07 dockets.

MR. CAVROS: Good morning, Commissioners. George Cavros on behalf of the Southern Alliance for Clean Energy. I'll be representing the organization in the 02 and the 07 dockets.

MS. KAUFMAN: Good morning, Commissioners. Vicki Gordon Kaufman and Jon Moyle of the Moyle Law Firm on behalf of the Florida Industrial Power Users Group in the 01, 02, and 07 dockets.

MS. KEATING: Good morning, Commissioners. Beth Keating with the Gunster Law Firm here today for FPU in the 01 and 02 dockets, for FPU and Florida City Gas in the 03 docket, and for FPU, Indiantown, Fort Meade, Florida City Gas, and Chesapeake in the 04 docket.

MR. WRIGHT: Good morning, Commissioners. Robert Scheffel Wright and John T. LaVia, III, of the Gardner, Bist, Weiner Law Firm in the 01 fuel cost recovery docket. We're appearing on behalf of the Florida Retail Federation. In the 02 docket we're appearing on behalf of Walmart Stores East and Sam's

East, LP. Thank you.

MR. REHWINKEL: Good morning, Commissioners. Charles Rehwinkel, Patty Christensen, and J. R. Kelly with the Office of Public Counsel on behalf of the people of the State of Florida in all dockets.

MS. TAN: Martha Barrera for the 01 docket, Lee Eng Tan for the 02 docket, Kyesha Mapp and Keino Young for the 03 docket, Kelley Corbari for the 04 docket, and Charlie Murphy for staff on the 07 docket.

MS. HELTON: And I'm Mary Anne Helton. I'm here as your advisor on all the dockets. And I'd also like to enter an appearance for your General Counsel, Curt Kiser.

CHAIRMAN GRAHAM: Okay. So those five dockets that we're going to address today, staff, I take it we're taking in the order of docket 02, then 03, then 04, then 01, then 07, in that order?

MS. TAN: That is correct. And, Chairman, I'd also like to note that the following parties have been excused from attending the hearing: St. Joe Natural Gas Company in the 03 and the 04 docket, Peoples Gas System in the 03 and the 04 docket, Sebring Gas System in the 04 docket, and PCS Phosphate/White Springs in the 01, 02, and 07 dockets.

CHAIRMAN GRAHAM: Okay. Well, if there's nothing else, then I guess we move to the individual dockets.

MS. TAN: That is correct.

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MS. BARRERA: Good morning, Commissioners. This is Docket 140001. Staff will note that PCS Phosphate/White Springs has been excused from the hearing. Staff will also note that there are several stipulations in the Prehearing Order, page 28 -- excuse me -- to 43, and additional stipulations were entered into after the Prehearing Order was issued. Staff prepared a chart showing the stipulated, the additional stipulated issues. All parties either agree or take no position on all the stipulations that are before the Commission today, making them all Type 2 stipulations.

The issues that remain are Issues 1C, Issues 10 and 11 pertaining to Duke Energy Florida only. Duke witness Mr. Foster will testify as to these issues. Opening statements on these issues are limited to five minutes per party, and staff recommends that opening statements be heard after the Commission addresses the proposed stipulations.

CHAIRMAN GRAHAM: Okay. Commissioners?

MS. BARRERA: Mr. Chairman?

CHAIRMAN GRAHAM: Yes.

MS. BARRERA: Staff suggests that since the parties are proposing stipulations on all the issues except Issues 1C, 10, and 11 as to Duke Energy, the Commissioners should make a bench decision. And if the Commission decides a bench decision is appropriate, we recommend that the proposed stipulations should be approved. And then staff recommends that testimony on Issues 1C, 10, and 11 with regard to Duke Energy Florida should be heard once a bench decision is made on the stipulated issues.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And prior to making a motion approving the stipulated issues, I just wanted to make a few comments on some of the issues that were stipulated, specifically Issue, I believe it's 2C and dealing with FPL's incentive mechanisms.

As you recall, at the end of 2012 we approved a settlement agreement that allowed FPL to implement an incentive mechanism associated with certain activities, and there was a threshold established at that point where any savings up to that threshold would go solely to the customers. And in that issue and the testimony associated with that, FPL has reported that customers will receive almost $25 million in benefits that they would not have received prior to that settlement agreement and prior to that incentive mechanism being in place. So I think that's important. I think that's a good thing for customers, and I think it should be noted. I know all those here that have read through the materials moving forward understand that, but I want to make sure that the public does as well.

And the other issue that I wanted to discuss, and it really pertains to several issues, and that is the Issue 1 and others associated with that on all the companies' activities to mitigate against price volatility with natural gas.

As I've stated several times, and we've stated as a Commission, as we continue to rely on natural gas for fuel for generation, we're going to continue to be susceptible to fluctuations. So I agree with staff's recommendation, the stipulations that activities were prudent. I think we could probably do more to mitigate against those fluctuations, and I'm interested to see what actions take place in the future to do so.

With that, Mr. Chairman, if there are no other comments, I'm prepared to make a motion to approve all the stipulations with exception -- on all issues with exception of Issues 1C, 10, and 11.

COMMISSIONER EDGAR: Second.

CHAIRMAN GRAHAM: It's been moved and seconded to approve the stipulated issues on all issues except for 1C, 10, and 11.

Any further discussion on the motion?

Seeing none, all in favor, say aye.

(Vote taken.)

Any opposed? By your action, you've approved all issues except for Issues 1C, 10, and 11.

Okay, staff. What about prefiled direct -- prefiled testimony?

MS. BARRERA: Yes, Commissioner. Staff recommends that the prefiled testimony and exhibits of all the witnesses, of course, except Duke witness Thomas G. Foster, be entered into the record at this time as though read.

CHAIRMAN GRAHAM: So we will enter the prefiled direct testimony of all witnesses except Duke's witness Foster into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 140001-EI

MARCH 3, 2014

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 and Light Company (FPL) as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2013 results of FPL's activities under the Incentive Mechanism that was approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI.

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 Exhibit GJY-1, consisting of four pages:

- Page 1 – Total Gains Schedule
- Page 2 – Wholesale Power Detail
- Page 3 – Asset Optimization Detail
- Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. It was created by the Stipulation and Settlement that was approved in FPL's 2012 rate case by Order No. PSC-13-0023-S-EI. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially outsourcing the optimization function to a third party in the form of an Asset Management Agreement (AMA). Under the Incentive Mechanism, customers receive 100% of the gains up to $46 million. Incremental gains above $46 million are to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $46 million and $100 million; and customers receive 50% and FPL receives

50% of all incremental gains above $100 million. FPL is allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs, as well as variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh. The 514,000 MWh threshold represents the level of sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case.

Q. Please summarize the activities and results of the Incentive Mechanism for 2013.

A. FPL's activities under the Incentive Mechanism in 2013 delivered nearly $24.6 million in benefits for customers. During 2013, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation and firm electric transmission. Additionally, FPL entered into an Asset Management Agreement during 2013. The total gains of nearly $24.6 million did not exceed the sharing threshold of $46 million and, therefore, customers receive 100% of those benefits. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2013.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2013.

A. The details of FPL's 2013 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $11,153,006 on wholesale sales and savings of $3,205,747 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2013.

A. The details of FPL's 2013 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $10,205,119 of gains that were the result of seven different forms of asset optimization.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2013?

A. Yes. FPL incurred personnel expenses of $263,407 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. Additionally, FPL's actual wholesale power sales in 2013 totaled 1,944,763 MWh, or 1,430,763 MWh above the 514,000 MWh threshold, resulting in variable power plant O&M expenses of $2,160,452 (reflects the volume above the threshold multiplied by $1.51/MWh; the average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs). Page 4 of Exhibit GJY-1 provides the details of FPL's Incremental Optimization Costs for

2013.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2013?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2013. On the wholesale power side, suitable market conditions helped drive FPL's wholesale power sales to the highest level since 2004 and the second highest level in the last 13 years. Gains on power sales reached the highest level since 2008. Asset optimization activities related to natural gas that had not taken place prior to the inception of the Incentive Mechanism generated slightly more than $9.1 million in customer benefits, and optimization of FPL's firm transmission service on the Southern Company system added another $1.1 million in benefits. In total, these activities delivered $24,563,872 of benefits to customers, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of only $2,423,859.

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. 140001-EI

MARCH 28, 2014

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 2013. This data is required per Item 5 of the Resolution of Issues in Docket 011605-EI that was 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-2 – August through December 2013 Hedging Activity True-Up.

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. For 2013, FPL implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL’s 2012 Risk Management Plan that was approved by the Commission in Order No. PSC-11-0579-FOF-EI, issued on December 16, 2011.

Q. Please summarize FPL’s 2013 hedging activities.

A. Consistent with its approved 2012 Risk Management Plan, FPL hedged a portion of its fuel portfolio for 2013 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 2013 natural gas prices settled, on average, slightly higher from the forward prices that were in effect when FPL was executing its natural gas hedges for 2013. As would be expected under the approved hedging approach, this increase in natural gas prices resulted in reported natural gas hedging savings for the year, as shown on Exhibit GJY-2. Conversely, heavy oil prices decreased from the forward prices that were in effect when FPL was executing its heavy oil hedges for 2013. As shown on Exhibit GJY-2, this resulted in reported heavy oil hedging costs for the year.

Q. Does your Exhibit GJY-2 provide the detail on FPL's 2013 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. 140001-EI

SEPTEMBER 15, 2014

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 and 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 sales and purchased power transactions. In addition, I review the interim results of FPL's 2014 hedging program and its 2015 Risk Management Plan. Lastly, my testimony addresses the Incremental Optimization Costs included in FPL's 2015 Projection Filing and the 2013 results of the Incentive Mechanism that was approved in Order No. PSC-13-0023-S-EI dated January 14, 2013.

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-3: 2015 Risk Management Plan
- GJY-4: Hedging Activity Supplemental Report for 2014 (January through July)
- GJY-5: Appendix I
- Schedules E2 through E9 of Appendix II
- Schedules E2 through E9 of Appendix III assuming the Woodford Gas Reserves Project is not implemented

Q. How do FPL's 2015 Projection Schedules reflect its request in this docket for Commission approval of the costs associated with the Woodford Gas Reserves Project?

A. Because the due date for FPL's 2015 Projection Filing (August 22, 2014) is prior to the Commission's decision on the Woodford Gas Reserves Project, FPL has filed two sets of Projection Schedules, one set that includes the costs associated with the Woodford Gas Reserves Project and one set that does not include these costs. All references in my testimony related to the quantities and costs of wholesale (off-system) power and purchased power transactions that appear on Schedules E6 through E9 are part of the set of Projection Schedules that include the costs associated with the Woodford Gas Reserves Project.

Q. What are the projected costs from FPL's wholly-owned subsidiary that are included in the Projection Schedules that are associated with the Woodford Gas Reserves Project?

A. FPL has included approximately $47.7 million in projected costs related to the Woodford Gas Reserves Project. These costs are projected to be more than offset by the savings resulting from reduced gas purchases at market prices. As shown in the testimony and exhibits of FPL witness Keith, customers are projected to pay approximately $7 million less in 2015 with the Woodford Gas Reserves Project than they would without it.

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies has FPL used for the 2015 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 July 28, 2014 for its 2015 projection filing, which is the most current information that could be incorporated into FPL's schedule for calculating the 2015 FCR Clause factors.

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 and has used this methodology consistently since that time.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2015 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.

Average heavy oil prices are forecasted to be slightly lower in 2015 compared with projected 2014 average levels primarily due to the assumed reduction in the global crude oil price. Crude oil prices are expected to remain strong over the next few months due to OPEC supply disruptions in Iraq and Libya, combined with geopolitical risks in the Middle East. This is despite a strong surge in non-OPEC supply and North American shale oil production that is expected to grow by 1.33 million barrels per day in 2014. The United States Strategic Petroleum Reserve will also act as a deterrent to prices moving up significantly in the short-term. By mid-2015, oil prices are expected to stabilize as OPEC supply improves on the assumption of reduced geopolitical risk and improvement in Iraqi supplies, while the North American supply growth continues. The Energy Information Authority's (EIA) July 2014 Short-Term Energy Outlook report anticipates non-OPEC supply to grow by 0.97 million barrels per day in 2015, of which the majority will come from U.S. shale oil production growth. While projected growth in non-OECD demand of 1.36 million barrels per day should boost global demand in 2015, the increase in non-OPEC supply will help reduce the call on OPEC supply in 2015 and stabilize prices at a lower level. As always, an increase in geopolitical concerns could create upward pressure on oil prices.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2015 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 2015 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 coal at SJRPP and Plant Scherer for the January through December 2015 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 2015 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.

Natural gas prices are projected to remain fairly stable throughout 2015. Although working natural gas rigs are down approximately 80% since the peak in August 2008 and 20% year-on-year, efficiency improvements in the shale regions are leading to record levels of production of natural gas. Natural gas production is expected to grow by an average rate of 4.1% in 2014 and 1.2% in 2015. Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada. Liquefied natural gas (LNG) imports have fallen over the past several years because high prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to export LNG from the United States. Cheniere Energy's Sabine Pass facility is expected to be the first facility scheduled to come online in stages beginning in late 2015. Total natural gas consumption in 2015 is expected to average 72.1 BCF per day, a decrease of 0.3 BCF per day based on an assumed return to near-normal winter weather, which will contribute to lower residential and commercial consumption. Natural gas storage levels, a key benchmark for the supply/demand balance, were 0.82 trillion cubic feet (TCF) on March 28, 2014, or 0.88 TCF (52%) below the level at the same time a year ago and 0.99 TCF (55%) below the five-year average from 2009 through 2013. Natural gas storage is currently projected to reach 3.43 TCF at the end of October 2014, or 0.38 TCF below the level at the same time last year. However, production growth and demand losses should bring storage levels back to 5 year averages in 2015 if weather conditions are normal.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2015 period?

A. The key factors mainly relate to the balance of gas transportation and demand in Florida, specifically, (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 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 1,324,000 MMBtu/day, depending on the month. FPL has firm transportation capacity on Gulfstream of 695,000 MMBtu/day.

Additionally, FPL has firm transportation capacity on several upstream pipelines that provide FPL access to on-shore gas supply. FPL has 580,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline, 200,000 MMBtu/day of firm transport on the Transcontinental Pipe Line Gas Company, LLC

(Transco) Zone 4A lateral, and 145,000 MMBtu/day (April through October) on the Gulf South Pipeline Company, LP (Gulf South) pipeline. In addition, FPL's second agreement with Gulf South for 200,000 MMBtu/day of firm transportation capacity (year-round) begins on April 1, 2015. This transportation capacity is associated with an expansion of the Gulf South system and was executed in 2012. The firm transportation on the SESH, Transco, and Gulf South pipelines does not increase transportation capacity into the state; however FPL's firm transportation rights on these pipelines provide access for up to 1,125,000 MMBtu/day from April through October 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 2015 period, 50,000 MMBtu/day to 150,000 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 describe FPL's natural gas storage position?

A. FPL currently holds 2.5 BCF of firm natural gas storage capacity in Bay Gas Storage, located in southwest Alabama. FPL has continually evaluated its storage capability as its reliance on natural gas has grown. While the acquisition of upstream transportation capacity (i.e., SESH) has helped mitigate a large portion of risk associated with off-shore natural gas supply, natural gas storage capacity remains an important part of FPL's gas portfolio. Approximately 20% of FPL's supply continues to be sourced from off-shore sources. Additionally, as FPL's reliance on natural gas has increased, the importance of natural gas storage in helping balance consumption "swings" due to weather and unit availability has also increased. FPL has recently executed an amendment to its Firm Storage Agreement with Bay Gas to increase its capacity to 4.0 BCF beginning September 1, 2014. This amendment improves the overall pricing of FPL's entire Bay Gas position, provides for increased injection and withdrawal rights, and provides access to additional injection and withdrawal points. The amendment does not change the term of the original agreement. This increase in storage capacity improves reliability by providing a relatively inexpensive insurance policy against supply and infrastructure problems while also increasing FPL's ability to manage supply and demand on a daily basis.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2015 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 2015?

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 2015.

Q. Please describe the significant planned outages for the January through December 2015 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 March 23, 2015 until April 25, 2015 or 33 days during the period. St. Lucie 2 is scheduled to be out of service from September 7, 2015 until October 9, 2015 or 32 days during the period. Turkey Point Unit 3 is scheduled to be out of service from October 19, 2015 until November 18, 2015 or 30 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2015 period.

A. FPL does not project any significant changes to its fossil generation capacity during 2015.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2015?

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. FPL's customers benefit from both purchases and sales as 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 10 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 1,750,000 MWh of wholesale (off-system) power sales for the period of January through December 2015. The projected fuel cost related to these sales is $73,475,400. The projected transaction revenue from these sales is $93,986,650. The projected gain for these sales is $15,911,250.

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 2015 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 368,250 MWh at a cost of $18,998,000. If FPL generated this energy, FPL estimates that it would cost $28,569,550. Therefore, these purchases are projected to result in savings of $9,571,550.

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

A. Yes. FPL purchases energy under three Unit Power Sales Agreements (UPS) with the Southern Companies. The agreements are comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 163 MW of coal generation (Scherer Unit 3). The UPS agreements have a term that runs through December 31, 2015. 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 2015 period.

A. UPS energy purchases for the period are projected to be 1,934,258 MWh at an energy cost of $78,964,923. 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 1,838,512 MWh for the period at an energy cost of $65,719,000. 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 492,739 MWh at a cost of $3,673,157. 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 3,284,130 MWh at a cost of $142,883,700.

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 573,053 MWh of energy at a cost of $4,351,540. These projections are shown on Schedule E6 of Appendix II.

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

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program has been, and remains, the reduction of fuel price volatility. Reducing fuel price volatility helps deliver greater price certainty to FPL's customers. FPL does not engage in speculative hedging strategies aimed at "out guessing" the market.

Q. Has FPL filed a comprehensive risk management plan for 2015, consistent with the Hedging Order Clarification Guidelines as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2015 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up filing on July 25, 2014. The 2015 Risk Management Plan is included as Exhibit GJY-3.

Q. Please provide an overview of FPL's 2015 Risk Management Plan.

A. FPL's 2015 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 2015 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2015 for its projected natural gas requirements in 2016. FPL plans to hedge the percentages of its 2016 projected natural gas requirements over the time periods in 2015 that are described in the plan. As described in the plan, FPL discontinued heavy fuel oil hedging in 2013 and does not intend to execute hedges for its 2016 heavy fuel oil requirements.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2014, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2014 (January through July) on August 13, 2014. The Hedging Activity Supplemental Report is identified as Exhibit GJY-4.

Q. Have FPL's 2014 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. At the time FPL was placing its hedges for its 2014 projected natural gas requirements, market prices were different than the actual settlement prices that have occurred in 2014.

For example, in January 2013, the average monthly NYMEX forward price for natural gas for the January through July 2014 period was approximately \$3.98 per MMBtu. In July 2013, the average monthly NYMEX forward price for the January through July 2014 period was approximately \$3.93 per MMBtu. The actual average NYMEX monthly settlement price for this same time period in 2014 was \$4.75 per MMBtu or \$0.77 per MMBtu higher than the forward prices seen in January 2013 and \$0.82 per MMBtu higher than the forward prices seen in July 2013. Ultimately, FPL's natural gas hedges resulted in savings of \$131,436,091 for the January through July 2014 period.

