BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160001-EI

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

Pages 1 through 228

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN JULIE I. BROWN COMMISSIONER LISA POLAK EDGAR COMMISSIONER ART GRAHAM COMMISSIONER RONALD A. BRISÉ COMMISSIONER JIMMY PATRONIS
DATE:	Wednesday, November 2, 2016
TIME:	Commenced at 9:54 a.m. Concluded at 10:26 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, CRR, RPR Official FPSC Reporter (850) 413-6734

APPEARANCES:

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

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

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

MATTHEW R. BERNIER, ESQUIRE, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301-7740; and JOHN BURNETT and DIANNE TRIPLETT, ESQUIRES, 299 First Avenue North, St. Petersburg, Florida 33701, appearing on behalf of Duke Energy Florida, Inc.

JON C. MOYLE, JR., and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

APPEARANCES (Continued:)

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

ROBERT SCHEFFEL WRIGHT and JOHN T. LaVIA, III, ESQUIRES, Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of the Florida Retail Federation

J. R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL; ERIK L. SAYLER; PATRICIA A. CHRISTENSEN; and STEPHANIE MORSE, ESQUIRES, Office of Public Counsel, c/o the Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

JAMES W. BREW, and LAURA A. WYNN, ESQUIRES, Stone, Mattheis, Xenopoulos & Brew, P.C., 1025 Thomas Jefferson Street, NW, Eight Floor, West Tower, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate - White Springs.

APPEARANCES (Continued:)

DANIJELA JANJIC and SUZANNE BROWNLESS, 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, Advisor to the Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

I N D E X

WITNESSES

EXHIBITS

NAME:	ID.	ADMTD.

No exhibits in this volume

P R O C E E D I N G S

CHAIRMAN BROWN: I'd like to -- there are five dockets, as you know, that we are going to address today, and we will be taking appearances all at once today. I know some folks have replaced other folks and made notices of appearances. But, please, when you enter your appearance, declare the dockets that you're entering the appearance for.

Also, I know that after the parties make their appearances, staff will be needing to make theirs. So we're going to start right now with Florida Power & Light.

MR. BUTLER: Thank you, Madam Chair.

John Butler appearing on behalf of Florida Power & Light Company in the 01, 02, and 07 dockets. I'd also like to enter an appearance for Wade Litchfield in those three dockets, for Ken Rubin in the 02 docket, and Maria Moncada in the 01 and 07 dockets. Thank you.

CHAIRMAN BROWN: Thank you.

Duke.

MR. BERNIER: Good morning, Madam Chair. Matt Bernier with Duke Energy. I'd like to enter an appearance in the 01, 02, and 07 dockets. I'd also like to enter an appearance for Dianne Triplett in those same three dockets, and for John Burnett in the 01 docket.

CHAIRMAN BROWN: Thank you.

Gulf.

MR. BADDERS: Good morning. Russell Badders on behalf of Gulf Power. With me I have Jeffrey A. Stone, and Steve Griffin is also in this docket in 02, 01, and 07.

CHAIRMAN BROWN: Thank you.

TECO.

MR. BEASLEY: Good morning, Madam Chair. Jim Beasley in the 01, 02, and 07 dockets on behalf of Tampa Electric Company. I'd also like to enter an appearance for J. Jeffry Wahlen and Ashley M. Daniels in the same dockets.

CHAIRMAN BROWN: Thank you.

Mr. Moyle.

MR. MOYLE: Good morning.

CHAIRMAN BROWN: Good morning.

MR. MOYLE: Jon Moyle on behalf of the Florida Industrial Power Users Group, FIPUG. And I'd also like to enter an appearance for Karen Putnal.

CHAIRMAN BROWN: Thank you. And the dockets that you will be --

MR. MOYLE: Oh, I'm sorry. 01, 02, and 07.

CHAIRMAN BROWN: Thank you.

MR. MOYLE: Thank you.

MS. SPARKMAN: Good morning. My name is Paula Sparkman, and I'm here on behalf of Sebring Gas in the 04 docket.

CHAIRMAN BROWN: Thank you.

Good morning.

MR. MUNSON: Good morning. I'm Greg Munson. I'm here on behalf of Florida City Gas in the 03 and 04 dockets. Also here on behalf of Florida Public Utilities in the 01 and 02 dockets; Florida Public Utilities, FPUC-Fort Meade in the 03 docket; Florida Public Utilities, FPUC-Fort Meade, FPUC-Indiantown District, Florida Division of Chesapeake Utilities Corporation in the 04 docket.

CHAIRMAN BROWN: Very complicated.

MR. MUNSON: I have notes.

CHAIRMAN BROWN: Thank you.

Good morning.

MR. BREW: Good morning. James Brew for White Springs Agricultural Chemical/PCS Phosphate appearing in the 01, 02, and 07 dockets. And I'd like to make an appearance for Laura Wynn.

CHAIRMAN BROWN: Thank you.

Good morning, Mr. Wright.

MR. WRIGHT: Good morning, Madam Chairman, Commissioners. Robert Scheffel Wright and John T.

LaVia, III, appearing on behalf of the Florida Retail Federation in the fuel docket, 0001. Thank you.

CHAIRMAN BROWN: Thank you.

Good morning, Ms. Christensen.

MS. CHRISTENSEN: Good morning. Patricia Christensen on behalf of the Office of Public Counsel. I'd also like to put in an appearance for J.R. Kelly, the Public Counsel; Charles Rehwinkel; Erik Sayler; and Stephanie Morse in the 01, 02, 03, 04, and 07 dockets.

CHAIRMAN BROWN: Thank you so much.

All right. Back to staff.

MS. TAN: Lee Eng Tan for the 02 docket, Margo Leathers and Wesley Taylor for the 03 docket, Kelley Corbari for the 04 docket, Charles Murphy and Bianca Lherisson for the 07 docket, and Danijela Janjic and Suzanne Brownless for the 01 docket.

CHAIRMAN BROWN: Thank you.

MS. HELTON: And Mary Anne Helton. I'm here as your advisor in all of the dockets.

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CHAIRMAN BROWN: And now we are moving to the 01 docket. All right. So we're going to open up the 01 docket, and I believe there is a pamphlet that is being presented to folks right now.

MS. JANJIC: Chairman Brown, before we proceed, can we take a five-minute break?

CHAIRMAN BROWN: I just love five-minute breaks.

MS. JANJIC: I think you will like this one. Thank you.

CHAIRMAN BROWN: All right. We'll go ahead and take a five-minute break and reconvene at 10:00. Thank you.

(Recess taken.)

Okay. That was a seven-minute break, but thank you, guys. I think it was a very productive seven minutes. And I want to make sure Commissioner Edgar is on the phone too. Commissioner Edgar, you're on the phone; right?

COMMISSIONER EDGAR: I am here. Thank you.

CHAIRMAN BROWN: Great. So we have opened up the 01 docket, and there are some preliminary matters, my understanding. And would you like to address those at this time?

MS. JANJIC: Yes, Chairman. Staff would like to note that all witnesses have been excused and opening statements, if any, are limited to three minutes per party.

In addition, there are proposed stipulations on all the issues. And since 1B was contested until this morning, PCS Phosphate would like to address the Commission at this time. So I'm going to open up to them.

CHAIRMAN BROWN: Okay. Well, I will open up to Mr. Brew. I want to first thank you all. There's been a lot of time and discussion and energy among the parties and staff on getting to a point where we're at today. Again, this is a year-long process, and it looks like it's going to continue to be even more in-depth and more detailed discussions. So I want to take the opportunity first to just really give some gratitude to all of you folks for working together. And, Mr. Brew, with that, you have a generous three minutes.

MR. BREW: Thank you, Madam Chairman.

Good morning, everyone. This involves specifically, with respect to Duke, Issues 1A, 1B, and 2B, which is the proposed stipulation to start a generic proceeding to look at how to hedge better, the proposal to stop hedging or establish a moratorium on hedging, and, in Duke's case, withdrawing its proposed 2017 risk management plan.

The concern that PCS has is -- and I was trying to think of an approach. Normally Mr. Moyle at this point would resort to an automobile analogy.

CHAIRMAN BROWN: What do you have?

MR. BREW: But I'm not going to go there. This is more -- there's a Chinese proverb that says there's two best times to plant a tree: 20 years ago and today. And the joint stipulation kind of adopts that philosophy here, which is there's two best times to stop hedging: Five years ago and several billions of dollars in losses and today. Well, hedging doesn't work that way. You have -- the discussion has to go further. You actually have to look at the facts.

And what we have here is you have a staff exhibit, Mr. Cicchetti, showing Henry Hub prices at the lowest prices we've seen since 1999. You have Duke's discovery responses in their testimony showing that their expected hedging losses are basically drying up. In fact, 80 percent of their hedges for this year were incurred before -- through July. And they're, at this point, expecting to show a net gain on hedges by 2018, and their hedging program is rolling 36 months. And they're also forecasting, with increased demand and the beginning of liquified natural gas exports, that there will be upward pressure on prices. So you look at those facts and say, my goodness, why are we stopping hedging now? Even if we're hedging badly, why are you stopping it now?

So that was -- PCS's point is that the notion of having a generic proceeding to hedge better is crucial because of -- Duke's generation is almost 70 percent gas now on a $1.4 billion budget. How they hedge and hedging effectively is absolutely crucial to ratepayers, and it's probably the biggest factor affecting overall bills. And so we firmly support starting the generic proceeding. Our concern, frankly, is that we can have a generic proceeding and end up with exactly the same testimony next year as we had this year.

