BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 130001-EI

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

Pages 1 through 289

PROCEEDINGS: HEARING

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

DATE: Monday, November 4, 2013

TIME: Commenced at 9:30 a.m.
Concluded at 10:06 a.m.

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

REPORTED BY: JANE FAUROT, RPR
Official FPSC Reporter
(850) 413-6732

APPEARANCES:

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

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

JOHN T. BURNETT, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, 106 E. College Ave., Suite 800, Tallahassee, Florida 32301, appearing on behalf of Duke Energy Florida, Inc.

KAREN PUTNAL, ESQUIRE, c/o Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

JOHN T. BUTLER and KENNETH M. RUBIN, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408, appearing on behalf of Florida Power & Light Company.

APPEARANCES (Continued):

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, ESQUIRES, Florida Retail Federation, c/o Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of Florida Retail Federation.

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

J.R. KELLY, PUBLIC COUNSEL, PATRICIA A. CHRISTENSEN, CHARLES REHWINKEL, and JOSEPH A. MCGLOTHLIN, 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.

JAMES W. BREW and F. ALVIN TAYLOR, ESQUIRES, PCS Phosphate - White Springs, c/o Brickfield Law Firm, 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of PCS Phosphate - White Springs.

APPEARANCES (Continued):

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

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

I N D E X

PREFILED TESTIMONY INSERTED

EXHIBITS

NUMBER:	ID.	ADMTD.

(No exhibits.)

P R O C E E D I N G S

CHAIRMAN BRISÉ: Good morning. We'll go ahead and call this hearing to order. It's our annual clause hearings. And, Staff, would you read the notice, please.

MS. GILCHER: By notice issued September 27, 2013, this time and place is set for a hearing conference in the following dockets: 130001-EI, 130002-EG, 130003-GU, 130004-GU, and 130007-EI. The purpose of the hearing conference is set out in the notice.

CHAIRMAN BRISÉ: All right. Thank you. At this time we will take appearances. And, staff, do we have any specific instructions that we want to give with respect to that?

MS. GILCHER: Staff suggests that all parties give their appearances at the same time. There are five dockets to address this morning. All parties should enter their appearances and declare the dockets that they are entering their appearance for.

CHAIRMAN BRISÉ: Okay. Thank you. All right. At this time we'll take appearances.

MR. BUTLER: Good morning, Mr. Chairman. John Butler and Ken Rubin. We're appearing in the 01, the 02, and the 07 dockets.

MS. DANIELS: Good morning, Commissioners. I am Ashley Daniels appearing with Jim Beasley and Jeff Wahlen of Ausley McMullen on behalf of Tampa Electric in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Okay. Thank you.

MR. STONE: Good morning, Commissioners. I'm Jeffrey A. Stone of the law firm Beggs and Lane and I'm appearing on behalf of Gulf Power Company in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. REHWINKEL: Good morning, Commissioners. Charles Rehwinkel and Patricia Christensen in all dockets; Joseph McGlothlin in 01 and 07. And J.R. Kelly, the Public Counsel, is here.

CHAIRMAN BRISÉ: Thank you.

MR. WRIGHT: Good morning, Mr. Chairman and Commissioners. Robert Scheffel Wright and John T. LaVia, III, appearing on behalf of the Florida Retail Federation in the fuel docket, 130001. The same attorneys also appearing on behalf of DeSoto County Generating Company in the ECRC docket, 130007.

Thank you.

CHAIRMAN BRISÉ: Thank you.

MR. KEATING: Good morning, Commissioners. Beth Keating with the Gunster law firm. I'm here today on behalf of FPUC in the 01 and 02 dockets; on behalf of FPUC and Florida City Gas in the 03 docket; and on behalf of FPUC, FPUC Indiantown, Chesapeake, and Florida City Gas in the 04 docket.

CHAIRMAN BRISÉ: Thank you.

MS. PUTNAL: Good morning. I am Karen Putnal with the Moyle Law Firm and appearing today on behalf of Florida Industrial Power Users Group in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. BREW: Good morning, Mr. Chairman. I'm James Brew. I'm appearing for White Springs Agricultural Chemicals, PCS Phosphate in the 01, 02, and 07 dockets. And I'd like to make an appearance for F. Alvin Taylor, as well.

CHAIRMAN BRISÉ: Thank you.

MR. HORTON: Mr. Chairman, Norman H. Horton, Jr., appearing on behalf of Sebring Gas System in the 04 docket.

CHAIRMAN BRISÉ: Thank you.

MS. TRIPLETT: Good morning. Diane Triplett, John Burnett, and Matt Bernier, appearing on behalf of Duke Energy Florida in the 01, 02, and 07 dockets. And also appearing in the 07 docket is Gary Perko. Thank you.

CHAIRMAN BRISÉ: Thank you.

MS. CORBARI: Kelly Corbari appearing in the 04 docket.

CHAIRMAN BRISÉ: Okay.

MS. GILCHER: Julia Gilcher appearing in the 02 and 01 docket. I'd also like to make an appearance in the 02 docket for Lee Eng Tan and in the 01 docket for Martha Barrera.

CHAIRMAN BRISÉ: Thank you.

MR. LAWSON: Michael Lawson for the 03 docket.

MR. MURPHY: Charles Murphy in the 07 docket.

MS. HELTON: And, Mary Anne Helton, advisor to the Commission in all of the dockets. And also here today is the General Counsel, Curt Kiser.

CHAIRMAN BRISÉ: Thank you.

Are we missing anyone? Okay.

Are there any parties that have been excused from the hearing?

MS. GILCHER: Yes, Chairman. There's been three parties excused from the hearing today; St. Joe Natural Gas Company, Peoples Gas System, and Southern Alliance for Clean Energy.

CHAIRMAN BRISÉ: Okay. And it's my understanding that St. Joe Natural Gas Company had an interest in Docket 03 and 04?

MS. GILCHER: Correct.

CHAIRMAN BRISÉ: And Peoples Gas, 03 and 04, as well.

MS. GILCHER: Correct.

CHAIRMAN BRISÉ: And Southern Alliance for Clean Energy in the 02 docket.

MS. GILCHER: Correct.

CHAIRMAN BRISÉ: Okay. The order that we plan to take up the dockets today is 02, 03, 04, 07, and then 01.

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CHAIRMAN BRISÉ: Let's proceed to Docket 01. But just before we go there, we're going to take a ten-minute break, because I think it's going to take the bulk of our time today. So we're going to take a ten-minute break or so, just for our health, all right? All right.

(Recess.)

CHAIRMAN BRISÉ: All right. We are going to go ahead and reconvene at this time. And I think we opened Docket 130001 before we went into our break, so are there any preliminary matters that we need to deal with?

MS. BARRERA: Yes, Chairman. Staff will note that there are several stipulations in the prehearing order, and we have prepared a chart for the Commissioners showing the stipulated issues and another chart showing the nonstipulated issues. The nonstipulated issues for Issue 1C, Duke will present one witness, and requests that the witness be taken out of order prior to FP&L, who has three witnesses. For Issue 18B, 25B, and 25C, FPL would present three witnesses. It's our understanding there is cross-examination for the four witnesses and all other witnesses have been excused from the proceedings.

There are also fallout issues related to the forgoing FPL issues. These fallout issues have been identified in your chart of nonstipulated issues. They are 29, 30, 31, 32, and 34, and they are stipulated as to all the other utilities.

CHAIRMAN BRISÉ: Okay. Thank you.

Prefiled testimony.

MS. BARRERA: Staff asks that the prefiled testimony of all of witnesses whose issues have been stipulated and who are identified with an asterisk in Section VI, Pages 4 and 5, of the prehearing order be inserted into the record as though read.
Cross-examination has been waived for the excused witnesses, and all Commissioners have agreed. The only witnesses who are left to testify at this time are

Thomas Foster for Duke, T.J. Keith, D. Grissette, and C.R. Rote for FPL.

CHAIRMAN BRISÉ: All right. Should we move the exhibits -- I mean, not exhibits, the prefiled testimony of those witnesses stipulated at this time?

MS. BARRERA: Yes. And at this time we move that that testimony be filed in the record as though read.

CHAIRMAN BRISÉ: Okay. We will move the testimony of the witnesses that have been stipulated into the record as though read, seeing no objections.

Okay.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF ILIANA H. PIEDRA

DOCKET NO. 130001-EI

SEPTEMBER 27, 2013

Q. Please state your name and business address.

A. My name is Iliana H. Piedra. My business address is 3625 N.W. 82nd Ave., Suite 400, Miami, Florida, 33166.

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

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

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

A. I have been employed by the Florida Public Service Commission since January 1985.

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Business Administration degree with a major in accounting from Florida International University in 1983. I am also a Certified Public Accountant licensed in the State of Florida.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

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

A. Yes. I filed testimony in the City Gas Company of Florida rate case, Docket No. 940276-GU, the General Development Utilities, Inc. rate cases for the Silver Springs Shores Division in Marion County and the Port Labelle Division in Glades and Hendry Counties in

Dockets Nos. 920733-WS and 920734-WS, respectively, the Florida Power & Light Company storm cost recovery case in Docket No. 041291-EI, the Embarq storm cost recovery case in Docket No. 060644-TL, the K W Resort Utilities Corp. rate case in Docket No. 070293-SU, the Florida Power & Light Company fuel recovery in Docket 120001-EI and in Docket No. 130009-EI related to Florida Power & Light Company's Proposed Turkey Point Units 6 and 7.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Power & Light Company (FPL or Utility) which addresses the Utility's filing in Docket No. 130001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 23, 2013. This audit report is filed with my testimony and is identified as Exhibit IHP-1.

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

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

We obtained FPL's supporting detail of the hedging settlements for the twelve months ended July 31, 2013. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

We traced the monthly balances of hedging transactions from FPL's April 5 and

August 16, 2013 filings in this docket for the period August 1, 2012 to July 31, 2013 to FPL's Derivative Settlement Report. We selected various hedging transactions from two counterparties from August 2012, June 2013 and July 2013 for natural gas and for heavy oil as a sample and traced them from the Derivative Settlement Report to the invoices, purchase statements, confirmation notices, deal tickets and contracts. FPL does not have any tolling agreements where natural gas is provided to generators under purchase power agreements. We recalculated the gains and losses. We compared these recalculated gains and losses with FPL's journal entries for realized gains and losses. We compared a sample of the purchase prices to the futures rates published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained FPL's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2013, and compared them with the Utility's Risk Management Plan. The hedged targets for both natural gas and heavy oil were traced to the Planned Position Strategy Schedule. The fuel burn forecast was traced to the Fuel Burn Summary. The volumes of the oil hedged before and after rebalancing were traced to the Oil Hedged Schedule and the Deal tickets, the percentage hedged was randomly recalculated for accuracy. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We reviewed an internal audit related to separation of duties. Also, external audit work papers were reviewed in the Fuel Audit in Docket No. 130001-EI. No exceptions were noted.

Q. Please review the audit findings in this audit report, Exhibit IHP-1.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF SIMON O. OJADA

DOCKET NO. 130001-EI

SEPTEMBER 27, 2013

Q. Please state your name and business address.

A. My name is Simon O. Ojada. My business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

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

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

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

A. I have been employed by the Florida Public Service Commission since April 1997.

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Science degree from the University of South Florida with a major in Finance in 1991, a Bachelor of Science Degree from Florida Metropolitan University with a major in Accounting in 1994, and a Master of Business Administration with a concentration in Accounting in 1997.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. No.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Duke Energy Florida, Inc. (DEF or Utility) which addresses the filing in Docket No. 130001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 23, 2013. This audit report is filed with my testimony and is identified as Exhibit SOO-1

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

A. Yes. The audit was prepared by me.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

I reviewed DEF's supporting detail of the hedging settlements for the twelve months ended July 31, 2013. I traced the monthly balances of hedging transactions from DEF's Hedging Results Report for the period August 1, 2012, to December 30, 2012, and its Hedging Information Report for the period January 1, 2013 to July 31, 2013 to its Hedging Summary by Commodity Reports for 2012 and 2013. I selected 20 natural gas hedging transactions from August 2012 through July 2013 as a sample and traced them from the Hedging Results and Hedging Information Reports to the third-party confirmation notices, contracts and to the general ledger. I verified that the hedging settlements were in compliance with the Risk Management Plan. No exceptions were noted.

<u>Gains and Losses</u>

I recalculated the gains and losses by multiplying the volume by the difference between the fixed price and the settlement price from the trade confirmation documents and compared them to the recorded gains and losses per the general ledger. No exceptions were noted.

Hedged Volume and Limits

I obtained and reviewed DEF's Risk Management Plan. I reviewed the quantity limits and authorizations for all hedged fuel types. No significant variances were noted for natural gas. The amount of oil hedged during this period was minimal. The actual monthly volumes of hedged burns for Numbers 6 and 2 Oils and Barge and Rail Transportation varied, but on an annual basis, all fell between the allowable percentages of actual and projected burn volumes. No exceptions were noted.

Separation of Duties

I reviewed DEF's written procedures for separation of duties related to hedging activities. I reviewed the evaluations performed by DEF's Audit Services Department and the external auditor's report. Both concluded that effective internal controls were in place in separating hedging activities.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DEBRA M. DOBIAC

DOCKET NO. 130001-EI

SEPTEMBER 27, 2013

Q. Please state your name and business address.

A. My name is Debra M. Dobiac. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399.

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

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

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

A. I have been employed by the Commission since January 2008.

Q. Briefly review your educational and professional background.

A. I graduated with honors from Lakeland College in 1993 and have a Bachelor of Arts degree in accounting. Prior to my work at the Commission, I worked for 6 years in internal auditing at the Kohler Company and First American Title Insurance Company. I also have approximately 12 years of experience as an accounting manager and controller.

Q. Please describe your current responsibilities.

A. Currently, I am a Public Utilities Analyst II with the responsibilities of managing regulated utility financial audits. I am also responsible for creating audit work programs to meet a specific audit purpose.

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

A. Yes. I testified in the Aqua Utilities Florida, Inc. Rate Case, Docket No. 080121-WS, the Water Management Services, Inc. Rate Case, Docket No. 100104-WU, the Gulf Power Company Rate Case, Docket No. 110138-EI, and the Water Management Services, Inc. Rate Case, Docket No. 110200-WU.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Gulf Power Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 130001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 27, 2013. This audit report is filed with my testimony and is identified as Exhibit DMD-1.

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

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2013. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

<u>Gains and Losses</u>

We traced the monthly balances of all hedging transactions from Gulf's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2012 to July 31, 2013. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the New York Mercantile Exchange (NYMEX) Henry Hub Gas futures contract rates. We compared these recalculated gains and losses with Gulf's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained Gulf's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2013, and compared them with the Utility's Risk Management Plan. There were immaterial variances for January to July 2013 between the percentages of actual and projected natural gas burned that were hedged. Since the projected burn for August to December 2012 included limited amounts of natural gas burned applicable to the purchased power agreement tolling arrangements, there were significant variances between the percentages of actual and projected natural gas burned that were hedged. These variances were the result of an inaccurate burn forecast.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this audit report, Exhibit DMD-1.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF RONALD A. MAVRIDES

DOCKET NO. 130001-EI

SEPTEMBER 27, 2012

Q. Please state your name and business address.

A. My name is Ronald A. Mavrides. My business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

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

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

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

A. I have been employed by the Florida Public Service Commission since October 2007.

Q. Briefly review your educational and professional background.

A. In 1990, I received a Bachelor of Science Degree from the University of Central Florida with a major in accounting. I am also a Certified Government Auditing Professional and a Certified Management Accountant.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I presented testimony in the Fuel and Purchased Power Cost Recovery Clause Docket Nos. 090001-EI and 110001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Tampa Electric Company (TECO or Utility) which addresses the Utility's filing in Docket No. 130001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 23, 2013. This audit report is filed with my testimony and is identified as Exhibit RAM-1.

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

A. Yes. The audit was prepared by me.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

I reviewed TECO's Hedging Information Reports filed on April 1, 2012, and August, 16, 2013. I examined the report for reasonableness and used it as a basis for our sample tests. I requested a listing of each futures, options, and swap contracts executed by TECO for the 12-month period covered by the Hedging Information Report. I requested the volumes for each fuel TECO actually hedged using a fixed price contract or instrument. TECO only hedges natural gas. I tested a sample of 31 transactions, choosing two months of transactions from the 12-month period for natural gas. I traced the transactions to the general ledger and trade confirmation documents. No exceptions were noted.