As acknowledged in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for natural gas results in savings for customers. Conversely, hedging in the opposite market conditions would result 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. As previously stated, FPL's hedging objective is to reduce fuel price volatility and deliver greater price certainty.

<u>THE INCENTIVE MECHANISM</u>

Q. Is FPL seeking to recover through the FCR Clause projected incremental operating and maintenance expenses (Incremental Optimization Costs) during the January through December 2015 period with respect to implementing its program for expanded short-term wholesale purchases and sales, as well as asset optimization measures (the Incentive Mechanism) that was approved in Order No. PSC-13-0023-S-EI, dated January 14, 2013?

A. Yes. FPL has included projected Incremental Optimization Costs associated with the Incentive Mechanism in its projections for 2015.

Q. What types of Incremental Optimization Costs is FPL entitled to include for recovery through the fuel clause?

A. Per Order No. PSC-13-0023-S-EI, FPL is entitled to recover reasonable and prudent Incremental Optimization Costs from two categories: (i) incremental personnel, software and hardware costs associated with managing the various asset optimization activities, and (ii) variable power plant O&M costs incurred to generate additional output in order to make wholesale sales in excess of 514,000 MWh.

Q. Please describe the costs that are included in FPL's projections for incremental personnel, software, and hardware expenses.

A. FPL projects to incur incremental expenses of $405,054 in 2015 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism. FPL is also projecting to incur $48,480 in licensing fees from OATI for its WebTrader software. The OATI WebTrader software is a tool used for power trading. The features of WebTrader will facilitate streamlined trade entry, transmission procurement, power scheduling, and accounting checkout. FPL expects that the WebTrader software will help FPL deliver additional value to customers by facilitating speed and flexibility in our power trading.

Q. Please describe the costs that are included in FPL's projections for variable power plant O&M expenses.

A. FPL projects to incur incremental expenses related to variable power plant O&M of $1,866,360 in 2015. FPL projects to sell 1,750,000 MWh of economy power (Schedule E6) in 2015 which is 1,236,000 MWh above the 514,000 MWh of such sales that were projected in FPL's 2013 Test Year and used as a threshold for power sales in the Incentive Mechanism. Based on data provided as part of the 2013 Test Year projections, FPL has determined that its incremental variable power plant O&M cost is $1.51/MWh. Applying this rate to projected excess sales of 1,236,000 MWh above the threshold yields total variable power plant O&M of $1,866,360 in 2015.

Q. Has FPL included in its 2014 actual-estimated FCR true-up and 2015 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E3 and Capacity Clause-Transmission of Electricity by Others) for both 2014 and 2015.

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2013?

A. FPL's asset optimization activities in 2013 delivered total net benefits (excluding variable power plant O&M and personnel expenses) of $24,300,464. The total gains did not exceed the sharing threshold of $46 million and, therefore, customers received 100% of these benefits.

Q Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2013?

A. Yes. I have compared how customers would have fared under the prior wholesale-sales sharing mechanism with the results FPL has achieved under the new Incentive Mechanism. For the purpose of this comparison, I have included the same savings of $17.6 million from optimization activities for power sales, power purchases and releases of electric transmission capacity under both mechanisms, as FPL was engaging in those activities prior to the Commission's approval of the Incentive Mechanism. For those savings, the previous sharing mechanism would have yielded net benefits to FPL's customers of $15.8 million, while FPL would have retained $1.8 million because the three-year rolling average threshold for wholesale sales would have been exceeded. In contrast, under the Incentive Mechanism, FPL also is incented to pursue beneficial natural gas transportation, storage and trading activities. These generated $9.1 million of additional savings in 2013. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received $24.3 million of savings under the Incentive Mechanism (the $46 million sharing threshold was not reached in 2013). This is $8.5 million more than customers would have received if the prior sharing mechanism were still in effect, clear proof that the Incentive

Mechanism is working to deliver added value for customers as FPL and the Commission envisioned when it was approved.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DON GRISSETTE

DOCKET NO. 140001-EI

SEPTEMBER 15, 2014

Q. Please state your name and address.

A. My name is Don Grissette. 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 as General Manager of Change Management and Organizational Development in the Nuclear Business Unit as of August 2014. My prior position was General Manager of Organizational Effectiveness, also in the Nuclear Business Unit.

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

A. I am responsible for the continuous improvement process for improving fleet efficiency, organizational design and effectiveness of the nuclear fleet. Prior to my current position, I was responsible for the daily and strategic activities for the nuclear fleet's Training, Licensing, Performance Improvement, and Security organizations.

Q. Have you previously filed testimony in this or a predecessor 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. Nuclear fuel costs were input values to the POWERSYM model that is used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2015 through December 2015. I am also updating plant security costs; Fukushima costs; and outage events.

<u>**Nuclear Fuel Costs**</u>

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

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and current operating schedules, for the period January 2015 through December 2015.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2015 through December 2015.

A. FPL projects the nuclear units will produce 297,514,072 MMBtu of energy at a cost of $0.6540 per MMBtu, excluding spent fuel disposal costs, for the period January 2015 through December 2015.

Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 16, which is attached as an exhibit to FPL witness Keith's testimony.

<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 2015 through December 2015?

A. FPL projects that it will incur $38.2 million in incremental nuclear power plant security costs in 2015. The costs consist of $3.0 million of capital expenditures and $35.2 million of O&M expenses.

Q. Please provide a brief description of the items included in incremental nuclear power plant security costs.

A. The projection includes the additional costs incurred in 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.

Fukushima Costs

Q. What is FPL's projection of Fukushima costs at FPL's nuclear power plants for the period January 2015 through December 2015?

A. FPL's current projection of Fukushima-related costs for 2015 is approximately $45.0 million of capital expenditures and $180,045 of O&M expenses. These estimates are for total expenditures. FPL witness Keith discusses adjustments to reflect the incremental 2015 Fukushima-related recovery amounts that FPL seeks to include in the Capacity Clause.

Q. Please provide a brief description of the items included in this projection of Fukushima-related costs.

A. FPL expects to pursue the following activities in 2015:

- Flooding Re-evaluation: FPL will complete flooding integrated assessments based on re-evaluation results obtained in 2013 and 2014.
- Station Black out Mitigation: FPL will implement its Station Black-out mitigation strategies. The implementation will include:

- o Design and implementation of hardened storage for portable equipment.
- o Engineering and purchase of equipment to install low leakage Reactor Coolant Pump Seals (RCP) in 2015 and 2016. RCP seal injection is lost during a station blackout. Existing RCP seals would stop functioning following the loss of injection pressure, resulting in excessive RCS leakage. New low leakage seals greatly reduce this potential for RCS inventory loss and thus provide more robust protection against any impairment of core-cooling capacity.
- o Purchase of portable equipment.
- o Modifications to existing plant equipment that upgrade, protection or provide a means to tie portable equipment into existing electrical and fluid systems.
- o FPL's share of costs incurred for equipment, storage, and transportation, to support the shared Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).
- o Station Black-out staffing studies.

▪ Spent fuel Instrumentation: FPL will procure and install two new level instruments in each Spent Fuel Pool.

▪ Emergency Preparedness facility and procedure upgrades.

- Payment of NRC fees charged for NRC man-hours spent reviewing FPL's responses associated with the various regulatory orders and information requests.

<u>2014 Outage Events</u>

St. Lucie

Q. Has FPL experienced any unplanned outages at St. Lucie Unit 2 in 2014?

A. Yes. In April 2014, while Unit 2 was shut down to perform a scheduled refueling outage the following events delayed the restart of the unit:

- During reactor coolant pump start-ups, a monitor alarm indicated the presence of foreign materials in the steam generator. The foreign material was identified and removed from the primary side of the 2B steam generator.
- During the inspection of the 2B Steam Generator Feed Ring, it was identified that repairs would be required for the feed ring supports.
- After completing repairs to the Hydrazine pump discharge isolation valve as part of the scheduled outage work, the pump failed its post maintenance test, which required additional repair work.
- While performing local leak rate testing, a containment purge valve penetration failed to pressurize and required repair.

Q. What was the source of foreign material in the steam generator?

A. There is no definitive conclusion as to how the material entered the steam generator. FPL could not determine from inspection of the foreign material where it originated, and an exhaustive review of the records for work performed during this most recent outage did not indicate any instance where it appeared that foreign material might have been introduced into the steam generator. FPL believes that the foreign material most likely entered the steam generator as a result of refueling activities, and most likely during a previous refueling outage.

Q. What corrective actions have been initiated to address this event?

A. FPL shut down the plant and retrieved the foreign material from the steam generator. Because the source of the foreign material has not been definitively determined, FPL was not in a position to take corrective actions specific to the event. In an abundance of caution, however, FPL revised the maintenance procedure to maintain the reactor cavity in Foreign Material Exclusion Area, Level 1 (FMEA1) while performing maintenance through re-installation of the permanent reactor head. There are 3 levels of controls applied to open systems that prevent foreign material from being introduced. Level 1 is highest with the most controls. Previously, Level 1 had applied only until the temporary reactor head was in place. This practice was within established procedures and was considered sufficient, because placement of the temporary reactor head substantially reduces the potential for foreign material to enter the reactor cooling system. Nonetheless, FPL has elected to be even more conservative in order to further reduce foreign-material risk.

Q. Please describe the circumstances related to the 2B Steam Generator Feed Ring repairs.

A. During steam generator secondary side visual inspections, foreign objects were found on the loose part trapping screens and damage to feed ring components was discovered. Further inspections were performed to characterize the damage and to determine the origin of the foreign objects. It was determined that the foreign object discovered in secondary side of the 2B Steam Generator was a key that formed part of a support structure for the feed ring. Leakage from all feed ring inspection port covers in both Steam Generators was also observed.

Q. What corrective actions have been initiated to address this event?

A. FPL modified the steam generator feed rings to eliminate the need for the existing key/keyway supporting structure and replaced all four bolted feed ring inspection covers with welded inspection caps to prevent leakage. FPL will inspect both Units 1 and 2 feed ring systems in their next respective refueling outages to verify that the modifications have addressed the conditions that were discovered in this event.

Q. Please describe the circumstances related to the Hydrazine pump discharge isolation valve repair.

A. The Hydrazine pump discharge isolation valve repair failed its post-maintenance test. The valve was disassembled and found not to permit full valve closure.

Q. What corrective actions have been initiated to address this event?

A. The valve was reassembled and verified to be set up and stroked correctly in accordance with the Vendor Manual. FPL will develop a maintenance procedure by the end of 2014 to clarify how future solenoid valve disassembly, inspection, assembly and testing are to be performed based on applicable Vendor Manual and valve drawing information.

Q. Please describe the circumstances related to the Containment Purge valve repair.

A. While performing local leak rate testing, a penetration failed to pressurize. Further inspection found air blowing out of a valve which indicates the containment purge valve was not seating properly.

Q. What corrective actions have been initiated to address this event?

A. FPL repaired the valve so that it could seat properly. FPL did not conclude that any further corrective actions were necessary.

Q. How many days was St. Lucie Unit 2 out of service due to these events?

A. The Unit 2 outage was extended due to these four events by approximately 18 days.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 2 in 2014?

A. Yes. In July, Unit 2 was manually shut down after performing emergency core cooling isolation valve integrity testing which revealed a small leak inside containment. A defect was identified on an Outlet Vent Valve inside the Safety Injection Tank (SIT), and the valve was repaired. The outage duration for this event was approximately 7 days. FPL is in the process of investigating and evaluating this recent outage event.

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2014?

A. Yes. In March 2014, while Unit 3 was shut down to perform a scheduled refueling outage, there were duration extensions associated with the 10 year In-Service Inspection (ISI) for the reactor head and vessel, the fuel core offload and emergent equipment conditions that occurred at various times throughout the outage.

Q. Please describe the circumstances related to the duration extensions for the ISI Inspection.

A. The ISI inspection took longer than planned due to first-time use of new equipment and set up for the inspection, which is only performed once every 10 years. Also, additional ultrasonic testing of the reactor coolant piping nozzles, known as the Rainbow robot exam, was required to follow up and clarify the results of the initial testing. While it is not unusual to have to perform this follow-up testing, FPL cannot predict in advance whether the testing will be required or, if so, how extensive it will be. Therefore, the planned outage duration for an ISI inspection does not include projected time for follow-up testing and thus any such testing necessarily extends the actual outage duration.

Q. Please describe the circumstances related to the fuel core offload and reload.

A. During refueling operations, several equipment issues occurred that caused schedule delays, including: failure of an underwater lighting fixture, failure of the manipulator crane finger latching device, and failure of the upender cart to travel to its full-up position. FPL maintenance crews resolved each equipment deficiency as it arose. FPL did not identify any design, maintenance or procedural concerns associated with these equipment failures and thus no further corrective actions were required.

Q. Please describe the emergent equipment conditions that contributed to the duration extension.

A. There were various, minor equipment issues that were addressed as they occurred throughout the outage. A typical planned refueling outage work scope includes approximately 1000 planned Work Orders. However, much of the equipment used during refueling operations is not accessible during plant operation and has not been inspected or tested since the previous refueling. Some of this equipment required repair due to emergent conditions, causing outage schedule delays. It is not unusual to find emergent conditions that must be addressed during a refueling outage. FPL cannot predict these emergent conditions or how much time will be required to address them, so the planned outage duration does not include time to address them. Therefore, there is always the possibility of the actual outage duration being extended to the extent that emergent conditions are identified during the outage which have to be addressed on the outage's critical path.

Q. How many additional days was Turkey Point Unit 3 out of service due to these issues?

A. The Unit 3 outage extension was approximately 8 days.

Q. Has FPL experienced any other unplanned outages at Turkey Point Unit 3 in 2014?

A. Yes. Unit 3 was manually shut down on August 11, 2014 due to a loss of instrument air system pressure. The outage duration for this event was approximately 3 days. FPL is currently in the process of investigating and evaluating this recent outage.

Q. Did FPL respond prudently to the events you have described that resulted in outage duration extensions at FPL's nuclear units?

A. Yes. FPL responded promptly and effectively to each event, in order to minimize the resulting duration extension. FPL has also evaluated what corrective actions are warranted for the events and either has already implemented them or is in the process of doing so.

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. 140001-EI

MARCH 3, 2014

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 & State Governmental Affairs Department.

Q. Have you previously testified in predecessors to 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 2013 through December 2013. The Net True-Up for the FCR is an under-recovery, including interest, of $98,482. The Net True-Up for the CCR is an over-recovery, including interest, of $11,054,159. FPL is requesting Commission approval to include the FCR true-up under-recovery of $98,482 in the calculation of the FCR factor for the period January 2015 through December 2015. FPL is also requesting Commission approval to include the CCR true-up over-recovery of $11,054,159 in the calculation of the CCR factor for the period January 2015 through December 2015.

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 A1 through A12 for the January 2013 through December 2013 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 you present?

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

Q. Please explain the calculation of the FCR net true-up amount.

A. Appendix I, page 1, titled "Summary of Net True-Up," shows the calculation of the Net True-Up for the period January 2013 through December 2013, an under-recovery of $98,482.

The Summary of the Net True-up amount shown on Appendix I, page 1 shows the actual End-of-Period True-Up under-recovery for the period January 2013 through December 2013 of $143,313,441 on line 1. The Actual/Estimated True-Up under-recovery for the same period of $143,214,959 is shown on line 2. Line 1 less line 2 results in the Net Final True-Up for the period January 2013 through December 2013, an under-recovery of $98,482 (line 3).

The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

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

A. Yes. Appendix I, page 2, titled "Calculation of Final True-up Amount," shows the calculation of the FCR actual true-up by month for January 2013 through December 2013.

Q. Have you provided a schedule showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2013?

A. Yes. Appendix I, page 3, provides a comparison of jurisdictional fuel revenues and costs on a dollar per MWh basis. Appendix I, page 4, compares the actual End-of-Period True-up under-recovery of $147,864,095 to the Actual/Estimated End-of-Period True-up under-recovery of $147,765,613 resulting in the $98,482 net under-recovery.

Q. Please describe the variance analysis on page 3 of Appendix I.

A. Appendix I, page 3, provides a comparison of Jurisdictional Total Fuel Revenues and Jurisdictional Total Fuel Costs (including Net Power

Transactions) on a dollar per MWh basis. The $98,482 under-recovery was primarily due to an increase due to consumption of $1,113,003, which was mostly offset by a decrease due to price of $1,012,478.

Actual total fuel revenues collected were $18,243,093 higher than projected and actual consumption was 619,417 MWh higher than projected, yet revenues collected per MWh were $0.00150 lower than projected. Of the $18,243,093 increase in fuel revenues collected, $18,397,362 was due to the increase in consumption, partly offset by a decrease in price (revenues per MWh) of $154,269.

Actual total fuel costs incurred were $18,343,618 higher than projected and as I state above, actual consumption was 619,417 MWh higher than projected, yet fuel costs per MWh were $0.01135 lower than projected. Of the $18,343,618 increase in total fuel costs incurred, $19,510,365 was due to the increase in consumption, partly offset by a decrease in price (fuel costs incurred per MWh) of $1,166,747.

The increase in fuel costs due to consumption of $19,510,365 minus the increase in fuel revenues due to consumption of $18,397,362 resulted in a total increase due to consumption of $1,113,003. The decrease in fuel costs due to price of $1,116,747 minus the decrease in fuel revenues due to price of $154,269 resulted in a total decrease due to price of $1,012,478. The increase due to consumption of $1,113,003, partly offset by the decrease due to price of $1,012,478 resulted in an under-recovery of $100,525. This under-recovery of $100,525 plus the increase of $2,043 in interest that was primarily due to higher than expected commercial paper rates results in the total true up under-recovery of $98,482.

Q. Turning to page 4 in Appendix I, 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 an increase of $17,804,754. As shown on Appendix I, page 4, this increase was due primarily to a $19.6 million increase in Fuel Cost of Purchased Power, a $6.4 million increase in the Fuel Cost of System Net Generation, a $1.6 million increase in Non-Recoverable Oil/Tank Bottoms, a $1.2 million increase in Energy Cost of Economy Purchases, a $0.9 million decrease in the Fuel Cost of Power Sold, and a $0.3 million increase in the Variable Power Plant O&M Costs. These amounts were partially offset by a $10.2 million decrease in Energy Payments to Qualifying Facilities (QFs), a $1.4 million increase in Gains from Off-System Sales, a $0.5 million higher credit to Inventory Adjustments, a $0.2 million decrease in Nuclear Fuel Disposal Costs, and a $53,090 decrease in Scherer Coal Cars Depreciation & Return.

<u>Fuel Cost of Purchased Power ($19.6 million increase)</u>

The increase in Fuel Cost of Purchased Power was primarily attributable to higher than projected utilization of the Unit Power Sales (UPS) agreements, partially offset by lower than projected St. John’s River Power Park (SJRPP) purchases.

Higher than projected purchases resulted in a total UPS variance of approximately $24.6 million. FPL purchased approximately 560,000 MWh more UPS power than projected, resulting in a volume variance of approximately $22.5 million. The remaining variance for UPS of approximately $2.1 million was due to higher fuel costs, $40.94/MWh versus a projection of $40.14/MWh.

In addition, St. Lucie purchases resulted in a total cost variance of approximately $455,000. FPL purchased approximately 42,000 more MWh than projected, while the overall unit cost was $0.25/MWh higher than originally projected.