And so we've -- just looking at the information in the record and in the exhibits, you would say this is a great time to reexamine our hedging practices, but it's a bad time to stop hedging altogether.

The problem is that, and what Duke and I have talked about this morning, is that their authority to engage in additional hedges really expires if the joint stipulation is adopted and their 2017 plan is withdrawn.

Also, their 2017 plan scales back what they were going to hedge for 2018 anyway. So we really haven't accomplished much, which really gets to the real nub of things, which is that under the current strategy, the utilities will take necessarily a path of least resistance. You don't like the hedging costs, fine, we won't do it. That's not really addressing customers' needs here.

So you have a circumstance in which it makes all the sense in the world to continue even the process they're doing. Instead, we're going to do less of it or none. And so what we've come back to and what I've talked to Duke about is that the combination of those three issues, including withdrawal of their -- Duke's 2017 plan, means that there's nothing really to be gained by briefing the issue of what they should -- how much additional they should have for 2018. What it does mean is that PCS's comment on Issue 1A, which is that it's crucial that the generic docket be expedited, is really what we need to focus on and would like the Commission to address. We would suggest that no later than early January we start convening meetings to address the issues because there is a real serious gap between the staff testimony looking at more risk-adjusted approaches to hedges and the utility approach in terms of not doing anything that actually involves accepting potential risk on their side.

And so those are really crucial issues that we need to get to, so our proposal is that we're agreeable to go with the joint stipulation, provided that the generic docket is expedited and activities begin right after the beginning of the new year or sooner, if possible. Thank you.

CHAIRMAN BROWN: Thank you, Mr. Brew. And does that change any of your positions as you --

MR. BREW: It would technically change our position on 1B to be "No position."

CHAIRMAN BROWN: Okay. Thank you for that clarity.

And Duke.

MR. BERNIER: Thank you, Madam Chair. I'd like to thank Mr. Brew and PCS Phosphate for the good conversations we had. I can confirm much of what he said regarding our '16 and '17 plans, and I also agree that the hedging workshops, should it be your preference, should be held as expeditiously as possible. Other than that, we're, you know, very happy with the way this has turned out, and thank your staff and all the parties, so.

CHAIRMAN BROWN: Thank you. And before we get into the discussion by the Commissioners and get into the record, I want to see if the Commissioners have any questions of Mr. Brew or Duke at this time.

Seeing none, do any of the other parties wish to make brief remarks or opening statements?

Yes, Mr. Moyle.

MR. MOYLE: I was just going to say that, you know, FIPUG has taken a position that we would rather pay at the pump. We don't like hedging. We've lost billions of dollars in hedging, and just as a matter of policy we're comfortable paying at the pump.

The reason that we signed the stipulation is because it has in there that hedging will stop, that the utilities are withdrawing their hedging plans, and it's stopping, taking a breath. People are going to look at it and make a judgment, an informed judgment about, okay, what should be the plan. And it could be a wide variety of things, including we just don't need hedging, period, zero, or we do it in a revised way.

You also have before you the FPL settlement, which puts a four-year hiatus on hedging. So I know that's a separate docket, but, you know, I think that, from FIPUG's perspective, hedging has not worked well. And we understand the market may change and it may be, boy, if we had hedged, we would have saved money. We understand that. But I think our overall preference is to not have hedging. That's the position we've advocated, that's the position that's realized by the withdrawal of the plan, so we support the stipulation in that regard. But that being said, we're happy to participate in these workshops. We think they'll be good, informative, and look forward to them, and would, likewise, encourage that they be done sooner rather than later. Thank you.

CHAIRMAN BROWN: Thank you, Mr. Moyle.

Any other parties that wish to address the Commission, this is the time to do it.

Seeing none, we're going to go to the record, and then we'll go back to the Commissioners.

Staff, let's go to the prefiled testimony.

MS. JANJIC: Staff will ask that the prefiled testimony of all witnesses identified in Section VI of the Prehearing Order be inserted into the record as though read.

CHAIRMAN BROWN: We will go ahead and enter into -- pardon me -- insert into the record as though read all witnesses identified in Section VI of the Prehearing Order.

DUKE ENERGY FLORIDA

DOCKET NO. 160001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January through December, 2015

DIRECT TESTIMONY OF
Christopher A. Menendez

March 2, 2016

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC, as Rates and Regulatory Strategy Manager.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida, LLC ("DEF" or the "Company"). These responsibilities include completion of regulatory financial reports and analysis of state, federal, and local regulations and their impacts on DEF. In this capacity, I am responsible for DEF's Final True-Up, Estimated/Actual Projection and Projection Filings in the Fuel Clause, Capacity Cost Recovery Clause and Environmental Cost Recovery Clause.

Q. Please describe your educational background and professional experience.

A. I joined the Company on April 7, 2008 as a Senior Financial Specialist in the Florida Planning & Strategy group. In that capacity, I supported the development of long-term financial forecasts and the development of current-year monthly earnings and cash flow projections. In 2011, I accepted a position as a Senior Business Financial Analyst in the Power Generation Florida Finance organization. In that capacity, I provided accounting and financial analysis support to various generation facilities in DEF's Fossil fleet. In 2013, I accepted a position as a Senior Regulatory Specialist. In that capacity, I supported the preparation of testimony and exhibits for the Fuel Docket as well as other Commission Dockets. In October 2014, I was promoted to my current position. Prior to working at DEF, I was the Manager of Inventory Accounting and Control for North American Operations at Cott Beverages. In this role, I was responsible for inventory-related accounting and inventory control functions for Cott-owned manufacturing plants in the United States and Canada. I received a Bachelor of Science degree in Accounting from the University of South Florida, and I am a Certified Public Accountant in the State of Florida.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide DEF's Fuel Adjustment Clause final true-up amount for the period of January 2015 through December 2015, and DEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __(CAM-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. __(CAM-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. __(CAM-3T), Schedules A1 through A3, A6, and A12 for December 2015, year-to-date; and Exhibit No. __(CAM-4T), a schedule outlining the 2015 capital structure and cost rates applied to capital projects. Exhibit No. __(CAM-4T) is included for informational purposes only, as DEF's 2015 Actual True-Up Filing does not include a capital return component. Schedules A1 through A9, and A12 for the year ended December 31, 2015, were previously filed with the Commission on January 20, 2016. Revised Schedules A3 and A4 for the year ended December 31, 2015 were filed with the Commission on February 10, 2016.

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

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. 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. The Company relies on the information included in this testimony in the conduct of its affairs.

Q. Would you please summarize your testimony?

A. Per Order No. PSC-15-0586-FOF-EI, the projected 2015 fuel adjustment true-up amount was an over-recovery of $78.7 million. The actual over-recovery for 2015 was $116.6 million resulting in a final fuel adjustment true-up over-recovery amount of $37.8 million. Exhibit No. __(CAM-1T).

The projected 2015 capacity cost recovery true-up amount was an under-recovery of $38.6 million. The actual amount for 2015 was an under-recovery of $35.8 million resulting in a final capacity true-up over-recovery amount of $2.9 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2015 for fuel cost recovery?

A. The actual ending balance as of December 31, 2015 for true-up purposes is an over-recovery of $116,563,080.

Q. How does this amount compare to DEF's estimated 2015 ending balance included in the Company's estimated/actual true-up filing?

A. The actual true-up amount attributable to the January - December 2015 period is an over-recovery of $116,563,080, which is $37,832,048 higher than the re-projected year end over-recovery balance of $78,731,031.

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional over-recovery of $116,563,080 shown on your Exhibit No. __(CAM-1T)?

A. The factors contributing to the over-recovery are summarized on Exhibit No. __(CAM-1T), sheet 1 of 7. Net jurisdictional fuel revenues were favorable to the forecast by $60.3 million, while jurisdictional fuel and purchased power expense decreased $44.6 million, resulting in a difference in jurisdictional fuel revenue and expense of $104.9 million. The $60.3 million increase in jurisdictional fuel revenues is primarily attributable to the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA) refund of $40 million set forth in RRSSA paragraph 6.b and a favorable sales variance for the year. The $40 million refund is accounted for as an increase to retail revenue in actuals, resulting in the revenue variance, but is treated as a reduction to fuel and purchased power expense in the 2015 Projection filing. The $44.6 million decrease in jurisdictional fuel and purchased power expense is primarily attributable to a favorable system variance from projected fuel and net purchased power of $38.5 million as more fully described below. The RRSSA refunds and adjustments are also discussed more fully below. The $116.6 million over-recovery also includes the deferral of $11.6 million of 2014 over-recovery approved in Order No. PSC-15-0586-FOF-EI. The net result of the difference in jurisdictional fuel revenues and expenses of $104.9 million, plus the 2014 deferral of $11.6 million and plus the 2015 interest provision calculated on the deferred balance throughout the year, is an over-recovery of $116.6 million as of December 31, 2015.

Q. Please explain the components contributing to the $37.8 million variance between the actual over-recovery of $116.6 million and the approved, estimated/actual over-recovery of $78.7 million.