Gains and Losses

I recalculated the gains and losses by multiplying the volume by the difference between the fixed price and the settlement price from the trade confirmation documents, and compared them to the recorded gains and losses per the general ledger. No exceptions were noted.

Hedged Volume and Limits

I obtained and reviewed TECO's Risk Management Plan. I compared the percentage limits of purchased power hedged in the Risk Management Plan with the actual volumes of hedged burns. All variances were immaterial and were a result of inaccurate forecasting and unit outages. No further work was done.

Separation of Duties

I reviewed TECO's written procedures for separation of duties related to hedging activities. There were no internal and external auditor's workpapers specifically addressing the separation of duties. No exceptions were noted.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 130001-EI

APRIL 5, 2013

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 2012. This data is required per Item 5 of the Resolution of Issues in Docket 011605-EI approved by the Commission per Order No. PSC-02-1484-FOF-EI, which states:

"5. Each investor-owned utility shall provide, as part of its

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

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

Q. Are you sponsoring an exhibit for this proceeding?

A. Yes. I am sponsoring Exhibit GJY-1 – August through December 2012 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 2012, FPL implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL's 2011 Risk Management Plan that was approved by the Commission in Order No. PSC-11-0094-FOF-EI, issued on February 1, 2011.

Q. Please summarize FPL's 2012 hedging activities.

A. Consistent with its approved 2011 Risk Management Plan, FPL hedged a portion of its fuel portfolio for 2012 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 2012 natural gas prices declined from the forward prices that were in effect when FPL was executing its natural gas hedges for 2012. As would be expected under the approved hedging approach, this decline in natural gas prices resulted in reported natural gas hedging costs for the year, as shown on Exhibit GJY-1. Conversely, heavy oil prices increased from the forward prices that were in effect when FPL was executing its heavy oil hedges for 2012. As shown on Exhibit GJY-1, this resulted in reported heavy oil hedging savings for the year.

Q. Does your Exhibit GJY-1 provide the detail on FPL's 2012 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. 130001-EI

AUGUST 30, 2013

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 and purchased power transactions. I also review the interim results of FPL's 2013 hedging program and its 2014 Risk Management Plan. Additionally, I describe the Incremental Optimization Costs included in FPL's 2014 projection filing that are associated with the Incentive Mechanism that was approved in Order No. PSC-13-0023-S-EI, dated January 14, 2013. Lastly, I present the projected fuel savings resulting from the operation of the Riviera Beach Next Generation Clean Energy Center (RBEC) from June through December 2014.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-2: 2014 Risk Management Plan
- GJY-3: Hedging Activity Supplemental Report for 2013 (January through July)
- GJY-4: Appendix I
- Schedules E2 through E9 of Appendix II

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies has FPL used for the 2014 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time and are consistent with the prices at which FPL can execute transactions for its hedging program. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the future is incorporated into the curves at all times. The methodology allows FPL to execute hedges consistent with its forecasting method and to optimize the dispatch of its units in changing market conditions. FPL utilized forward curve prices from the close of business on August 5, 2013 for its 2014 projection filing, which is the most current information that could be incorporated into FPL's schedule for calculating the 2014 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.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2014 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 2014 compared with projected 2013 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, as well as a reduction in the inventories of the Organisation for Economic Co-operation and Development (OECD) member countries. This is despite a strong surge in non-OPEC supply and North American shale oil production that is expected to grow by 1.1 million barrels per day in 2013. The United States Strategic Petroleum Reserve will also act as a deterrent to prices moving up significantly in the short-term. By mid-

2014, oil inventories should stabilize as OPEC supply improves and North American supply growth continues. The International Energy Agency (IEA) anticipates non-OPEC supply to grow by 1.5 million barrels per day in 2014, of which North American shale oil is expected to contribute 0.9 million barrels per day. While projected growth in non-OECD demand of 1.4 million barrels per day should boost global demand in 2014, the increase in non-OPEC supply will help reduce the call on OPEC supply in 2014 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 2014 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 2014 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 2014 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 2014 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 2014. Although working natural gas rigs are down approximately 76% 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. However, growth has slowed in 2013 and this trend will continue into 2014. Forecast lower 48 production growth of 0.5 - 1.0 BCF/day will be led by increased contributions from byproduct wet gas plays, while non-associated gas declines continue. Stronger residential/commercial demand, especially in the Northeast due to heating oil-to-natural gas switching and new gas pipelines, could partly mitigate lackluster gas demand for power generation and the slow pace of demand expansion from the industrial sector; nonetheless, year-on-year demand growth in 2014 is expected to be lower by approximately 0.6 BCF/Day. Natural gas storage levels, a key benchmark for supply/demand balance, are projected to be approximately 0.2 TCF higher, year-on-year, by the end of March 2014. Thereafter, narrower production gains, coupled with larger import losses, could pull storage back down to current levels.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2014 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. 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 to 925,000 MMBtu/day of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2014 period, 30,000 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. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2014 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 2014?

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 2014.

Q. Please describe the significant planned outages for the January through December 2014 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 2 is scheduled to be out of service from March 3, 2014 until April 6, 2014 or 34 days during the period. Turkey Point Unit 3 is scheduled to be out of service from March 17, 2014 until April 19, 2014 or 33 days during the period. Turkey Point Unit 4 is scheduled to be out of service from September 24, 2014 until October 30, 2014 or 36 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2013 period.

A. FPL projects to put the RBEC into commercial operation on June 1, 2014. This unit will add an additional 1,212 MW of summer capacity and 1,344 MW of winter capacity.

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 2014?

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 11 members, including FPL. FPL can also purchase and sell power during emergency conditions under several types of Emergency Interchange agreements that are in place with other utilities within Florida.

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

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

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

A. FPL has projected 1,655,000 MWh of wholesale (off-system) power sales for the period of January through December 2014. The projected fuel cost related to these sales is $65,345,750. The projected transaction revenue from these sales is $80,554,500. The projected gain for these sales is $11,080,000.

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 2014 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 278,500 MWh at a cost of $13,403,538. If FPL generated this energy, FPL estimates that it would cost $18,526,538. Therefore, these purchases are projected to result in savings of $5,123,000.

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

A. Yes. FPL purchases energy under three Unit Power Sales Agreements (UPS) with the Southern Companies. The agreements are comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 165 MW of coal generation (Scherer Unit 3). The UPS agreements have a term that runs through December 31, 2015. FPL also has 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 2014 period.

A. UPS energy purchases for the period are projected to be 1,875,616 MWh at an energy cost of $73,825,771. 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 1,737,760 MWh for the period at an energy cost of $67,452,000. 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 488,814 MWh at a cost of $3,045,725. 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 2,940,405 MWh at a cost of $126,567,361.

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 629,817 MWh of energy at a cost of $4,342,565. These projections are shown on Schedule E6 of Appendix II.

HEDGING/ RISK MANAGEMENT PLAN

Q. Please describe FPL's hedging objectives.

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

Q. Has FPL filed a comprehensive risk management plan for 2014, consistent with the Hedging Order Clarification Guidelines as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2014 Risk Management Plan as part of its annual

Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up filing on August 2, 2013. The 2014 Risk Management Plan is included as Exhibit GJY-2.

Q. Please provide an overview of FPL's 2014 Risk Management Plan.

A. FPL's 2014 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 2014 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2014 for its projected natural gas requirements in 2015. FPL plans to hedge the percentages of its 2015 projected natural gas requirements over the time periods in 2014 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 2015 heavy fuel oil requirements.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2013, consistent with the Hedging Order Clarification Guidelines, as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2013 (January through July) on August 16, 2013. The Hedging Activity

Supplemental Report is included as Exhibit GJY-3.

Q. Have FPL's 2013 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 2013 projected natural gas and heavy oil requirements, market prices were different than the actual settlement prices that have occurred in 2013.

For example, at the beginning of January 2012, the average monthly NYMEX forward price for natural gas for the first quarter of 2013 was approximately $3.87 per MMBtu. At the end of July 2012, the average monthly NYMEX forward price for the first quarter of 2013 was approximately $3.69 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $3.34 per MMBtu or $0.53 per MMBtu lower than the forward prices seen in January and $0.35 per MMBtu lower than the forward prices seen in July. Conversely, at the beginning of January 2012, the average monthly NYMEX forward price for natural gas for the second quarter of 2013 was approximately $3.83 per MMBtu. At the end of July 2012, the average monthly NYMEX forward price for the second quarter of 2013 was approximately $3.67 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $4.09 per MMBtu or $0.26 per MMBtu higher than the forward prices seen in January and $0.42 per MMBtu higher than the forward prices seen in July. Ultimately, FPL's natural gas hedges resulted in savings of $25,819,945 for the January through July 2013 period.

Forward heavy oil prices for 2013 were erratic during 2012, increasing significantly from the January to April time period, retreating below first of the year prices thereafter, peaking again into the beginning of September and retreating back to first of the year prices by year-end. Ultimately, FPL's heavy oil hedges resulted in costs of $547,584 for the January through July 2013 period.

As acknowledged in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for heavy oil results in lost opportunities for savings in the fuel costs paid by customers; however, this lost opportunity is a reasonable trade-off for reducing customers' exposure to fuel price increases when market conditions change in the other direction. Conversely, hedging in the type of market conditions described above for natural gas results in savings for customers. As previously stated, however, FPL's hedging objective is to reduce fuel price volatility and deliver greater price certainty.

INCREMENTAL OPTIMIZATION COSTS ASSOCIATED WITH THE INCENTIVE MECHANISM

Q. Is FPL seeking to recover through the FCR Clause projected incremental operating and maintenance expenses (Incremental Optimization Costs) during the January through December 2014 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 2014.

Q. What types of Incremental Optimization Costs can FPL 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 $389,472 in 2014 for the salaries and employee-related expenses of 2.5 employees that were added in 2013 to support the Incentive Mechanism (the other half of the expenses for one of these employees relates to other activities and is not included in FPL's request for FCR Clause recovery). FPL is not projecting any software or hardware expenses related to asset optimization in 2014.

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 $1,722,910 in 2014. FPL projects to sell 1,655,000 MWh of economy power (Schedule E6) in 2014 which is 1,141,000 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 1,141,000 MWh above the threshold yields total variable power plant O&M of $1,722,910 in 2014.

Q. Has FPL included in its 2013 actual-estimated FCR true-up and its 2014 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism?

A. FPL has included savings on wholesale power purchases and gains on wholesale power sales for both 2013 and 2014. FPL has not attempted at this time, however, to project 2013 or 2014 Incentive Mechanism savings for other types of optimization measures. FPL does not yet have sufficient experience with the other types of optimization measures to provide meaningful projections of what it will be able to achieve. FPL will reflect the impact of all forms of Incentive Mechanism savings in subsequent true-up filings for 2013 and 2014.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF RBEC

Q. Will the operation of RBEC during 2014 result in fuel savings for FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the June through December, 2014 period, the operation of RBEC is projected to save FPL's customers $82,000,000.

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

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the operation of RBEC. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the RBEC fuel savings. In order to calculate the RBEC fuel savings, FPL ran two separate production cost simulations, one without RBEC and one with RBEC. A comparison of the total system fuel costs from POWERSYM for the two simulations showed that the fuel costs were $82,000,000 lower in the case that included RBEC than in the case without RBEC.

Q. Does this conclude your testimony?

A. Yes it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 130001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2012

DIRECT TESTIMONY OF
JOSEPH MCCALLISTER

REDACTED

April 5, 2013

Q. Please state your name and business address.

A. My name is Joseph McCallister. 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 Progress Energy Carolinas, an affiliate company of Progress Energy Florida, Inc. ("PEF", "Petitioner" or "Company") as Director, Gas Oil and Power. I am responsible for the natural gas, fuel oil and emission group 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 and fuel oil acquisition and transportation needed to support the generation needs for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Progress Energy Carolinas and Progress Energy Florida. In addition, this group is responsible for the emission allowance ("EA") position management for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Progress Energy Carolina and Progress Energy Florida.

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

A. Yes.

Q. Please briefly describe your work experience.

A. I received a Bachelor Degree in Business Administration majoring in Accounting from The Ohio State University. While at Progress Energy, from 2003 until mid 2006, I served as the Director of Portfolio and Market Risk Assessment through mid 2006, the Director of Gas and Oil Trading from mid 2006 through early 2009, and the Director of Gas, Oil and Power Trading from early 2009 to the present. Prior to my tenure with Progress Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies. Summary experiences over this time period include gas and power scheduling, real time power trading and scheduling management, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets and wholesale contract agreements, and corporate planning.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August-December 2012 hedging true-up data and summarize the results of PEF's hedging activity for calendar year 2012 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 2012.

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

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

Q. What hedging activities did PEF undertake for 2012 and what were the results?

A. PEF utilized approved physical and financial agreements to hedge a portion of its projected natural gas, heavy oil and light oil fuel burns, and a portion of the estimated fuel surcharge exposure embedded in PEF's coal river barge and railroad transportation agreements. These activities resulted in a net hedge cost for 2012 of $345.8 million.

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

A. Yes. The hedging activities executed by PEF were consistent with those outlined in its 2012 Risk Management Plan ("Plan"). In the Plan filed in August 2011, PEF's hedging target ranges were to hedge [redacted] to [redacted] of its forecasted natural gas burns for calendar year 2012 with a target to hedge approximately [redacted] of the forecasted natural gas burns over time. With respect to heavy oil and light oil forecasted to be burned at PEF's owned generation facilities for calendar year 2012, PEF targeted to hedge a minimum of [redacted] and [redacted], respectively. With respect to the coal river and rail transportation estimated fuel surcharge exposures for calendar year 2011, PEF 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. In December 2011, based on PEF's forecasted burns and estimated coal rail and river barge transportation agreements, PEF's hedge percentages were approximately [redacted], [redacted], [redacted], [redacted] and [redacted] respectively for forecasted natural gas, heavy oil, and light oil burns, and estimated fuel surcharge exposures in the coal river and rail transportation agreements. As such, PEF was within its targeted hedge ranges for calendar year 2012 going into the year.

For calendar year 2012, PEF's actual hedge percentages based on actual burns for natural gas, heavy oil and light oil, were approximately [redacted], [redacted] and [redacted], respectively. PEF hedge percentages for the estimated fuel surcharges embedded in PEF's coal river and rail transportation in 2012 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. As outlined previously, based on forecasted heavy oil burns and hedges in place as of December 2011, PEF was approximately [redacted] hedged for calendar year 2012. Given the actual to forecasted 2012 burn variances, the resulting actual hedge percentage for heavy oil was lower than the targeted minimum of [redacted] based on forecasted calendar basis.

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

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

Q. Does this conclude your testimony?

A. Yes.

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 2013

FPSC DOCKET NO. 130001-EI

DIRECT TESTIMONY OF JOSEPH McCALLISTER

August 30, 2013

REDACTED

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Joseph McCallister. 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 Progress. I am the Director of Gas, Oil and Power in the Fuels and Power Optimization Department. This section is responsible for natural gas, fuel oil and emission allowance activity for the Duke Energy Indiana ("DEI"), Duke Energy Kentucky ("DEK"), Duke Energy Carolina ("DEC"), Duke Energy Progress ("DEP"), and Duke Energy Florida ("DEF") systems.

Q. Please describe your education background and professional experience.

A. I received a Bachelor Degree in Business Administration majoring in Accounting from The Ohio State University. Prior to the merger between Progress Energy and

Duke Energy, at Progress Energy I served as the Director of Portfolio and Market Risk Assessment from 2003 until mid 2006, , the Director of Gas and Oil Trading from mid 2006 through early 2009, and the Director of Gas, Oil and Power Trading from early 2009 through July 2012. Prior to my tenure with Progress Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies. Summary experiences over this time period include gas and power scheduling, real time power trading and scheduling management, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets and wholesale contract agreements, and corporate planning.