The increase was partially offset by lower than projected SJRPP purchases and lower than projected unit costs for those purchases. SJRPP purchases were approximately $5.5 million lower than projected. FPL purchased approximately 55,000 fewer MWh than projected, while the overall unit cost was $1.91/MWh lower than projected.

<u>Fuel Cost of System Net Generation ($6.4 million increase)</u>

FPL's natural gas cost averaged $4.83 per MMBtu, which was $0.05 per MMBtu or 1.11% lower than projected during the period and FPL consumed 15,370,392 more MMBtus (2.8%) than projected during the period. The net $44.8 million increase in the cost of natural gas reflects a $74.2 million increase due to higher than projected consumption, partially offset by a $29.4

million decrease due to lower than projected unit costs.

FPL's coal cost averaged $2.71 per MMBtu, which was $0.05 per MMBtu or 2.0% higher than projected during the period. Additionally, FPL consumed 4,673,263 more MMBtus (8.0%) than projected during the period. Of the total $15.8 million increase for coal, $12.7 million was due to higher than projected consumption and $3.1 million was due to higher than projected unit costs.

FPL's light oil cost averaged $21.37 per MMBtu, which was $0.93 per MMBtu or 4.5% higher than projected during the period. Additionally, FPL consumed 416,398 more MMBtus (85.2%) than projected during the period. Of the total $9.4 million increase for light oil, $8.9 million was due to higher than projected consumption and $0.5 million was due to higher than projected unit costs.

FPL's heavy oil cost averaged $14.62 per MMBtu, which was $0.03 per MMBtu or 0.24% lower than projected during the period. Additionally, FPL consumed 3,313,299 less MMBtus (77.6%) than projected during the period. Of the total $48.6 million decrease for heavy oil, $48.4 million was due to lower than projected consumption and $0.1 million was due to lower than projected unit costs.

FPL's nuclear fuel cost averaged $0.61 per MMBtu, which was $0.06 per

MMBtu or 9.1% lower than projected during the period. Additionally, FPL consumed 2,733,534 more MMBtus (1.0%) than projected during the period. Of the total $14.9 million decrease for nuclear, $16.6 million was due to lower than projected unit costs, partially offset by a $1.7 million increase due to higher than projected consumption.

Non-Recoverable Oil/Tank Bottoms ($1.6 million increase)

The increase in non-recoverable oil/tank bottoms was primarily due to $0.4 million associated with a tank at Manatee which was placed in service in August 2013 and $1.2 million associated with a tank at Riviera Beach Energy Center placed in service in December 2013. Neither amount had been projected.

Energy Cost of Economy Purchases ($1.2 million increase)

The increase of $1.2 million for the Energy Cost of Economy Purchases is primarily attributable to higher than projected economy purchases. FPL purchased approximately 17,000 MWh more of economy energy than projected. Higher economy purchases resulted in a volume variance of approximately $744,000, or 62% of the total variance. The costs of economy purchases were, on average, $3.13/MWh higher than projected, resulting in a variance of approximately $463,000, or 38% of the total variance.

Variable Power Plant O&M Costs ($0.3 million increase)

Variable Power Plant O&M Costs are driven by sales volumes in excess of the

514,000 MW threshold applicable to the Incentive Mechanism. The variance is primarily due to higher sales of economy power. FPL sold approximately 246,000 MWh more economy power than projected.

Fuel Cost of Power Sold ($0.9 million decrease)

The approximately $0.9 million decrease in Fuel Cost of Power Sold was primarily due to lower than projected fuel costs of economy sales, partially offset by higher than projected economy sales. FPL's average fuel cost attributable to economy sales was $25.57/MWh compared to an estimate of $29.54/MWh. However, FPL sold approximately 246,000 MWh more economy power than projected. The total variance related to fuel costs of economy sales was approximately $630,500 lower than projected. This variance was increased by approximately $312,400, primarily due to lower than projected sales related to the St. Lucie Reliability Exchange.

Energy Payments to Qualifying Facilities ($10.2 million decrease)

The variance for Energy Payments to QFs was attributable to both lower than projected QF purchases and lower than projected unit costs for those purchases. FPL purchased approximately 119,000 MWh less from QF facilities. Lower purchases resulted in a variance of approximately $5 million or 49% of the total variance. The unit costs of QF purchases were approximately $2.35/MWh less than projected. Lower than projected fuel costs resulted in a variance of approximately $5.2 million, or 51% of the total variance.

Gains from Off-System Sales ($1.4 million increase)

The variance for Gains from Off-System Sales was primarily due to higher than projected economy sales. FPL sold approximately 246,000 MWh more of economy power than projected. This variance was partially offset by a lower than projected average margin on economy sales of $0.10/MWh. Overall, 113% of the total variance of $1.4 million for Gains from Off-System Sales was attributable to higher than projected economy sales, partially offset by 13% lower than projected margins on economy sales.

Scherer Coal Cars Depreciation & Return ($53,090 decrease)

The majority of the variance relates to proceeds received from the rail company for damaged rail cars.

Q. What was the variance in retail (jurisdictional) FCR revenues?

A. As shown on Appendix I, page 4, line 29, actual jurisdictional FCR revenues, net of revenue taxes, were approximately $18.2 million or 0.6% higher than the actual/estimated projection. This was primarily due to higher than projected jurisdictional sales, which were approximately 619,416,729 kWh, or 0.6% higher than the actual/estimated projection.

CAPACITY COST RECOVERY CLAUSE (CCR)

Q. Please explain the calculation of the CCR net true-up amount.

A. Appendix II, page 1, titled “Summary of Net True-Up” shows the calculation of the CCR Net True-Up for the period January 2013 through December 2013, an over-recovery of $11,054,159, which FPL is requesting to be included in the calculation of the CCR factors for the January 2015 through December 2015 period.

The actual End-of-Period under-recovery for the period January 2013 through December 2013 of $14,303,032 shown on line 1 less the Actual/Estimated End-of-Period under-recovery for the same period of $25,357,191 shown on line 2 that was approved by the Commission in Order No. PSC-13-0665-FOF-EI, results in the Net True-Up over-recovery for the period January 2013 through December 2013 of $11,054,159 (line 3).

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

A. Yes. Appendix II, page 2, titled “Calculation of Final True-up” shows the calculation of the CCR End-of-Period true-up for the period January 2013 through December 2013 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 “Calculation of True-Up and Interest Provision” for the FCR clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity charges and applicable revenues for 2013?

A. Yes. Appendix II, page 3, titled “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 2013 through December 2013.

Q. What was the variance in net capacity charges?

A. Appendix II, page 3, line 14 provides the variance in Jurisdictional Capacity Charges, which is a decrease of $6,799,533 or 1.0%. This $6.8 million decrease was primarily due to a $6.1 million decrease in Incremental Plant Security, a $2.1 million decrease in Transmission of Electricity by Others, a $0.5 million increase in Transmission Revenues from Capacity Sales, decreases of $98,678 and $8,727 in Incremental Nuclear NRC Compliance (Fukushima) costs for O&M and Capital, respectively. These decreases were slightly offset by a $1.2 million increase in Payments to Non-cogenerators and a $0.7 million increase in Payments to Co-generators.

<u>Incremental Plant Security Costs ($6.1 million decrease)</u>

The decrease in incremental plant security costs was primarily due to lower costs incurred due to deferral of modification pending endorsement from the NRC of NEI 13-10 Cyber Security Control. Additionally, the scheduling of the Turkey Point NRC Force On Force Exercise was deferred into 2014. The decrease also reflects scheduling five officer teams instead of four teams which resulted in less overtime and training costs. Also, site modifications to long term posts at St. Lucie resulted in reduced staffing requirements. Finally, work scheduled for Version 4 of the NERC Critical Infrastructure Protection (CIP) Standards was not performed because Version 5 superseded Version 4 late in 2013, and workforce improvements were implemented at the Ft. Myers plant on their NERC CIP Project which resulted in lower than projected costs.

Transmission of Electricity by Others ($2.1 million decrease)

The approximately $2.1 million variance is due to higher than projected UPS power purchases, resulting in lower than projected unutilized transmission costs. FPL purchased approximately 560,000 more MWh than projected for the last five months of 2013.

Transmission Revenues from Capacity Sales ($0.5 million increase)

The approximately $0.5 million increase in Transmission Revenues from Capacity Sales is attributable to higher than projected economy sales. FPL sold approximately 246,000 MWh more of economy power than projected, resulting in higher transmission revenues.

Incremental Nuclear NRC Compliance Costs (Fukushima) - O&M ($98,678 decrease)

Costs were $98,678 less than estimated because certain project management costs were deemed to be capital instead of O&M. The remaining O&M costs incurred were less than the amount in base rates ($144,000).

Incremental Nuclear NRC Compliance Costs (Fukushima) - Capital ($8,727 decrease)

Costs incurred in 2013 associated with flooding and seismic evaluations have not been charged to the project pending guidance from the NRC and a clearer determination of the scope and nature of required modifications. Also, the Modification Design Phase started later in 2013 than anticipated. The calculation of depreciation expense and return on capital investment for this project is provided on page 6 of Appendix II.

Payments to Non-Cogenerators ($1.2 million increase)

The $1.2 million increase was due primarily due to costs associated with the SJRPP agreement. Approximately $2.3 million of the SJRPP variance was due to higher costs for Property Taxes and Cumulative Capital Recovery Amount (CCRA) payments than projected. These amounts were partially offset by lower payments ($1.1 million) for Debt Service, Transmission Service, and JEA O&M/Inventory expense charges to FPL. There was also a small reduction in costs of approximately $35,000 due to Capacity Availability Performance Adjustment (CAPA) payments related to the Franklin unit in the UPS agreement.

Payments to Co-generators ($0.7 million increase)

The $0.7 million variance is due primarily to increased capacity payments to Cedar Bay (CB) and Indiantown (ICL) due to better availability performance. Approximately 91.6%, or $627,000, of the net variance was attributable to higher than projected capacity payments to CB. Approximately 1.2%, or $8,000, of the net variance was attributable to higher than projected capacity payments to ICL. Payments to Broward North were approximately $49,000 higher than projected due to an adjustment related to payments made from

April to July 2013. The adjustment caused approximately 7.2% of the total variance.

Q. What was the variance in CCR revenues?

A. As shown on page 3, line 15, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes) were $4,253,873 or 0.6% higher than the actual/estimated projection. This was primarily due to higher than projected jurisdictional sales, which were approximately 619,416,729 kWh, or 0.6% higher than the actual/estimated projection.

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 4 and 5. Page 4 shows the actual capacity payments for QFs, the Southern Company UPS contract and the SJRPP contract for the period January 2013 through December 2013. Page 5 provides the Short Term Capacity Payments for the period January 2013 through December 2013.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the fuel clause?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2013 through December 2013 are included on pages 7 and 8 of 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. 140001-EI

JULY 25, 2014

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 2014 through December 2014.

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 2014 through December 2014. FCR Schedules A1 through A9 provide actual data for the period January 2014 through June 2014. They are filed monthly with the Commission, are served on all parties and are incorporated herein by reference. The FCR Schedules contained in Appendix I also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2014 through December 2014.

The CCR Schedules contained in Appendix II provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2014 through December 2014.

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 the Company's 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 the data that 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 2014 through June 2014 and revised estimates for July 2014 through December 2014 to original projections for 2014.

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 methodology used in calculating the interest provision for all 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 AA financial 30-day rates as published in the Federal Reserve website on the first business day of the current and the subsequent month. The average interest rate for the projected months is the actual rate published as of the first business day in July 2014 reflecting the last business day in June 2014.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the 2014 actual/estimated true-up by month?

A. Yes. Appendix I, Page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2014 through December 2014.

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, Page 1 shows 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 2015 FCR factors is an under-recovery of $259,911,839 (Appendix I, Page 1, Column 14, Line 43). This $259,911,839 under-recovery includes the 2013 final true-up under-recovery of $98,482 (Appendix I, Page 1, Column 14, Line 41), filed with the Commission on March 3, 2014, and the actual/estimated true-up under-recovery, including interest, of $259,813,358 (Appendix I, Page 1, Column 14, Lines 38 plus 39) for the period January 2014 through December 2014.

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 variances between the actual/estimated amounts and original projections for 2014?

A. Yes. Appendix I, Page 2 provides a comparison of jurisdictional revenues and costs on a dollar per MWh basis. Appendix I, Page 3 provides a variance calculation that compares the actual/estimated period data to the data from the original projections for the January 2014 through December 2014 period.

Q. Please describe the variance analysis on Page 2 of Appendix I.

A. Appendix I, Page 2, provides a comparison of Jurisdictional Total Fuel Revenues and Jurisdictional Total Fuel Costs (including Net Power Transactions) on a dollar per MWh basis. The $259,911,839 under-recovery is primarily due to an increase in fuel prices resulting in a variance of $259,479,340 and a slight decrease due to consumption resulting in a variance of $190,792.

Jurisdictional total fuel revenues to be collected are estimated to be $42,775,974 lower than projected, consumption is estimated to be 119,895 MWh lower than projected and revenues per MWh are estimated to be $0.36711 lower than projected. Of the $42,775,974 decrease in jurisdictional fuel revenues,

$38,811,890 is due to a decrease in price (revenues collected per MWh) and $3,964,084 is due to a decrease in consumption.

Total jurisdictional fuel costs are estimated to be $216,894,157 higher than projected, jurisdictional fuel costs per MWh are estimated to be $2.08722 higher than projected, and as I stated above, consumption is estimated to be 119,895 MWh less than projected. Of the $216,894,157 increase in total jurisdictional fuel costs, $220,667,450 is due to an increase in price (fuel costs incurred per MWh), partly offset by a decrease in consumption of $3,773,292.

The decrease in jurisdictional fuel costs due to consumption of $3,773,292 minus the decrease in jurisdictional fuel revenues due to consumption of $3,964,084 resulted in a total variance due to consumption of $190,792. The increase in jurisdictional fuel costs due to fuel prices of $220,667,450 minus the decrease in jurisdictional fuel revenues due to price of $38,811,890 resulted in a total variance due to price of $259,479,340. The variance due to consumption of $190,792 and the variance due to price of $259,479,340 resulted in an under-recovery of $259,670,132. When the interest amount of $143,226 associated with the 2014 actual/estimated true-up amount and the 2013 final true-up under-recovery amount of $98,482 are added to the calculation, the total amount of the variance is $259,911,839.

Q. Please summarize the variance schedule on Page 3 of Appendix I.

A. FPL originally projected Jurisdictional Total Fuel Costs and Net Power Transactions to be $3.331 billion for 2014 (Appendix I, Page 3, Column 3, Line

37). The Actual/Estimated Jurisdictional Total Fuel Costs and Net Power Transactions are now projected to be $3.548 billion for that period (actual data for January 2014 through June 2014 and revised estimates for July 2014 through December 2014) (Appendix I, Page 3, Column 2, Line 37). Therefore, Jurisdictional Total Fuel Costs and Net Power Transactions are $216.9 million, or 6.5% higher than the original projections (Appendix I, Page 3, Column 4, Line 37). Jurisdictional Fuel Revenues, net of revenue taxes for 2014 are projected to be $42.8 million, or 1.2% lower than the original projections (Appendix I, Page 3, Column 4, Line 30).

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

A. Below are the primary reasons for the $216.9 million variance.

<u>Fuel Cost of System Net Generation ($276.5 million increase)</u>

Natural gas costs are currently projected to be $214.9 million (7.5%) higher than the original projections. Natural gas consumption in the actual/estimated period is projected to be 569,070,175 MMBtu, which is approximately 1.4% higher than the 561,356,468 MMBtu included in the original projections. The unit cost of natural gas burned in the actual/estimated period is projected to be 6.0% higher than what was included in the original projections ($5.45 per MMBtu vs. $5.14 per MMBtu).

Coal costs are currently projected to be $25.3 million (19.1%) higher than the original projections. Coal consumption in the actual/estimated period is projected to be 57,140,707 MMBtu, which is 13.3% higher than the 50,434,432 MMBtu included in the original projections. The unit cost of coal in the actual/estimated period is projected to be $2.76 per MMBtu, which is 5.1% higher than the $2.63 per MMBtu included in the original projections.

Light oil costs are currently projected to be $22.8 million (1,450.0%) higher than the original projections. Light oil burn in the actual/estimated period is projected to be 1,135,191 MMBtu, which is 1,397.8% higher than the 75,793 MMBtu included in the original projections. The unit cost of light oil in the actual/estimated period is projected to be $21.44 per MMBtu, which is 3.5% higher than the $20.72 per MMBtu included in the original projections.

Heavy oil costs are currently projected to be $15.3 million (37.9%) higher than the original projections. Heavy oil burn in the actual/estimated period is projected to be 3,800,312 MMBtu, which is 37.7% higher than the 2,760,893 MMBtu included in the original projections. The unit cost of heavy oil in the actual/estimated period is projected to be $14.68 per MMBtu, which is 0.2% higher than the $14.65 per MMBtu included in the original projections.

Nuclear generation costs are currently projected to be $1.8 million (1.0%) lower than the original projections. Nuclear consumption in the actual/estimated period is projected to be 295,360,859 MMBtu, which is 0.7% lower than the 297,384,483 MMBtu included in the original projections. The unit cost of nuclear fuel in the actual/estimated period is projected to be $0.637 per MMBtu, which is 0.3% lower than the $0.638 per MMBtu included in the original projections.

Generation data by fuel type for the actual/estimated period January 2014 through December 2014 are included in Appendix I, Schedule E3.

<u>Fuel Cost of Purchased Power ($30.9 million increase)</u>

The variance for the Fuel Cost of Purchased Power is primarily attributable to higher than originally projected purchases under the SJRPP and UPS PPA agreements, as well as the St. Lucie Plant Reliability Exchange. FPL now projects to purchase 732,788 MWh more firm power under these agreements, resulting in a variance of $25.8 million, or 84% of the total variance. The net increase in projected firm purchases is primarily attributable to a decrease in projected unit fuel costs at SJRPP which results in an increase of almost 470,000 MWh of purchases from the facility. In total, the average unit cost of purchases under these agreements is now estimated to be $1.05/MWh higher than the original projections, resulting in a variance of $5.1 million, or 16% of the total variance. The combination of higher purchases and fuel costs results in a total variance of $30.9 million.

<u>Variable Power Plant O&M Costs over 514,000 MWH Threshold ($0.1 million increase)</u>

The variance for Variable Power Plant O&M Costs is due to higher than originally projected economy sales.

Incremental Personnel, Software and Hardware Costs ($72,701 increase)

The variance for Incremental Personnel, Software and Hardware Costs is primarily attributable to the addition of incremental O&M costs associated with OATI WebTrader software. FPL is projecting to spend $72,000 in licensing fees and integration costs for the WebTrader software from July through December 2014. The OATI WebTrader software is a tool used for power trading. The features of WebTrader will facilitate streamlined trade entry, transmission procurement, power scheduling and accounting checkout. FPL expects that the WebTrader software will help FPL deliver additional asset optimization value to customers.

Gains from Off-System Sales ($32.0 million increase)

The variance for Gains from Off-System Sales is primarily attributable to higher than projected margins on economy sales. FPL now projects that the average margin on economy sales will be $13.83/MWh higher than originally projected, resulting in a variance of $29.0 million, or 91% of the total variance. In addition, FPL now expects to sell 442,252 MWh more economy power than originally projected, resulting in a variance of $3.0 million, or 9% of the total variance. Higher margins on economy sales coupled with an overall higher volume of economy sales results in a total variance for Gains from Off-System Sales of $32.0 million.