A. The major factors contributing to the $37.8 million variance are a $19.1 million increase in sales and a $17.5 million decrease in system fuel and net power costs.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 7, which helps to explain the $38.5 million favorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(CAM-1T), sheet 6 of 7 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the <u>amount</u> (MWH's) of energy required; (2) changes in the <u>heat rate</u> of generated energy (BTU's per KWH); and (3) changes in the <u>unit price</u> of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH). The $38.5 million favorable system variance is mainly attributable to lower than projected fuel pricing, partially offset by higher than expected purchased power transactions and the $40 million RRSSA refund, which was treated as a reduction to fuel expense for rate-making purposes in DEF's Projection filing, but was treated as an adjustment to revenue in actuals.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. __(CAM-3T) in the footnote to line 6b on page 1 of 2, Schedule A2.

Q. Did the Company make an adjustment for changes in coal inventory based on an Aerial Survey?

A. Yes, DEF included a unfavorable adjustment of $2.2 million to coal inventory, which is attributable to the semi-annual aerial surveys conducted on May 12, 2015 and October 26, 2015 in accordance with Order No. PSC-97-0359-FOF-EI, issued in Docket No. 970001-EI. This adjustment represents 0.46% of the total coal consumed at the Crystal River facility in 2015.

Q. Were there any impacts to the 2015 True-up filing associated with the 2013 RRSSA?

A. Yes. Paragraphs 6.a, 6.b, and 7.a all impact the 2015 true-up. Paragraph 6.a requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2015 through the Fuel Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 6.b requires DEF to refund retail customers $40 million in 2015 through the Fuel Clause. Paragraph 7.a allows DEF to increase fuel rates by $1.00/mWh, or 0.10 ¢/kWh, for the accelerated recovery of the carrying charges associated with the CR3 Regulatory Asset and requires that the increases be added to the fuel factor at secondary metering consistent with the normal fuel projection process. These impacts are addressed further in the testimony below.

Q. Have you included these impacts in your calculation of the true-up balance?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules and how this is included in the final true-up amount?

A. The 2015 Projection Filing, approved in Commission Order PSC-14-0701-FOF-EI, established the refund of the $10 million through a reduction in 2015 fuel rates for Residential and General Service, Non-Demand customers. The rate reduction is inherently reflected in the Jurisdictional Fuel Revenues reported in Exhibit No.___ (CAM-1T) (Sheets 2 and 3 of 7) on line C1. The refund of $10 million is shown on line C.1c. This amount is included in the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 6.b is included in your schedules and how this is included in the final true-up amount?

A. Exhibit No. ___ (CAM-1T) (Sheets 2 and 3 of 7) shows the refund of $40 million on line C.1a allocated evenly over the 12-month period. This amount is included in the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 7.a is included in your schedules and how this is included in the final true-up amount?

A. Exhibit No.___ (CAM-1T) (Sheets 2 and 3 of 7) shows the fuel adjustment to revenue of $38.6 million on line C.1b. This amount is removed from the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Did DEF exceed the economy sales threshold in 2015?

A. Yes. DEF did exceed the gain on economy sales threshold of $1.7 million in 2015. As reported on Schedule A1, Line 15a, the gain for the year-to-date period through December 2015 was $3.7 million. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gain in excess of the three-year rolling average. For 2015, that amount is $0.4 million.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2016 hearings been updated to incorporate actual data for all of year 2015?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2013 through 2015, as follows:

Year	Actual Gain
2013	$427,107
2014	$4,493,609
2015	$3,720,655
Three-Year Average	$2,880,457

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2015 for capacity cost recovery?

A. The actual ending balance as of December 31, 2015 for true-up purposes is an under-recovery of $35,762,070.

Q. How does this amount compare to the estimated 2015 ending balance included in the Company’s estimated/actual true-up filing?

A. When the estimated 2015 under-recovery of $38,643,255 is compared to the $35,762,070 actual under-recovery, the final capacity true-up for the twelve month period ended December 2015 is an over-recovery of $2,881,185.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission in Order No. PSC-96-1172-FOF-EI. The true-up amount was determined in the manner set forth on the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the actual period-end capacity over-recovery of $2.8 million?

A. Exhibit No. __(CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $2.8 million over-recovery is due primarily to an understatement of projected capacity expenses of approximately $7.0 million. The misstatement was the result of DEF incorrectly projecting an annual capacity expense component for a few contracts. The misstatement was made in the projection only; actuals were unaffected. This was offset by an accounting error of $8.8 million that understated actual capacity expense in December 2015; this was corrected in January 2016. These issues were both known and corrected in DEF's Midcourse petition filed on February 8, 2016 in Docket No. 160001-EI.

Q. Does this conclude your direct true-up testimony?

A. Yes.

DUKE ENERGY FLORIDA

DOCKET NO. 160001-EI

Fuel and Capacity Cost Recovery
Estimated/Actual True-Up Amounts
January through December 2016

DIRECT TESTIMONY OF
Christopher A. Menendez

August 4, 2016

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 160001-EI?

A. Yes, I provided direct testimony on March 2, 2016.

Q: Has your job description, education, background and professional experience changed since that time?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission approval, Duke Energy Florida's (DEF or the Company) estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2016.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (CAM-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2016 estimated/actual fuel and purchased power true-up balance and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required per Order No. PSC-16-0001-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2016 estimated/actual capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2016 and estimated data from July through December 2016.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2016 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an under-recovery of $26,217,663. The calculation begins with the actual over-recovered balance of $40,239,626 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2016. This balance plus the estimated July through December 2016 monthly true-up calculations comprise the estimated

$26,217,663 under-recovered balance at year-end. The projected December 2016 true-up balance includes interest which is estimated from July through December 2016 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.03% per month.

Q. How does the current fuel price forecast for July through December 2016 compare with the same period forecast used in the Company's 2016 Midcourse filing approved in Order No. PSC-16-0120-PCO-EI?

A. Natural gas costs increased $0.04/mmbtu (1%), coal costs decreased $0.10/mmbtu (3%), and light oil increased $4.32 /mmbtu (17%).

Q. Have you made any adjustments to your estimated fuel costs for the period July through December 2016?

A. Yes, we made two adjustments totaling a net reduction of $4,422,996. We made an adjustment to reduce fuel costs by $86,882 (grossed up to $87,366 from retail to system) for the amortization of interest on the refund pursuant to the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI. Additionally, DEF made an adjustment to remove the replacement power costs associated with the current Hines Unit 4 outage until the investigation into the cause of the outage is complete. This adjustment reduced fuel costs by $4,310,050 (grossed up to $4,335,630 from retail to system). These adjustments are included on Schedule E1-B (sheet 2), line A5, from July – December 2016.

Q. Were there any impacts to the 2016 Estimated/Actual filing associated with the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA)?

A. Yes. Paragraphs 6.a and 6.b both impact the 2016 Estimated/Actual true-up balance. Paragraph 6.a requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2016 through the Fuel Clause, allocated 94% to Residential customers and 6% to General Service Non-Demand customers. Paragraph 6.b requires DEF to refund to retail customers $60 million in 2016 through the Fuel Clause.

Q. Have you included these impacts in your calculation of the 2016 Estimated/Actual true-up balance?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. The 2016 Projection Filing, approved in Commission Order No. PSC-15-0586-FOF-EI, established the refund of the $10 million through a reduction in 2016 fuel rates for Residential and General Service Non-Demand customers, which was also included in DEF's Midcourse Filing, approved in Commission Order No. PSC-16-0120-PCO-EI. The rate reduction is inherently reflected in the Jurisdictional Fuel Revenues reported in Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) on line C.1. The refund of $10 million is shown on line C.1c. This amount is included in the 2016 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 6.b is included in your schedules and how it is included in the Estimated/Actual true-up amount?

A. Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) shows the refund of $60 million on line C.1a allocated evenly over the 12-month period. This amount is included in the 2016 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2016?

A. No, DEF estimates the total gain on non-separated sales during 2016 will be $585,247, which does not exceed the three-year rolling average of $2,880,457.

Q. On May 25, 2016, an outage occurred at the Hines Combined Cycle Plant. Has DEF included the replacement power costs resulting from this outage into the 2016 Estimated/Actual True-Up filing?

A. No, DEF has not included replacement power costs resulting from this outage; the root cause analysis of the event is on-going and therefore it is premature to incorporate this event into the fuel forecast.

CAPACITY COST RECOVERY

Q. What is the amount of DEF's 2016 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an over-recovery of $14,665,234. The estimated true-up calculation begins with the actual under-recovered balance of $37,105,465 for the month of June 2016. This balance plus the estimated July through December 2016 monthly true-up calculations comprise the estimated $14,665,234 over-recovered balance at year-end. The projected December 2016 true-up balance includes interest which is estimated from July through December 2016 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.03% per month.

Q. What are the primary drivers of the estimated year-end 2016 capacity over-recovery?

A. The $14.7 million over-recovery is primarily attributable to higher than projected capacity revenues of approximately $7.3 million and lower than projected capacity expenses of approximately $7.4 million.

Q. Has DEF included the nuclear cost recovery amounts approved in Order No. PSC-15-0586-FOF-EI?

A. Yes, DEF has included $56,469,745 of 2016 recoverable expenses associated with the CR-3 Uprate project.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA

DOCKET NO. 160001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2017

DIRECT TESTIMONY OF
Christopher A. Menendez

September 1, 2016

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 160001-EI?