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

A: Yes. As the Director of Gas, Oil and Power, I am responsible, along with the other members of the section, for the management of the gas and oil procurement, transportation, hedging activities, and administration of gas and oil contracts with various suppliers for DEI's, DEK's, DEC's, DEP's, and DEF's electrical power generation facilities.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to outline DEF's hedging objectives and activities for 2014 and outline DEF's hedging results for January 2013 through July 2013.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits:

- Exhibit No. ___ (JM-1P) – 2014 Risk Management Plan (*originally filed August 2, 2013, redacted version attached*); and
- Exhibit No. ___ (JM-2P) – Hedging Results for January 2013 through July 2013 (*originally filed August 16, 2013, redacted version attached*).

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

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

Q. Describe DEF's hedging activities that the Company will execute for 2014.

A. DEF will hedge a percentage of its projected natural gas and light oil fuel oil burns, and a portion of the estimated fuel surcharge exposure embedded in DEF's coal river barge and railroad transportation agreements. DEF will utilize approved physical and financial agreements. With respect to hedging activity, natural gas represents the largest component of DEF's overall hedging activity given it is the largest fuel cost component. DEF's target hedging percentage ranges are between [redacted] to [redacted] percent of its current 2014 forecasted calendar annual burns. DEF anticipates to target to hedge a minimum of [redacted] percent of its forecasted natural gas burn projections for 2014. With respect to light oil forecasted to be burned at DEF's owned generation facilities for calendar year 2014, during the balance of

2013 and 2014, DEF will target to hedge a minimum of [redacted] percent of its forecasted light oil burns for the 2014 calendar period. With respect to coal river and rail transportation estimated fuel surcharges, for calendar year 2014 DEF will target to hedge between [redacted] and [redacted] percent of the estimated fuel surcharge exposure in the coal rail and river barge transportation agreements, during the balance of 2013 and 2014. Hedging in the ranges and targets provided allows DEF to monitor actual fuel burns, updated fuel forecasts, and make any adjustments as needed throughout the year.

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

As of August 21, 2013, for 2014 DEF has hedged approximately [redacted] percent of its forecasted natural gas burns. In addition, as of August 21, 2013, for 2014 DEF has hedged approximately [redacted] percent and [redacted] percent of its estimated fuel surcharge exposure based on the contractual provisions in the coal rail and river barge transportation agreements, respectively. DEF will continue to execute additional hedges for 2014 throughout the remainder of 2013 and during 2014 consistent with its on-going strategy.

Q. What were the results of DEF's hedging activities for January through July 2013?

A. The Company's natural gas hedging activities for January through July 2013 have resulted in hedges being above the closing natural gas settlement prices for the periods of January 2013 through July 2013 by approximately $81.3 million. The Company's overall fuel oil hedging activities have resulted in hedges being above the closing settlement prices for the periods of January 2013 through July 2013 by approximately $0.3 million. These overall hedge results were driven primarily by declines in natural gas prices after the execution of DEF's 2013 hedging transactions. The hedging activities were executed consistent with its Risk Management Plan. Although DEF's hedging activity did not result in net fuel cost savings, the activities did achieve the objective to reduce the impacts of fuel price risk and volatility, and greater fuel price certainty for DEF's customers.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 130001-EI

GPIF Schedules for
January through December 2012

DIRECT TESTIMONY OF MATTHEW J. JONES

March 15, 2013

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 Manager of Portfolio Management.

A. As Director of Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Progress Energy Florida, Inc. ("Progress Energy" or "Company"), as well as Progress Energy Carolinas, 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 PEF's GPIF reward/penalty amount for the period of January through December 2012. This calculation was based on a comparison of the actual performance of PEF'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. PEF's calculated GPIF incentive amount is a reward of $3,262,447. 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 PEF's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 23 of my exhibit summarizes the planned outages experienced by PEF'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 2013**

FPSC DOCKET NO. 130001-EI

GPIF TARGETS AND RANGES FOR
JAUARY THROUGH DECEMBER 2014

**DIRECT TESTIMONY OF
MATTHEW J. JONES**

AUGUST 31, 2013

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 2012 and also present the development of the Company's GPIF targets and ranges for the period January through December 2014. 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 2012?

A. DEF's calculated GPIF incentive amount for this period was a reward of $3,262,447. Please refer to my testimony filed March 15, 2013 for the details of how this incentive amount was calculated.

Q. Do you have an exhibit to your testimony?

A. Yes. I have 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 2014 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 82% 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 rates can then be converted into an overall equivalent unplanned outage factor (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 41-77 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. Were adjustments made to historical heat rates to account for estimated net output changes associated with scrubber and SCR installations?

A. No. All scrubbers and SCRs were in service prior to the historical data period.

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 2013?

A. The estimated maximum incentive for the Company is $20,529,186. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MJJ-1P).

Q. **Should the Commission consider termination of the existing GPIF mechanism at this time?**

A. No. DEF believes that the GPIF mechanism is useful. While DEF does not directly base generation performance decisions on GPIF considerations/results, the GPIF does allow the Commission to view monthly detail on specific generation unit performance and further allows the Commission to conduct an annual analysis of generation performance trends over time.

Q. Should the Commission make any modifications to the GPIF?

A. DEF believes the current GPIF process and structure have and continue to encourage utilities to efficiently operate their base load plants. However, as indicated in a previous interrogatory response, DEF could support revising the method by which the maximum GPIF reward is calculated, whereby the new process sets the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings; the reward and penalty amounts would then be calculated as a linear interpolation from maximum allowed incentive dollars, thereby preserving the symmetrical relationship between rewards and penalties. DEF believes this revision directly ties the utility reward (penalty) to the resulting fuel savings or loss experienced by the ratepayer.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2012 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 2012 through December 2012.

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.

COM 5
AFD 6
APA
ECO 1
ENG 1
GCL 1
IDM
TEL
CLK 1-Ct Rep

Q. What has FPUC calculated as the final remaining true-up amounts for the period January 2012 through December 2012?

A. For Northwest Florida the final remaining true-up amount is an under recovery of $1,121,875. For Northeast Florida the calculation is an over recovery of $1,786,701.

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 2012 period and the total true-up amounts to be collected or refunded during the January - December 2013 period.

Q. What was the actual end of period true-up amount for January - December 2012?

A. For Northwest Florida it was $2,599,479 under recovery and for Northeast Florida it was $2,045,337 over recovery.

Q. What have you calculated to be the total true-up amount to be collected or refunded during the January – December 2013 period?

A. Using six months actual and six months estimated amounts, we calculated an under recovery for Northwest Florida of $1,477,604 and an over recovery of $258,636 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, have not been recovered through base rates, and the fuel related costs are specific to a division rather than related to the consolidated entity. 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 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, 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 No. 120001-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 2012 true up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. "Gunster", Christensen and Associates "Christensen" and Sterling Energy Services "Sterling" for assistance in the development and enactment of projects/programs designed to reduce their fuel rates to its customers. We had separate types of administrative costs included in our true up for the Northwest division and Northeast division.

Northwest division:

The costs associated with the legal and consulting work on the PPA amendment are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPUC purchases all of its power requirements for its Northwest Division from Gulf Power through the existing PPA. FPUC was able to negotiate changes in the PPA that, before its subsequent appeal, would have resulted in measurable fuel savings (approximately $6 million), over the remaining term of the agreement, to the Northwest Division customers. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

The costs associated with the legal and consulting work for the development of a restructured allocation schedule of the Company's Demand costs. FPUC has proposed that its current methodology for allocating its demand costs, adapted from the results of Gulf Power Company's Load Factor Research, is not the most appropriate approach given the differences in the demographics and consumption habits between our customers and theirs. Since FPUC does not currently have the resources to conduct its own load factor research, Christensen was requested to research and develop a allocation basis that best served our customer base. FPUC proposes that these costs are directly related to fuel, not recovered in base rates and were incurred to more accurately allocate fuel cost between the customer classes.

Northeast Division:

The legal and consulting costs associated with the development and negotiations of the renewable energy contract are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. The Rayonier renewable energy contract 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. 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 and Sterling have also been performing due diligence in their occasional review and analysis of the terms of the current Purchased Power Agreements between FPUC and its power suppliers (JEA and Rock-Tenn) in the efforts of further discovering avenues towards negotiating cost reductions.

The costs associated with the legal and consulting work for the development of a restructured allocation schedule of the Company's Demand costs. FPUC has proposed that its current methodology for allocating its demand costs, adapted from the results of FP&L's Load Factor Research, is not the most appropriate approach given the differences in the demographics and consumption habits between our customers and theirs. Since FPUC does not currently have the resources to conduct its own load factor research, Christensen was requested to research and develop a allocation basis that best served our customer base. FPUC proposes that these costs are directly related to fuel, not recovered in base rates and were incurred to more accurately allocate fuel cost between the customer classes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI
Fuel and Purchased Power Cost Recovery Clause
Revised Direct Testimony of
Curtis Young
(2012 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 2012 through December 2012.

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

A. Yes. Exhibit________ (Revised 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 2012 through December 2012?

A. For Northwest Florida the final remaining true-up amount is an under recovery of $1,118,689. For Northeast Florida the calculation is an over recovery of $1,786,671.

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 2012 period and the total true-up amounts to be collected or refunded during the January - December 2013 period.

Q. What was the actual end of period true-up amount for January - December 2012?

A. For Northwest Florida it was $2,596,293 under recovery and for Northeast Florida it was $2,045,337 over recovery.

Q. What have you calculated to be the total true-up amount to be collected or refunded during the January – December 2013 period?

A. Using six months actual and six months estimated amounts, we calculated an under recovery for Northwest Florida of $1,477,604 and an over recovery of $258,666 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, have not been recovered through base rates, and the fuel related costs are specific to a division rather than related to the consolidated entity. 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 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, 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 No. 120001-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.

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Q. What were the costs outside of purchased fuel costs, included in the 2012 true up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. "Gunster", Christensen and Associates "Christensen" and Sterling Energy Services "Sterling" for assistance in the development and enactment of projects/programs designed to reduce their fuel rates to its customers. We had separate types of administrative costs included in our true up for the Northwest division and Northeast division.

Northwest division:

The costs associated with the legal and consulting work on the PPA amendment are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPUC purchases all of its power requirements for its Northwest Division from Gulf Power through the existing PPA. FPUC was able to negotiate changes in the PPA that, before its subsequent appeal, would have resulted in measurable fuel savings (approximately $6 million), over the remaining term of the agreement, to the Northwest Division customers. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

The costs associated with the legal and consulting work for the development of a restructured allocation schedule of the Company's Demand costs. FPUC has proposed that its current methodology for allocating its demand costs, adapted from the results of Gulf Power Company's Load Factor Research, is not the most appropriate approach given the differences in the demographics and consumption habits between our customers and theirs. Since FPUC does not currently have the resources to conduct its own load factor research, Christensen was requested to research and develop a allocation basis that best served our customer base. FPUC proposes that these costs are directly related to fuel, not recovered in base rates and were incurred to more accurately allocate fuel cost between the customer classes.

Northeast Division:

The legal and consulting costs associated with the development and negotiations of the renewable energy contract are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. The Rayonier renewable energy contract 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. 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 and Sterling have also been performing due diligence in their occasional review and analysis of the terms of the current Purchased Power Agreements between FPUC and its power suppliers (JEA and Rock-Tenn) in the efforts of further discovering avenues towards negotiating cost reductions.

The costs associated with the legal and consulting work for the development of a restructured allocation schedule of the Company's Demand costs. FPUC has proposed that its current methodology for allocating its demand costs, adapted from the results of FP&L's Load Factor Research, is not the most appropriate approach given the differences in the demographics and consumption habits between our customers and theirs. Since FPUC does not currently have the resources to conduct its own load factor research, Christensen was requested to research and develop a allocation basis that best served our customer base. FPUC proposes that these costs are directly related to fuel, not recovered in base rates and were incurred to more accurately allocate fuel cost between the customer classes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

DOCKET NO. 130001-EI

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

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

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 2014 – December 2014.

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 2013 – December 2013 based on 6 Months Actual and 6 Months Estimated data.

Q. What was the final remaining true-up amount for the period January 2012 – December 2012 for the Northwest division?

A. In the Northwest Division, the final remaining true-up amount was an under-recovery of $1,118,689. The final remaining true-up amount for the Northeast Division was an over-recovery of $1,785,473.

Q. What is the estimated true-up amount for the period January 2013 – December 2013?

A. In the Northwest Division, there is an estimated over-recovery of $363,316. The Northeast Division has an estimated over-recovery of $1,229,516.

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

A. The Company has determined that at the end of December 2013, based on six months actual and six months estimated, the Company will under-recover $755,373 in purchased power costs in the Northwest Division to be collected and will over-recover $3,014,989 in the Northeast Division to be refunded during January 2014 – December 2014.

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

A. **Yes.**

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2014 Projection Testimony of
Curtis D. Young
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. What is the purpose of your testimony at this time?

A. I 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 2014 - December 2014 fuel cost recovery adjustments for its two electric divisions. In addition, I 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 2013 – December 2013 and to establish a "true-up" amount to be collected or refunded during January 2014 - December 2014.

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 Schedules E1, E1A, E2, E7, and E10 for the Northwest Division and E1, E1A, E2, E7, E8, and E10 for the Northeast Division. Composite Exhibit Number CDY-3 contains this information. The Company has also introduced Schedules Proforma E-1b, A, B and C reflective of the Stipulation Agreement between FPUC and the Office of Public Counsel (OPC) in this filing. Composite Exhibit Number CMM-1 contains this information with the exception of Schedule C which is contained in Composite Exhibit Number PMC-1.

Q. Did you follow the same procedures that were used in the prior period filings in preparing the projected cost factors for January – December 2014 for both the Northwest and Northeast Divisions?

A. Yes, the Company has generally used the same methodology as in prior period filings; however, in this filing the Company has made some changes in the process. The Company is changing the methodology to estimate a portion of the transmission costs incurred by its Northwest Florida Division that should be distributed to its Northeast Florida Division customers to improve the fairness of the cost allocation.

Q. Why is it appropriate to change the allocation of the transmission costs to the Northeast Florida customers?

A. The transmission charge (associated with transmission facilities in Northwest Florida) within the fuel charge should be allocated more fairly to both divisions in order to offset the disparity that currently exists related to transmission cost recovery in the two divisions. This change will allow all customers to contribute to the Northwest Florida transmission charge within the fuel clause just as all customers contribute to the Northeast Florida transmission related plant included in the consolidated base rates. 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 is included in rate base. In the Northwest division, Gulf Power / Southern Company own the transmission facilities. To allow for fair recovery of these costs, the fuel portion should be allocated between the two electric divisions, similar to the rate base portion included for recovery in consolidated base rates. This allows for equitable cost distribution and recovery between all of our customers. Further details of this process and methodology are addressed in the testimony of Mr. Mark Cutshaw.

Q. What other changes have you made in the methodology of preparing your projected cost factors?

A. The Company has adjusted the rate differential in its residential step rates for both its Northwest Florida and Northeast Florida divisions from one cent to 1.25 cents.

Q. For what purpose was this adjustment made?

A. The Company sees this as a step to help soften the impact of the anticipated fuel costs on its residential customers who are least able to withstand any added costs. This adjustment to the step differential would allow those residential customers whose consumption for any given month is 1,000 KWH or less to be billed at a further reduced rate. Additionally, we believe that this approach will help induce energy conservation.

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 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, have not been recovered through base rates, and the fuel related costs are specific to a division rather than related to the consolidated entity.

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 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, 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 No. 120001-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 2013 true-up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. "Gunster", Christensen and Associates "Christensen" and Sterling Energy Services "Sterling" 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. The Rayonier renewable energy contract was finalized in early 2012. This contract has provided 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. Christensen and Sterling 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 FPUC 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 True-up as well as our 2014 Projections. The associated legal and consulting costs, included in the rate calculation of the Company's 2014 Projection factors, were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates. Moreover, the aforementioned charges for legal and consulting services in the 2013 true-up were incurred by the Northeast Florida division only and any rate savings derived would solely benefit the Northeast Florida customers. Therefore the Company maintains that the separate type of administrative costs included in its true-up associated with these rate saving endeavors for the customers in its Northeast Florida division are appropriately recoverable through the fuel clause.