Nuclear Fuel Disposal Costs ($17.3 million decrease)

The variance for Nuclear Fuel Disposal Costs is due to the Department of Energy setting the Nuclear Fuel Disposal Fee rate to zero effective May 15, 2014.

Fuel Cost of Power Sold ($17.0 million increase)

The variance for the Fuel Cost of Power Sold is primarily attributable to higher than projected economy sales. FPL now projects that it will sell 442,252 MWh more economy power than originally projected, resulting in a variance of $17.5 million. This variance is partially offset by lower than originally projected fuel costs attributable to economy sales. FPL now projects that its average fuel costs attributable to economy sales will be approximately $0.31/MWh lower, resulting in a variance of $0.7 million. The combination of higher economy sales and lower fuel costs on economy sales results in a total variance of $16.8 million, or almost 99% of the total variance. The remaining variance of $0.2 million is attributable to higher than originally projected fuel costs on St. Lucie Plant Reliability Exchange sales, offset by lower than originally projected St. Lucie Plant Reliability Exchange sales.

Energy Payments to Qualifying Facilities ($7.5 million decrease)

The variance for Energy Payments to Qualifying Facilities is primarily attributable to lower than projected energy payments for QF purchases. FPL now estimates that the unit energy cost for QF purchases will be approximately $2.14/MWh less than originally projected, resulting in a variance of $6.2 million, or 83% of the total variance. In addition, FPL now estimates that it will purchase approximately 29,591 MWh less from QF facilities, resulting in a variance of $1.3 million, or 17% of the total variance. The net decrease in projected QF purchases is primarily caused by a significant unit energy cost increase at the Indiantown Co-Gen facility, which results in a decrease in purchases from this facility of approximately 241,000 MWh. The combination of lower unit energy costs at the QF facilities other than Indiantown Co-Gen and lower purchases results in a total variance of $7.5 million for Energy Payments to Qualifying Facilities.

<u>Energy Cost of Economy Purchases ($0.9 million decrease)</u>

The variance for Energy Cost of Economy Purchases is primarily attributable to lower than projected economy purchases. FPL now projects that it will purchase 31,908 MWh less economy energy than its original projections. Lower economy purchases result in a volume variance of approximately $1.5 million, or 163% of the total variance. This is partially offset by higher than originally projected unit costs for economy purchases of $0.6 million, or 63% of the total variance. The combination of lower purchases and slightly higher unit costs results in a net variance of $0.9 million for the Energy Cost of Economy Purchases.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the CCR 2014 actual/estimated true-up amount you are requesting this Commission to approve.

A. Appendix II, Page 1 shows the calculation of the CCR actual/estimated true-up amount. The calculation of the actual/estimated true-up for the period January 2014 through December 2014 is an over-recovery of $11,131,639 including interest (Appendix II, Page 1, Column 14, Lines 19 plus 20).

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 for 2014?

A. Yes. Appendix II, Page 2 shows the actual/estimated capacity charges and applicable revenues (January 2014 through June 2014 reflects actual data and the data for July 2014 through December 2014 is based on updated estimates) compared to the original projections for the January 2014 through December 2014 period.

Q. Please explain the variances related to capacity charges.

A. As shown in Appendix II, Page 2, Column 4, Line 15, the variance related to jurisdictional capacity charges is $10.9 million, a 2.0% decrease from original projections. The primary reason for this variance is an $11.5 million or 2.1% decrease in total system capacity costs (Page 2, Column 4, Line 11).

Below are the primary reasons for the $11.5 million decrease in total system capacity costs.

<u>Payments to Non-cogenerators ($7.8 million decrease)</u>

The $7.8 million decrease is primarily due to lower than projected costs associated with the SJRPP agreement. Approximately $8.5 million of the SJRPP variance is due to lower than projected costs for Debt Service, Transmission Service, Decommissioning, JEA O&M expense, and Inventory costs. These amounts were partially offset by $1.2 million of higher than projected costs for Property Taxes, and Cumulative Capital Recovery Amount (CCRA) payments. FPL also projects slightly lower costs than originally projected for the UPS agreements. Approximately $0.8 million of the UPS variance is due to lower costs for Capacity Availability Performance Adjustment (CAPA) payments related to the Franklin and Harris units, partially offset by $0.3 million of higher costs due to Change In Law (CIL) payments related to the Scherer unit.

Incremental Plant Security O&M Costs ($6.4 million decrease)

The $6.4 million decrease in Incremental Plant Security O&M Costs is primarily due to the inadvertent inclusion of Incremental Plant Security Capital Costs in the original projection.

Transmission Revenues from Capacity Sales ($0.6 million increase)

The variance for Transmission Revenues from Capacity Sales is due to higher than originally projected economy power sales. FPL sold approximately 302,000 MWh more of economy power than projected during the first half of the year. For the full year, FPL now projects to sell 442,252 MWh more economy power than originally projected.

Incremental Plant Security Capital Costs ($0.2 million decrease)

The $0.2 million variance is primarily due to NERC CIP Compliance work that has been moved from 2014 to 2015. Additionally, the in-service date for the St. Lucie Force-On-Force modifications shifted from October 2014 to December 2014, reducing the amount of depreciation expense in 2014.

<u>Incremental Nuclear NRC Compliance O&M Costs ($2.2 million increase)</u>

The $2.2 million increase in Incremental Nuclear NRC Compliance O&M Costs is due to seismic re-evaluation costs that were accumulated in deferred accounts pending NRC guidance and then were determined to be O&M costs in 2014. Also, additional scope was required to ensure potential flooding hazards do not impact plant safety equipment due to unique building penetrations features at St. Lucie.

<u>SJRPP Suspension Accrual ($1.4 million decrease)</u>

The $1.4 million decrease in the SJRPP Suspension Accrual is due to lower than projected accrual amounts when compared to the original calculations. The suspension date, (i.e., the point at which it is projected that FPL will no longer be able to take power purchased from units 1 and 2 due to IRS regulations), has been extended into April of 2019. Previously, this date was projected to occur in November of 2017.

In addition to the cost variances, Appendix II, Page 2, Column 4, line 16 shows that actual Capacity Cost Recovery Revenues (Net of Revenue Taxes) are $0.2 million higher than originally projected. The $10.9 million decrease in costs (Appendix II, Page 2, Column 4, Line 15) less the $0.2 million increase in revenues results in an actual/estimated 2014 true-up over-recovery amount of $11.1 million, including interest (Appendix II, Page 2, Column 4, Lines 19 plus

20). This over-recovery of $11.1 million including interest, plus the final 2013 true-up over-recovery of $11.1 million filed on March 3, 2014 results in a net over-recovery of $22.2 million to be carried forward to the 2015 CCR factors.

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. 140001-EI

SEPTEMBER 15, 2014

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 2014 Fuel Cost Recovery (FCR) actual/estimated true-up amount, which has been updated to include July 2014 actual data and which is incorporated into the calculation of the 2015 FCR factors.
- I present FCR factors for the period January 2015 through December 2015 that reflect the Woodford Gas Reserves Project (Gas Reserves Project) that was filed in this docket on June 25, 2014.

- As requested by Commission Staff, I also present 2015 FCR factors assuming the Gas Reserves Project is not implemented. Unless otherwise indicated, all references in my testimony are to the FCR factors that reflect implementation of the Gas Reserves Project.
- I present a revised 2014 Capacity Cost Recovery (CCR) actual/estimated true-up amount, which has been updated to include July 2014 actual data and which is incorporated into the calculation of the 2015 CCR factors.
- I present the CCR factors for the period January 2015 through December 2015. I also provide CCR factors for the period January 2015 through December 2015 including an adjustment to recover the non-fuel revenue requirements associated with West County Energy Center Unit 3 (WCEC-3) for the period January 2015 through December 2015, as approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.
- As requested by Commission Staff, I also present 2015 CCR factors assuming the Gas Reserves Project is not implemented. Unless otherwise indicated, all references in my testimony are to the CCR factors that reflect implementation of the Gas Reserves Project.
- I present the WCEC-3 revenue requirement calculation for the January 2015 through December 2015 period.

- Finally, I provide on pages 77-78 of Appendix II FPL's proposed cogeneration (COG) tariff sheets, which reflect 2015 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. On pages 71-72 of Appendix III, I provide COG tariff sheets that assume the Gas Reserves Project is not implemented.

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 (Appendix II)

- Schedules E1, E1-D, E1-E, E2, RS-1 and Inverted Rate Calculation provide the calculation of FCR factors for January 2015 through December 2015 including the Gas Reserves Project.
- Schedule E1-A, a revised Schedule E1-B that reflects July 2014 actual data, Schedules E1-C, E10, and H1.
- Pages 9 through 11, which provide the 2015 Projected Energy Losses by Rate Class.

TJK-6 (Appendix III)

- Schedules E1, E1-D, E1-E, E2, RS-1 Inverted Rate Calculation, E10 and H1 for the period January 2015 through December 2015, assuming the Gas Reserves Project is not implemented.

TJK-7 (Appendix IV)

- Page 1 provides the calculation of the revised 2014 Actual/Estimated CCR True-Up amount, which reflects July 2014 actual data.
- Pages 2 through 4 provide the calculation of the 2015 CCR factors including the Gas Reserves Project and excluding the WCEC-3 non-fuel revenue requirement for January 2015 through December 2015.
- Pages 5 through 8 provide the calculation of depreciation and return on incremental power plant security and incremental nuclear NRC compliance capital investments.
- Pages 11 through 13 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirement associated with WCEC-3 for the period January 2015 through December 2015.
- Page 14 combines the results from pages 2 through 4 and pages 11 through 13 to provide the total 2015 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2015 through December 2015.
- Page 15 provides the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the CCR

clause for the period January 2015 through December 2015.

TJK-8 (Appendix V)

- Provides the calculation of the CCR factors as in Appendix IV, but excluding the Gas Reserves Project.

TJK-9 (Appendix VI)

- Pages 1 and 2 provide the calculation of the WCEC-3 revenue requirement for January 2015 through December 2015.

<u>FUEL COST RECOVERY CLAUSE</u>

Q. Has FPL revised its 2014 FCR Actual/Estimated True-up amount that was filed on July 25, 2014 to reflect July actual data?

A. Yes. The 2014 FCR actual/estimated true-up amount has been revised to an under-recovery of $266,562,206, reflecting July 2014 actual data, plus interest. This $266,562,206 under-recovery, plus the 2013 final true-up under-recovery of $98,482, results in a net under-recovery of $266,660,688 (see Schedule E1-b, Page 3, Appendix II). This $266,660,688 under-recovery is included in the calculation of the FCR factors for the January 2015 through December 2015 period.

Q What adjustments are included in the calculation of the 2015 FCR factors shown on Schedules E1 included in Appendices II and III?

A. The total net true-up to be included in the 2015 FCR factors is an under-recovery of $266,660,688. This amount, divided by the projected retail sales of 108,216,882 MWh for January 2015 through December 2015, results in an increase of 0.2464¢ per kWh before applicable revenue taxes, as shown on Line 25 of Schedule E1. The Generating Performance Incentive Factor (GPIF) testimony of witness J. Carine Bullock, filed on March 7, 2014, proposes a reward of $11,814,923 for the period ending December 2013. This $11,814,923 reward, divided by the projected retail sales of 108,216,882 MWh for January 2015 through December 2015, results in an increase of 0.0109¢ per kWh, as shown on Line 29 of Schedule E1.

Q Have you prepared schedules providing results if the Gas Reserves Project is not implemented?

A. Yes, per the Commission Staff's request, my Exhibit TJK-6 provides Schedules E1, E1-D, E1-E, E2, RS-1 Inverted Rate Calculation, E10 and H1 assuming the Gas Reserves Project is not implemented. As can be seen by comparing the schedules in Exhibits TJK-5 and TJK-6, FPL would need to collect approximately $7 million in additional Fuel Clause revenues in 2015 if the Gas Reserves Project is not approved for implementation in 2015.

<u>CAPACITY COST RECOVERY CLAUSE</u>

Q. Has FPL revised its 2014 CCR Actual/Estimated True-up amount that was filed on July 25, 2014 to reflect July 2014 actual data?

A. Yes. The 2014 CCR actual/estimated true-up amount has been revised to an over-recovery of $10,299,210 (Appendix IV, Page 1, Line 19 plus Line 20), reflecting July 2014 actual data, plus interest and updated capital schedules for the depreciation and return on incremental power plant security and incremental nuclear NRC compliance capital investments. This $10,299,210 over-recovery, plus the 2013 final true-up over-recovery of $11,054,159 results in a net over-recovery of $21,353,369 (Appendix IV, Page 1, Line 24). This $21,353,369 net over-recovery is included in the calculation of the CCR factors for the January 2015 through December 2015 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2015 through December 2015?

A. Yes. Page 2 of Appendix IV provides this summary. Total Recoverable Jurisdictional Capacity Payments for the period January 2015 through December 2015 are $511,894,705 (Line 11). This $511,894,705 is decreased by the net over-recovery for 2013 and 2014 of $21,353,369 (Line 14 plus Line 15) and increased by the Nuclear Power Plant Cost Recovery Clause amount of $14,287,862 (Line 16) for which FPL has sought approval in Docket No. 140009-EI. The total jurisdictional CCR amount to be recovered in 2015, including taxes but excluding the 2015 WCEC-3 revenue requirement is $477,765,991.

Q. When will the Commission approve FPL's Nuclear Power Plant

Cost Recovery amount to be included in the 2015 CCR factors for 2015?

A. The Commission is scheduled to approve the Nuclear Power Plant Cost Recovery amount to be included in FPL's 2015 CCR factors at its October 2, 2014 Special Agenda Conference. Per the Order Establishing Procedure in this docket, if the Commission makes any changes to FPL's requested recovery amount of $14,287,862 on October 2, by October 20, 2014 FPL will submit to the Commission, with copies to all parties, revised schedules showing the calculation of the 2015 CCR factors.

Q Has FPL made adjustments to its Incremental Nuclear NRC Compliance (Fukushima) capital and O&M projections to reflect costs included in the 2013 rate case Test Year?

A. Yes. To reflect recovery only of incremental costs, FPL has reduced the capital costs by the $10 million that was included in its 2013 rate case Test Year and has reduced its 2015 O&M costs by the $144,000, which was also included in its 2013 Test Year.

Q. What is the projected WCEC-3 jurisdictional non-fuel revenue requirement for the January 2015 through December 2015 period?

A. The jurisdictional non-fuel revenue requirement for January 2015 through December 2015 is $149,615,862. The calculation of this amount is shown in my Exhibit TJK-9, which is included in Appendix VI. The $149,615,862 reflects the actual plant-in-service balance for

WCEC-3 with the return on equity (ROE) of 10.5%, as approved in the Settlement Agreement per Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.

Q. Have you provided a calculation of 2015 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirement associated with WCEC-3 for the period January 2015 through December 2015?

A. Yes. As approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013, FPL has included in Appendix VI the 2015 non-fuel revenue requirement associated with WCEC-3 of $149.6 million. Accordingly, Exhibit TJK-7, which is Appendix IV to my testimony, shows the calculation of the 2015 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2015 through December 2015.

Q. What is the total jurisdictional CCR amount to be recovered in 2015?

A. The total CCR jurisdictional amount to be recovered in 2015 is $627,381,853.

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

A. Yes. Page 3 of Appendix IV 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. What effective date is FPL 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 2015 (cycle day 1, which will be January 2, 2015) and that they remain effective until cycle day 21 of December 2015, or until they are modified by the Commission. This will provide for 12 months of billing on the FCR and CCR factors for all customers.

Q. What is FPL's proposed preliminary residential 1,000 kWh bill for the period beginning January, 2015?

A. Based on FPL's requests in this docket, Docket No. 140007-EI and an estimate of what will be filed in Docket No. 140002-EI on August 27, 2014, its preliminary residential 1,000 kWh bill for January 2015 through December 2015, including the Gas Reserves Project is $99.72. The components of this proposed preliminary bill are provided on Schedule E10, which is page 74 of Exhibit TJK-5, Appendix II. Should the Commission not authorize FPL to implement the Gas Reserves Project, the preliminary residential 1,000 kWh bill for January 2015 through December 2015 would increase to $99.78. The components of this bill are provided on Schedule E10, which is page 68 of Exhibit TJK-6, Appendix III.

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. 140001-EI

MARCH 7, 2014

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 process standardization and commercial support for FPL's fossil generating assets.

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

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report actual 2013 performance for Equivalent Availability Factor ("EAF") and Average Net Operating Heat Rate ("ANOHR") for the nine generating units used to determine the Generating Performance Incentive Factor ("GPIF"). In addition, I will explain adjustments that FPL proposes to the heat rate, net output factor ("NOF") and

Forced Outage Factor ("FOF") of Turkey Point Unit 4 ("PTN4") to address the impact on the operation resulting from the Extended Power Uprate ("EPU"). I have compared the performance of each unit to the targets approved in Commission Order No. PSC-12-0664A-FOF-EI issued January 28, 2013, for the period January through December 2013, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $23,628,477 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $11,814,923 that reflects FPL's proposed adjustment to PTN4 heat rate, NOF and FOF.

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

A. Yes. Exhibit JCB-1 shows the reward/penalty calculations. Page 1 of Exhibit JCB-1 is an index to the contents of the exhibit.

Q. Please explain how the total GPIF reward/penalty amount was calculated in general terms.

A. The steps involved in making this calculation are provided in Exhibit JCB-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +3.20, $23,628,477 in fuel savings and an adjusted GPIF reward of $11,814,923. Page 3 provides the new calculation of the maximum allowed incentive dollars as recently approved by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's performance indicators (EAF and ANOHR), the weighting factors, and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page, in columns 1 through 5, lists each of the nine GPIF units, the actual outage factors and the actual EAF for each unit and the proposed adjustment to actual FOF for PTN4 that is explained later in my testimony. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 16. These tables are based on the targets and target ranges submitted to, and approved by, the Commission.

Continuing with Exhibit JCB-1, Page 7 shows the adjustments to ANOHR. For each GPIF unit it shows, in columns 2 through 4, the target heat rate formula, the actual NOF, and the ANOHR for all units including the proposed modification to actual NOF and ANOHR for PTN4 that is explained later in my testimony. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 16. These tables are based on the targets and target ranges submitted to, and approved by, the Commission.

Q. Please explain the primary reason why FPL will receive a reward under the GPIF for the January through December 2013 period.

A. The primary reason that FPL will receive a reward for the period was that adjusted actual EAFs for St. Lucie Unit 2, Turkey Point Unit 4, and four of the fossil units were each better than target.

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

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 81.0%, compared to its target of 81.3%. This results in a -1.0 point penalty, which corresponds to a GPIF penalty of $398,156.

St. Lucie Unit 2 operated at an adjusted actual EAF of 97.7%, compared to its target of 90.2%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $4,728,335.

Turkey Point Unit 3 operated at an adjusted actual EAF of 78.9% compared to its target of 83.2%. This results in a -10.0 point penalty, which corresponds to a GPIF penalty of $3,497,267.

By utilizing the FOF adjustment that is explained later in my testimony, Turkey Point Unit 4 operated at an adjusted actual EAF of 76.5% compared to its target of 73.6%. This results in a +9.67 point reward, which corresponds to a GPIF reward of $2,995,598.

In total, the combined nuclear units' EAF performance results in a net GPIF reward of $3,828,510.