A. Yes, I provided direct testimony on March 2, 2016 and August 4, 2016.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the fuel and capacity cost recovery factors of Duke Energy Florida, LLC (DEF or the Company) for the period of January through December 2017.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__(CAM-3), consisting of Parts 1, 2 and 3. Part 1 contains DEF's forecast assumptions on fuel costs. Part 2 contains fuel cost recovery (FCR) schedules E1 through E10, H1 and the calculation of the inverted residential fuel rate. I have not included the schedule that supports the rate of return applied to capital projects recovered through the fuel clause pursuant to Order No. PSC-15-0001-PCO-EI, as there are no capital projects for which DEF is requesting recovery in this docket. Part 3 contains capacity cost recovery (CCR) schedules and is co-sponsored by Ms. Marcia Olivier.

FUEL COST RECOVERY CLAUSE

Q. Please describe the fuel cost factors calculated by the Company for the projection period.

A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of 3.663 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.5874 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.0058 ¢/kWh, and an estimated prior period under-recovery true-up of 0.0669 ¢/kWh. Utilizing this factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for service taken at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors.

Schedule E1-D, lines 11-12 show the Company's proposed tiered rates of 3.377 ¢/kWh for the first 1,000 kWh and 4.377 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rates" schedule in Part 2.

Schedule E1-E develops the Time of Use (TOU) multipliers of 1.247 On-peak and 0.885 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level which results in the final TOU fuel factors to be applied to customer bills during the projection period.

Q. What is the amount of the 2016 net true-up that DEF has included in the fuel cost recovery factor for 2017?

A. DEF has included a projected under-recovery of $26,217,663. This amount includes a projected actual/estimated under-recovery for 2016 of $26,191,847, and the final 2015 true-up net under-recovery of $25,816, which is comprised of the 2015 over-recovery of $116,563,080 net of DEF's Midcourse Correction true-up of $116,588,896.

Q. What is the change in the levelized residential fuel factor for the projection period from the fuel factor currently in effect?

A. The projected levelized residential fuel factor for 2017 of 3.667 ¢/kWh is an increase of 0.707 ¢/kWh or 24% from the 2016 Midcourse Correction levelized residential fuel factor of 2.960 ¢/kWh.

Q. Were there any impacts to the 2017 Projection filing associated with the 2013 RRSSA?

A. No. The RRSSA refunds were complete in 2016.

Q. Please explain the increase in the 2017 fuel factor compared with the 2016 Midcourse Correction fuel factor.

A. The primary drivers of the increase in the 2017 fuel factor are the difference in prior period true-up amount and completion of the RRSSA refunds. The 2016 Midcourse Correction fuel factor included a $200 million over-recovery, whereas the 2017 fuel factor includes a $26 million under-recovery; this results in a net change of approximately $226 million or 0.576 ¢/kWh. As mentioned above, DEF completed the final RRSSA refunds in 2016. In 2016, DEF included both a $60 million refund to all retail customers, pursuant to paragraph 6.b, and a $10 million refund to Residential and General Service Non-Demand customers, pursuant to paragraph 6.a. The completion of the $60 million refund in 2016 results in a net change of approximately 0.153 ¢/kWh. The completion of the $10 million refund results in an approximately net change of 0.047 ¢/kWh for Residential customers and approximately 0.030 ¢/kWh for General Service Non-Demand customers.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2017?

A. No, DEF has made no adjustments for 2017.

Q. Is DEF proposing to continue the tiered rate structure for residential customers?

A. Yes. DEF is proposing to continue use of the inverted rate design for residential fuel factors to encourage energy efficiency and conservation. Specifically, the Company proposes to continue a two-tiered fuel charge whereby the charge for a customer's monthly usage in excess of 1,000 kWh (second tier) is priced one cent per kWh higher than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000 kWh price change breakpoint is reasonable in that approximately 71% of all residential energy is consumed in the first tier and 29% of all energy is consumed in the second tier. The Company believes the one cent higher per unit price, targeted at the second tier of the residential class' energy consumption, will promote energy efficiency and conservation. This inverted rate design was incorporated in the Company's base rates approved in Order No. PSC-02-0655-AS-EI.

Q. How was the inverted fuel rate calculated?

A. I have included a page in Part 2 of my exhibit that shows the calculation of the fuel cost factors for the two tiers of the residential rate. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 3.667 ¢/kWh shown on Schedule E1-D. The two factors are then calculated by allocating the total revenues to the two tiers for residential customers based on the total annual energy usage for each tier.

Q. How do DEF's projected gains on non-separated wholesale energy sales for 2017 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2017 is estimated to be $612,488 which is below the benchmark of $2,933,170. 100% of gains below the benchmark and 80% of gains above the benchmark will be distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-00-1744-PAA-EI. Therefore, since the total gain on non-separated sales was below the benchmark, none of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2014 and 2015 of $4,493,609 and $3,720,655, respectively, and estimated gains for 2016 of $585,247 in accordance with Order No. PSC-00-1744-PAA-EI.

Q. Please explain the entry on Schedule E1, line 12, "Fuel Cost of Stratified Sales."

A. DEF has several wholesale contracts with SECI. One contract provides for the sale of supplemental energy to supply the portion of their load in excess of SECI's own resources. The fuel costs charged to SECI for supplemental sales are calculated on a "stratified" basis in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. There are other contracts with SECI, Reedy Creek and the City of Homestead for fixed amounts of base, intermediate, peaking and plant-specific capacity. DEF is crediting average fuel cost of the appropriate strata in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified and plant-specific sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's fuel cost recovery factor was calculated.

A. The process begins with a fuel price forecast and a system sales forecast. These forecasts are input into the Company's production cost simulation model along with purchased power information, generating unit operating characteristics, maintenance schedules, incremental delivered fuel prices and other pertinent data. The model then computes system fuel consumption and fuel and purchased power costs. This information is the basis for the calculation of the Company's fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. System sales are forecasted by the DEF Load and Fundamentals Forecasting Department using a sales-weighted 30-year average of weather conditions at the St. Petersburg, Orlando and Tallahassee weather stations, population projections from the Bureau of Economic and Business Research at the University of Florida, and economic assumptions from Moody's Analytics.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecasts for natural gas and fuel oil (residual and distillate) are based on a combination of third party forecasts, observable market data in the industry as well as hedges and/or forward contracts currently in place. For coal, a third party forecast is used. Additional details and forecast assumptions are provided in Part 1 of my exhibit.

Q. Are current fuel prices the same as those used in the development of the projected fuel factor?

A. No. Fuel prices can change significantly from day to day, particularly in the storm season. Consistent with past practices, DEF will continue to monitor fuel prices and update the projection filing prior to the November hearing if changes in fuel prices warrant such an update.

Q. On May 25, 2016, an outage occurred at the Hines Combined Cycle Plant. Has DEF included the replacement power costs resulting from this outage into the 2017 Projection Filing?

A. No, DEF has not included replacement power costs resulting from this outage; the root cause analysis of the event is on-going and therefore it is premature to incorporate this event into the fuel forecast. DEF expects to address this outage in the 2016 Final True-Up Filing filed in next year's docket.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the schedules that are included in Exhibit__(CAM-3) Part 3.

A. The following schedules are included in my exhibit:

Schedule E12-A – Calculation of Projected Capacity Costs – Year 2017

Page 1 of Schedule E12-A includes estimated 2017 calendar year system capacity payments to qualifying facilities (QF) and other power suppliers, as well as recovery of nuclear costs pursuant to Rule 25-6.0423. The retail portion of the capacity payments is calculated using separation factors consistent with DEF's 2013 RRSSA approved in Order No. PSC-13-0598-FOF-EI. Total nuclear costs included in the 2017 Projected Capacity Costs are limited to costs for the CR3 Uprate project pursuant to the stipulation approved by the Commission in Order No. PSC-15-0521-FOF-EI; per that Order, all known Levy Nuclear Project costs and credits will be presented for Commission review in the 2017 NCRC docket. The revenue requirements for the CR3 Uprate project are as stipulated by DEF and the RRSSA signatories and approved by bench vote of the FPSC on August 9, 2016, in Docket 160009-EI. As discussed in Ms. Olivier's testimony, the ISFSI costs are included on line 38 of Schedule E12-A, page 1. Schedule E12-A, page 2, provides dates and MWs associated with the QF and purchase power contracts.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2016

Schedule E12-B, which is also included in Exhibit __(CAM-2) to my direct testimony filed on August 4, 2016 in the 2016 estimated/actual true-up filing, calculates the estimated true-up capacity over-recovered balance for calendar year 2016 of $14,665,234. This balance is carried forward to Schedule E12-A, line 31 to be returned to customers from January through December 2017.

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-D is the calculation of the 12CP and 1/13 average demand allocators for each rate class. As addressed in the testimony of DEF Witness Olivier, Schedule E12-D also includes the uniform percentage calculation and allocation of the ISFSI revenue requirement to the rate classes.

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Schedule E12-E calculates the CCR factors for capacity and CR3 Uprate costs for each rate class based on the 12CP and 1/13 annual average demand allocators from Schedule E12-D. The factors for capacity, CR3 Uprate and Levy for the Residential, General Service Non-Demand, General Service (GS-2), and Lighting secondary delivery rate class in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity (including revenue taxes) from Schedule E12-A by the class demand allocation factor, and then dividing by estimated effective sales at the secondary metering level. The factor for ISFSI Dry Cask Storage in cents per kWh is calculated by dividing recoverable costs allocated on Schedule E12-D by estimated effective sales at the secondary metering level. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor. The factors allocate capacity, CR3 Uprate and Levy costs to rate classes in the same manner in which they would be allocated if they were recovered in base rates. The factors allocating ISFSI Dry Cask Storage are addressed in Ms. Olivier's testimony.