Summary Rates

Q. What are the final remaining true-up amounts for the period January – December 2012 for both Divisions?

A. In the Northwest Division, the final remaining true-up amount was an under-recovery of $1,118,689. The final remaining amount for the Northeast Division was an over-recovery of $1,785,473.

Q. What are the estimated true-up amounts for the period of January – December 2013?

A. In the Northwest Division, there is an estimated over-recovery of $363,316. The Northeast Division has an estimated over-recovery of $900,204.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2014 year?

A. The Company has determined that at the end of December 2013 based on six months actual and six months estimated. We will have under-recovered $755,373 in purchased power costs in our Northwest Division. Based on estimated sales for the period January - December 2014, it will be necessary to add .22876¢ per KWH to collect this under-recovery. In our Northeast division we will have over-recovered $2,685,677 in purchased power costs. This amount will be refunded at (.91612¢) per KWH during the January - December 2014 period (excludes GSLD1 and Standby customers). Page 3 and 10 of Revised Composite Exhibit Number CDY-3 provides detailed calculations of the respective true-up amounts.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period?

A. In the Northwest Division the total fuel adjustment factor as shown on Line 33, Schedule E-1 is 6.069¢ per KWH. In the Northeast Division the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E-1, is 4.844¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2014 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 Schedule E-10 in Composite Exhibit Number CDY-3, a residential customer in the Northwest Division using 1,000 KWH will pay $133.31, a decrease of $2.03 from the previous period. In the Northeast Division a residential customer using 1,000 KWH will pay $125.47, a decrease of $8.88 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

REVISED Direct Testimony 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 2014 - December 2014.

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 revised E1-A, E1-B, and E1-B1 for the Northeast Division. They are included in Composite Prehearing Identification Number Revised CDY-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and

Interest Provision for the period January 2013 - December 2013 based on 6 Months Actual and 6 Months Estimated data.

Q. What was the final remaining true-up amount for the period January 2012 - December 2012 for the Northwest division?

A. In the Northwest Division, the final remaining true-up amount was an under-recovery of $1,118,689. The final remaining true-up amount for the Northeast Division was an over-recovery of $1,785,473.

Q. What is the estimated true-up amount for the period January 2013 - December 2013?

A. In the Northwest Division, there is an estimated over-recovery of $363,316. The Northeast Division has an estimated over-recovery of $900,204.

Q. What is the total true-up amount to be collected or refunded during January 2014 - December 2014?

A. The Company has determined that at the end of December 2013, based on six months actual and six months estimated, the Company will under-recover $755,373 in purchased power costs in the Northwest Division to be collected and will over-recover $2,685,677 in the Northeast Division to be refunded during January 2014 - December 2014.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI
FUEL AND PURCHASED POWER RECOVERY CLAUSE

Testimony of
P. Mark Cutshaw
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw and my business address is 911 South 8th Street, Fernandina Beach, Florida 32034.

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

A. I am employed by Florida Public Utilities Company and serve as the Director, System Planning and Engineering.

Q. What is the purpose of your testimony?

A. My testimony focuses on allocations of transmission costs for FPU customers in both the Northwest and Northeast Florida Divisions. The transmission costs involve both base rates and the fuel adjustment factors contained within the rate. My testimony will provide the background information surrounding this issue and a solution that will provide improved rate equity for all FPU customers.

Q. Can you please provide a brief overview of your professional background?

A. I have been employed by Florida Public Utilities Company for twenty two years and have served in the role of General Manager and Director in both the Northwest and Northeast Florida Divisions. During this time I have been involved in the management, operations and regulatory activities of the electric divisions and have had the opportunity to be involved in a number of Dockets filed before the FPSC during which I provided testimony on several different topics.

Q. Have you previously testified in this Docket?

A. No, though I have filed testimony in fuel and non-fuel related dockets of the Florida Public Service Commission (Florida PSC) in previous years.

Q. Have you previously been involved in FPU rate development with respect to cost allocation issues?

A. Yes, I have been involved in the cost allocation issues in the two previous rate proceedings filed by FPU and have also been involved in cost allocation related to the fuel adjustment clause in this docket.

Q. What other dockets in which you have been involved has bearing on this docket?

A. Docket #030438-EI, Florida Public Utilities Company (FPU) MFR before the Florida Public Service Commission (FPSC) included the consolidation of base rates between the Northeast and Northwest divisions. Prior to this filing, rates between the two divisions were separately determined based upon the rate base, expenses and purchased power contacts for that specific division. All rate proceedings were filed separately and were approved by the FPSC.

Docket #031135-EI, Petition for approval to implement consolidated fuel adjustment surcharge by FPU was not approved by the FPSC. The intent for this docket was to allow for a consolidated fuel adjustment surcharge that would co-exist with the consolidated base rates in order to provide cost allocation equity for all FPU electric customers. This decision required that the fuel adjustment surcharge in both divisions be based solely on the purchase power contracts for that respective division.

Docket #070304-EI, Florida Public Utilities Company (FPU) MFR before the Florida Public Service Commission (FPSC) continued the consolidation of base rates between the two divisions while the fuel adjustment surcharge remained separated by division.

Q. Can you briefly describe the operational aspects of the two electric divisions within FPU?

A. Yes. The Company provides retail electricity services in two non-contiguous service regions including the Northeast and Northwest Divisions, both located in northern Florida. Separated by over 225 miles, the distribution facilities of the two divisions are planned and managed separately.

The Northwest Florida Division receives generation and transmission service from Southern Company at five Gulf Power Company owned substation locations within the division. FPU owns and operates a substation interconnection within each of the substations and then provides distribution service to retail electric customers.

The Northeast Florida Division receives generation and transmission service from JEA at a JEA owned substation in Nassau County but outside the retail service territory for the division. FPU owns and operates transmission lines to four FPU owned and operated substations and then provides distribution service to retail electric customers. The Northeast Florida Division also provides transmission service to two industrial customers.

Q. Can you briefly describe value of the transmission assets in the Northeast and Northwest Florida Divisions?

A. The Northeast Florida Division currently has approximately $4.5 million of transmission plant assets included in the base rates for FPU electric customers. Based upon the 2007 rate proceeding, the transmission assets in Northeast Florida represent approximately 10% of total plant assets. (Docket #070304-EI, MFR Schedule E-3a, page 1 of 2) The Northwest Florida Division has no transmission plant assets. Both divisions have similar investment levels for the remaining plant assets included in the base rates which include substation, distribution, general plant, etc. investments.

Q. What impact does the difference in transmission plant assets have on the rates in the Northeast and Northwest Florida Divisions?

A. This investment in transmission plant assets in the Northeast Florida Division is incorporated into the determination of base rates for all FPU customers. At present, base rates allow revenue recovery in the amount of approximately $1.6 million (See Schedule C) per year based on transmission plant assets which are collected from customers in both divisions. From this it appears that base rates in the Northwest Florida Division include recovery for transmission assets from which they receive no benefit.

Q. What recommendation do you have to address this allocation issue?

A. In order to provide for inter-divisional equity in base rates without a major rate proceeding, it appears that modifications in the fuel adjustment surcharge cost allocations between the divisions would be an acceptable solution to address this situation. Allocation of a portion of the transmission component of the Northwest Florida fuel adjustment surcharge to the Northeast Florida fuel adjustment surcharge would remove much of the inequity that currently exist.

As indicated in Schedule C, approximately $1.6 million is collected through base rates to provide the necessary revenue recovery for the transmission plant assets. Approximately $800,000 is currently recovered from customers in Northwest Florida who do not benefit from the transmission plant assets. To offset this recovery through base rates, we propose to reallocate an equal portion of transmission cost which is included in the Southern Company purchased power agreement from the Northwest Florida fuel adjustment to the Northeast Florida fuel adjustment. This allocation would assign the transmission plant asset cost to the appropriate FPU division and customers receiving the benefit would have this incorporated into the overall rate.

Q. Are there currently other cost allocations within the fuel adjustment clause

that are similar in design to your recommendation?

A. Yes. As part of the Southern Company generation and transmission agreement for the Northwest Florida Division, there exists a distribution facilities charge that is billed each month. This distribution facilities charge covers distribution facilities that are provided by Gulf Power Company. Based on the fact that FPU owned and operated distribution facilities are included within the base rates for both divisions, this distribution facilities charge has been equally allocated between both divisions and recovered within the fuel adjustment surcharge appropriate for the division.

Q. Does Florida Public Utilities Company propose to make base rate changes in the current docket?

A. No, the Company's base rates will remain unchanged at this time.

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. 130001-EI
Date of Filing: March 1, 2013

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, 2012 through December 31, 2012. 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 2012 through December 2012, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Throughout my testimony I present comparisons using information presented on various December 2012 period-to-date A-Schedules included in Appendix 1 submitted with Witness Dodd's testimony. As will be discussed by Witness Dodd, the projected amounts presented in these A-Schedules reflect the two Mid-Course filings Gulf submitted in 2012. Gulf's recoverable total fuel cost and net power transaction expense was $442,338,064, which is $74,664.241 or 14.44% below the projected amount of $517,002,305. Actual net power transaction energy was 11,584,360,706 KWH compared to the projected net energy of 12,571,657,000 KWH or 7.85% below projections. The resulting actual average cost of 3.8184 cents per KWH was 7.15% below the projected cost of 4.1124 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2012 included in Appendix 1 of Witness Dodd's exhibit. The lower total fuel and net power transaction expense is attributed to a higher quantity of energy sales (KWH) revenue combined with a lower per unit cost (cents per KWH) for available energy than projected for the period. The total quantity of energy 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 below projections by $6,497,452 or 1.15% and the total quantity of available energy was above projections by 4,469,358,073 KWH or 31.81%. The actual cost per KWH of available energy was 3.0035 cents per KWH which is 25.01% lower than the projected cost of

4.0051 cents per KWH. The lower cost per KWH for available energy is due primarily to a lower than projected cost per KWH for purchased power. These purchases were primarily from gas fired generating units that Gulf has under Purchase Power Agreements (PPA's). The lower market price for natural gas during the period yielded lower that projected energy purchase prices under Gulf's PPA's.

Q. During the period January 2012 through December 2012, 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 $334,006,797 or 23.32% below the projected amount of $435,601,965. Actual generation was 8,390,935,000 KWH compared to the projected generation of 10,221,352,000 KWH, or 17.91% below projections. The resulting actual average fuel cost of 3.9806 cents per KWH was 6.60% below the projected fuel cost of 4.2617 cents per KWH. The lower total fuel expense is attributed primarily to a lower quantity of fuel burned than projected for the period. The actual quantity of fuel consumed was 77,238,446 MMBTU which is 24.54% below the projected quantity of 102,359,831 MMBTU. The generation mix was more heavily weighted to natural gas fired generation than projected due to efforts to utilize available natural gas fired generation which was lower in cost. The percentage of energy generated from natural gas fired resources was 50.42%, which was 32.68% higher than the projected percentage of 38.00%. The weighted average fuel cost for natural gas was $2.72 cents per KWH, which is 10.82% below the projected cost of $3.05 cents per KWH. The weighted average fuel cost for coal, plus lighter fuel, was $5.27 cents per KWH, which is 5.19% higher than the projected cost of $5.01 cents per KWH. This information is found on Schedule A-3, period-to-date, for the month of December 2012 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 $216,831,932 (line 17 of Schedule A-5, period-to-date, for December 2012) compared to the projected cost of $308,083,147 or 29.62% below the projected amount. The lower total coal cost was due to the quantity (tons) of coal purchased for the period being 26.99% lower than projected. The actual weighted average price of coal purchased was $107.41 per ton which is 3.61% below the projected price of $111.43 per ton. Gulf deferred some planned contract coal shipments to future periods and purchased no spot coal during the current period.

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

A. The total cost of coal burned was $212,177,155 (line 21 of Schedule A-5, period-to-date, for December 2012). This is 32.77% lower than the projection of $315,609,569. The lower total coal cost was due to the quantity of coal burned being 33.55% below projections. The weighted average coal burn cost was 1.17% above projections for the period.

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

A. The total actual cost of natural gas burned for generation was $115,261,613 (line 34 of Schedule A-5, period-to-date, for December 2012). This is 2.18% below the projection of $117,834,358. The quantity of gas burned was 13.69% higher than projected due to natural gas fired units being more economic to operate than coal fired generation on a cents per KWH basis. The actual weighted average gas burn cost was $3.68 per MMBTU, which is 14.02% lower than the projected burn cost of $4.28 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 2012 complied with the Risk Management Plan filed on August 1, 2011.

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 2,018,661 tons. Gulf purchased none of this coal on the spot market. Spot purchases are classified as coal purchase agreements with terms of one year of less. Spot coal purchases are typically needed to allow a portion of the purchase quantity commitments to be adjusted in response to changes in coal burn that may occur during the year. There were no spot coal purchases for the period due to coal burn (tons) being 33.55% lower than projected during 2012 and a carryover of contract coal tons from the previous year. Natural gas prices were lower than projected and the low cost of gas fired generation allowed Gulf to shift generation from coal fired units to natural gas fired units. Gas fired generation was 8.91% above projections and coal fired generation was 34.48% below projections for the period. Gulf purchased all of its 2012 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 (3.61% as reported on line 16 of Schedule A-5, period to date, for the month of December 2012).

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 2012, Gulf's weighted average cost of natural gas purchases for generation was $3.69 per MMBTU. This was 13.79% lower than the projection of $4.28 per MMBTU (line 29 of Schedule A-5, period-to-date, for December 2012). Gulf was able to hold per unit fuel costs to very reasonable levels for its customers by following its Fuel Risk Management Plan. The volatility of Gulf's natural gas cost has been reduced by utilizing financial hedging as described in the Fuel Risk Management Plan. As shown on Schedule 4 of my exhibit, the 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 0.28 and standard deviation of 0.53. By contrast, the calculation of the volatility of Gulf's hedged delivered cost of natural gas for the period yields a variance of 0.18 and a standard deviation of 0.43. 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 26,210,000 MMBTU of natural gas in 2012 using financial instruments. This represents 37% of Gulf's 70,482,403 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 a combination of financial swap contracts that fixed the price of gas to a certain price and option contracts. The option contracts consisted entirely of "costless collars" which established a floor and ceiling price between which the actual price would float. The option contracts settle only if the actual NYMEX last day price was outside the bounds of the collar. The total volume of gas hedged using financial swap contracts was 23,550,000 MMBTU and the total volume of gas hedged using option contracts was 2,660,000 MMBTU. These swaps settled against either a NYMEX Last Day price or Gas Daily price.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2012 through December 2012?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2012 hedging program resulted in a net financial loss of $32,865,554 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2012 included in Appendix 1 of Witness Dodd's exhibit. The settlements of Gulf's swap contracts resulted in a net loss of $30,798,584 and the settlement of Gulf's option contracts resulted in a net loss of $2,066,970 during the period.

Q. What is the current status of Gulf Power's litigation against Coalsales II, LLC for breach of contract?

A. As previously reported, Gulf filed a complaint with the U.S. District Court for the Northern District of Florida on June 22, 2006, against Coalsales for breach of contract. On September 30, 2009, the court issued its order granting Gulf's motion for partial summary judgment and denying Coalsales' motion for summary judgment on the breach of contract issue. The issue of Gulf's damages was heard by the court without a jury in February 2010. On September 30, 2010, the court issued an order initially ruling in favor of Coalsales on the question of damages. That order was later rescinded in response to Gulf's Motion to Alter or Amend Judgment, or Alternatively, for Relief from Judgment. In July 2011, the court granted Gulf's motion after finding that the cover coal purchases by Gulf in 2007 were reasonable and scheduled another evidentiary hearing on August 25, 2011 to address the issue of Gulf's 2007 cover damages. In September 2011, the court found that Gulf is entitled to a judgment against Coalsales in the amount of $20,527,789, which represents the difference between the contract price of Gulf's 2007 cover purchases and the price Gulf would have paid for the same quantity of coal under the coal supply agreement. Additionally the court denied Coalsales motion for its attorney's fees and costs to be recovered from Gulf. On January 19, 2012, the court amended its September 2011 judgment and entered a judgment in favor of Gulf Power for damages in the amount of $20,527,789 and prejudgment interest in the amount of $6,896,183.85 for a total judgment of $27,423,972.85 plus taxable costs and post judgment interest. The order and final judgment each specify that post-judgment interest is to be calculated from September 30, 2011, until the date the judgment is paid at a rate of 0.10%. The case is currently on appeal to the United States Court of Appeals for the Eleventh Circuit. The appellate court heard the oral argument of the parties on January 31, 2013. Any damage recovery ultimately obtained from Coalsales will result in a credit to Gulf's retail customers through the fuel cost recovery clause and will necessarily result in reduced fuel costs for those customers.