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

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,357 Btu/kWh compared to its target of 10,810 Btu/kWh. This results in a +10.0 point reward, which corresponds to a GPIF reward of $939,013.

The St. Lucie Unit 2 adjusted actual ANOHR is 10,415 Btu/kWh compared to its target of 10,899 Btu/kWh. This results in a +10.0 point reward, which corresponds to a GPIF reward of $950,103.

The Turkey Point Unit 3 adjusted actual ANOHR is 10,899 Btu/kWh compared to its target of 11,382 Btu/kWh. This results in a +10.0 point reward, which corresponds to a GPIF reward of $1,216,280.

By utilizing the three-year average for ANOHR and NOF that is explained later in my testimony, Turkey Point Unit 4 adjusted actual ANOHR results in 11,661 Btu/kWh compared to its target of 11,660 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

In total, the combined nuclear units' heat rate performance results in a GPIF reward of $3,105,396 when FPL's proposed modification to reflect the three-year average for ANOHR and NOF for PTN4 is used.

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

A. $6,933,906.

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

A. Regarding EAF performance, four of the five fossil generating units performed better than their availability targets resulting in a reward of $6,338,704 while the remaining unit performed worse than its availability target resulting in a penalty of $52,126. Thus, the combined fossil units' availability performance results in a net GPIF reward of $6,286,578.

Regarding ANOHR, one out of the five fossil units (Martin 8) operated with an ANOHR that was below the ±75 Btu/kWh dead band, resulting in a reward. However, the low actual ANOHR is due in part to the energy input from Martin Solar. In contrast, the ANOHR target is based on three years of Martin 8 operations before the solar energy input was as substantial as it was in 2013 and is today. Accordingly, FPL has adjusted the Martin 8 ANOHR to exclude the effect of Martin Solar energy input, so that it is more directly comparable to the operations during the target-setting period. With this adjustment, the Martin 8 reward is $507,584 reflecting a reward reduction of more than $1.8 million. Once there have been three years of Martin 8 operations with substantial solar input, this type of adjustment will no longer be needed. Out of the remaining four fossil units, two operated with ANOHRs that were within the ±75 Btu/kWh dead band and so received no incentive reward or penalty while the other two operated above the dead band so they received penalties totaling $1,913,146. Thus, the combined fossil units' heat rate performance results in a net GPIF penalty of $1,405,562.

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

A. The net GPIF availability performance reward of $6,286,578 plus the net GPIF heat rate performance penalty of $1,405,562 results in a total GPIF reward for FPL's fossil units of $4,881,016.

Q. To recap, what is the total GPIF result for the period January through December 2013?

A. The total GPIF result for the period January through December 2013 is $23,628,477 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $11,814,923.

Q. Is FPL proposing an adjustment to the reward/penalty calculations for PTN4 as a result of its 2013 EPU activities?

A. Yes. FPL believes that this adjustment is reasonable and appropriate in order to address a statistical anomaly that I will discuss below. The effect of the adjustment is to lower the 2013 GPIF heat rate reward for PTN4. This adjustment is consistent with the adjustment made and approved by the Commission in 2013 for FPL's other three nuclear units as a result of their respective EPU activities in 2012.

Q. **Please explain the reason for FPL's proposed adjustment.**

A**.** In order to explain the adjustment, it will be useful first to briefly describe how achieved heat rates are compared to target heat rates for the purpose of determining GPIF rewards or penalties.

Because the achievable heat rate for a generating unit is dependent in part on the NOF at which the unit is operating (i.e., generally, operation at full load is more efficient than operation at partial load), the GPIF methodology provides for adjustments to the ANOHR of the GPIF units once the actual heat rate and net output factor are known at the end of the projection period. (Page 4.214, Paragraph 2.3.7 of the GPIF manual). This adjustment is made based on a curve that correlates expected ANOHR with NOF based on regression analysis. While the details of the calculation are complex, the effect of the adjustment is to express the actual ANOHR and the target ANOHR at the same NOF, so that the reward/penalty determination will properly reflect the utility's success in operating the units efficiently rather than simply the differences in efficiency due to the actual NOF being different than what was projected at the time the targets were set.

Normally, regression analysis is an appropriate and effective basis for developing the correlation curves between ANOHR and NOF, because the actual NOF falls within or at least very close to the range of NOF values from which the regression equations are determined. However, due to the number and duration of periods when PTN4 was operated at partial load for testing purposes as a result of the EPU, the 2013 actual NOF was considerably lower than normal for this unit. This NOF falls well outside the range of the NOFs from which the regression equation was calculated and consequently does not provide a statistically valid basis for adjusting the actual ANOHR as prescribed by the GPIF methodology.

Q. How does FPL propose to perform the GPIF ANOHR reward/penalty calculations for PTN4 in the absence of statistically valid correlation curves?

A. Consistent with last year's treatment for St. Lucie Units 1&2 and Turkey Point Unit 3**,** FPL calculated the three-year average (2010-2012) for ANOHR and NOF for PTN4 and used those values as a proxy to represent its 2013 performance. A three-year time frame was chosen since it is consistent with the time frame used in developing GPIF heat rate targets. FPL believes this is a reasonable approach in the absence of a reliable basis for performing the calculation using actual 2013 performance.

Q. What is the impact on the total reward amount of using the three-year actual ANOHR and NOF performance for PTN4?

A. FPL's proposed adjustment reduces the 2013 GPIF reward by $1.4 million.

Q. Did FPL also make an adjustment to the availability (EAF) reward/penalty calculations for PTN4 to reflect the impact of the EPU?

A. Yes. The GPIF reward/penalty calculation for availability does not have a direct counterpart to the need to correlate ANOHR and NOF in the GPIF reward/penalty calculation for heat rate. Therefore, there is no regression equation and no concern about statistical validity. Nonetheless, FPL closely scrutinized the manner in which EAF is calculated to determine whether any form of adjustment for the impact of the EPU outage would be warranted. FPL focused on whether the FOF and the maintenance outage factor ("MOF") that are used in determining EAF for PTN4 might be unrepresentatively low as a result of the EPU outage, which would tend to increase the calculated reward. The reason for this focus is that FOF and MOF reflect, respectively, the number of forced outage hours and maintenance outage hours during the year, divided by the total number of hours in the year (8,760 hours in 2013). Because PTN4 was out of service for an extended period in 2013 due to the EPU and would have had no opportunity for either forced or maintenance outages during that period, FPL was concerned that using the full 8,760 hours as the denominator might result in calculated FOFs and MOFs that were lower than what one would reasonably expect if the unit had operated throughout the year.

FPL recalculated the FOF for PTN4 using the actual number of hours that the unit was available to be in service (i.e., net of the EPU outage hours). This re-calculation resulted in a modest increase in the FOF for PTN4. The MOF for this unit was zero, so it was unaffected by the re-calculation (i.e., because the numerator was zero, reducing the denominator could not affect the resulting factor).

The increased FOF for PTN4 reduced the reward calculation by $102,404. This modest reduction, even after adjusting for the extended time the unit was out of service, confirmed that PTN4 had excellent reliability performance in 2013 after the EPU. It is very common that the initial period of operation following extensive modifications to a nuclear unit (or any piece of complex equipment) will entail a series of minor outages to address “infant mortality” issues on the new equipment. Such outages would increase the FOF and/or MOF for the unit. Instead, the performance of this nuclear unit in 2013 after it returned from the EPU outage was strong, notwithstanding the extensive, unprecedented scope of the EPU work that was performed.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF J. CARINE BULLOCK

DOCKET NO. 140001-EI

SEPTEMBER 15, 2014

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. 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, 2015.

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 exhibits JCB-2 and JCB-3. The first page of these exhibits is an index to the contents of the corresponding exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. How does FPL's 2015 GPIF Projection reflect its request in this docket for Commission approval of the Woodford Gas Reserves Project?

A. Because the due date for FPL's 2015 Projection Filing (August 22, 2014) is prior to the Commission's decision on the Woodford Gas Reserves Project, FPL has filed two sets of GPIF exhibits. One set (JCB-2) assumes the Woodford Gas Reserves Project is approved and implemented, while the other set (JCB-3) assumes it is not approved. Unless otherwise indicated, all references in my testimony address JCB-2.

Q. Please summarize the 2015 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, 2015, FPL projects a weighted system equivalent planned outage factor of 6.5% and a weighted system equivalent unplanned outage factor of 7.0%, which yield a weighted system equivalent availability target of 86.5%. The targets for this period reflect planned refuelings for St. Lucie Unit 1, St. Lucie Unit 2 and Turkey Point Unit 3. FPL also projects a weighted system ANOHR target of 8,449 Btu/kWh for the period January through December, 2015. 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. Exhibits JCB-2 and JCB-3, pages 6 and 7, contain the information summarizing the targets and ranges for EAF and ANOHR for the eleven generating units that FPL proposes to be considered as GPIF units for the period January through December, 2015. 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 or projected unit overhauls following the projection period.

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, POWRSYM. 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 are responsible for 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 eleven units which FPL proposes to use for the period January through December, 2015 represent the top 83.2% of the total forecasted system net generation for this period excluding the Cape Canaveral Energy Center and Riviera Energy Center. These units came into service in 2013 and 2014, respectively, and were excluded from the GPIF calculation because there is insufficient historical data to include them. Consistent with the GPIF Manual, these units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2015 EAF and ANOHR performance targets represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

DUKE ENERGY FLORIDA

DOCKET NO. 140001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2013

DIRECT TESTIMONY OF
James McClay

March 28, 2014

Q. Please state your name and business address.

A. My name is James McClay. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I work for Duke Energy Carolinas (DEC) an affiliate company of Duke Energy Florida, Inc. ("DEF", "Petitioner" or "Company") as the Manager of Gas Trading. I manage the natural gas group procurement, scheduling and hedging activities in the Fuel Procurement Section of the Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the natural gas procurement and scheduling needed to support the gas generation needs for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida.

Q. Have you testified before in this proceeding?

A. No

Q. Please briefly describe your work experience.

A. I received a Bachelor Degree in Business Administration majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003. In early 2003, I became the Director of Power Trading and Portfolio Management for Progress Ventures and held that position through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through June 2012 I worked for Progress Energy Carolinas as the Manager of Gas and Oil Trading. After the merger with Duke Energy in July 2012, I became the Manager of Gas Trading for DEC through the present. Prior to my tenure with Duke Energy, I spent approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and primary broker/ dealers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August-December 2013 hedging true-up data and summarize the results of DEF's hedging activity for calendar year 2013 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 is the Hedging Activity Report for the period August – December 2013.

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

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

Q. What hedging activities did DEF undertake for 2013 and what were the results?

A. DEF utilized approved physical and financial agreements to hedge a portion of its projected natural gas and light oil fuel burns, and a portion of the estimated fuel surcharge exposure embedded in DEF's coal river barge and railroad transportation agreements. These activities resulted in a net hedge cost for 2013 of $141.3 million.

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

A. Yes. The hedging activities executed by DEF were consistent with those outlined in its 2013 Risk Management Plan ("Plan"). In the Plan filed in August 2012, DEF's hedging target ranges were to hedge [redacted] to [redacted] of its forecasted natural gas burns for calendar year 2013 with a target to hedge approximately [redacted] of the forecasted natural gas burns over time. With respect to light oil forecasted to be burned at DEF's owned generation facilities for calendar year 2013, DEF targeted to hedge a minimum of [redacted]. With respect to the coal river and rail transportation estimated fuel surcharge exposures for calendar year 2013, DEF targeted to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposures based on contractual provisions in the coal rail and river barge transportation agreements. As of December 2012, based on DEF's forecasted burns and estimated coal rail and river barge transportation agreements, DEF's hedge percentages were approximately [redacted], [redacted], [redacted] and [redacted] respectively for forecasted natural gas, and light oil burns, and estimated fuel surcharge exposures in the coal river and rail transportation agreements. As such, DEF was within its targeted hedge ranges for calendar year 2013 going into the year.

For calendar year 2013, DEF's actual hedge percentages based on actual burns for natural gas and light oil, were approximately [redacted] and [redacted], respectively. DEF hedge percentages for the estimated fuel surcharges embedded in DEF's coal river and rail transportation in 2013 were [redacted] and [redacted], respectively. The actual hedge percentages for natural gas, light oil, and the estimated fuel surcharges for coal river and rail transportation were within the ranges outlined in the Plan. As outlined in the Plan, actual hedge percentages for any monthly period, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns.

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

A. Yes. DEF's hedging activity met the stated objective of DEF's hedging strategy to reduce the impacts of fuel price volatility over time and provide a greater degree of fuel price certainty to DEF's customers. The hedging activities are consistent with Commission Orders No. PSC-02-1484-FOF-EI and No. PSC-08-0667-PPA-EI. DEF's hedging activities are conducted in an environment of strong internal controls and executed in a structured manner. DEF'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.

DUKE ENERGY FLORIDA, INC.

DOCKET NO. 140001-EI

**GPIF Schedules for
January through December 2013**

DIRECT TESTIMONY OF
MATTHEW J. JONES

March 7, 2014

Q. Please state your name and business address.

A. My name is Matthew J. Jones. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy as Director of Analytics for Fuels and Systems Optimization.

Q. Describe your responsibilities as Director of Analytics.

A. As Director of Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Florida, Inc. ("DEF" or "Company"), as well as Duke Energy Progress, Inc., Duke Energy Carolinas, Inc., Duke Energy Indiana Inc., and Duke Energy Kentucky, Inc. My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of DEF's GPIF reward/penalty amount for the period of January through December 2013. This calculation was based on a comparison of the actual performance of DEF's 7 GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. _______ (MJJ-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 24-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount has been calculated for this period?

A. DEF's calculated GPIF incentive amount is a reward of $2,231,853. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward (penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 15 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

Q. Have you provided the as-worked planned outage schedules for DEF's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 23 of my exhibit summarizes the planned outages experienced by DEF's GPIF units during the period. Page 24 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA, INC.
FOR
FUEL AND CAPACITY COST RECOVERY
FINAL TRUE-UP FOR THE PERIOD
JANUARY THROUGH JULY 2014

FPSC DOCKET NO. 140001-EI

GPIF TARGETS AND RANGES FOR
JAUARY THROUGH DECEMBER 2015

DIRECT TESTIMONY OF
MATTHEW J. JONES

AUGUST 22, 2014

Q. Please state your name and business address.

A. My name is Matthew J. Jones. My business address is 526 South Church Street, Charlotte, NC 28202.

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

A. I am employed by Duke Energy as Director of Analytics for Fuels and Systems Optimization.

Q. What are your responsibilities in that position?

A. As Director of Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Florida ("DEF" or the "Company"), as well as Duke Energy Progress, Inc., Duke Energy Carolinas, Inc. Duke Energy Indiana, Inc. and Duke Energy Kentucky, Inc. These responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a B.A. in Anthropology from State University of New York in 2001. From 2001 until 2004, I worked as an Account Representative for National Loop Company in Green Island, NY. From 2004 until 2007, I attended graduate school at Indiana University – Bloomington, where I earned a Master of Business Administration and a Doctor of Jurisprudence, *cum laude*. While at Indiana University, I also studied Comparative and International Law at a study abroad program at Christ Church College at Oxford University. In 2008, I joined Duke Energy as a Commercial Associate, spending a six month rotation working in Business Development Analytics where I worked on Wholesale Ratemaking and another six month rotation in the FERC Legal group where I worked on wholesale contract drafting and compliance issues. In 2009, I entered the Business Development Analytics group where I worked in dispatch pricing, production cost modeling, and fuel burn forecasting for the Duke Energy Carolinas system. In 2010, I entered the Integrated Resource Planning group to help rebuild the Kentucky model in preparation for environmental legislation analysis and later in 2010, I became the Director of Wholesale and Commodities Business Support, where I had the responsibility to manage wholesale ratemaking, dispatch pricing, production cost modeling, fuel burn forecasting, position reporting, budgeting for bulk power marketing, and general analytical support for Fuels Hedging, Bulk Power Marketing, and Wholesale Origination for North and South Carolina, Indiana and Kentucky. In July of 2012, I became the Director of Analytics for Fuels and System Optimization, where, in addition to the responsibilities outlined in the previous question, I also manage the Contract Administration and Fuels System Support organizations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period of January through December 2013 and also present the development of the Company's GPIF targets and ranges for the period January through December 2015. These GPIF targets and ranges have been developed from individual unit equivalent availability, average net operating heat rate targets, and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. What GPIF incentive amount was calculated for the period January through December 2013?

A. DEF's calculated GPIF incentive amount for this period was a reward of $2,231,853. Please refer to my testimony filed March 7, 2014 for the details of how this incentive amount was calculated.

Q. Do you have an exhibit to your testimony?

A. Yes. I am sponsoring Exhibit No. _____ (MJJ-1P), which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2015 projection period, the GPIF program includes the following units: Bartow Unit 4, Crystal River Units 4 and 5; and Hines Units 1 through 4. Combined, these units account for 84% of the estimated total system net generation for the period.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my Exhibit No. ___ (MJJ-1P).

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance, and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined through a review of three years of monthly data points. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage <u>rates</u> can then be converted into an overall equivalent unplanned outage <u>factor</u> (EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%.

The supporting tables and graphs for the target and range rates are contained in pages 41-76 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Were adjustments made to historical unit availability to account for significant anomalies in the historical project?

A. No.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my Exhibit No. ___ (MJJ-1P).

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data to a linear relationship with Net Operating Factor (NOF), and ranges at a 90% confidence level were also established assuming a normal distribution. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 26-40 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in the case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of simulations was made using a production costing model in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2014?

A. The estimated maximum incentive for the Company is $21,941,791. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MJJ-1P).

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 140001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2013 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis Young, 1641 Worthington Road, Suite 220, West Palm Beach, Fl 33409.

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 Analyst for Florida Public Utilities Company. I have performed various accounting and analytical 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 January 2013 through December 2013.

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

A. Yes. Exhibit________ (CDY-1) consists of Schedules A, B, 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 January 2013 through December 2013?

A. For Northwest Florida the final remaining true-up amount is an under recovery of $1,777,389. For Northeast Florida the calculation is an over recovery of $1,255,621.

Q. How were these amounts calculated?

A. They are the difference between the actual end of period true-up amounts for the January through December 2013 period and the total true-up amounts to be collected or refunded during the January - December 2014 period.

Q. What was the actual end of period true-up amount for January - December 2013?

A. For Northwest Florida it was $2,532,762 under recovery and for Northeast Florida it was $3,941,298 over recovery.

Q. What have you calculated to be the total true-up amount to be collected or refunded during the January – December 2014 period?

A. Using six months actual and six months estimated amounts, we calculated an under recovery for Northwest Florida of $755,373 and an over recovery of $2,685,677 for Northeast Florida.

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel clause for each respective division.

Q. Please explain how these costs were determined to be recoverable under the fuel clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the other costs included in the fuel clause are directly related to fuel and have not been recovered through base rates. Specifically, as illustrated in Order 14546, the costs the Company has included are fuel-related costs and were not anticipated or included in the cost levels used to establish the current base rates. To be clear, these costs are not tied to the Company's internal staff involvement in fuel and purchased power procurement and administration. Instead, these costs are associated with external contracts, which were unanticipated in the Company's last rate case, and which, consequently, tend to be more volatile depending upon the issue. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of Fuel costs, as well as the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel clause in Order No. PSC-05-1252-FOF-EI, issued in Docket No. 050001-EI. Additionally, in Docket No. 120001-EI and Docket No. 130001-EI, the Commission determined that certain legal and consulting costs associated with the review and analysis of the Company's existing purchase power agreements, as well as the development and negotiations for a renewable energy contract with Rayonier were appropriate and recoverable through the fuel clause.