Pursuant to the 2013 RRSSA, DEF has prepared the billing rates for the demand (General Service Demand, Curtailable, and Interruptible) rate classes to be on a kilo-watt (kW) rather than a kilo-watt-hour (kWh) basis. These changes are reflected in columns 13 – 19.

Q. Has DEF used the most recent load research information in the development of its capacity cost allocation factors?

A. Yes. The 12CP load factor relationships from DEF's most recent load research conducted for the period April 2014 through March 2015 are incorporated into the capacity cost allocation factors. This information is included in DEF's Load Research Report filed with the Commission on July 31, 2015.

Q. What is the 2017 projected average retail CCR factor?

A. The 2017 average retail CCR factor is 1.094 ¢/kWh, made up of capacity of 0.949 ¢/kWh, ISFSI of 0.013 ¢/kWh and nuclear costs of 0.132 ¢/kWh.

Q. Please explain the change in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The total projected average retail CCR factor of 1.094 ¢/kWh is 0.194 ¢/kWh, or 15%, lower than the 2016 Midcourse Correction factor of 1.288 ¢/kWh, approved in Order No. PSC-16-0120-PCO-EI. This decrease is primarily attributable to the difference in prior-period true-up balance and conclusion of the Osprey Tolling Agreement.

Q. Does this conclude your testimony?

A. Yes

DUKE ENERGY FLORIDA

DOCKET NO. 160001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2015

DIRECT TESTIMONY OF JOSEPH MCCALLISTER

April 6, 2016

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 Duke Energy Progress, an affiliate company of Duke Energy Florida, LLC ("DEF" or "Company") as the Director, Natural Gas Oil and Emissions. 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 ("DEI"), Duke Energy Kentucky ("DEK"), Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), and DEF. In addition, this group is responsible for the emission allowance ("EA") position management for DEI, DEK, DEC, DEP and DEF.

Q. Have you testified before the Commission in previous fuel clause proceedings?

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 Duke 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, the Director of Gas, Oil and Power from early 2009 to June 2012, and Director of Gas, Oil and Emissions from July 2012 to the present. Prior to my tenure with Duke 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. The Company relies on information contained in my testimony and exhibits when conducting its affairs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August-December 2015 hedging true-up data and summarize the results of DEF's hedging activity for calendar year 2015 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, and Commission Order No. PSC-09-0255-PAA-EI issued in April 2009.

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 2015 and Exhibit No. __ (JM-2T) which shows DEF's monthly projected 2015 light oil burns and the amount that had been hedged as of January 2015.

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

A. The objectives of DEF's hedging program to reduce price risk and provide greater cost certainty for DEF's customers.

Q. What hedging activities did DEF undertake for 2015 and what were the results?

A. DEF utilized approved financial agreements to hedge a portion of its projected natural gas and light oil fuel burns, and a portion of the estimated fuel surcharge exposure embedded in DEF's coal river barge and railroad transportation agreements. These activities resulted in a net hedge cost for 2015 of $226.5 million.

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

REDACTED

A. Yes. The financial hedging activities executed by DEF were consistent with those outlined in its 2015 Risk Management Plan ("Plan"). In the Plan filed in August 2014, DEF's hedging target ranges were to hedge [redacted] to [redacted] of its forecasted natural gas burns for calendar year 2015 with a target to hedge a minimum of [redacted] of the forecasted natural gas burns over time. With respect to light oil forecasted to be burned at DEF's owned generation facilities for calendar year 2015, DEF targeted to hedge a minimum of [redacted]. With respect to the coal river and rail transportation estimated fuel surcharge exposures for calendar year 2015, DEF targeted to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposures based on contractual provisions in the coal rail and river barge transportation agreements.

For 2015, DEF's hedge percentages based on actual burns for natural gas and light oil were approximately [redacted] and [redacted], respectively. DEF hedge percentages for the estimated fuel surcharges embedded in DEF's coal river and rail transportation in 2015 were [redacted] and [redacted], respectively. The actual hedge percentages for natural gas and the estimated fuel surcharges for coal river and rail transportation were within the ranges outlined in the Plan. As outlined above, DEF's actual hedge percentage for light oil of [redacted] was

REDACTED

lower than the targeted minimum hedge percentage of [redacted] for 2015. With respect to light oil forecasted usage, in January of 2015 DEF had hedged approximately [redacted] of its forecasted light oil usage based on DEF's forecasted burns for 2015, which was higher than the targeted minimum hedge percentage of [redacted]. This is summarized in Exhibit No. __ (JM-2T). Overall, actual fuel oil usage was higher in 2015 than forecasted which resulted in the lower actual overall light oil hedge percentage. 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. In addition, as outlined in DEF's 2016 Risk Management filed and approved in Docket No. 150001-EI, after 2015, DEF no longer hedges light oil for its generation or estimated fuel surcharges for rail transportation.

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

A. Yes. DEF's hedging activity met the stated objective of DEF's hedging program to reduce price risk and provide greater cost certainty for DEF's customers. The hedging activities are consistent with Commission Orders No. PSC-02-1484-FOF-EI, No. PSC-08-0667-PPA-EI, and No. PSC-09-0255-PAA-EI. DEF's hedging activities are conducted in an environment of strong internal controls and executed in a structured manner. DEF's hedging activities do not attempt to outguess the market and may or may not result in net fuel cost savings, but have achieved the objectives of reduced fuel price volatility.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA, LLC. FOR

FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH JULY 2016

FPSC DOCKET NO. 160001-EI

DIRECT TESTIMONY OF Joseph McCallister

August 18, 2016

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 work for Duke Energy Progress, LLC, an affiliate company of Duke Energy Florida, LLC ("DEF", "Petitioner" or "Company"), as the Director, Natural Gas Oil and Emissions. 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, Duke Energy Progress and Duke 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, Duke Energy Progress and Duke Energy Florida.

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. While at Duke 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, the Director of Gas, Oil and Power from early 2009 to June 2012, and Director of Gas, Oil and Emissions from July 2012 to the present. Prior to my tenure with Duke 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.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to outline DEF's hedging objectives and activities for 2017, and outline DEF's hedging results for January 2016 through July 2016.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the follow exhibits:

- Exhibit No. ___ (JM-1P) – 2017 Risk Management Plan (*filed August 4, 2016*); and
- Exhibit No. ___ (JM-2P) – Hedging Results for January 2016 through July 2016 (*filed August 18, 2016*).

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 for a portion of fuel costs.

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Q. Describe DEF's hedging activities that the Company will execute for 2017.

A. DEF will hedge a percentage of its projected natural gas burns utilizing approved 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 2017 forecasted calendar annual burns. DEF anticipates to target to hedge [redacted] percent of its forecasted natural gas burn projections for 2017 as outlined in the Risk Management Plan. With respect to coal river transportation estimated fuel surcharge exposures, DEF will no longer execute financial hedge transactions for periods after 2016. 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. 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.

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As of August 2, 2016, DEF has hedged approximately [redacted] percent of its forecasted natural gas burns for 2017. DEF will continue to execute additional hedges for 2017 throughout the remainder of 2016 and during 2017 consistent with its on-going strategy.

Q. What were the results of DEF's hedging activities for January through July 2016?

A. The Company's natural gas hedging activities for the period of January 2016 through July 2016 have resulted in hedges being above the closing natural gas settlement prices by approximately $114.9 million**.** The Company's overall fuel oil hedging activities have resulted in hedges being below the closing settlement prices for the period of January 2016 through July 2016 by approximately $0.08 million. These overall hedge results were driven primarily by a decrease in natural gas prices after the execution of DEF's 2016 hedging transactions. The hedging activities were executed consistent with DEF's Risk Management Plan. DEF's hedging activity did achieve the objective to reduce the impacts of fuel price risk and volatility, and providing greater fuel price certainty for DEF's customers.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 160001-EI

GPIF Schedules for January through December 2015

DIRECT TESTIMONY OF MATTHEW J. JONES

March 16, 2016

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 Carolinas, LLC ("DEC") as Managing Director of Analytics for Fuels and Systems Optimization.

Q. Describe your responsibilities as Managing Director of Analytics.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of DEF's Generating Performance Incentive Factor ("GPIF") reward/(penalty) amount for the period of January through December 2015. This calculation was based on a comparison of the actual performance of DEF's Seven (7) GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

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

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

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

A. DEF's calculated GPIF incentive amount is a reward of $2,255,421. 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 primarily concern 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.

Additionally, the Bartow combined cycle ("CC") unit has the capability to run in single cycle mode when the steam turbine is in an outage. During such an outage, its heat rate will deviate significantly from its normal range. DEF's heat rate target setting process for the Bartow CC unit excludes historical data when it ran in single cycle mode. During March and April 2015, Bartow combined cycle unit ran in single cycle mode while the unit was in its planned outage. To be consistent with the target setting process, single cycle mode heat rate data was excluded from actuals for the purposes of calculating the heat rate for Bartow combined cycle in year 2015 during those times when the unit was running in single cycle as the result of a planned outage.