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

A. No.

Q. During the period January 2012 through December 2012 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 ($113,915,789) or 149.00% above the projected amount of ($45,749,000). Total kilowatt hours of power sales were (6,935,858,367) KWH compared to estimated sales of (1,479,204,000) KWH, or 368.89% above projections. The resulting average fuel cost of power sold was 1.6424 cents per KWH or 46.90% below the projected amount of 3.0928 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2012 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 below budget prices for natural gas which reduced the fuel reimbursement rate (cents per KWH) paid to Gulf for typical power sales.

Q. During the period January 2012 through December 2012, 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 $189,205,979 or 74.05% above the estimated amount of $108,708,000. Total kilowatt hours of purchased power were 10,129,284,073 KWH compared to the estimate of 3,829,509,000 KWH or 164.51% above projections. The resulting average fuel cost of purchased power was 1.8679 cents per KWH or 34.20% below the estimated amount of 2.8387 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2012 included in Appendix 1 of Witness Dodd's exhibit.

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

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

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

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

Q. During the period January 2012 through December 2012, 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 2012 through December 2012 recovery period, as shown on line 4 of Schedule CCA-2 of Witness Dodd's Exhibit, was $45,160,245. Gulf's total re-projected net purchased power capacity cost for the same period was $45,793,117, as indicated on line 4 of Schedule CCE-1B of Witness Dodd's exhibit filed August 1, 2012. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $632,872 or 1.38% lower than the re-projected amount. This lower actual cost is primarily due to Gulf having lower IIC reserve sharing costs than the re-projected amount for the 2012 recovery period. Gulf's actual capacity reserves (MW) were higher than projected due to a lower actual load responsibility for Gulf used in the IIC reserve sharing calculation.

Q. Was Gulf's actual 2012 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 2012, 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. 130001-EI
August 2, 2013

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 2013 through December 2013 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2013 through June 2013 and projected fuel and net power transaction costs for July 2013 through December 2013. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses, and purchased power capacity costs.

Q. During the period January 2013 through December 2013 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 $484,762,325 which is $15,346,729 or 3.27% above the original projected amount of $469,415,596. 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 4.0757 cents per kWh or 7.65% higher than the original projection of 3.7860 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 Dodd's testimony, Schedule E-1 B-1, Line 21.

Q. During the period January 2013 through December 2013 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 $377,089,060 which is $17,174,223 or 4.77% above the original projected amount of $359,914,837. Total generation is expected to be 8,680,795,000 kWh compared to the original projected generation of 8,760,831,000 kWh or 0.91% below original projections. The resulting average fuel cost is expected to be 4.3439 cents per kWh or 5.74% above the original projected amount of 4.1082 cents per kWh. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 6.

Q. What are the reasons for the difference between Gulf's original projection of the 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) offset by lower 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. Projected prices for natural gas for the period are expected to be higher than original projections for the period due to changes in market fuel prices. A higher projected demand for natural gas in the market has driven the projected price higher and prices are expected to remain higher for the remainder of the period. The quantity of natural gas burn is expected to be below original projections in response to the 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 2013?

A. The total fuel cost of system net generation for the first six months of 2013 was $165,295,860 which is $1,663,574 or 1.00% less than the projection of $166,959,434. On a fuel cost per kWh basis, the actual cost was 4.27 cents per kWh, which is 5.43% higher than the projected cost of 4.05 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 0.89% higher than projected and heat rate (Btu/kWh) of the generating units operating being 4.60% higher than projected. The higher price of fuel is a result of higher market prices for natural gas than projected for the period. The natural gas fired units were also operated at lower loads than projected which resulted in reduced efficiency for these units. This information is found on Schedule A-3 Period to Date of the June 2013 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2013?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2013 was $107,456,711 which is $2,388,151 or 2.27% higher than the projection of $105,068,560. On a fuel cost per kWh basis, the actual cost was 4.98 cents per kWh which is 2.92% lower than the projected cost of 5.13 cents per kWh. The higher than projected total cost of coal burned (including boiler lighter) is due to total MMBtu of coal burn being 4.13% above the estimated burn for the period. The lower per kWh cost of coal fired generation is due to actual coal prices (including boiler lighter) being

1.75% lower than projected on a $/MMBtu basis and the weighted average heat rate (Btu/kWh) of the coal fired generating units that operated being 1.20% lower than projected. This information is found on Schedule A-3 Period to Date of the June 2013 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. Another factor contributing to the lower cost of coal fired generation (cents/kWh) is that weighted average coal unit heat rates are lower than projected for the period. Generating unit heat rates have been impacted by the mix of generating units that operated to meet system loads.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2013?

A. The total cost of natural gas burned for generation for the first six months of 2013 was $57,367,043 which is $4,124,690 or 6.71% lower than Gulf's projection of $61,491,733. The total gas fired generation was 1,701,038 MWH which is 17.30% lower than the projection of 2,056,898 MWH for the period. The total cost of natural gas burned for generation is lower than the forecast due to the amount of gas fired generation being lower than projected. On a cost per unit basis, the actual cost of gas fired generation was 3.37 cents per kWh which is 12.71% higher than the projected cost of 2.99 cents per kWh. Actual natural gas prices were $4.60 per MMBtu or 5.50% higher than the projected cost of $4.36 per MMBtu. This information is found on Schedule A-3 Period to Date of the June 2013 Monthly Fuel Filing.

Q. For the period January 2013 through June 2013, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 15,660,000 MMBtu of natural gas for the period using fixed price financial swaps. This equates to 53.6% of the actual natural gas burn for Gulf's combined cycle generating units during the period of 29,230,027 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 2013 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 financial swaps that fixed the price of gas to a certain price. 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 15,660,000 MMBtu.

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

A. No fees, commission, or option premiums were incurred. Gulf's gas hedging program generated a hedging expense related to settlements of

$6,785,904 for the period January through June 2013. This information is found on Schedule A-1, Period to Date, line 2 of the June 2013 Monthly Fuel Filing.

Q. During the period January 2013 through December 2013 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 $(105,548,180) or 38.31% above the original projected amount of $(76,315,241). Total kilowatt hours of power sales is expected to be (3,991,436,927) kWh compared to the original projection of (2,527,086,000) kWh or 57.95% above projections. This current projection of fuel cost of power sold is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 18.

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

A. The greater total credit to fuel expense from power sales is attributed to a significantly higher quantity of power sales than originally projected, offset to a degree 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 2.6444 cents/kWh which is 12.43% lower than the original projection of 3.0199 cents/kWh. Lower prices for electricity during the period due to lower system loads have decreased the fuel reimbursement rate 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 2013?

A. The total fuel cost of power sold for the first six months of 2013 was $(45,643,179) which is $(11,384,179) or 33.23% higher than our projection of $(34,259,000). The quantity of power sales for the period was 86.90% higher than projected. The actual cost was 1.9309 cents per kWh which is 28.71% below the projected cost of 2.7086 cents per kWh. This information is found on Schedule A-1, Period to Date, line 17 of the June 2013 Monthly Fuel Filing.

Q. During the period January 2013 through December 2013 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 $213,221,445 or 14.75% above the original projected amount of $185,816,000. The total amount of purchased power is expected to be 7,204,508,558 kWh compared to the original projection of 6,164,950,000 kWh or 16.86% above projections. The resulting average fuel cost of purchased power is expected to be 2.9596 cents per kWh or 1.81% below the original projected amount of 3.0141 cents per kWh. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 13.

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

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of lower cost energy to supplement its own generation to meet load demands. The lower projected price per kWh for purchased power is due to Gulf's ability to obtain power from lower cost generating resources under terms of the Southern Company IIC. Lower demand for electricity in the market has made available a higher amount of lower cost energy for purchase during off peak periods.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2013?

A. The total fuel cost of purchased power for the first six months of 2013 was $101,301,444 which is $11,060,444 or 12.26% higher than our projection of $90,241,000. The higher than anticipated purchased power expense is due to the actual quantity of purchases being 30.38% 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 the lower price of available power relative to Gulf's fuel cost of generated power making it the economic choice for providing energy to customers during certain periods of time. On a fuel cost per kWh basis, the actual cost was 2.6024 cents per kWh which is 13.90% lower than the projected cost of 3.0225 cents per kWh. This information is found on Schedule A-1, Period to Date, line 12 of the June 2013 Monthly Fuel Filing.

Q. What is the current status of Gulf Power's litigation against Coalsales II, LLC for breach of contract?

A. As previously reported, Gulf filed a complaint with the U.S. District Court for the Northern District of Florida on June 22, 2006, against Coalsales for breach of contract. The United States District Court for the Northern District of Florida entered a judgment in favor of Gulf Power Company for more than $20 million in contract damages related to breach occurring in 2007, the final year of the contract, along with both pre-judgment and post-judgment interest and taxable costs. The resulting judgment was then appealed to the Eleventh Circuit Court of Appeals. On June 26, 2013, the Eleventh Circuit Court of Appeals issued an opinion affirming all aspects of the final judgment of the trial court. The time period for pursuing further appellate review has passed and the judgment entered by the trial court is now final. Peabody Energy has committed in writing to wire transfer sufficient funds to Gulf to fully satisfy the final judgment by close of business on August 8, 2013. The damage recovery ultimately obtained from Coalsales has resulted in a credit to Gulf's retail customers through the fuel cost recovery clause in July 2013 as shown on Witness Dodd's Schedule E-1B, page 2 of 2, line C-8..

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, 2013 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

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

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

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

Q. During the period January 2013 through December 2013, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 4 of Schedule CCE-1b in the exhibit to Witness Dodd's testimony, Gulf's total current net capacity payment projection for the January 2013 through December 2013 recovery period is $45,966,336. Gulf's original projection for the period was $45,479,478 and is shown on Line 4 of Schedule CCE-1B filed August 28, 2012. The difference between these projections is $486,858 or 1.07% greater than the original projection of net capacity payments. The variance is due to an increase in projected 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 2013?

A. Actual net capacity payments during the first six months of 2013 were $18,027,697 which is $390,578 or 2.21% higher than projected for the period. The variance is due to an increase in projected reserve sharing capacity payments per the provisions 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 and Exhibit of
H. R. Ball
Docket No. 130001-EI
Date of Filing: August 30, 2013

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, 2014 through December 31, 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 four separate exhibits I am sponsoring as part of this testimony. My first exhibit (HRB–2) consists of a schedule filed as an attachment to my pre-filed testimony that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short-term fuel expense projections. The second exhibit (HRB-3) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on April 5, 2013 and assigned Document Number DN 01760-13 (redacted) and 01725-13 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August through December 2012 in compliance with Order No. PSC-08-0316-PAA-EI. The third 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 August 16, 2013 and assigned Document Number DN 04800-13 (redacted) and 04813-13 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for January through July 2013 in compliance with Order No. PSC-08-0316-PAA-EI. The fourth exhibit (HRB-5) 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 August 2, 2013 and assigned Document Number DN 04484-13 (redacted) and 04462-13 (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-2), _____ (HRB-3), _____ (HRB-4), and_____ (HRB-5) 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 2014 through December 2014 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $460,454,834. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 19.

Q. How does the total projected fuel and net power transactions cost for the 2014 period compare to the updated projection of fuel cost for the same period in 2013?

A. The total updated cost of fuel and net power transactions for 2013, reflected on Schedule E-1B-1 line 21 of Witness Dodd's testimony filed in this docket on August 2, 2013, is projected to be $484,762,325. The projected total cost of fuel and net power transactions for the 2014 period reflects a decrease of $24,307,491 or 5.01% less than the same period in 2013. On a fuel cost per kWh basis, the 2013 projected cost is 4.0757 cents per kWh and the 2014 projected fuel cost is 3.7681 cents per kWh, a decrease of 0.3076 cents per kWh or 7.55%.

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 2014 is $358,926,706. The projection of fuel cost of system generated power for 2014 is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 5.

Q. How does the projected total fuel cost of generated power for the 2014 period compare to the updated projection of fuel cost for the same period in 2013?

A. The total updated cost of fuel to meet 2013 system generated power needs, reflected on Schedule E-1B-1, line 6 of Witness Dodd's testimony filed in this docket on August 2, 2013, is projected to be $377,089,060. The projected total cost of fuel to meet system net generation needs for the 2014 period reflects a decrease of $18,162,354 or 4.82% less than the same period in 2013. Total system net generation in 2014 is projected to be 8,933,268,000 kWh, which is 252,473,000 kWh or 2.91% higher than is currently projected for 2013. On a fuel cost per kWh basis, the 2013 projected cost is 4.3439 cents per kWh and the 2014 projected fuel cost is 4.0179 cents per kWh, a decrease of 0.3260 cents per kWh or 7.50%. This lower projected total fuel expense and average per unit fuel cost is the result of a lower projected cost of coal and natural gas for the period.

Weighted average coal burned price for 2013 as reflected on Schedule E-3, line 29 of Witness Dodd's testimony filed in this docket on August 2, 2013, is projected to be 104.54 $/ton. Weighted average coal burned price for 2014, as reflected on Schedule E-3, line 29 of the exhibit to Witness Dodd's testimony, is projected to be 95.02 $/ton. This reflects a cost decrease of 9.52 $/ton or 9.11%. Several of Gulf's coal supply contracts have or will expire by the end of 2013 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 the majority of Gulf's 2014 projected coal burn needs. The remaining coal supply needs, if any, will be purchased on the spot market. Weighted average natural gas price for 2013, as reflected on Schedule E-3, line 33 of the exhibit to Witness Dodd's testimony filed in this docket on August 2, 2013, is projected to be 4.73 $/MMBtu. When the cost of natural gas hedging settlements (Schedule E-1-B1, line 1a) is included in the total delivered gas cost, the 2013 projected cost is 5.09 $/MMBtu. Weighted average natural gas price for 2014, as reflected on Schedule E-3, line 33 of the exhibit to Witness Dodd's testimony, is projected to be 4.74 $/MMBtu. This is a decrease in price of 0.35 $/MMBtu or 6.88%. The projected cost of landfill gas to supply the Perdido Landfill Gas to Energy Facility in the 2013 projection period is $689,900 and the rate as reflected on Schedule E-3, line 42 of the exhibit to Witness Dodd's testimony filed in this docket on August 2, 2013, is projected to be 2.80 cents per kWh. The total projected cost for landfill gas in 2014 is $680,294 and the total facility generation is projected to be 24,720,000 kWh. The average rate, as reflected on Schedule E-3, line 42 of the exhibit to Witness Dodd's testimony, is projected to be 2.75 cents per kWh.

Q. Does the 2014 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-5) to this testimony.

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

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

Q. What fuel price hedging programs will be utilized by Gulf to protect 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 2013 through July 2013?

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 April 5, 2013 and also on August 16, 2013 detailing its natural gas hedging transactions for August 2012 through July 2013. As noted earlier, I am sponsoring these reports as exhibits ______ (HRB-3 and HRB-4) to my testimony in this docket.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2013 through 2014?

A. Gulf has natural gas financial hedges in place for 2013 to adequately mitigate price risk. Gulf currently has natural gas hedges in place for 2014 and continues to look for opportunities to enter into financial hedges that we believe will provide price stability to the customer and protect against unanticipated dramatic price increases in the natural gas market.

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

A. Gulf has a disciplined process in place to evaluate the benefits of gas hedging transactions prior to entering into financial hedges that consider both market price and anticipated burn. The focus of this process is to mitigate the price volatility and risk of natural gas purchases for the customer and not to attempt to speculate in the natural gas market. Gulf's current strategy is to have gas hedges in place that do not exceed the anticipated gas burn at its Smith Unit 3 combined cycle plant 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 period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $72,244,995. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 17.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2014 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2013?