Q. Which legal and consulting costs were allowed to be recovered through the fuel clause in 2012 and 2013?

A. In both years, the Commission allowed FPUC to recover costs associated with work done by Christensen and Associates ("Christensen"), Gunster, Yoakley, & Stewart, ("Gunster") and Sterling Energy Services ("Sterling") pertaining to the Rayonier renewable energy contract, which was finalized in early 2012. This contract provides for the purchase of power at rates lower than the existing Purchase Power Agreement between FPUC and JEA. FPUC realized reduced fuel rates for the Northeast Division customers as a result of this agreement, beginning in mid-2012. The costs associated with the development, negotiation, and regulatory approvals for the contract had not been included in expenses during the last FPUC consolidated electric base rate proceeding; thus, they were not being recovered through the Company's base rates. Consequently, the Commission allowed these costs to be passed through the fuel clause. The Company believes that the costs addressed herein are similar to those allowed to be recovered through the fuel clause in 2012 and 2013. As such, the Company believes the costs addressed herein are likewise appropriate for recovery through the fuel clause.

Q. What are the costs outside of purchased fuel costs, included in the 2013 final true up for Florida Public Utilities Company?

A. The Company engaged Christensen, Gunster, and Sterling, as well as, King & Spalding, LLP ("King and Spalding"), and Pace Global, a Siemens Industry, Inc. Company ("Pace") (all jointly referred to herein as "Consultants"), for services directly related to fuel costs and fuel cost reductions for the feasibility research and analysis, of projects/programs designed to protect current fuel savings, and to possibly further reduce fuel costs to its customers.

Specifically, Christensen performed a due diligence review and cost analysis of the pricing under the current Purchased Power Agreements between FPUC and its power suppliers (JEA, Rayonier and Rock-Tenn) with the goal of determining whether there are further avenues for achieving cost reductions.

Additionally, the Consultants provided services related to reviewing and evaluating the impact of the new Generation facility at Rayonier on our purchased power costs, and the impact from the loss of the purchased power from Rayonier. The Consultants also assisted the Company in its evaluation of alternatives on what could be done to protect fuel savings to our customers, and what can be done to further reduce the Company's costs for purchased power.

The specified legal and consulting costs were not included in expenses during the last FPUC consolidated electric rate base proceeding and are not being recovered through base rates. While the cogeneration project has not yet been finalized, the Company's efforts in this regard are moving forward. The Company fully expects that the cogeneration project, with which these legal and consulting expenses are associated, will come to fruition and ultimately produce significant fuel savings for customers, as well as increased reliability, for customers in the Northeast Division. As such, consistent with past Commission precedent, these fuel-related costs should be deemed appropriately recoverable through the fuel clause.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 140001-EI
Fuel and purchased power cost recovery clause with
generating performance incentive factor.

Direct Testimony (Estimated/Actual) of
Curtis D. Young
On Behalf of
Florida Public Utilities

Q. Please state your name and business address.

A. Curtis D. Young, 1641 Worthington Road Suite 220, West Palm Beach, FL 33409.

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

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

Q. Have you previously testified in this Docket?

A. Yes.

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

A. I will briefly describe the basis for the Company's computations that were made in preparation of the schedules that have been submitted to support the calculation of the levelized fuel adjustment factor for January 2015 – December 2015.

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 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-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2014 – December 2014 based on 6 Months Actual and 6 Months Estimated data.

Q. What was the final remaining true-up amount for the period January 2013 – December 2013 for the Northwest division?

A. In the Northwest Division, the final remaining true-up amount was an under-recovery of $1,806,713. The final remaining true-up amount for the Northeast Division was an over-recovery of $1,213,227.

Q. What is the estimated true-up amount for the period January 2014 – December 2014?

A. In the Northwest Division, there is an estimated under-recovery of $757,446. The Northeast Division has an estimated under-recovery of $1,538,409.

Q. What is the total true-up amount to be collected or refunded during January 2015 – December 2015?

A. The Company has determined that at the end of December 2014, based on six months actual and six months estimated, the Company will under-recover $2,564,159 in purchased power costs in the Northwest Division to be collected and will under-recover $325,182 in the Northeast Division to be collected during January 2015 – December 2015.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 140001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2015 Projection Panel Testimony of
Curtis D. Young and Mark Cutshaw
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis D. Young, 1641 Worthington Road Suite 220, West Palm Beach, FL 33409.

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 Analyst. I have performed various accounting and analytical 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. Have you previously testified in this Docket?

A. Yes.

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw, 911 South Eighth Street, Fernandina Beach, Florida 32034.

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 Director of System Planning and Engineering. I joined FPU in May 1991 as Division Manager in the Marianna (Northwest Florida) Division. In January 2006, I became the General Manager of our Northeast Florida Division, and in 2013, I moved into my current position of Director of System Planning and Engineering. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. Since joining FPU, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues.

Q. Have you previously testified in this Docket?

A. Yes.

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

A. We will briefly describe the basis for the computations that were made in the preparation of the various Schedules that the Company has submitted in support of the January 2015 - December 2015 fuel cost recovery adjustments for its consolidated electric divisions. In addition, we will explain the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2014 – December 2014 and to establish a "true-up" amount to be collected or refunded during January 2015 - December 2015. We will also discuss future plans for additional generation capacities that will be available and the beneficial impact on the customers.

Q. Were the schedules filed by the Company completed by you?

A. Yes.

Q. Which of the Staff's set of schedules has your company completed and filed for approval in this Docket?

A. The Company has filed Consolidated Electric Schedules E1, E1A, E2, E7, E8, E10 and Attachment A. Composite Exhibit Number CDY-3 contains this information. The Company has also provided for informational purposes Schedules E1, E1A, E2, E7, and E10 for the Northwest Division and Schedules E1, E1A, E2, E7, E8, and E10 for the Northeast Division.

Q. Did you follow the same procedures that were used in the prior period filings in preparing the projected cost factors for January – December 2015 for both the Northwest and Northeast Divisions?

A. No, the Company has generally used the same methodology as in prior period filings; however, the Company has made some changes in the process. The Company is hereby submitting a consolidated fuel filing of its two electric divisions.

Q. Why is the Company requesting a Consolidated Fuel Filing?

A. In 2003 when FPU first petitioned the Commission for a consolidation of its base rates through its rate case proceedings in Docket No. 030438-EI, there were subsidy effects in base rates. The Company had also petitioned for a consolidation of its fuel rates that year in Docket No. 080001-EI, as was already implemented by other regulated IOU's in the state, which would have ultimately resulted in extinguishing any subsidy effects in base rates. However, while the Commission approved FPU's petition to consolidate its base rates, its request for consolidation of its fuel rates was denied thus creating a subsidy effect in base rates.

Q. What was the nature of this subsidy effect in base rates?

A. Our Northwest division pays for a portion of transmission facilities via a transmission charge through the fuel clause, where similar costs in our Northeast division are paid through consolidated base rates since FPU owns the transmission related plant and it is included in rate base. In the

Northwest division, Gulf Power / Southern Company own the transmission facilities. The Company acknowledges that the Northeast Division transmission assets being in base rates has resulted in an interdivisional inequity and has taken steps to mitigate that inequity through its fuel clause. In its testimony for the 2009 Fuel Projection filing through Docket No. 080001-EI, FPU requested approval to allocate a portion of the distribution substation charges incurred by the NW Division towards the NE Division fuel costs in an effort to allow all customers to contribute to the distribution charge within fuel just as all customers contribute to the substation plant related costs included in base rates. In 2013, in its 2014 Fuel Projection filing through Docket No. 130001-EI, further steps were taken to allocate a portion of the Northwest Division transmission costs for fuel to the Northeast Division as a means of further mitigating the inequity in base rates until consolidation of fuel could be implemented.

Q. Should the Commission approve consolidation of the fuel factors for FPU's Northeast and Northwest divisions for purposes of fuel cost recovery beginning in 2015?

A. Yes. The Company feels this is appropriate based on the consolidation of electric base rates between the two divisions, which matches the methodologies used by most electric utilities that have standard rates for all customers. For the majority of electric utilities in Florida, fuel rates are consolidated even though costs from production capacity or off-system purchases vary based on many factors. This fuel rate consolidation allows

FPUC to standardize fuel costs, as is done by other utilities, and assist in stabilizing fuel rate charges to all customers now and in the future. The Company considers the consolidation of its Northwest Florida and Northeast Florida divisions within the fuel clause as the optimal solution in achieving a fair allocation of fuel-related costs among its customers.

Q. Aside from eliminating the subsidy effects in base rates, what other benefits are provided to your customers from this consolidation of your fuel rates?

A. An obvious benefit is the mitigation of the price shock to the ratepayers derived from periodic changes in fuel costs. By consolidating its two electric divisions through the fuel clause, the Company is able to reduce the impact that the changing fuel costs has on the customers' bills by spreading its effect over a wider customer base. One other benefit to the customers is with regards to the Company's distribution of potential cost savings. FPU continues to pursue available opportunities towards reducing its purchased power costs. These endeavors have reaped cost savings for the Company and its customers in the past and we anticipate that this will trend continue with one exception. In the past, each of these cost-saving programs / projects was typically designated in either the Northwest Florida or Northeast Florida division. As a result the cost savings derived from a given project would only benefit those customers specific to that division. By consolidating the Northwest Florida and Northeast Florida divisions, the benefits of any fuel-related cost savings to the Company may now be shared by all customers regardless of their service location.

Q. If consolidation of fuel factors for FPU's northeast and northwest division is not approved, should FPU be allowed to continue to allocate transmission costs consistent with the methodology approved in Order No. PSC-13-0665-FOF-EI?

A. Yes, if consolidation is not approved, the transmission plant inequities will continue between the divisions without an allocation in the fuel clause between the two divisions as described within the testimony.

If the Commission does not approve consolidation of the fuel factors, the Company should be allowed to continue to allocate transmission costs consistent with the methodology approved by Commission Order No. PSC-13-0665-FOF-EI.

Q. Based on the consolidation request, has the Company investigated means to reduce costs for its customers in its consolidated electric divisions?

A. Yes. The Company has aggressively sought opportunities to engage its current base load providers for both electric divisions in discussions for an arrangement that would be more beneficial for the FPU customers. Since 2007, when purchased power rates began to increase significantly from both providers, FPU has been very assertive in challenging each cost determination performed by JEA and Southern Company that resulted in an increase to the purchased power rate. These very focused and steady efforts have resulted in the mitigation of the rate of increase in purchased power cost for FPU and its customers. In January 2011, the Company was also successful in an Amendment to the Gulf Power contract, reducing costs to customers in its NW division.

These same focused and steady efforts are continuing today and, in our opinion, have resulted in a reduced rate of increase to FPU and its customers.

During this same time period, the Company has investigated opportunities with other wholesale power suppliers. During the investigation relationships were developed with other suppliers, informal studies of generation and transmission capacity arrangements were reviewed and contract possibilities were discussed. Although these opportunities are not possible until the expiration of the existing contracts, this information does provide FPU with market knowledge and information that assist with discussions.

Also, the Northeast Division provides service to two paper mills on Amelia Island that have significant on site generation capabilities which has created opportunities for some limited purchased power for FPU. Based on this potential, FPU has entered into arrangements with these alternative power providers that have thus far proven very advantageous. FPU is continuing to look at these and all other avenues for reducing purchased power costs that are available to the Company which will provide benefits to all FPU customers with the consolidation of rates.

Q. What type of investigation has the Company done related to reduction of purchased power cost?

A. Since the merger with Chesapeake in 2009, the Company has focused many resources on how to reduce the purchased power cost and its impact on customers. As previously mentioned, during this time other wholesale power providers have been approached and opportunities explored, review of new electric generation technology has been conducted, Combined Heat and Power (CHP) partners have been identified, experts in the area of CHP projects have been retained and parties have come together to evaluate electric generation projects. These partners and experts have assisted FPU with the review and evaluation process. Ultimately, most of the projects evaluated were not prudent ventures for the Company. However, the Company's review team found that certain limited projects, one partner in particular, are viable alternative power options for the Company and provide benefits to the partners and customers. FPU is continuing to evaluate this type of opportunity both inside and outside of the FPU service territory.

Q. What arrangements with "alternative power providers" do you refer to?

A. The first very successful arrangement that I am referring to is the renewable energy contract with Rayonier Performance Fibers, LLC, which was entered into in early 2012 and approved by the Commission in Docket No. 120058-EQ. Through a cooperative effort, FPU and Rayonier were able to develop a purchased power agreement that allows Rayonier to produce renewable energy and sell that energy to FPU at a cost below that of the current wholesale power provided while still being beneficial to Rayonier. Not only did this increase the amount of renewable energy in the area, it provides lower cost energy that is passed directly through to FPU customers in the form of reduced power cost.

Secondly, FPU is also working in partnership with [redacted] Eight Flags Energy, LLC, a subsidiary of Chesapeake Utilities Corporation (Chesapeake [redacted] The details of the arrangement are currently being finalized and we anticipate filing with the Commission in the very near future. [redacted] will provide customers in both divisions, assuming the consolidation of fuel cost is approved, with a significant benefit in the reduction of purchase power cost

Q. How have these two new arrangements proven beneficial to the Company?

A. With regard to the first contract with Rayonier, that agreement alone is expected to produce overall savings of $1.27 million over the 10-year term of the contract, and the Company has every expectation that the contract will be extended, thereby extending the benefits. The expected annual energy produced will be 16,980 mWh's and an incentive is provided to Rayonier to ensure this occurs in that any failure to maintain the agreed capacity factor will result in reducing the overall monthly payments to Rayonier. [redacted] efforts are underway to get this completed, approved and in service by the second quarter of 2016. Once consummated and in service, this new project is expected to produce even more significant benefits for the Company and all of its electric customers. [redacted]

[redacted]

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up and projected amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel clause.

Q. Please explain how these costs were determined to be recoverable under the fuel clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the other costs included in the fuel clause are directly related to fuel, have not been recovered through base rates.

Specifically, as illustrated in item 10 of Order 14546, the costs the Company has included are fuel-related costs and were not anticipated or included in the cost levels used to establish the current base rates. To be clear, these costs are not tied to the Company's internal staff involvement in fuel and purchased power procurement and administration. Instead, these costs are associated with external contracts which consequently, tend to be more volatile depending upon the issue. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of Fuel costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in Docket Nos. 120001-EI and 130001-EI, the Commission determined that many of the costs associated with the legal and consulting work incurred by the Company as fuel related, particularly those costs related to the purchase power agreement review and analysis, were recoverable under the fuel clause. Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. What were the costs outside of purchased fuel costs, included in the 2014 true-up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. "Gunster", Christensen and Associates "Christensen" and Cantrell Advisors "Cantrell" for assistance in the development and enactment of projects/programs designed to reduce their fuel rates to its customers. The legal and consulting costs associated with the development and negotiations of the power supply contracts (JEA) are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. Christensen and Cantrell have been performing due diligence in their occasional review and analysis of the terms of the current Renewable Energy Agreement between FPUC and Rayonier in order to increase the production of renewable energy and for further discovering avenues towards negotiating cost reductions. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates. Christensen has been performing due diligence in their occasional review and analysis of the terms of the current Purchased Power Agreement between FPU and JEA in the efforts of further discovering avenues towards minimizing cost increases and/or negotiating cost reductions. The resulting savings from their efforts have been included in the 2013 and 2014 True-up as well as our 2015 Projections. The associated legal and consulting costs, included in the rate calculation of the Company's 2015 Projection factors, were not included in expenses during the last FPU consolidated electric base rate proceeding and are not being recovered through base rates.

Summary Rates

Q. What are the final remaining true-up amounts for the period January – December 2013 for both Divisions?

A. The final remaining consolidated true-up amount was an under-recovery of **$521,768**.

Q. What are the estimated true-up amounts for the period of January – December 2014?

A. There is an estimated consolidated under-recovery of **$2,385,797**.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2015 year?

A. The Company has determined that at the end of December 2014, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of **$2,907,565**.

Q. Should the Commission approve FPU's proposal to under recover fuel costs in 2015 in order to mitigate rate increases to customers?

A. Yes. To mitigate the rate shock to our customers, the Company requests a three year period to collect the current under recovery from its consolidated electric division. The Company expects a fuel cost reduction from a generation project beginning in 2016. To provide for stabilization of rates over the next several years, the Company requests permission to collect this under-recovery over a three year period to normalize the swings expected in fuel costs over the next several years. Amortizing one third of this under-recovery in calendar year 2015 will result in a collection of $969,188 in the January through December 2015 year.

Q. What is the amount of under-recovery the Company is requesting to collect over the January through December 2015 period?

The Company has an under-recovery of $**969,188,** which is 1/3 of the total under recovery that is expected at December 31, 2014. Based on estimated sales during this period on a consolidated electric basis, it will be necessary to add .15649 cents per KWH to collect this under-recovery.

Q. What will the total consolidated fuel adjustment factor, excluding demand cost recovery, be for the consolidated electric division for the period?

A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is 6.183¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2015 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on consolidated Schedule E-10 in Composite Exhibit Number CDY-3, a residential customer using 1,000 KWH will pay **$137.89**. This is an increase of **$4.58** over the previous period in the Northwest Division and an increase of **$12.42** over the previous period in the Northeast Division.

Q. **If the Commission approves FPUC's request in Docket No. 140025-EI to consolidate the Company's current outdoor lighting (OL-2) and street lighting (SL-3) rate classes into a single Lighting Service (LS) rate class, what is the appropriate consolidated fuel rate for the new LS rate class?**

A. The consolidated fuel rate for the new Lighting Service (LS) rate class is 7.751 cents per KWH. The computation of this fuel rate is provided in Attachment A of Composite Exhibit Number CDY-3.

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. 140001-EI
Date of Filing: March 3, 2014

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 (SES). 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, 2013 through December 31, 2013. 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 four schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January 2013 through December 2013, 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 $480,927,817 which is $1,086,392 or 0.23% above the projected amount of $479,841,425. Actual net power transaction energy was 11,531,258,090 KWH compared to the projected net energy of 12,332,167,000 KWH or 6.49% below projections. The resulting actual average cost of 4.1706 cents per KWH was 7.19% above the projected cost of 3.8910 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2013 included in Appendix 1 of Witness Dodd's exhibit. The higher total fuel and net power transaction expense is attributed to a higher per unit cost (cents per KWH) for available energy than projected for the period offset somewhat by a lower quantity of energy (KWH) available after economy and other power sales are deducted. The total quantity of power sales is higher than projected as a result of Gulf's available energy being lower cost than other energy sources which resulted in these generating assets being economically dispatched to serve system load. The actual total cost of available energy was above projections by $1,617,574 or 0.28% and the total quantity of available energy was above projections by 1,225,337,447 KWH or 8.05%. The actual cost per KWH of available energy was 3.499 cents per KWH which is 7.19% lower than the projected cost of 3.770 cents per KWH. The lower cost per KWH for available energy is due primarily to the mix of available energy containing a higher percentage of purchased power.

These energy purchases were primarily from lower cost gas fired generating units that Gulf has secured under Purchase Power Agreements (PPA's).