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

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

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA
FOR
FUEL AND CAPACITY COST RECOVERY
FINAL TRUE-UP FOR THE PERIOD
JANUARY THROUGH JULY 2016

FPSC DOCKET NO. 160001-EI

GPIF TARGETS AND RANGES FOR
JAUARY THROUGH DECEMBER 2017

DIRECT TESTIMONY OF
MATTHEW J. JONES

September 1, 2016

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 Corporation ("Duke Energy") as Managing Director of Analytics for Fuels and Systems Optimization. Duke Energy Florida, LLC ("DEF" or "Company") is a wholly-owned subsidiary of Duke Energy.

Q. What are your responsibilities in that position?

A. As Managing Director of Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy's regulated utility subsidiaries, including DEF, as well as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Duke Energy Indiana LLC, 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. 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*. In 2008, I joined Duke Energy as a Commercial Associate, spending a six month rotation working in Business Development and another six month rotation in the FERC Legal group. 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 work on the Kentucky IRP model 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 was also given the responsibility for the Contract Administration and Fuels System Support organizations. In 2014, my title was changed to Managing Director and my organization now includes Quantitative Analytics.

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 2015 and also present the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2017. 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 2015?

A. DEF's calculated GPIF incentive amount for this period was a reward of $2,255,421. Please refer to my testimony filed March 16, 2016 for the details of how this incentive amount was calculated.

Q. Do you have an exhibit to your testimony?

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

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

A. For the 2017 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 85% 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 EUOF and planned outage factor ("POF") when added to the equivalent availability factor ("EAF") will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%.

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

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

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

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

A. No.

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

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

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

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

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

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

Q. How were the GPIF weighting factors determined?

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

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

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

Q. What is the Company's estimated maximum incentive amount for 2017?

A. The estimated maximum incentive for the Company is $20,940,995. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MJJ-1P).

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA

DOCKET NO. 160001-EI

Fuel and Capacity Cost Recovery
Projection 2017

DIRECT TESTIMONY OF
Marcia Olivier

September 1, 2016

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Marcia Olivier. My current business address is 299 First Avenue North, Saint Petersburg, FL 33701.

Q. By whom are you employed and what are your responsibilities?

A. I am employed by Duke Energy Florida ("DEF") as a Director of Rates and Regulatory Planning. I am currently responsible for overseeing rate cases, reporting earnings surveillance results, supporting recovery of the dry cask storage construction project at the Crystal River 3 nuclear plant ("CR3"), and supporting various regulatory filings and initiatives.

Q. Please summarize your educational background and professional experience.

A. I hold a Bachelor of Science degree in Accounting and a Bachelor of Science degree in Finance from the University of South Florida and have almost 20 years of utility experience, primarily in the regulatory area.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. On June 15, 2016, DEF filed a "Petition for Approval of Stipulation to Amend RRSSA" (Docket No. 160151). "RRSSA" refers to the 2013 Revised and Restated Stipulation and Settlement Agreement. This third RRSSA amendment moves the recovery of the dry cask storage capital costs, also referred to as the Independent Spent Fuel Storage Installation ("ISFSI"), from base rates to the Capacity Cost Recovery Clause ("CCR"). While the Commission decision on this amendment is not expected until September 13, 2016, DEF has included the revenue requirements and customer rate impacts in its 2017 CCR projection filing. I will explain the calculation of the revenue requirements and customer rate impacts included in this filing.

I will also support the amounts included in the CCR related to the CR3 Batch 19 nuclear fuel sale and the second amendment to the RRSSA.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___(MO-1), ISFSI;
- Exhibit No. ___(MO-2), Batch 19 Fuel Sale; and
- Exhibit No. ___(MO-3), RRSSA Second Amendment.

These exhibits were prepared under my direction and control, and are true and accurate.

I am also co-sponsoring the following lines of Exhibit No. ___(CAM-3), Schedule E12-A, Page 1 of 2: Lines 26, 27 and 38.

Q. Please summarize your testimony.

A. The ISFSI project is expected to go into service in June 2017. Therefore, Allowance for Funds Used During Construction ("AFUDC") will cease and the calculation of CCR revenue requirements will commence July 1, 2017. I will explain two things related to the ISFSI: 1) the calculations in Exhibit No. ___(MO-1), "ISFSI;" and 2) the allocation of these revenue requirements to the rate classes in Schedule E-12D (attached as an exhibit to Mr. Chris Menendez's testimony).

I am also supporting two other CCR items, related to nuclear fuel sales proceeds and the second RRSSA amendment that were removed from the CR3 Regulatory Asset.

III. CALCULATION OF THE ISFSI REVENUE REQUIREMENT AND ALLOCATION TO THE RATE CLASSES

Q. Please explain the calculation of the 2017 projected CCR revenue requirement.

A. Exhibit No. ___ (MO-1) begins with the beginning ISFSI construction balance as of January 1, 2016. The retail portion of monthly expenditures are then added, after removing the co-owner portion (8.2194%) and multiplying the remaining expenditures by the 92.885% separation factor in the RRSSA, Exhibit 1, approved in Order No. PSC-13-0598-FOF-EI. Monthly AFUDC is calculated by multiplying the monthly average balance before AFUDC by .48676%. This rate is based on the annual rate of 6% in Exhibits 3 and 10 to the RRSSA, discounted to a monthly amount by applying the AFUDC discount formula set forth in Rule 25-6.0141(3)(a), F.A.C. AFUDC will continue through June 2017, the expected construction completion date. Beginning in July 2017, the pretax annual rate of return of 8.12% (per RRSSA, Exhibit 10, Line 20) is divided by 12 and multiplied by the monthly average balance to arrive at the monthly revenue requirement. In total the ISFSI revenue requirement for 2017 is projected to be $5,283,567. This amount is included in Schedule E12-A, Page 1 of 2, Line 38 (attached to Mr. Menendez's testimony).

Q. Why has amortization been excluded from the revenue requirement calculation?

A. Pursuant to Order No. PSC-15-0027-PAA-EI, amortization is being deferred pending final recovery from the Department of Energy ("DOE") of the ISFSI capital costs. DEF continues to claim damages against the Federal Government due to the Federal Government's partial breach of its contractual obligations to DEF to pick up the spent nuclear fuel from CR3 and store it in a federal repository. DEF is currently litigating its 2011-2013 claim, and DEF expects to file its final claim related to the ISFSI after completion of the ISFSI construction project. Once all of these claims have been resolved, DEF will begin amortizing the remaining unrecovered balance over a period to be approved by the Commission at a future date.

Q. Is the allocation of the revenue requirement to rate classes the same as the allocation of all other CCR revenue requirements?

A. No. As reflected in DEF's June 15, 2016 petition for approval of the third RRSSA amendment to recover the ISFSI costs through the CCR rather than base rates, the RRSSA signatories agreed to amend Paragraph 5(e)(1) to state that the ISFSI "shall be allocated to the rate classes annually at the percentages that would have been calculated under the methodology described in the first sentence of Paragraph 5g." RRSSA Paragraph 5g states:

> "The retail base rate change(s) described in paragraph 5e(1) and 5e(2) shall be established by the application of a uniform percentage increase to the demand and energy charges, including delivery voltage credits, power factor adjustments, and premium distribution service reflected in the Company's base rate schedules existing at the time of the base rate increase(s) and shall be calculated using the billing determinants included in the Company's most recent projection clause filing…"

In order to preserve the intent of the RRSSA and comply with the third RRSSA amendment, DEF must allocate the ISFSI revenue requirement differently than the other CCR revenue requirements.

Q. Please explain the allocation of the ISFSI revenue requirement on Schedule E12-D.

A. Columns (11) and (12) have been added to Schedule E12-D (attached as an exhibit to Mr. Menendez's testimony). Column 11 includes the projected 2017 base rate demand and energy revenues by rate class based on the most current base rate revenue forecast. The total revenue requirement is then allocated in Column (12) to the rate classes based on the revenues in Column (11). These revenue requirements by rate class are then reflected in Schedule E12-E Column (4) (attached to Mr. Menendez's testimony).

IV. OTHER CCR ITEMS

Q. Are you supporting any other items contained in the "E" Schedules attached as an exhibit to Mr. Menendez's testimony?

A. Yes, I am supporting two of those items. The first regarding the proceeds related to certain nuclear fuel sales. The Commission, in Order No. PSC-15-0465-S-EI, approved a stipulation that, among other things, provided for recovery through the CCR of a return on nuclear fuel sales proceeds until those proceeds have been received at a pre-tax return rate of 8.12%. DEF has included the monthly revenue requirements on Schedule E12-A (attached to Mr. Menendez's testimony), page 1 of 2, line 27, and Exhibit No. ___(MO-2) provides the support for those amounts.

My testimony also supports the treatment of the approximately $38 million in nuclear cost recovery costs that were removed from the CR3 Regulatory Asset (pursuant to the second RRSSA amendment approved in Order No. PSC-16-0138-FOF-EI) and ordered to be recovered through the CCR over a period of two years beginning January 2017, including a carrying charge rate of 3%. DEF has included the monthly revenue requirements on Schedule E12-A (attached to Mr. Menendez's testimony), page 1 of 2, line 26, and Exhibit No. ___(MO-3) provides the support for those amounts.

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. 160001-EI

MARCH 2, 2016

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. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation; maintenance and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division

(EMT) of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002. In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. My regulatory responsibilities include the preparation of testimony for all fossil fuel, interchange, and hedging-related areas for the Fuel and Capacity Cost Recovery Clauses, including the preparation of Discovery and audit responses. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2015 results of FPL's activities under the Incentive Mechanism that was approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI.