A. The total updated recoverable fuel cost and gains on power sales in 2013, reflected on Schedule E-1B-1, line 18 of Witness Dodd's testimony filed in this docket on August 2, 2013, is projected to be $105,548,180. The projected recoverable fuel cost and gains on power sales in 2014 represents a decreased credit of $33,303,185 or 31.55%. Total quantity of power sales in 2014 is projected to be 2,183,462,000 kWh, which is 1,807,974,927 kWh or 45.30% less than currently projected for 2013. On a fuel cost per kWh basis, the 2013 projected cost is 2.6444 cents per kWh and the 2014 projected fuel cost is 3.3087 cents per kWh, which is an increase of 0.6643 cents per kWh or 25.12%. 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 $173,773,123. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 12.

Q. How does the total projected purchased power cost for the 2014 period compare to the projected purchased power cost for the same period in 2013?

A. The total updated cost of purchased power to meet 2013 system needs, reflected on Schedule E-1B-1, line 13 of Witness Dodd's testimony filed in this docket on August 2, 2013, is projected to be $213,221,445. The projected cost of purchased power to meet system needs in 2014 is $39,448,322 or 18.50% less than is currently projected for 2013. The total quantity of purchased power in 2014 is projected to be 5,470,006,000 kWh, which is 1,734,502,558 kWh or 24.08% lower than is currently projected for 2013. On a fuel cost per kWh basis, the 2013 projected cost is 2.9596 cents per kWh and the 2014 projected fuel cost is 3.1768 cents per kWh, which represents an increase of 0.2172 cents per kWh or 7.34%.

Q. What is Gulf's projected recoverable capacity payments for the 2014 cost recovery period?

A. The total recoverable capacity payments for the period are $64,075,540. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 10. Schedule CCE-4 of Mr. Dodd's testimony shows 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 2014 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 $63,882,932 is shown on Schedule CCE-4, line 34 in the exhibit to Witness Dodd's testimony. The total capacity cost included on Schedule CCE-4 line 34 is the sum of lines 1 and 2 of Schedule CCE-1.

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

A. No, however, two existing PPA agreements (Shell's Coral Baconton, and Southern Power's Dahlberg) will expire on May 31, 2014 and the associated capacity payments have been removed from the projection.

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 $148,000 in its capacity cost recovery projection. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 3.

Q. How 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 2014 Projected Jurisdictional Capacity Payments, found in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 6, are $61,868,429. This amount is $17,477,147 or 39.37% greater than the current estimate of $44,391,282 (Schedule CCE-1B, line 6) for 2013 that was filed in Mr. Dodd's actual/estimated true-up testimony in this docket on August 2, 2013. 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 will increase beginning in June 2014 due primarily 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 expire 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. 130001-EI
Date of Filing: March 1, 2013

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, cost of service activities, 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 2012 through December 2012 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 2013 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 2012 through December 2012.

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 2012 through December 2012, 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 2012 through December 2012. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for January 2012 through December 2012 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 2012 through December 2012 to be refunded or collected through the fuel cost recovery factors in the period January 2014 through December 2014?

A. A net amount to be recovered of $9,333,695 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $9,333,695 was calculated by taking the difference in the estimated and actual over/under-recovery amounts for the period January 2012 through December 2012. The estimated over-recovery was $66,160,565 as shown on Schedule E-1B, Line 6 + 7 + 8 filed August 1, 2012. The actual over-recovery was $56,826,870 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2012 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 1, 2012.

Q. Mr. Dodd, has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2012 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2010 through 2012 is calculated as follows:

Year	Actual Gain
2010	$ 802,338
2011	463,514
2012	519,587
Three-Year Average	$ 595,146

Q. What is the actual threshold for 2013?

A. The actual threshold for 2013 is $595,146.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements for the period of January 2012 through December 2012?

A. Yes. On line 2 of Schedule A-1, Period-to-Date, for December 2012 included in Appendix 1, Gulf has recorded a net loss of $32,865,554 related to hedging activities in 2012. Mr. Ball addresses the details of those hedging activities in his testimony.

Q. Mr. Dodd, how were the A-Schedules included in Appendix 1 impacted by the two Mid-Course filings Gulf submitted in 2012? A. The two Mid-Course filings in 2012 included re-projections for the remaining future months in 2012. Since the December 2012 period-to-date "projected" amounts presented on the A-Schedules are simply an accumulation of current month projected data throughout the year, these amounts for calendar year 2012 are a blend of multiple projections. January and February projected amounts were from Gulf's original 2012 Projection filing submitted in 2011. March and April projected amounts were from Gulf's first Mid-Course filing submitted in January 2012. May and June projected amounts were from Gulf's second Mid-Course filing submitted in May 2012. July through December projected amounts were from Gulf's 2012 Estimated/Actual True-up Filing submitted in August 2012.

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 2012 through December 2012. In addition, Capacity Cost Recovery Schedule A-12 for the months of January 2012 through December 2012 is included in Appendix 1.

Q. What is the actual purchased power capacity cost true-up amount related to the period of January 2012 through December 2012 to be refunded or collected in the period January 2014 through December 2014?

A. An amount to be refunded of $102,776 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $102,776 was calculated by taking the difference in the estimated January 2012 through December 2012 under-recovery of $592,654 and the actual under-recovery of $489,878, 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-12-0664-FOF-EI dated December 21, 2012. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed August 1, 2012.

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 2012 through December 2012. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the under-recovery for the period January 2012 through December 2012. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

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
Richard W. Dodd
Docket No. 130001-EI
Date of Filing: August 2, 2013

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. 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, cost of service activities, 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. Dodd's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (RWD-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2013 through December 2013 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2013 through December 2013 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. Dodd, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2014 through December 2014?

A. The fuel cost recovery true-up for this period is an increase of 0.1434 ¢/kWh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2013 period of $6,665,066. It also includes a final under-recovery for the January through December 2012 period of $9,333,695 (see Schedule 1 of Exhibit RWD-1 in this docket filed on March1, 2013). The resulting total under-recovery of $15,998,761 will be included for recovery during 2014.

Q. Mr. Dodd, 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 2014 through December 2014 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2014 through December 2014?

A. The true-up for this period is an increase of 0.0194 ¢/kWh as shown on Schedule CCE-1A. This includes an estimated under-recovery of $2,263,786 for January 2013 through December 2013. It also includes a final over-recovery of $102,776 for the period of January 2012 through December 2012 (see Schedule CCA-1 of Exhibit RWD-1 in this docket filed March 1, 2013). The resulting total under-recovery of $2,161,010 will be included for recovery during 2014.

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
Richard W. Dodd
Docket No. 130001-EI
Date of Filing: August 30, 2013

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. Have you previously filed testimony before this Commission in this on-going docket?

A. Yes.

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 2014 through December 2014. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2014 through December 2014.

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. Dodd's exhibit consisting of 15 schedules, be marked as Exhibit No. _____(RWD-3)

Q. Mr. Dodd, what is the levelized projected fuel factor for the period January 2014 through December 2014?

A. Gulf has proposed a levelized fuel factor of 4.169¢/kWh. This factor is based on projected fuel and purchased power energy expenses for January 2014 through December 2014 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 2014 is 0.366¢/kWh more or 9.6 percent higher than the levelized fuel factor in place January through December 2013.

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 2014 through December 2014.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $15,998,761 to be collected during 2014 includes an estimated under-recovery for the January through December 2013 period of $6,665,066 plus a final under-recovery for the period January through December 2012 of $9,333,695. The estimated over-recovery for the January through December 2013 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 2012 through December 2012?

A. The GPIF result is shown on Line 31 of Schedule E-1 as an increase of 0.0149¢/kWh to the levelized fuel factor, thereby rewarding Gulf $1,662,342.

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. Dodd, 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. Dodd, 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 4.201¢/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. Dodd, 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 2014 through December 2014. 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 2012 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 2013 is 3.832¢/kWh compared with the proposed factor of 4.201¢/kWh. For a residential customer who uses 1,000 kWh in January 2014, the fuel portion of the bill would increase from $38.32 to $42.01.

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 2014 through December 2014.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2014 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 $462,977 has been calculated for 2013 as follows:

2011 actual gains	463,514
2012 actual gains	519,586
2013 estimated gains	405,832
Three-Year Average	$462,977

This amount represents the minimum projected threshold for 2014 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 2014 for the months of January through August and 80 percent once the threshold is met in September.

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 2013 of my exhibit RWD-3 relate to the calculation of the PPCC recovery factors for the period January 2014 through December 2014.

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 2014 through December 2014, is $63,734,932. The jurisdictional amount is $61,868,4298. 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 used in Gulf's last rate case and 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 used in Gulf's last rate case.

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. 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 uses 1,000 kWh will be $6.80.

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 2014 and continuing through the last billing cycle of December 2014.

Q. Mr. Dodd, 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. 130001-EI
Date of Filing: March 15, 2013

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, 2012, through December 31, 2012.

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 16 through 31 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 15 of Schedule 5. Pages 3 through 10 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-11-0579-FOF-EI is on page 11 of Schedule 2. The results are: Crist 4, +10.00 points; Crist 5, +10.00 points; Crist 6, -5.38 points; Crist 7, +10.00 points; Smith 1, -3.45 points; Smith 2, -5.19 points; Daniel 1, -10.00 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 9 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 10 through 17 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in September 2011, are shown on page 20 of Schedule 3. As calculated on page 21 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: Crist 4, -6.25 points; Crist 5, +10.00 point; Crist 6, +9.33 points; Crist 7, -3.18 points; Smith 1, +10.00 points; Smith 2, +6.14 points; Daniel 1, +5.73 points, and Daniel 2, +2.46 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 +3.62 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $1,662,342.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 11 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 21 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $1,662,342 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. A. Young, III
Docket No. 130001-EI
Date of Filing: August 30, 2013

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, 2014 through December 31, 2014.

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 5, 6 and 7, Smith Units 1, 2 and 3, be included as the Company's GPIF units. The projected net generation from these units is approximately 81% of Gulf's projected net generation for 2014.

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, 2014 through December 31, 2014?

A. I would like to refer you to page 28 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 25 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 26 and 27 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 28 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. Should the Commission consider termination or modification of the existing GPIF process at this time?

A. No. The GPIF process was reviewed most recently in 2006 in Docket No. 060001-EI. As a result of that thorough review and the review undertaken in this docket, Gulf has not identified any reasons that justify the termination or modification of the GPIF process. While Gulf does not believe any revisions to the current GPIF process are necessary, Gulf is not opposed to modifications to how rewards or penalties are calculated as long as the modifications are symmetrical. Gulf would be agreeable to setting the maximum reward/penalty at 50 percent of the fuel savings/loss and using a linear interpolation of the reward/penalty. This modification to the GPIF process was raised by the Commission's staff in this docket.

Q. Mr. Young, would you please summarize your testimony?

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 5, 6 and 7, Smith Units 1, 2 and 3 for inclusion under the GPIF for the period of January 1, 2014 through December 31, 2014.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 28 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 18 through 29 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

5. The GPIF process should be continued and not modified.

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

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 03/1/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Administrator, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 16 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2012 through December 2012 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"), the Capacity Cost Recovery Clause ("Capacity Clause") as well as the wholesale incentive benchmark for January 2013 through December 2013.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No.___ (PAR-1), consisting of four documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2012 through December 2012?

A. The final true-up amount for the Capacity Clause for the period January 2012 through December 2012 is an under-recovery of $126,648.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2012 Through December 2012", provides the calculation for the final under-recovery of $126,648. The actual capacity cost under-recovery, including interest, was $6,829,153 for the period January 2012 through December 2012 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $6,702,505 actual/estimated under-recovery approved in Order No. PSC-12-0664-FOF-EI issued December 21, 2012 in Docket No. 120001-EI, results in a final under-recovery of $126,648 for the period, as identified in Document No. 1, page 4 of 4. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2014 through December 2014.

Q. What is the estimated effect of this $126,648 under-recovery for the January 2012 through December 2012 period on residential bills during January 2014 through December 2014?

A. The $126,648 under-recovery will increase a 1,000 kWh residential bill by approximately $0.008.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2012 through December 2012?

A. The final Fuel Clause true-up for the period January 2012 through December 2012 is an over-recovery of $903,071. The actual fuel cost over-recovery, including interest, was $70,222,929 for the period January 2012 through December 2012. This $70,222,929 amount, less the $69,319,858 actual/estimated over-recovery amount approved in Order No. PSC-12-0664-FOF-EI, issued December 21, 2012 in Docket No. 120001-EI results in a net over-recovery amount for the period of $903,071.

Q. What is the estimated effect of the $903,071 over-recovery for the January 2012 through December 2012 period on residential bills during January 2014 through December 2014?

A. The $903,071 over-recovery would decrease a 1,000 kWh residential bill by approximately $0.05.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2012 Through December 2012". It shows the calculation of the final fuel over-recovery of $903,071.

Line 1 shows the total company fuel costs of $753,972,194 for the period January 2012 through December 2012. The jurisdictional amount of total fuel costs is $752,733,796, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over-recovered fuel costs for the period, shown on line 4. The resulting $58,269,734 over-recovered fuel costs for the period, interest, true-up collected and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery of $70,222,929 shown on line 9. The $70,222,929 actual over-recovery amount less the $69,319,858 actual/ estimated over-recovery amount shown on line 10, results in a final $903,071 over-recovery amount for the period January 2012 through December 2012 as shown on line 11.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2012 Through December 2012", shows the calculation of the actual over-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2012 through December 2012?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $88,637,133 less than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2012 through December 2012?

A. As shown on line C3 of Document No. 3, the company collected $30,888,830 or 3.7 percent less jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of the transactions for each of Commission Schedules A6, A7, A8, A9 as well as capacity information on schedule A12.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2013, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2013 benchmark is $1,366,094, which is the three-year average of $2,948,964, $902,388 and $246,931 actual gains on non-separated wholesale sales, excluding emergency sales, for 2010, 2011 and 2012, respectively.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 8/2/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Administrator, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 16 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

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 January 2013 through December 2013 fuel and purchased power and capacity true-up amounts to be recovered in the January 2014 through December 2014 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2013, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2014 fuel and purchased power costs and capacity cost recovery factors.

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

A. Yes. I have prepared Exhibit No. ____ (PAR-2), which contains three documents. Document No. 1 is comprised of

Schedules E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2013 through December 2013. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2013 through December 2013. Document No. 3 provides the actual/estimated Polk Unit 1 ignition oil conversion project capital costs and fuel savings for the period of January 2013 through December 2013. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2014 through December 2014 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2013 through December 2013 is an over-recovery of $15,630,547.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2014 through December 2014 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2014 is the sum of the final true-up amount for the period January 2012 through December 2012 and the actual/estimated true-up amount for the period January 2013 through December 2013.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2012?

A. The final true-up was an over-recovery of $903,071. The actual fuel cost over-recovery, including interest was $70,222,929 for the period January 2012 through December 2012. The $70,222,929 amount, less the actual/estimated over-recovery amount of $69,319,858 approved in Order No. PSC-12-0664-FOF-EI, issued December 21, 2012 in Docket No. 120001-EI resulted in a net over-recovery amount for the period of $903,071.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2013 through December 2013?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of

$14,727,476 for the January 2013 through December 2013 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (PAR-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2014 through December 2014 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2014 through December 2014 is an under-recovery of $591,765 as shown in Exhibit No. ____ (PAR-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2014 through December 2014 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2014 capacity cost recovery factors is the sum of the final true-up amount for 2012 and the actual/estimated true-up amount for January 2013 through December 2013.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2012?

A. The final 2012 true-up is an under-recovery of $126,648. The actual capacity cost under-recovery including interest was $6,829,153 for the period January 2012 through December 2012. This amount, less the $6,702,505 actual/estimated under-recovery amount approved in Order No. PSC-12-0664-FOF-EI issued December 21, 2012 in Docket No. 120001-EI results in a net under-recovery amount for the period of $126,648 as identified in Exhibit No. ____ (PAR-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2013 through December 2013?

A. The actual/estimated true-up amount is an under-recovery of $465,117 as shown on Exhibit No. ____ (PAR-2), Document No. 2, page 1 of 5.

Polk Unit 1 Ignition Oil Conversion

Q. What did Tampa Electric calculate as the actual/estimated Polk Unit 1 ignition oil conversion project costs for the period January 2013 through December 2013?