Q. During the period January 2013 through December 2013, 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 $344,085,442 or 7.47% below the projected amount of $371,844,425. Actual generation was 8,154,050,000 KWH compared to the projected generation of 8,927,032,000 KWH, or 8.66% below projections. The resulting actual average fuel cost of 4.2198 cents per KWH was 1.31% above the projected fuel cost of 4.1654 cents per KWH. The lower total fuel expense is attributed primarily to the quantity of KWH generated being 8.66% lower than projected for the period. The actual quantity of fuel consumed was 83,281,090 MMBTU which is 2.52% above the projected quantity of 81,237,802 MMBTU. The percentage of energy generated from coal fired resources was 55.67%, which was 2.96% higher than the projected percentage of 54.07%. The weighted average fuel cost for natural gas was $3.39 cents per KWH, which is 4.95% above the projected cost of $3.23 cents per KWH. The weighted average fuel cost for coal, plus lighter fuel, was $4.88 cents per KWH, which is 1.61% lower than the projected cost of $4.96 cents per KWH. This information is found on Schedule A-3, period-to-date, for the month of December 2013 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 $190,145,353 (line 17 of Schedule A-5, period-to-date, for December 2013) compared to the projected cost of $206,816,428 or 8.06% below the projected amount. The lower total coal cost was due to the quantity (tons) of coal purchased for the period being 1.93% lower than projected and the actual weighted average price of coal purchased being $99.73 per ton which is 6.25% below the projected price of $106.38 per ton. Gulf deferred some planned contract coal shipments to future periods and purchased some lower cost spot coal during the current period for operational reasons.

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

A. The total cost of coal burned was $217,371,796 (line 21 of Schedule A-5, period-to-date, for December 2013). This is 8.82% lower than the projection of $238,408,703. The lower total coal cost was due to the quantity of coal burned being 5.17% below projections and the actual weighted average coal burn cost being $101.82 per ton which is 3.85% below the projected burn cost of $105.90 per ton 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 $120,362,711 (line 34 of Schedule A-5, period-to-date, for December

2013). This is 6.88% below the projection of $129,260,650. The lower total gas cost was due to the quantity of gas burned being 8.47% lower than projected. The actual weighted average gas burn cost was $4.68 per MMBTU, which is 1.74% higher than the projected burn cost of $4.60 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 2013 complied with the Risk Management Plan filed on August 1, 2012.

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. As shown in Schedule 1 of my exhibit, total coal shipments for the period amounted to 1,906,634 tons. Gulf purchased 20% 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 due either to economic or operational reasons. Gulf purchased 80% of its 2013 coal supply 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 shipments to Gulf's generating plants for the period as reported on the monthly FPSC 423 reports.

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 shipments 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 a relatively small variance between the estimated purchase price of coal and the actual price for the period (6.25% below projected as reported on line 16 of Schedule A-5, period to date, for the month of December 2013).

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 2013, Gulf's weighted average cost of natural gas purchases for generation was $4.71 per MMBTU. This was 2.17% higher than the projection of $4.61 per MMBTU (line 29 of Schedule A-5, period-to-date, for December 2013). 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 calculated volatility of Gulf's delivered cost of natural gas for the Smith 3 and Central Alabama PPA combined cycle generating units for the period is represented by a variance of 0.12 and standard deviation of 0.34. By contrast, the calculation of the volatility of Gulf's hedged delivered cost of natural gas for the period yields a variance of 0.08 and a standard deviation of 0.28. The lower values for variance and standard deviation for the set of hedged prices demonstrates that Gulf's 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 financial instrument?

A. Gulf Power hedged 34,980,000 MMBTU of natural gas in 2013 using financial instruments. This represents 56% of Gulf's 62,236,729 MMBTU of actual gas burn for Smith Unit 3 (as reported on Schedule A-4) plus the actual gas burn for the Central Alabama PPA combined cycle unit during the period. The amount of natural gas burn by month for these units is reported on Schedule 4 of my exhibit.

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 swap contracts that fixed the price of gas to a certain price. The total volume of gas hedged for the period was hedged using financial swap contracts. 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 2013 through December 2013?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2013 hedging program resulted in a net financial loss of $14,654,866 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2013 included in Appendix 1 of Witness Dodd's exhibit.

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

A. No.

Q. During the period January 2013 through December 2013 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 ($94,695,182) or 0.56% above the projected amount of ($94,164,000). Total kilowatt hours of power sales were (4,918,616,357) KWH compared to estimated sales of (2,892,370,000) KWH, or 70.05% above projections. The resulting average fuel cost of power sold was 1.9252 cents per KWH or 40.86% below the projected amount of 3.2556 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2013 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 higher total credit to fuel expense from power sales is attributed to the higher total quantity of energy sales (KWH) than projected. The more favorable position of Gulf's generating assets in system economic dispatch to serve load resulted in a greater quantity of energy sales. This was offset somewhat by a below budget fuel reimbursement rate (cents per KWH) paid to Gulf for typical power sales.

Q. During the period January 2013 through December 2013, 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 $216,685,778 or 7.18% above the estimated amount of $202,161,000. Total kilowatt hours of purchased power were 8,295,824,447 KWH compared to the estimate of 6,297,505,000 KWH or 31.73% above projections. The resulting average fuel cost of purchased power was 2.6120 cents per KWH or 18.63% below the estimated amount of 3.2102 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2013 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.

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 2013 through December 2013, 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 2013 through December 2013 recovery period, as shown on line 4 of Schedule CCA-2 of Witness Dodd's Exhibit, was $46,237,515. Gulf's total re-projected net purchased power capacity cost for the same period was $45,966,336, as indicated on line 4 of Schedule CCE-1B of Witness Dodd's exhibit filed August 2, 2013. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $271,179 or 0.59% higher than the re-projected amount. This higher actual cost is primarily due to Gulf having higher IIC reserve sharing costs than the re-projected amount for the 2013 recovery period.

Q. Was Gulf's actual 2013 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 Southern electric system 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 2013, 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.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
H. R. Ball
Docket No. 140001-EI
July 25, 2014

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 2014 through December 2014 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2014 through June 2014 and projected fuel and net power transaction costs for July 2014 through December 2014. 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 one exhibit (HRB-2) I am sponsoring as part of this testimony. This exhibit consists of a purchase power agreement between Gulf and Bay County, Florida.

Counsel: We ask that Mr. Ball's exhibit as described be marked for identification as Exhibit No. ________ (HRB-2).

Q. During the period January 2014 through December 2014 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 $503,586,400 which is $43,131,566 or 9.37% above the original projected amount of $460,454,834. The higher total fuel and net power transaction expense for the period is attributed to a combination of higher than projected total fuel cost of system net generation combined with a higher total fuel cost of purchased power resulting in a higher total cost of available power which is offset by higher fuel revenue from power sales. The resulting average per unit fuel cost is projected to be 4.1229 cents per kWh or 9.42% higher than the original projection of 3.7681 cents per kWh. The higher average per unit fuel and net power transactions cost (cents per kWh) is attributed to a higher per unit fuel cost of generated power for the period driven primarily by higher costs for natural gas combined with a lower per unit fuel cost and gains on power sales. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 21.

Q. During the period January 2014 through December 2014 how will Gulf Power Company's recoverable total fuel cost of generated power compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable total fuel cost of generated power for the period is $408,146,475 which is $49,219,769 or 13.71% above the original projected amount of $358,926,706. Total generation is expected to be 10,007,009,000 kWh compared to the original projected generation of 8,933,268,000 kWh or 12.02% above original projections. The resulting average fuel cost is expected to be 4.0786 cents per kWh or 1.51% above the original projected amount of 4.0179 cents per kWh. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 6.

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

A. The higher total fuel expense is due to higher average per unit fuel costs (cents/kWh) combined with a higher than originally projected quantity of generated power (kWh). Delivered coal prices per MMBtu are projected to be slightly below original projections for the period due to a change in the mix of contract coal in the coal supply mix. The price of natural gas is expected to be higher than original projections for the period due to changes in market fuel prices driven by higher demand. The quantity of natural gas burn is expected to be below original projections in response to higher market prices for natural gas decreasing economic dispatch of Gulf's gas fired generating units.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2014?

A. The total fuel cost of system net generation for the first six months of 2014 was $216,218,518 which is $30,642,487 or 16.51% higher than the projection of $185,576,031. On a fuel cost per kWh basis, the actual cost was 4.33 cents per kWh, which is 6.39% higher than the projected cost of 4.07 cents per kWh. This higher than projected cost of system generation on a cents per kWh basis is due to a combination of fuel cost in $/MMBtu being 4.12% higher than projected and heat rate (Btu/kWh) of the generating units operating being 2.11% higher than projected. The higher price of fuel is a result of higher market prices for natural gas than projected for the period combined with coal fired units operating at reduced efficiency levels during the period. This information is found on Schedule A-3 Period to Date of the June 2014 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2014?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2014 was $144,637,314 which is $23,044,312 or 18.95% higher than the projection of $121,593,002. On a fuel cost per kWh basis, the actual cost was 5.00 cents per kWh which is 5.93% higher than the projected cost of

4.72 cents per kWh. The higher than projected total cost of coal burned (including boiler lighter) is due to total MMBtu of coal burn being 20.98% above the estimated burn for the period. The higher per kWh cost of coal fired generation is due to the weighted average heat rate (Btu/kWh) of the coal fired generating units that operated being 7.73% higher than projected offset somewhat by actual coal prices (including boiler lighter) being 1.42% lower than projected on a $/MMBtu basis. This information is found on Schedule A-3 Period to Date of the June 2014 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 lower due to a change in the timing of contract shipments to Gulf's coal fired generating plants. The primary 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.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2014?

A. The total cost of natural gas burned for generation for the first six months of 2014 was $68,816,377 which is $6,931,449 or 11.20% higher than Gulf's projection of $61,884,928. The total gas fired generation was 2,050,002 MWH which is 6.08% higher than the projection of 1,932,435 MWH for the period. The total cost of natural gas burned for generation is higher than the forecast due to higher prices for gas combined with increased generation for the period. On a cost per unit basis, the actual cost of gas fired generation was 3.36 cents per kWh which is 5.00% higher than the projected cost of

3.20 cents per kWh. Actual natural gas prices were $5.66 per MMBtu or 21.46% higher than the projected cost of $4.66 per MMBtu. The higher natural gas cost ($/MMBtu) was offset somewhat by gas fired unit heat rate (Btu/KWH) being 13.43% less or more efficient than projected. This information is found on Schedule A-3 Period to Date of the June 2014 Monthly Fuel Filing.

Q. For the period January 2014 through June 2014, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 16,440,000 MMBtu of natural gas for the period. This equates to 62.6% of the actual natural gas burn for Gulf's combined cycle generating units during the period of 27,265,511 MMBtu. This amount is the sum of the Plant Smith Unit 3 burn as reported on Schedule A-3 Period to Date of the June 2014 Monthly Fuel Filing and the Central Alabama PPA natural gas burn for 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 using a combination of financial swaps that fixed the price of gas to a certain price and option contracts. The option contracts consisted entirely of "costless collars" that set a floor and ceiling price between which the price would float. The option contracts settled only if the market price was outside the price bounds of the collar. The swaps settled against either a NYMEX Last Day price or Gas Daily price. The amount of gas hedged for the period using financial swaps was

15,540,000 MMBtu and the amount of gas hedged for the period using option contracts was 900,000 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 gain related to settlements of $8,459,355 for the period January through June 2014. This information is found on Schedule A-1, Period to Date, line 2 of the June 2014 Monthly Fuel Filing.

Q. During the period January 2014 through December 2014 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 $(124,532,648) or 72.38% above the original projected amount of $(72,244,995). Total kilowatt hours of power sales is expected to be (4,253,858,911) kWh compared to the original projection of (2,183,462,000) kWh or 94.82% above projections. This current projection of fuel cost of power sold is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-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 greater total credit to fuel expense from power sales is attributed to a significantly higher quantity of power sales than originally projected, offset somewhat by a lower reimbursement rate (cents per kWh) for power sales. The currently projected price for the fuel cost and gains on power sales is 2.9275 cents/kWh which is 11.52% lower than the original projection of 3.3087 cents/kWh. The lower projected fuel reimbursement rate for power sales during the period are due to lower projected fuel costs associated with the units that are projected to set system pool interchange rates 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 2014?

A. The total fuel cost of power sold for the first six months of 2014 was $(74,083,248) which is $(34,109,248) or 85.33% higher than our projection of $(39,974,000). The quantity of power sales for the period was 115.24% higher than projected. The actual cost was 2.6728 cents per kWh which is 13.90% below the projected cost of 3.1042 cents per kWh. This information is found on Schedule A-1, Period to Date, line 17 of the June 2014 Monthly Fuel Filing.

Q. During the period January 2014 through December 2014 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 $219,972,573 or 26.59% above the original projected amount of

$173,773,123. The total amount of purchased power is expected to be 6,461,093,663 kWh compared to the original projection of 5,470,006,000 kWh or 18.12% above projections. The resulting average fuel cost of purchased power is expected to be 3.4046 cents per kWh or 7.17% above the original projected amount of 3.1768 cents per kWh. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-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 lower cost energy to supplement its own generation to meet load demands. The higher projected price per kWh for purchased power is due to higher natural gas market prices for the period.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2014?

A. The total fuel cost of purchased power for the first six months of 2014 was $114,431,573 which is $35,891,081 or 45.70% higher than our projection of $78,540,492. The higher than projected purchased power expense is due to the actual quantity of purchases being 43.70% higher than projected. The majority of these purchases are from Gulf's PPAs which are contracts associated with gas fired generating units. Purchased power quantity is higher due to higher demand and the availability of lower cost energy purchases to meet this demand. On a fuel cost per kWh basis, the actual cost was 3.2296 cents per kWh which is 1.39% higher than the projected cost of 3.1854 cents per kWh. This information is found on Schedule A-1, Period to Date, line 12 of the June 2014 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, 2014 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. Were there any other significant developments in Gulf's purchased power program during the period?

A. Yes, Gulf has renewed its purchase power agreement with Bay County, Florida, a copy which is filed as exhibit ______ (HRB-2) to this testimony. This new agreement is effective July 23, 2014 and has a three year term. This is an "as available energy" only agreement and has no capacity value. The Bay County Facility, located in Panama City, Florida, has a maximum output rating of 13.65 MW and is classified as a Renewable Generating Facility.

Q. What is the impact of the renegotiated agreement on Gulf's fuel cost of purchased power?

A. The price Gulf pays for energy under this agreement has been reduced to reflect the lower market price for natural gas which served as the benchmark for establishing a replacement energy price. The rate for purchase and sale of energy pursuant to this agreement is fixed for the entire term.

Q. Should the renewal of the Bay County purchase power agreement be accepted as reasonable and prudent?

A. Yes. The renegotiated and renewed agreement is reasonable and prudent and in the best interests of Gulf's customers and Bay County. As such, it should be approved for cost recovery through the fuel cost recovery clause.

Q. During the period January 2014 through December 2014, 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 Boyett's testimony, Gulf's total current net capacity payment projection for the January 2014 through December 2014 recovery period is $62,478,533. Gulf's original projection for the period was $63,734,932 and is shown on Line 4 of Schedule CCE-1 filed August 30, 2013. The difference between these projections is $1,256,399 or 1.97% less than the original projection of net capacity payments. The variance is due to a decrease in both projected capacity payments under Gulf's purchase power agreements (PPA's) and reserve sharing capacity payments per the provisions of the IIC.

Q. How did the total projected net capacity transactions cost compare to the actual cost for the first six months of 2014?

A. Actual net capacity payments during the first six months of 2014 were $19,021,847 which is $1,262,551 or 6.22% lower than projected amount of $20,284,398 for the period. The variance is primarily due to a decrease in the capacity payments associated with Gulf's PPA's for the period in addition to a decrease in Gulf's reserve sharing payments.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 140001-EI
Date of Filing: August 22, 2014

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, 2015 through December 31, 2015. 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 four separate exhibits I am sponsoring as part of this testimony. My first exhibit (HRB–3) 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-4) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on March 28, 2014 and assigned Document Number DN 01373-14 (redacted) and 01372-14 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August through December 2013 in compliance with Order No. PSC-08-0316-PAA-EI. The third exhibit (HRB-5) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 13, 2014 and assigned Document Number DN 04362-14 (redacted) and 04363-14 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for January through July 2014 in compliance with Order No. PSC-08-0316-PAA-EI. The fourth exhibit (HRB-6) I am sponsoring is Gulf Power Company's "Risk Management Plan for Fuel Procurement." This exhibit was filed with the Commission Clerk pursuant to a separate request for confidential classification on July 25, 2014 and assigned Document Number DN 03980-14 (redacted) and 03982-14 (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 four exhibits as just described be marked for identification as Exhibit Nos. _____ (HRB-3), _____ (HRB-4), _____ (HRB-5), and_____ (HRB-6) 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 2015 through December 2015 recovery period?
A. Gulf's projected total fuel and net power transaction cost for the period is $441,827,719. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 19.

Q. How does the total projected fuel and net power transactions cost for the 2015 period compare to the updated projection of fuel cost for the same period in 2014?
A. The total updated cost of fuel and net power transactions for 2014, reflected on Schedule E-1B-1 line 21 of Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be $503,586,400. The projected total cost of fuel and net power transactions for the 2015 period reflects a decrease of $61,758,681 or 12.26% less than the same period in 2014. On a fuel cost per kWh basis, the 2014 projected cost is 4.1229 cents per kWh and the 2015 projected fuel cost is 3.6441 cents per kWh, a decrease of 0.4788 cents per kWh or 11.61%.

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 2015 is $280,069,719. The projection of fuel cost of system generated power for 2015 is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 5.

Q. How does the projected total fuel cost of generated power for the 2015 period compare to the updated projection of fuel cost for the same period in 2014?

A. The total updated cost of fuel to meet 2014 system generated power needs, reflected on Schedule E-1B-1, line 6 of Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be $408,146,475. The projected total cost of fuel to meet system net generation needs for the 2015 period reflects a decrease of $128,076,756 or 31.38% less than the same period in 2014. Total system net generation in 2015 is projected to be 7,527,320,000 kWh, which is 2,479,689,000 kWh or 24.78% lower than is currently projected for 2014. On a fuel cost per kWh basis, the 2014 projected cost is 4.0786 cents per kWh and the 2015 projected fuel cost is 3.7207 cents per kWh, a decrease of 0.3579 cents per kWh or 8.78%. This lower projected total fuel expense and average per unit fuel cost is the result of a lower projected cost of coal and a higher percentage of generation coming from lower cost (cents/kWh) natural gas units for the 2015 period. Weighted average coal burned price for 2014 as reflected on Schedule E-3, line 29 of Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be $90.25 per ton. Weighted average coal burned price for 2015, as reflected on Schedule E-3, line 29 of the exhibit to Witness Boyett's testimony, is projected to be $78.49 per ton. This reflects a cost decrease of $11.76 per ton or 13.03%. Several of Gulf's coal supply contracts have or will expire by the end of 2014 and these are being replaced with lower priced coal supply agreements. Gulf's coal supply agreements have firm price and quantity commitments with the contract coal suppliers and these contracts will cover much of Gulf's 2015 projected coal burn needs. The remaining coal supply needs will be purchased on the spot market. Weighted average natural gas price for 2014, as reflected on Schedule E-3, line 33 of the exhibit to Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be $5.32 per MMBtu. When the cost of natural gas hedging settlements (Schedule E-1-B1, line 1a) is included in the total delivered gas cost, the 2014 projected cost is $5.10 per MMBtu. Weighted average natural gas price for 2015, as reflected on Schedule E-3, line 33 of the exhibit to Witness Boyett's testimony, is projected to be 5.12 $/MMBtu. This is an increase in price of $0.02 per MMBtu or 0.39%. As reflected on Schedule E-3, lines 40 and 41 of the exhibit to Witness Boyett's testimony, the projected fuel cost of Gulf's coal fired generation is 3.96 cents per kWh and the projected fuel cost of Gulf's gas fired generation is 3.51 cents per kWh for the 2015 period. The generation mix in 2014, as reflected on Schedule E-3, lines 23 and 24 of the exhibit to Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be 60.14% coal and 39.61% gas. The generation mix in 2015, as reflected on Schedule E-3, lines 23 and 24 of the exhibit to Witness Boyett's testimony, is projected to be 47.28% coal and 52.30% gas which is more heavily weighted to lower cost natural gas fired generation. The projected cost of landfill gas to supply the Perdido Landfill Gas to Energy Facility in the 2014 projection period is $754,039 and the rate as reflected on Schedule E-3, line 42 of the exhibit to Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be 3.01 cents per kWh. The total projected cost for landfill gas in 2015 is $963,353 and the total facility generation is projected to be 31,952,000 kWh. The average rate, as reflected on Schedule E-3, line 42 of the exhibit to Witness Boyett's testimony, is projected to be 3.02 cents per kWh.