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

A. Yes, I am sponsoring Exhibit GJY-1, consisting of four pages:

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

Q. Please provide an overview of the Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. It was created by the Stipulation and Settlement that was approved in FPL's 2012 rate case by Order No. PSC-13-0023-S-EI. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value from a third party in the form of an Asset Management Agreement (AMA). Per Order No. PSC-13-0023-S-EI, under the Incentive Mechanism, customers receive

100% of the gains up to $46 million. Incremental gains above $46 million are to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $46 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million. Also, per the Order, FPL is allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs, as well as variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case).

Q. Please summarize the activities and results of the Incentive Mechanism for 2015.

A. FPL's activities under the Incentive Mechanism in 2015 delivered $46,884,377 in total gains. During 2015, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation and firm electric transmission. Additionally, FPL entered into an Asset Management Agreement related to a small portion of upstream gas transportation during 2015. The total gains of $46,884,377 exceeded the sharing threshold of $46 million. Therefore, the incremental gains above $46 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2015.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2015.

A. The details of FPL's 2015 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $23,397,901 on wholesale sales and savings of $9,577,611 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2015.

A. The details of FPL's 2015 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had total gains of $13,908,866 that were the result of seven different forms of asset optimization.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2015?

A. Yes. FPL incurred personnel expenses of $407,058 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $66,492 in expenses related to the final implementation and licensing fees of OATI WebTrader software. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $473,550 in 2015. Additionally, FPL's actual wholesale power sales from its own generation resources in 2015 totaled 2,211,963 MWh, or 1,697,963 MWh above the 514,000 MWh threshold, resulting in variable power plant O&M expenses of $2,563,924 (reflects the volume above the threshold multiplied by $1.51/MWh; the average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs). Page 4 of Exhibit GJY-1 provides the details of FPL's Incremental Optimization Costs for 2015.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2015?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2015. On the wholesale power side, similar to 2014, suitable market conditions in the first quarter helped drive strong wholesale power sales. Overall, FPL was able to consistently capitalize on power market opportunities throughout the year to deliver nearly $33 million in customer benefits. Asset optimization activities related to natural gas that had not taken place prior to the inception of the Incentive Mechanism generated slightly more than $11.8 million in gains, and optimization of FPL's firm transmission service on the Southern Company system added another $2.1 million in gains. In total, these activities delivered $46,884,377 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $3,037,474.

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. 160001-EI

APRIL 6, 2016

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. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation, maintenance, and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division

(EMT) of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002. In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. My regulatory responsibilities include the preparation of testimony for all fossil fuel, interchange, and hedging-related areas for the Fuel and Capacity Cost Recovery Clauses, including the preparation of Discovery and audit responses. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

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 2015. This data is required per Item 5 of the Resolution of Issues that was approved by the Commission in Order No. PSC-02-1484-FOF-EI, issued on October 30, 2002, 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 in Order No. PSC-08-0667-PAA-EI, issued on October 8, 2008.

Q. Are you sponsoring an exhibit for this proceeding?

A. Yes. I am sponsoring Exhibit GJY-2 – August through December 2015 Hedging Activity True-Up (Pages 1 through 15).

Q. Does your Exhibit GJY-2 provide the detail on FPL's 2015 hedging activities required by Item 5 of the Resolution of Issues?

A. Yes. All hedging activity details required by Item 5 of the Resolution of Issues are included on pages 1 through 13 of Exhibit GJY-2.

Q. Does your Exhibit GJY-2 include the details of the Woodford Gas Reserves Project ("Woodford Project") that was approved in Order No. PSC-15-0038-FOF-EI issued on January 12, 2015?

A. Yes. The results of the Woodford Project are included on pages 1 through 13 of Exhibit GJY-2.

Q. Does your Exhibit GJY-2 provide the information required by Gas Reserves Guidelines II.A and II.B that were approved in Order No. PSC-15-0284-FOF-EI issued on July 14, 2015?

A. Yes. Consistent with FPL's July 31, 2015 letter to the Commission Clerk's office, the information required by Gas Reserves Guidelines II.A and II.B is on pages 14 and 15 of Exhibit GJY-2.

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 natural gas purchases in 2015, FPL implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL's 2014 Risk Management Plan that was approved by the Commission in Order No. PSC-13-0665-FOF-EI issued on December 18, 2013.

Q. Please summarize FPL's 2015 hedging activities.

A. Consistent with its approved 2014 Risk Management Plan, FPL hedged a portion of its natural gas fuel portfolio for 2015 utilizing financial swaps. FPL's hedging activities for 2015 also incorporated the estimated output of gas reserves from the Woodford Project beginning in March 2015. As described in the 2014 Risk Management Plan, FPL did not hedge heavy fuel oil for 2015, primarily due to the significant drop in heavy oil consumption projections.

Overall, actual 2015 natural gas prices settled, on average, approximately $1.44 per MMBtu lower than the forward prices that were in effect when FPL was executing its financial swaps for 2015 and, on average, approximately $1.75 per MMBtu lower than the gas price forecast utilized in the original Woodford Project filing. As would be expected under the approved hedging approach, this decrease in natural gas prices resulted in reported natural gas hedging costs for the year, as shown on Exhibit GJY-2.

Q. For the Woodford Project, are there additional factors beyond the market price of natural gas that can have an impact on hedging results and projected savings?

A. Yes. While the market price of natural gas is the most significant driver of hedging results and projected savings for the Woodford

Project, there are two other factors that play a role: the cost of production and the volume of gas produced. Unlike the market price of natural gas that is completely outside of FPL's control, the cost of production and the volumes produced can be managed. As seen on page 14 of Exhibit GJY-2, the updated economic evaluation of the Woodford Project shows that decreased production costs coupled with higher expected production volumes are projected to provide an additional $39.5 million in customer savings for the life of the project compared to FPL's original projections. In other words, for the factors that are within its control, FPL is successfully delivering even better value for customers from the Woodford Project than was originally estimated.

Q. What is FPL now projecting as the overall impact to customers' fuel bills related to the Woodford Project?

A. As shown on page 14 of Exhibit GJY-2, the updated economic evaluation indicates a $15.3 million impact to customers' fuel bills over the life of the Woodford Project assuming that future natural gas prices track the projections used in the analysis. Of course, if that happens, then customers will benefit substantially from savings on overall fuel costs.

Q. What would be the impact of the significant decrease in projected natural gas prices on FPL's overall natural gas costs that are passed through to customers?

A. The projected decrease in future natural gas prices would have a substantial impact on FPL's overall natural gas costs and customers' fuel bills. For example, since the original Woodford Project filing, gas prices have fallen $2.91 per MMBtu for gas delivered in 2018. Applying this drop to FPL's approximate annual natural gas requirement of 600 billion cubic feet, yields a reduction in natural gas costs of over $1.7 billion for 2018 alone.

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. 160001-EI

AUGUST 4, 2016

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 (1) FPL's refund calculation for the Woodford Gas Reserves Project ("Woodford") and (2) FPL's refund calculation for the correction in the variable power plant O&M ("VOM") adder under the Incentive Mechanism.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-3: Woodford Refund Calculation
- GJY-4: VOM Correction Refund

<u>WOODFORD REFUND CALCULATION</u>

Q. Please explain FPL's overall approach for "unwinding" all Woodford expenses from the Fuel Clause.

A. The "unwinding" of the Woodford expenses from the Fuel Clause will occur in two distinct parts. First, customers will receive a refund that represents the difference between the actual Woodford expenses from March 2015 through June 2016 and the amount that the volume of natural gas that FPL received from Woodford would have cost customers if FPL had procured that volume in the market. For reference, FPL has used the Columbia Gulf Mainline Index to determine the market price of natural gas. This index represents the price FPL would have paid for natural gas delivered into the Southeast Supply Header ("SESH") pipeline, which is the location at which FPL delivered the Woodford production volume. This is also the index that FPL has used to calculate hedging gains/(losses) associated with Woodford for its Hedging Activity Reports that are filed in August and April of each year. The balance of "unwinding" the Woodford expenses will occur as part of the normal true-up process in the Fuel Clause. I will explain both of these parts in more detail in this testimony. Throughout my testimony, I will reference Tables 1 through 3 of Exhibit GJY-3 that detail the overall calculations.

Q. What are the total expenses that FPL has included in its Fuel Clause Recovery ("FCR") factors for Woodford?

A. As shown on Line 1 in Table 3 of Exhibit GJY-3, the total expenses for Woodford that FPL has included in its FCR factors are $84,560,446. This total is comprised of two components. The first component totaled $26,985,345 (Exhibit GJY-3, Table 1, Column I, Row 13) of actual expenses for 2015 that were rolled into FPL's 2016 Midcourse Correction FCR factors, as FPL's 2015 FCR factors did not include any cost projections for Woodford. The second component totaled $57,575,101 (Exhibit GJY-3, Table 2, Column A, Row 13) of projected 2016 expenses, which were also included in FPL's 2016 Midcourse Correction FCR factors.