A. The actual/estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2013 through December 2013 are $2,356,259. This is shown in Exhibit No. ____ (PAR-2), Document No. 3.

Q. What did Tampa Electric calculate as the actual/estimated Polk Unit 1 ignition oil conversion project fuel savings for the period January 2013 through December 2013?

A. The actual/estimated fuel savings for the period January 2013 through December 2013 are $11,909,927, as shown in Exhibit No. ___ (PAR-2), Document No. 3.

Q. Should Tampa Electric's Polk Unit 1 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2013 through December 2013 actual/estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers; therefore, the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Administrator, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 16 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2014 through December 2014. I will also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2014.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. Exhibit No. _____ (PAR-3), consisting of five documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors utilizing the Commission approved allocation methodology from Order No. PSC-09-0283-FOF-EI issued April 30, 2009, in Docket No. 080317-EI based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). Document No. 2, consisting of three pages, provides the projected capacity cost recovery factors utilizing the company's proposed allocation methodology submitted in Docket No. 130040-EI, based on 12 Coincident Peak ("CP") and 50 percent Average Demand ("AD"). Document No. 3, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2014 through December 2014 as well as Schedule H1 for January through December, 2011 through 2014. Document No. 4 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 5 provides the projected monthly Polk Unit 1 ignition oil conversion capital costs as well as the related fuel savings.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (PAR-3), Document No. 1, page 3 of 4. The capacity factors reflect Tampa Electric's approved rate design from Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009. In addition, capacity factors reflecting the company's proposed rate design, as submitted in Docket No. 130040-EI, are shown in Exhibit No. ___ (PAR-3), Document No. 2, page 3 of 3.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ____ (PAR-3), Document No. 1, Tampa Electric requests recovery of $31,495,469 after jurisdictional separation and prior year true-up, for estimated expenses in 2014.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2014 through December 2014.

A.

Rate Class and **Metering Voltage**	**Capacity Cost** **Cents per kWh**	**Recovery Factor** **$ per kW**
RS Secondary	0.196	
GS and TS Secondary	0.183	
GSD, SBF Standard		
Secondary		0.65
Primary		0.64
Transmission		0.64
IS, IST, SBI		
Primary		0.45
Transmission		0.44
GSD Optional		
Secondary	0.154	
Primary	0.152	
LS1 Secondary	0.053	

These factors are shown in Exhibit No. ____ (PAR-3), Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.172 cents per kWh compare to the factor for January 2013 through December 2013?

A. The proposed capacity cost recovery factor is 0.029 cents per kWh (or $0.29 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.201 cents per kWh for the January 2013 through December 2013 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2014?

A. The appropriate amount for the 2014 period is 3.911 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (PAR-3), Document No. 3, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2014 through December 2014.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF penalty of $1,177,059, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the January 2013 through December 2013 period. The net true-up amount for this period is an over-recovery of $15,630,547.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2014 through December 2014. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 4.

A. Exhibit No. ____ (PAR-3), Document No. 4 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2014 through December 2014.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	3.911
Tier I (Up to 1,000 kWh)	3.599
Tier II (Over 1,000 kWh)	4.599
Distribution Primary	3.872
Transmission	3.833
Lighting Service	3.872
Distribution Secondary	4.125 (on-peak)
	3.820 (off-peak)
Distribution Primary	4.084 (on-peak)
	3.782 (off-peak)
Transmission	4.043 (on-peak)
	3.744 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.911 cents per kWh compare to the levelized fuel adjustment factor for the January 2013 through December 2013 period?

A. The proposed fuel charge factor is 0.192 cents per kWh (or $1.92 per 1,000 kWh) higher than the average fuel charge factor of 3.719 cents per kWh for the January 2013 through December 2013 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2014 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events reflected in the 2014 projections: an increase in natural gas prices compared to 2013 and the inclusion of Polk 1 capital conversion costs, which is more than offset by the anticipated fuel savings of that project.

Q. Please describe current expectations regarding natural gas prices.

A. Tampa Electric expects a small increase in natural gas commodity prices in 2014, compared to anticipated prices for 2013. The projected natural gas price increase is driven by expectations that domestic and international economies will continue to strengthen. The recent prolonged economic downturn resulted in a decline in fuel commodity prices, particularly natural gas, which translated into a significant decrease in fuel and purchased power costs through 2012. Natural gas price expectations through the end of 2013 are for a small increase. The projected 2014 natural gas prices are 2.6 percent greater than 2013 prices on a dollar-per-mmBtu basis.

To mitigate fuel price volatility and comply with the company's Commission-approved Risk Management Plan, financial hedges have been entered into for natural gas in 2013 and 2014. The foundation for the company's natural gas forecast is the average of the New York Mercantile Exchange ("NYMEX") natural gas futures contract closing price published during the five consecutive business days between August 6, 2013 and August 12, 2013. Tampa Electric witness J. Brent Caldwell's direct testimony describes existing and forecasted natural gas costs and associated hedge results in more detail.

Q. What are the 2014 projected fuel savings for the Polk Unit 1 ignition oil conversion project?

A. The Commission approved Tampa Electric's recovery of the capital costs associated with the Polk Unit 1 ignition oil conversion in Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2013. Exhibit No. ____ (PAR-3), Document No. 5, displays the projected depreciation costs and return as well as the projected fuel savings for the project. As reflected on line 31 of that document, the project is expected to provide $6,148,946 in fuel savings in 2014.

Q. Do projected 2014 fuel savings for the Polk Unit 1 ignition oil conversion exceed the project depreciation and return expense?

A. Yes. The projected fuel savings of $6,418,946 exceed the 2014 depreciation and return expense of $4,329,501, as shown on Document No. 5 of my exhibit.

Q. Should the company's Polk Unit 1 ignition oil conversion project depreciation and return expense be approved for recovery through the fuel clause?

A. Yes. Tampa Electric has complied with the requirements of Order No. PSC-12-0498-PAA-EI, and the project's expected fuel savings exceed the costs. The 2014 projected net benefit of the project is $1,819,445, as shown on line 33 of Document No. 5. Therefore, the project costs should be approved for recovery through the fuel clause.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2014?

A. The company's projected 2014 benchmark is $650,665, which is the three-year average of $902,388, $246,932 and $802,676 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2011, 2012 and 2013 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2014 from non-separated wholesale sales to exceed its 2014 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2014. Therefore, all sales margins are expected to flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its base, capacity, fuel and purchased power, environmental and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is an increase of $11.86 beginning January 2014, when the impact of the company's proposed base rate change is considered. These charges are shown in Exhibit No. _____ (PAR-3), Document No. 3, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2014.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED SUPPLEMENTAL TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Administrator, Rates in the Regulatory Affairs Department.

Q. Are you the same Penelope A. Rusk that submitted prepared direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to address how the company's Capacity Cost Recovery clause ("capacity clause") and Fuel and Purchased Power Cost Recovery clause ("fuel clause") are affected as a result of the Stipulation and Settlement Agreement ("settlement") reached between Tampa Electric and interveners and approved by the Commission in Docket No. 130040-EI on September 11, 2013.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. Exhibit No. ____ (PAR-3), which consists of five documents was prepared under my direction and supervision. The revised pages submitted with my testimony today include the schedules that were affected by the settlement. Revised pages 1 and 3 of Document No. 1 are furnished as support for the projected capacity cost recovery factors utilizing the Commission approved allocation methodology based on 12 Coincident Peak ("CP") and 1/13th Average Demand ("AD"). Revised pages of Document No. 3, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, consist of Schedules E1, E1-D, E1-E, E2 and E10 for January 2014 through December 2014. My revised Document No. 4 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Finally, my revised Document No. 5 provides the projected monthly Polk Unit 1 ignition oil conversion capital costs as well as the related fuel savings.

Q. How did the settlement affect the capacity and fuel clauses?

A. The settlement resulted in three modifications to the calculations of the 2014 projected costs. The first modification was the change to the approved 12 CP and 1/13th AD allocation methodology for demand-related costs. The second modification occurred to include the settlement return on equity and equity ratio in the calculation of the Polk Unit 1 ignition oil conversion project costs. Finally, the third modification was the use of updated billing determinants through July 2013 to determine the fuel clause Tier 1 and Tier 2 usage values for residential customers.

Capacity Cost Recovery

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2014 through December 2014.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.202	

GS and TS Secondary	0.186	
GSD, SBF Standard		
Secondary		0.63
Primary		0.62
Transmission		0.62
IS, IST, SBI		
Primary		0.39
Transmission		0.38
GSD Optional		
Secondary	0.150	
Primary	0.149	
LS1 Secondary	0.025	

These factors are shown in Exhibit No. ____ (PAR-3), Document No. 1, revised page 3 of 4.

Fuel and Purchased Power Cost Recovery Factor

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2014 through December 2014.

A.

Metering Voltage Level	Fuel Charge Factor (cents per kWh)
Secondary	3.910
Tier I (Up to 1,000 kWh)	3.609

Tier II (Over 1,000 kWh)	4.609	
Distribution Primary	3.871	
Transmission	3.832	
Lighting Service	3.872	
Distribution Secondary	4.124	(on-peak)
	3.820	(off-peak)
Distribution Primary	4.083	(on-peak)
	3.782	(off-peak)
Transmission	4.042	(on-peak)
	3.744	(off-peak)

Q. What is the amount of Polk Unit 1 ignition oil conversion project costs to be recovered through the fuel clause?

A. Polk Unit 1 ignition oil conversion project costs of $4,250,042 for 2014 should be recovered through the fuel clause. This amount is less than the $6,148,946 estimated fuel savings of the project for 2014, resulting in $1,898,904 in net benefits to customers. These amounts are shown in revised Exhibit No. ____ (PAR-3), Document No. 5.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2014.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 03/15/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Compliance and Performance.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In August 2008, I was promoted to Manager, Operations Planning. Currently, I am the Manager of Compliance and Performance responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2012 through December 2012. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, I prepared Exhibit No. _____ (BSB-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2012 - December 2012 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2012 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, respectively.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2012 through December 2012 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon -1.513 Generating Performance Incentive Points ("GPIP"), the result is a penalty amount of $1,177,059 for the period.

Q. Please proceed with your review of the actual results for the January 2012 through December 2012 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,906,970,568. This produces the maximum penalty or reward amount of $7,780,732 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 32, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 32, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 504.0 planned outage hours were originally scheduled for 2012. Actual outage activities required 600.0 planned outage hours. Consequently, the actual equivalent availability of 67.0 percent is adjusted to 67.8 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 504.0 planned outage hours were originally scheduled for 2012. Actual outage activities required 353.5 planned outage hours. Consequently, the actual equivalent availability of 78.1 percent is adjusted to 76.7 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 576.0 planned outage hours were originally scheduled for 2012. Actual outage activities required 247.3 planned outage hours. Consequently, the actual equivalent availability of 72.2 percent is adjusted to 69.3 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 576.0 planned outage hours were originally scheduled for 2012. Actual outage activities required 717.1 planned outage hours. Consequently, the actual equivalent availability of 75.7 percent is adjusted to 76.9 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 960.0 planned outage hours were originally scheduled for 2012. Actual outage activities required 1,115.4 planned outage hours. Consequently, the actual equivalent availability of 70.0 percent is adjusted to 71.5 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 336.0 planned outage hours were originally scheduled for 2012. Actual outage activities required 190.0 planned outage hours. Consequently, the actual equivalent availability of 96.3 percent is adjusted to 94.7 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 1,511.0 planned outage hours were originally scheduled for 2012. Actual outage activities required 1,649.7 planned outage hours. Consequently, the actual equivalent availability of 78.8 percent is adjusted to 80.3 percent, as shown on Document No. 1, page 13 of 32.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32, column 4. This number is entered into the respective GPIP table for each particular unit, shown on pages 7 of 32 through 13 of 32. Page 4 of 32 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's seven GPIF units are shown on Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32, column 9. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 14 through 20 of 32. Page 4 of 32 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2012 through December 2012 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation found on page 32 of 32. The resulting value, -1.513, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the penalty amount is $1,177,059.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 08/30/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Compliance and Performance.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In August 2008, I was promoted to Manager, Operations Planning. Currently, I am the Manager of Compliance and Performance responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor ("GPIF") as ordered by the Commission.

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

A. Yes, Exhibit No. _____ (BSB-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2014 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. One Big Bend Unit 3 outage was identified as an outlying outage; therefore, the associated forced outage hours were removed from the study.

Q. Should the current GPIF methodology be eliminated or modified, and if the latter, how should it be modified?

A. No. The current GPIF methodology should not be eliminated or significantly modified. It continues to perform the function it was designed to accomplish when it was established in 1980 by Commission Order No. 9558 in Docket No. 800400-CI, issued September 19, 1980. There may be room for slight modifications to the various GPIF implementation methodologies to gain some uniformity in the manner in which the utilities administer the GPIF program, but there is no reason to eliminate or significantly modify the methodology.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2014 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2014 period, the projected EUOF for Bayside Unit 1 is 1.1 percent, and the POF is 4.9 percent. Therefore, the target EAF for Bayside Unit 1 equals 94.0 percent or:

$$100\% - (1.1\% + 4.9\%) = 94.0\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 1 - [0.80 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80 \ (1.1\%) + 0.95 \ (4.9\%)] = 94.4\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (1.1\%) + 1.10\ (4.9\%)] = 93.1\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2014 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2014; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from March 17, 2014 to March 25, 2014 and December 2, 2014 to December 10, 2014. There are 432 planned outage hours scheduled for the 2014 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 4.9 percent or:

$$\frac{432}{8{,}760} \times 100\% = 4.9\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 23.0 percent. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 6.6 percent. Big Bend Unit 4 has a POF of 18.1 percent. Polk Unit 1 has a POF of 5.2 percent. Bayside Unit 1 has a POF of 4.9 percent, and Bayside Unit 2 has a POF of 4.9 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. For each unit the most current 12-month ending value, June 2013, was used as a basis for the projection. All projected factors are based upon historical unit performance. These target factors are additive and result in a EUOF of 1.1 percent for Bayside Unit 1. The EUOF for Bayside Unit 1 is verified by the data shown on page 19, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

or

$$EUOF = \frac{(18 + 77)}{8{,}760} \times 100\% = 1.1\%$$

Relative to Bayside Unit 1, the EUOF of 1.1 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected EUOF for this unit is 16.4 percent. The unit will have two planned outages in 2014, and the POF is 23.0 percent. Therefore, the target equivalent availability for this unit is 60.6 percent.

Big Bend Unit 2

The projected EUOF for this unit is 18.6 percent. The unit will have two planned outages in 2014, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 74.9 percent.

Big Bend Unit 3

The projected EUOF for this unit is 19.4 percent. The unit will have two planned outages in 2014, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 74.1 percent.

Big Bend Unit 4

The projected EUOF for this unit is 19.3 percent. The unit will have two planned outages in 2014, and the POF is 18.1 percent. Therefore, the target equivalent availability for this unit is 62.6 percent.

Polk Unit 1

The projected EUOF for this unit is 10.8 percent. The unit will have two planned outages in 2014, and the POF is 5.2 percent. Therefore, the target equivalent availability for this unit is 84.0 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.1 percent. The unit will have two planned outages in 2014, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 94.0 percent.

Bayside Unit 2

The projected EUOF for this unit is 9.3 percent. The unit will have two planned outages in 2014, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 85.8 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 76.9 percent is shown on Page 5 of Document No. 1. This target is greater than last year's January through December actual performance.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 1 on page 19 of Document No. 1. Except for the months of March and December, the Equivalent Unplanned Outage Rate and the EUOF are equal. This is because no planned outages are scheduled during these months. During the months of March and December, the Equivalent Unplanned Outage Rate exceeds the EUOF due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2014 period.

A. The heat rate target for Big Bend Unit 1 is 10,501 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±301 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,271 Btu/Net kWh with a range of ±214 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,696 Btu/Net kWh, with a range of ±174 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,381 Btu/Net kWh with a range of ±186 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,506 Btu/Net kWh with a range of ±141 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,283 Btu/Net kWh with a range of ±118 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,387 Btu/Net kWh with a range of ±77 Btu/Net kWh. A zone of tolerance of ±75

Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $724,400,390 is shown on page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $14,961,899 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 10.47 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Bayside Unit 1, page 12, if the unit operates at 7,164 average net operating heat rate, fuel savings would equal $1,566,079 and 10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $14,961,899. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2014 is $2,066,528,003. This produces the maximum allowed jurisdictional incentive of $8,446,336 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met limiting total potential reward and penalty incentive dollars to $7,480,950.