Q. Does the 2015 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-6) 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 pipeline 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 its customers 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 its customers 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 2014 through July 2014?

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 March 28, 2014 and also on August 13, 2014 detailing its natural gas hedging transactions for August 2013 through July 2014. As noted earlier, I am sponsoring these reports as exhibits ______ (HRB-4 and HRB-5) to my testimony in this docket.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2014 through 2015?

A. Yes. Gulf has natural gas financial hedges in place for 2014 to adequately mitigate price risk. Gulf currently has natural gas hedges in place for 2015 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 by entering into financial hedge agreements whose total quantity exceed the projected natural gas burn for the period. 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 and the gas fired PPA units for which Gulf has tolling agreements. 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 are Gulf's projected recoverable fuel cost and gains on power sales for the 2015 period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $47,966,000. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 17.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2015 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2014?

A. The total updated recoverable fuel cost and gains on power sales in 2014, reflected on Schedule E-1B-1, line 18 of Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be $124,532,648. The projected recoverable fuel cost and gains on power sales in 2015 represents a decreased credit of $76,566,648 or 61.48%. Total quantity of power sales in 2015 is projected to be 1,503,711,000 kWh, which is 2,750,147,911 kWh or 64.65% less than currently projected for 2014. On a fuel cost per kWh basis, the 2014 projected cost is 2.9275 cents per kWh and the 2015 projected fuel cost is 3.1898 cents per kWh, which is an increase of 0.2623 cents per kWh or 8.96%. 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 for the units operating to meet incremental system loads. The marginal fuel costs to operate Gulf generating units that run to meet power sales requirements are passed on to the purchasers of power and are reflected in the higher rate (cents/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 $209,724,000. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 12.

Q. How does the total projected purchased power cost for the 2015 period compare to the projected purchased power cost for the same period in 2014?

A. The total updated cost of purchased power to meet 2014 system needs, reflected on Schedule E-1B-1, line 13 of Witness Boyett's testimony filed in this docket on July 25, 2014, is projected to be $219,972,573. The projected cost of purchased power to meet system needs in 2015 is $10,248,573 or 4.66% less than is currently projected for 2014. The total quantity of purchased power in 2015 is projected to be 6,100,957,000 kWh, which is 360,136,663 kWh or 5.57% lower than is currently projected for 2014. On a fuel cost per kWh basis, the 2014 projected cost is 3.4046 cents per kWh and the 2015 projected fuel cost is 3.4376 cents per kWh, which represents an increase of 0.0330 cents per kWh or 0.97%.

Q. What is Gulf's projected recoverable capacity payments for the 2015 cost recovery period?

A. The total recoverable capacity payments for the period are $85,462,232. This amount is captured in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 10. Schedule CCE-4 of Mr. Boyett's testimony shows there will be no projected cost associated with Southern Intercompany Interchange and lists the long-term purchased power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting cost. Also included in Gulf's 2015 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 $88,756,724 is shown on Schedule CCE-4, line 29 in the exhibit to Witness Boyett's testimony. The total capacity cost included on Schedule CCE-4 line 29 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 $160,000 in its capacity cost recovery projection. This amount is captured in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 3.

Q. How do the total projected net jurisdictional capacity payments for the 2014 period compare to the current estimated net jurisdictional capacity payments for the same period in 2013?

A. Gulf's 2015 Projected Jurisdictional Capacity Payments, found in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 6, are $86,002,133. This amount is $25,353,309 or 41.80% greater than the current estimate of $60,648,824 (Schedule CCE-1B, line 6) for 2014 that was filed in Mr. Boyett's actual/estimated true-up testimony in this docket on July 25, 2014. The projected capacity payment increase is the result of an increase in Gulf's estimated PPA capacity payments. Contract capacity payments under Gulf's Central Alabama PPA increased beginning in June 2014 due to a scheduled increase in the capacity rate which was negotiated by Gulf and Shell Energy N.A. as part of the original contract approved by the Commission in Order No. PSC-09-0534-PAA-EI. This increase is offset by a decrease in capacity payments under both the Coral Baconton and Dahlberg PPA agreements which expired on May 31, 2014.

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

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 140001-EI
Date of Filing: March 3, 2014

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

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Regulatory and Cost Recovery area. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery Department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the actual true-up amounts for the period January 2013 through December 2013 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will also present the actual benchmark level for the calendar year 2014 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2013 through December 2013.

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

A. Yes. My exhibit consists of 1 schedule that relates to the fuel and purchased power cost recovery actual true-up, 4 schedules that relate to the capacity cost recovery actual true-up, and 1 appendix that includes Schedules A-1 through A-9 and A-12 for the period January 2013 through December 2013, previously filed monthly with this Commission. Each of these documents was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of 5 schedules and 1 appendix be marked as Exhibit No. _____ (RWD-1).

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes.

Q. Which schedules of your exhibit relate to the calculation of the fuel and purchased power cost recovery true-up amount?

A. Schedule 1 of my exhibit relates to the fuel and purchased power cost recovery true-up calculation for the period January 2013 through December 2013. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for January 2013 through December 2013 are incorporated herein in Appendix 1.

Q. What is the actual fuel and purchased power cost true-up amount related to the period of January 2013 through December 2013 to be refunded or collected through the fuel cost recovery factors in the period January 2015 through December 2015?

A. A net amount to be recovered of $4,954,515 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $4,954,515 was calculated by taking the difference in the estimated and actual over/under-recovery amounts for the period January 2013 through December 2013. The estimated under-recovery was $6,665,066 as shown on Schedule E-1B, Line 6 + 7 + 8 filed August 2, 2013. The actual under-recovery was $11,619,581 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2013 Schedule A-2, page 2 of 3, included in Appendix 1. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed August 2, 2013.

Q. Mr. Dodd, has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2013 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2011 through 2013 is calculated as follows:

Year	Actual Gain
2011	463,514
2012	519,587
2013	194,730
Three-Year Average	$ 392,610

Q. What is the actual threshold for 2014?
A. The actual threshold for 2014 is $392,610.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements for the period of January 2013 through December 2013?
A. Yes. On line 2 of Schedule A-1, Period-to-Date, for December 2013 included in Appendix 1, Gulf has recorded a net loss of $14,654,866 related to hedging activities in 2013. Mr. Ball addresses the details of those hedging activities in his testimony.

Q. Mr. Dodd, you stated earlier that you are responsible for the purchased power capacity cost recovery true-up calculation. Which schedules of your exhibit relate to the calculation of this amount?
A. Schedules CCA-1, CCA-2, CCA-3 and CCA-4 of my exhibit relate to the purchased power capacity cost recovery true-up calculation for the period January 2013 through December 2013. In addition, Capacity Cost Recovery Schedule A-12 for the months of January 2013 through December 2013 is included in Appendix 1.

Q. What is the actual purchased power capacity cost true-up amount related to the period of January 2013 through December 2013 to be refunded or collected in the period January 2015 through December 2015?
A. An amount to be collected of $662,017 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $662,017 was calculated by taking the difference in the estimated January 2013 through December 2013 under-recovery of $2,263,786 and the actual under-recovery of $2,925,803, which is the sum of lines 10, 11, and 14 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in FPSC Order No. PSC-13-0665-FOF-EI dated December 18, 2013. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed August 2, 2013.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual under-recovery of purchased power capacity costs for the period January 2013 through December 2013. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the under-recovery for the period January 2013 through December 2013.

Q. Please describe Schedule CCA-4 of your exhibit.

A. Schedule CCA-4 provides additional details related to Lines 1 and 2 of Schedule CCA-2.

Q. Mr. Dodd, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 140001-EI
Date of Filing: July 25, 2014

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science Degree in Business Administration. I also hold a Masters in Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

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. Boyett's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (CSB-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2014 through December 2014 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2014 through December 2014 set forth in your exhibit?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case, the estimated true-up calculations include six months of actual data and six months of estimated data.

Q. Mr. Boyett, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2015 through December 2015?

A. The fuel cost recovery true-up for this period is an increase of 0.4335 ¢/kWh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2014 period of $43,001,980. It also includes a final under-recovery for the January through December 2013 period of $4,954,515 (see Schedule 1 of Exhibit RWD-1 in this docket filed on March 3, 2014). The resulting total under-recovery of $47,956,495 will be included for recovery during 2015.

Q. Mr. Boyett, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2015 through December 2015 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2015 through December 2015?

A. The true-up for this period is a decrease of 0.0054 ¢/kWh as shown on Schedule CCE-1A. This includes an estimated over-recovery of $1,263,407 for January 2014 through December 2014. It also includes a final under-recovery of $662,017 for the period of January 2013 through December 2013 (see Schedule CCA-1 of Exhibit RWD-1 in this docket filed March 3, 2014). The resulting total over-recovery of $601,390 will be refunded during 2015.

Q. Mr. Boyett, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Revised Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 140001-EI
Date of Filing: August 29, 2014

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science Degree in Business Administration. I also hold a Masters in Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power’s Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2015 through December 2015. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2015 through December 2015.

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

A. Yes. I have one exhibit consisting of 15 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit consisting of 15 schedules, be marked as Exhibit No. _____(CSB-2)

Q. Mr. Boyett, what is the levelized projected fuel factor for the period January 2015 through December 2015?

A. Gulf has proposed a levelized fuel factor of 4.335¢/kWh. This factor is based on projected fuel and purchased power energy expenses for January 2015 through December 2015 and projected kWh sales for the same period, and includes the true-up and GPIF amounts.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2015 is 0.166¢/kWh more or 4 percent higher than the levelized fuel factor in place January through December 2014.

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the levelized fuel factor for the period January 2015 through December 2015.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $47,956,495 to be collected during 2015 includes an estimated under-recovery for the January through December 2014 period of $43,001,980 plus a final under-recovery for the period January through December 2013 of $4,954,515. The estimated under-recovery for the January through December 2014 period includes 6 months of actual data and 6 months of estimated data as reflected on Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2013 through December 2013?

A. The GPIF result is shown on Line 31 of Schedule E-1 as an increase of 0.0228¢/kWh to the levelized fuel factor, thereby rewarding Gulf $2,523,938.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?
A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 29 of Schedule E-1.

Q. Mr. Boyett, how were the line loss multipliers used on Schedule E-1E calculated?
A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest MWh Load Flow Allocators.

Q. Mr. Boyett, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OSIII?
A. Gulf proposes a standard fuel factor, adjusted for line losses, of 4.369¢/kWh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Mr. Boyett, how were the time-of-use fuel factors calculated?
A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2015 through December 2015. These factors included the GPIF and true-up and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2014 and how would the change affect the cost of 1,000 kWh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2014 is 4.201¢/kWh compared with the proposed factor of 4.369¢/kWh. For a residential customer who is billed for 1,000 kWh in January 2015, the fuel portion of the bill would increase from $42.01 to $43.69.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2015 through December 2016.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2015 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $685,224 has been calculated for 2015 as follows:

2012 actual gains	519,587
2013 actual gains	194,730
2014 estimated gains	1,341,355
Three-Year Average	$ 685,224

This amount represents the minimum projected threshold for 2015 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2015.

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 for 2014 of my exhibit CSB-2 relate to the calculation of the PPCC recovery factors for the period January 2015 through December 2015.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Ball has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense, which includes a credit for transmission revenue, for the period January 2015 through

December 2015, is $88,596,724. The jurisdictional amount is $86,002,133. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What methodology was used to allocate the capacity payments by rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology approved by the Commission in Order No. PSC-12-0179-FOF-EI issued April 3, 2012, in Docket No. 110138-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs by rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study approved by the Commission in Order No. PSC-12-0179-FOF-EI issued April 3, 2012, in Docket No. 110138-EI.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2012 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

Q. Please describe the calculation of the ¢/kWh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, 12/13th of the jurisdictional capacity cost to be recovered is allocated by rate class based on the demand allocator. The remaining 1/13th is allocated based on energy.

Gulf has calculated the PPCC factor for the LP/LPT rate classes based on kilowatt (kW) rather than kilowatt hour (kWh) in accordance with Order No. PSC-13-0670-S-EI issued December 9, 2013 in Docket No. 130140-EI. The total revenue requirement assigned to rate class LP/LPT shown in column E is then divided by the sum of the projected billing demands (kW) for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each LP/LPT customer's billing demand (kW) to calculate the amount to be billed each month.

For all other rate classes, the total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kWh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kWh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The purchased power capacity costs recovered through the clause for a residential customer who is billed for 1,000 kWh will be $9.16.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?
A. The fuel and capacity factors will be effective beginning with Cycle 1 billings in January 2015 and continuing through the last billing cycle of December 2015.

Q. Mr. Boyett, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
M. A. Young, III
Docket No. 140001-EI
Date of Filing: March 7, 2014

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

A. My name is Melvin A. Young, III. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Alabama in Birmingham in 1984. I joined the Southern Company with Alabama Power in 1981 as a co-op student and continued with Alabama Power upon graduation in 1984. During my time at Alabama Power, I worked at Plant Gorgas, Plant Gadsden and in Power Generation Services where I progressed through various engineering positions with increasing responsibilities as well as first line supervision in Operations and Maintenance. I joined Gulf Power in 1997 as the Performance Engineer at Plant Crist. My primary responsibilities have been to monitor and test plant equipment and monitor overall plant heat rate. In addition to this, I have been responsible for major plant projects and was the primary reliability reporter. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company.

In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2013, through December 31, 2013.

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

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Mr. Young's Exhibit consisting of five schedules be marked as Exhibit No. _______ (MAY-1).

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 13 through 22 of Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 12 of Schedule 5. Pages 3 through 7 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-08-0030-FOF-EI is on page 8 of Schedule 2. The results are: Crist 6, -8.33 points; Crist 7, -6.96 points; Smith 3, -5.45 points; Daniel 1, -0.48 points; and Daniel 2, -10.00 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 6 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 7 through 11 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in August 2012, are shown on page 13 of Schedule 3. As calculated on page 14 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: Crist 6, +0.00 points; Crist 7, +10.00 points; Smith 3, +10.00 points; Daniel 1, +7.49 points, and Daniel 2, +0.00 points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was +6.41 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $3,075,930.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 8 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $3,075,930 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Revised Prepared Direct Testimony of
M. A. Young, III
Docket No. 140001-EI
Date of Filing: August 29, 2014

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

A. My name is Melvin A. Young, III. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Alabama in Birmingham in 1984. I joined the Southern Company with Alabama Power in 1981 as a co-op student and continued with Alabama Power upon graduation in 1984. During my time at Alabama Power, I worked at Plant Gorgas, Plant Gadsden and in Power Generation Services where I progressed through various engineering positions with increasing responsibilities as well as first line supervision in Operations and Maintenance. I joined Gulf Power in 1997 as the Performance Engineer at Plant Crist. My primary responsibilities have been to monitor and test plant equipment and monitor overall plant heat rate. In addition to this, I have been responsible for major plant projects and was the primary reliability reporter. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company.

In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2013, through December 31, 2013.

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

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Mr. Young's Exhibit consisting of five schedules be marked as Exhibit No. _______ (MAY-1).

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 13 through 22 of Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 12 of Schedule 5. Pages 3 through 7 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-08-0030-FOF-EI is on page 8 of Schedule 2. The results are: Crist 6, -8.33 points; Crist 7, -6.96 points; Smith 3, -5.45 points; Daniel 1, -0.48 points; and Daniel 2, -10.00 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 6 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 7 through 11 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in August 2012, are shown on page 13 of Schedule 3. As calculated on page 14 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: Crist 6, +0.00 points; Crist 7, +10.00 points; Smith 3, +10.00 points; Daniel 1, +7.49 points, and Daniel 2, +0.00 points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was +6.41 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $2,523,938.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 8 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $2,523,938 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Revised Prepared Direct Testimony of
M. A. Young, III
Docket No. 140001-EI
Date of Filing: August 29, 2014

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

A. My name is Melvin A. Young, III. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Alabama in Birmingham in 1984. I joined the Southern Company with Alabama Power in 1981 as a co-op student and continued with Alabama Power upon graduation in 1984. During my time at Alabama Power, I worked at Plant Gorgas, Plant Gadsden and in Power Generation Services where I progressed through various engineering positions with increasing responsibilities as well as first line supervision in Operations and Maintenance. I joined Gulf Power in 1997 as the Performance Engineer at Plant Crist. In this capacity, my primary responsibilities were to monitor and test plant equipment and monitor overall plant heat rate. In addition to this, I was responsible for major plant projects and was the primary reliability reporter. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company.

In this position I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2015 through December 31, 2015.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have prepared one exhibit entitled MAY-2 consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?
A. Yes, it was.
Counsel: We ask that Mr. Young's exhibit consisting of three schedules be marked for identification as Exhibit___(MAY-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?
A. We propose that Crist Units 6 and 7, Daniel Units 1 and 2, and Smith Unit 3, be included as the Company's GPIF units. The projected net generation from these units is approximately 94% of Gulf's projected net generation for 2015.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2015 through December 31, 2015?
A. I would like to refer you to page 23 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?
A. They were determined according to the GPIF Implementation Manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.
A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units and pages 4 through 20 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 21 and 22 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit indicated on page 23 of Schedule 1 of your exhibit calculated according to the appropriate GPIF Implementation Manual procedures?
A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?

A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of my exhibit.

Q. How were the target equivalent availabilities determined?

A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on page 2 of Schedule 2 of my exhibit.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?

A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of my exhibit, were determined per GPIF Implementation Manual procedures for Gulf.

Q. Mr. Young, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Mr. Young, would you please summarize your testimony?
A. Yes. Gulf asks that the Commission accept:

1. Crist Units 6 and 7, Daniel Units 1 and 2, and Smith Unit 3 for inclusion under the GPIF for the period of January 1, 2015 through December 31, 2015.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 23 of Schedule 1 and also on page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and also on page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

Q. Mr. Young, does this conclude your testimony?
A. Yes.

(Transcript continues in sequence with Volume 2.)

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

I, LINDA BOLES, CRR, RPR, 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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 30th day of October, 2014.

Linda Boles

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