Q. Please summarize your testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$
\begin{aligned}
GPIP: = (&0.0803\ EAP_{BB1} + 0.0071\ EAP_{BB2} \\
&+ 0.0489\ EAP_{BB3} + 0.0306\ EAP_{BB4} \\
&+ 0.0166\ EAP_{PK1} + 0.0589\ EAP_{BAY1} \\
&+ 0.0867\ EAP_{BAY2} + 0.1320\ HRP_{BB1} \\
&+ 0.1167\ HRP_{BB2} + 0.0877\ HRP_{BB3} \\
&+ 0.0896\ HRP_{BB4} + 0.0505\ HRP_{PK1} \\
&+ 0.1047\ HRP_{BAY1} + 0.0899\ HRP_{BAY2})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/ deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2014 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 8/30/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing group within the Fuels Management Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and am a registered Professional Engineer within the State of Florida. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of

Energy Products and Structures in the Wholesale Marketing group. My responsibilities are to evaluate short and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract structure, and help evaluate the processes used to value potential wholesale power transactions. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers and other wholesale generators.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 030001-EI, 040001-EI, and 080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchase and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, supplement generation during unit outages, and for economical purposes. When Tampa Electric considers making a power purchase, the company aggressively searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs.

The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company's contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2013 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short and long-term purchases based on price and availability of supply. Approximately seven percent of the expected energy needs for 2013 will be met using purchased power. This purchased power energy includes economy purchases, qualifying facilities, and existing firm purchased power agreements with Pasco Cogen, Calpine, and Southern Power Company. The testimony in previous years describes each existing firm purchased power agreement; however, in summary, all three purchases are call options with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase is 121 MW of intermediate capacity and continues through 2018. Both Calpine and Southern Power Company are peaking purchases with capacities of 117 MW and 160 MW, respectively. The Southern Power Company purchase continues through 2015, while the Calpine purchase continues through 2016. All of the aforementioned purchases provide supply reliability and help reduce fuel price volatility and were previously approved by the Commission as being cost-effective for Tampa Electric customers.

In addition to these purchases, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Has Tampa Electric entered into any other wholesale energy purchases beyond 2013?

A. No, besides the previously mentioned purchases, the company has not entered into any other purchases beyond 2013.

Q. Does Tampa Electric anticipate entering into any other wholesale energy purchases for 2014 and beyond?

A. In 2014, the Tampa Electric expects purchased power to meet approximately four percent of its energy needs. This energy includes contributions from the previously mentioned firm purchases. In addition, the company will continue to evaluate the short-term purchased power market as part of its purchasing strategy.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale power products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The Florida wholesale power market currently operates through bilateral contracts between various counterparties, and there is not a Florida trading hub where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity, the appropriate financial instruments to meet the company's needs do not currently exist. Tampa Electric has not purchased any wholesale energy derivatives; however, the company employs a diversified power supply strategy, which includes self-generation and short and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2013?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 117 MW purchased from Calpine and 121 MW purchased from Pasco Cogen are reliable, cost-based call options for power. These purchases serve as both a physical hedge and reliable source of economic power. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short and long-term capacity and energy purchases to augment the company's own generation for the year 2013 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather related events such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions during major weather-related events. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing the seller's fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company's existing three firm purchased power agreements are from dual-fuel resources. This allows these resources to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short and long-term purchase opportunities identified in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2013 and 2014.

A. Tampa Electric entered into various non-separated wholesale sales in 2013, and the company anticipates making additional non-separated sales during the balance of 2013 and in 2014. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2013, Tampa Electric anticipates its gains from non-separated wholesale sales to be $802,676, of which 100 percent would flow back to customers since they are less than the three-year rolling average threshold of $1,366,095. Similarly, in 2014, the company's projected gains from non-separated wholesale sales are $522,912, of which 100 percent would flow back to customers since they are less than the projected three-year rolling average threshold for that year of $650,665.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short and long-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. It also enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the Florida wholesale power market due to a lack of financial instruments appropriate for the company's operations. It does, however, employ a diversified power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 04/05/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering in 1988 from the University of South Florida. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel origination.

Q. Have you previously testified before the Florida Public Service Commission ("FPSC" or "Commission")?

A. Yes. I have previously testified before this Commission in Docket No. 120234-EI regarding the company's fuel procurement and delivery strategy for the Polk 2-5 Combine Cycle Conversion.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission's review, information regarding the 2012 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. ___ (JBC-1), entitled Tampa Electric's 2012 Hedging Activity True-up, was prepared under my direction and supervision. This report explains the company's risk management activities and results for the calendar year 2012.

Q. What is the source of the data you present in your testimony in this proceeding?

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

Q. What were the results of Tampa Electric's risk management activities in 2012?

A. As outlined in Tampa Electric's 2012 Hedging Activity True-up, filed as an exhibit to this testimony, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In particular, Tampa Electric established a financial hedging program to limit its exposure to spikes in the price of natural gas. Over time, this program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

The report indicates that Tampa Electric's 2012 hedging activities resulted in a net loss of approximately $61.5 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. Natural gas prices declined in 2012 due to lower demand as a result of the ongoing economic downturn as well as from an abundance of natural gas supply from non-conventional, shale gas production.

Q. Does Tampa Electric implement physical hedges for natural gas?

A. No, Tampa Electric does not hedge natural gas pricing through physical gas supply contracts. However, Tampa Electric does hedge its supply through diversification. In addition to financial hedging, Tampa Electric uses a variety of sources, delivery methods, inventory locations and contractual terms to enhance the company's supply reliability and flexibility to cost-effectively meet changing operational needs.

Tampa Electric continually pursues new creditworthy counterparties and maintains contracts for gas supplies from various regions and on different pipelines. The company also contracts for pipeline capacity to access non-conventional shale gas production which is less sensitive to interruption by hurricanes. Additionally, Tampa Electric has storage capacity with Bay Gas Storage near Mobile, Alabama. All of these actions enhance the effectiveness of Tampa Electric's gas supply portfolio.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, risk exposure analysis and business report generation functions. The Nucleus system records all financial natural gas hedging transactions, and the system calculates risk management reports.

Q. Did the company use financial hedges for commodities other than natural gas in 2012?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2012.

Tampa Electric's generation is comprised mostly of coal and natural gas. Although the price of coal has also decreased, it is historically stable compared to the prices of oil and natural gas. In addition, there is not an organized nor a liquid market for financial hedging instruments for the high-sulfur Illinois Basin coal that Tampa Electric uses at Big Bend Station, its largest coal-fired generation facility.

Tampa Electric consumes a small amount of oil; however, its low and erratic usage pattern makes price hedging impractical.

Similarly, Tampa Electric did not use financial hedges for wholesale power transactions because a liquid, published market does not exist for power in Florida.

Q. How does Tampa Electric assure physical supply of other commodities?

A. Tampa Electric assures sufficient physical supply of coal and oil through supply diversification, inventory sufficiency, and delivery flexibility for coal. For coal, the company enters into a portfolio of contracts with differing terms and various suppliers to obtain the types of coal used in its electric generation system. This is of particular importance because of increasing competition for Illinois Basin coal supply. This increased competition comes from domestic utilities that have added sulfur dioxide scrubbers to their coal plants and from the international market. This competition for low cost supply puts greater emphasis on the need for a robust coal supply portfolio.

Additionally in 2009, Tampa Electric added rail delivery capability for coal to Big Bend Station. The addition of rail to the existing waterborne transportation facilities enhanced Tampa Electric's access to coal supply and increased delivery reliability.

For oil, Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season. Competition for potentially limited oil supplies and oil transportation during a crisis emphasizes the need for maintaining sufficient inventory.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. Tampa Electric requests cost recovery pursuant to the Commission Order No. PSC-02-1484-FOF-EI, in Docket No.

011605-EI:

Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 8/2/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October

2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generation plants.

Q. Are you the same J. Brent Caldwell who previously filed direct testimony on behalf of Tampa Electric Company in this docket?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. ____ (JBC-2), entitled Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2014.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe this Exhibit.

A. My Exhibit, No. ____ (JBC-2) sets forth all of the various details of Tampa Electric's overall plan for mitigating risk in the company's procurement of generation fuel and purchased power during 2014.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generation plants.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe my Exhibit No. __ (JBC-3), entitled Tampa Electric Natural Gas Hedging Activities, January 1, 2013 through July 31, 2013.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. __ (JBC-3) shows details of Tampa Electric's hedging activities for natural gas for the seven month period January through July 2013.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
FILED: 08/30/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering in 1988 from the University of South Florida. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long-term fuel origination.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities. I also sponsor Tampa Electric's 2014 Fuel Procurement and Wholesale Power Purchases Risk Management Plan and Tampa Electric's Natural Gas Hedging Activities submitted on August 2, and August 16, 2013 in this docket.

Q. Have you previously testified before this Commission?

A. Yes. I testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project. I also submitted testimony in Docket Nos. 110001-EI, 120001-EI and 130040-EI.

2014 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2014?

A. In 2014, coal-fired generation is expected to be approximately 62 percent, and natural-gas fired generation is expected to be 38 percent, of total generation. Generation from oil is expected to be less than one percent of the total expected generation.

Q. Please describe Tampa Electric's fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all of its fuel needs. The company strives to maintain a large number of creditworthy and viable suppliers. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Similarly, the company maintains multiple delivery paths wherever possible. Having a greater number of fuel supply and delivery options provides increased reliability and lower costs for Tampa Electric's customers.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy.

A. Tampa Electric uses solid fuel as the sole fuel for the four pulverized-coal steam turbine units at Big Bend Station and as the primary fuel for the integrated-gasification combined cycle Polk Unit 1. The coal-fired units at Big Bend Station are fully scrubbed for sulfur-dioxide and nitrogen-oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit 1 currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, price, availability, deliverability and creditworthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric maintains a portfolio of bilateral coal supply contracts with varying term lengths: long, intermediate, and short. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market and shaping the company's coal procurement strategy to reflect current market conditions. Tampa Electric's strategy provides a stable supply of reliable fuel sources while still allowing flexibility for the company to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize Tampa Electric's solid fuel, coal and petroleum coke, supply for 2013.

A. Tampa Electric supplied Big Bend's coal needs through a combination of two "base" coal supply agreements that continue through 2014 and a collection of shorter term contracts and spot purchases. These shorter term purchases allowed the supply to adjust for changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2014 delivery?

A. Yes, Tampa Electric has contracted approximately three-fourths of its 2014 expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Tampa

Electric anticipates the remaining solid fuel purchases for Big Bend Station and Polk Unit 1 will be procured through spot market purchases during 2013 and 2014.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements?

A. Tampa Electric can receive coal at its Big Bend Station via both waterborne delivery and rail delivery. Once delivered to Big Bend Station, Polk Unit 1 solid fuel is transported to Polk Station via trucks.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitively priced and diverse, delivered coal, 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2013 and 2014?

A. Yes. Tampa Electric expects to receive approximately two million tons of coal through the Big Bend rail facility during 2014, for use at Big Bend Station.

As part of the CSX transportation agreement, Tampa Electric receives a per ton discount, treated as a reimbursement, for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause pursuant to the company's most recent rate case final order. The partial reimbursement expires at the end of 2014 with the expiration of the current agreement.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries?

A. Tampa Electric expects to receive the balance of its solid fuel supply needs as waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries may come through United Bulk Terminal, from other terminals along the Gulf Coast, or from foreign sources. The ultimate source is dependent upon quality, operational needs, and lowest overall delivered cost.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long and short term deliveries?

A. Similar to its coal strategy, Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate and swing natural gas supply contracts complemented with shorter term spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from approved counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric has improved the reliability and cost effectiveness of the physical delivery of natural gas to its power plants by diversifying its pipeline transportation assets, including receipt points, and utilizing pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. On a daily basis, Tampa Electric strives to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric's risk management activities reduce natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation arrangements.

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. The ability to deliver natural gas directly from two pipelines enhances the fuel delivery reliability of the Bayside Power Station, comprised of two large natural gas combine-cycle units and four aero derivative combustion turbines. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the aero derivative combustion turbine and to Polk Station from FGT to support the four natural gas combustion turbines at that station.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama to provide operational flexibility and reliability of natural gas supply. Currently the company reserves 1,250,000 MMBtu of storage capacity.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH"). SESH connects the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase through non-conventional shale gas and the Rockies Express. Thus, SESH gives Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Has Tampa Electric entered any natural gas supply transactions for 2014 delivery?

A. Yes. Approximately two-thirds of the company's expected natural gas requirements for 2014 are under contract. The balance of Tampa Electric's natural gas supply will be acquired through seasonal, monthly and daily purchases to meet its varying operational needs.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long, intermediate, and short term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Projected 2014 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), Wood Mackenzie, the Energy Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices and are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2014 projected fuel prices compare to the fuel prices projected for 2013?

A. Fuel prices for coal and natural gas are projected to be slightly higher in 2014 than prices projected for 2013.

The projected higher prices reflect expectations of continuing improvement in domestic and international economies and higher production costs for energy commodities.

Q. What are the market drivers of the expected 2014 price of natural gas?

A. The current market forecasts are projecting a slight increase to natural gas pricing in 2014 as compared to actual and estimated 2013 costs. An anticipated improvement to the economy and a market adjustment to shale gas production are expected to slightly raise the price in 2014 compared to 2013.

Q. What are the market drivers of the change in the price of coal?

A. The addition of FGD scrubbers on a number of coal plants has made Illinois Basin coal a viable option for those units thus increasing the demand and price for Illinois Basin coal. Additionally, over the past couple of years, coal inventories have declined, and in some areas, production has even been idled. However, with Tampa Electric's existing coal purchase agreements, the impact of coal market price changes is mitigated through 2014.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected fuel prices?

A. Yes. Tampa Electric prepared a scenario in which the forecasted price for natural gas was increased by 35 percent. Similarly, Tampa Electric prepared a scenario in which the forecasted price for natural gas was reduced by 20 percent. Due to Tampa Electric's generating mix combined with its Commission-approved natural gas hedging strategy, the impact of the fuel price changes under either scenario is mitigated.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Fuel Procurement and Wholesale Power Purchases Risk Management Plan ("Risk Management Plan"), submitted to the Commission on August 2, 2013 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2013 and 2014 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2013 natural gas supply needs and a portion of its expected 2014 natural gas supply needs in accordance with its plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with its approved Risk Management Plan. The current market position for natural gas hedges was provided in the company's Natural Gas Hedging Activities report submitted to the Commission in this docket on August 16, 2013.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2013 and 2014 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are also described in detail in Tampa Electric's Risk

Management Plan.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. Tampa Electric projects the volume of natural gas expected to be consumed in its power plants. The volume hedged is driven by the projected total natural gas consumption in its combined-cycle plants by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee and monitored by the Risk Management department. The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through July 31, 2013 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee.

On April 5, 2013, the company filed its 2012 Natural Gas Risk Management Activities as part of the final true-up process. Additionally, utilities must submit a Natural Gas Hedging Activity Report showing the results of hedging activities from January through July of the current year. The Hedging Activity Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Natural Gas Hedging Activities report, showing the results of its prudent hedging activities from January through July 2013, in this docket on August 16, 2013.

Q. Does Tampa Electric expect its hedging program to provide fuel savings?

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric employs a well-disciplined hedging program. This discipline requires consistent hedging based on expected needs and avoidance of speculative hedging strategies aimed at out-guessing the market. This discipline insures hedges will be in place should prices spike and also means hedges are in place when prices decline. Using this disciplined approach means that much of the volatility and uncertainty in natural gas prices are removed from the fuel cost used to generate electricity for our customers, but does not guarantee fuel savings.

Q. Does this conclude your testimony?

A. Yes, it does.

(Transcript continues in sequence with Volume 2.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

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

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

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

DATED THIS 5th day of November, 2013.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
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