Q. Should the full $84,560,446 of Woodford-related costs be refunded to customers?

A. No. The amount that is owed to FPL's customers is the difference between $84,560,446, which will be recovered through the FCR factors, and the amount that FPL would have paid at market prices for the Woodford production volume. As shown on Line 2 in Table 3 of Exhibit GJY-3, the market price of the Woodford production delivered to SESH is $60,066,885. This is composed of $15,730,138 for 2015 (Exhibit GJY-3, Table 1, Column H, Row 13) and $44,336,746 for 2016 (Exhibit GJY-3, Table 2, Column H, Row 13). Please note that of the $44,336,746 for the market price of natural gas in 2016, only the January through June period represents "actual" amounts. The July through December period is an estimated amount based on projected Columbia Gulf Mainline prices from FPL's July 5, 2016 fuel forecast. To the extent that the actual settlement prices are different than those estimates, the difference will become part of the final true-up that I will explain later in my testimony. In total, the amount that is currently owed, on an actual/estimated basis, before interest, is $84,560,446 minus $60,066,885, or $24,493,561. FPL has calculated interest of $38,999, so that the total amount to be refunded is $24,532,560 (Exhibit GJY-3, Table 3, Line 3).

Q. How will FPL refund the $24,532,560 to customers?

A. This amount will be treated as an actual/estimated over-recovery that will reduce FPL's 2017 FCR factors, consistent with the normal true-up process.

Q. Does the $24,532,560 refund amount appear as a hedging cost

for the Woodford Project on FPL's Hedging Activity Report?

A. No. The amount that appears on the Hedging Activity Report is $21,255,317, which is shown on Line 4 of Table 3 in Exhibit GJY-3 (Total Market Value Refund (HAR)). This reflects the difference between actual Woodford expenses for the March 2015 through June 2016 period and the settled market prices of natural gas for the same period. For each month in the period, FPL subtracted the product of the volume of natural gas delivered to SESH from Woodford and the settled Columbia Gulf Mainline Index from the actual Woodford expenses incurred up to the SESH delivery point. Column J in Table 1 and Column K in Table 2 of Exhibit GJY-3 show the monthly differences, or refund amount, owed to customers based on this calculation. In total, FPL has incorporated a refund of $21,294,315 in its monthly filing for June 2016 on Schedule A2 (Line No. 22). This total includes an interest amount of $38,999 calculated from March 2015 through June 2016 that is detailed in Columns K through O of Table 1 and Columns L through P of Table 2 in Exhibit GJY-3.

Q. Please explain the additional component of the $24,532,560 that will be refunded to customers.

A. The additional $3,238,245 to be refunded is described on Lines 7 and 8 of Table 3 as the January-June Total Actual True-up ($2,014,171) and July-December Estimated True-Up ($1,224,061).

The January through June actual true-up represents the difference between the projected monthly Woodford expenses that are part of the 2016 FCR factors (Exhibit GJY-3, Table 2, Column A, Rows 1 through 6) and the actual monthly Woodford expenses (Exhibit GJY-3, Table 2, Column D, Rows 1 through 6). For example, again referring to Table 2 in Exhibit GJY-3, in January 2016, FPL collected $5,905,286 (Column A, Row 1) from customers through its 2016 FCR factors. The actual Woodford expenses for January were $5,135,390 (Column D, Row 1), or a difference of $769,896 (Column I, Row 1). Utilizing this same principle each month, the total true-up portion for the January 2016 through June 2016 is $2,014,171 (Column I, Row 13).

The true-up portion for July 2016 through December 2016 is not known at this time because it will depend on the actual market price of natural gas, however Rows 7 through 12 in Column J of Table 2, show an estimate of that true-up amount based on the July 5, 2016 forecast of Columbia Gulf Mainline natural gas prices. The true-up for these months will be the difference between the projected monthly Woodford expenses that were included in FPL's 2016 FCR factors (Table 2, Column A, Rows 7 through 12) and the actual market price times the projected Woodford production volume that was used in the Fuel Clause projections. In other words, even though FPL is not receiving the natural gas from Woodford, the true-up that is generated each month is based on the original Woodford production projections as FPL will now procure that volume of gas at market prices. As shown on Row 13 in Column J of Table 2, based on the July 5, 2016 forecast, FPL projects that the true-up for the July 2016 through December 2016 period will be $1,224,061. The combination of these two true-up components ($2,014,171 and $1,224,061) equals the $3,238,232 additional amount to be refunded to customers, which is already reflected in the monthly true-ups. Please note that there is a small rounding difference of $13, as noted in Table 3, Line 9 of Exhibit GJY-3.

Q. Does FPL intend to make a final true-up to reflect the actual market prices for gas in July-December 2016?

A. Yes. Any differences between the projected market prices of natural gas and the actual settlement prices for the July 2016 through December 2016 period will be part of FPL's 2016 Final True-Up calculation and will be included in FPL's 2018 FCR factors.

VOM CORRECTION REFUND

Q. Why is FPL making a refund for VOM expenses?

A. In the process of calculating a new VOM rate for FPL's proposed continuation of the Incentive Mechanism based on the 2017 Test

Year MFRs, FPL discovered an error in its calculation of the $1.51 per MWh rate that had been derived from the 2013 Test Year MFRs. Specifically, FPL had inadvertently double counted Base Qualifying Facility (Steam and Other Production) expenses used in the calculation.

Q. How does the corrected calculation change the VOM adder?

A. Removing the double counted portion of Base Qualifying Facility (Steam and Other Production) expenses decreases the VOM adder from $1.51 per MWh to $1.36 per MWh.

Q. Over what period will this adjustment be made?

A. As shown in Exhibit GJY-4, FPL has recalculated the appropriate monthly VOM totals for the January 2013 through April 2016 period. FPL began using the correct adjusted rate in its May 2016 A-Schedules.

Q. How did FPL calculate the appropriate refund due to customers from this correction in the VOM adder?

A. As shown on Exhibit GJY-4, FPL multiplied the $1.36 per MWh rate times the monthly power sales above the applicable sales threshold to determine a total VOM amount that customers should have paid. The difference between this amount and the amount that was actually paid by customers represents the refund amount. FPL has also included interest beginning in March 2013 on the overcollected amount.

Q. What is the total VOM amount that FPL is refunding to customers?

A. As shown on Exhibit GJY-4 and on FPL's June 2016 A2 Schedule (Line No. 23), FPL is refunding $832,856 to its customers. This is comprised of a base refund of $830,871 and interest of $1,985.

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. 160001-EI

SEPTEMBER 2, 2016

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power sales and purchased power transactions. I also review the interim results of FPL's 2016 hedging program and its 2017 Risk Management Plan.

Lastly, my testimony addresses the Incremental Optimization Costs included in FPL's 2017 Projection Filing and the 2015 results of the Incentive Mechanism that was approved in Order No. PSC-13-0023-S-EI dated January 14, 2013.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-5: 2017 Risk Management Plan and Revised 2016 Risk Management Plan
- GJY-6: Hedging Activity Supplemental Report for 2016 (January through July)
- GJY-7: Appendix I
- Schedules E2 through E9 of Appendix II

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies has FPL used for the 2017 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 short-term is incorporated into the curves at all times. The methodology allows FPL to execute hedges consistent with its forecasting method and to optimize the dispatch of its units in changing market conditions. FPL utilized forward curve prices from the close of business on August 1, 2016 for its 2017 projection filing, which is the most current information that could be incorporated into FPL's schedule for calculating the 2017 FCR Clause factors.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections and has used this methodology consistently since that time.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2017 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) the level of working gas in underground storage throughout the period; (3) weather (particularly in the winter period); (4) the potential for imports and/or exports of Liquefied Natural Gas ("LNG") and Canadian natural gas; and (5) the terms of FPL's natural gas supply and transportation contracts.

In its August 2016 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts natural gas prices to average approximately $2.95 per MMBtu in 2017. Although working natural gas rigs are down approximately 95% since the peak in August 2008 and 61% year-on-year, efficiency improvements in the shale regions are leading to record levels of production of natural gas. The EIA expects production to increase in late 2016 and through 2017 in response to forecast price increases and increases in liquefied natural gas ("LNG") exports. Natural gas production is expected to grow by an average rate of 0.6% in 2016 and 2.9% in 2017. Increases in domestic natural gas production are expected to support growth in exports to Mexico and exports of LNG. According to the EIA, the United States is expected to become a net exporter of natural gas during the second quarter of 2017.

Total natural gas consumption in 2017 is expected to average 77.2 billion cubic feet ("BCF") per day, an increase of roughly 0.9 BCF/day from the projected consumption level in 2016. Natural gas consumption in the power sector is projected to increase by 4.8% in 2016 and then decrease by 1.7% in 2017, while industrial sector consumption is expected to increase by 2.5% in 2016 and by 1.1% in 2017 as new fertilizer and chemical projects come online. Natural gas storage levels, a key benchmark for the supply/demand balance, were 3.32 trillion cubic feet ("TCF") on August 5, 2016, or 0.36 TCF (12%) above the level at the same time a year ago and 0.44 TCF (15%) above the five-year average from 2011 through 2015. Natural gas storage is currently projected to reach approximately 4.04 TCF at the end of October 2016, which would be a record high level for that time of the year.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2017 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 1,377,500 MMBtu/day, depending on the month. FPL has firm transportation capacity on Gulfstream of 695,000 MMBtu/day. Additionally, FPL's 2017 projections include the addition of 400,000 MMBtu/day of firm natural gas transportation capacity on the Sabal Trail Transmission, LLC ("Sabal Trail") and the Florida Southeast Connection ("FSC") pipelines. FPL also projects that during the January through December 2017 period, varying levels of non-firm natural gas transportation capacity will be available, depending on the month.

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, 121,500 MMBtu/day of firm transport on the Transcontinental Gas Pipe Line Company, LLC ("Transco") Zone 4A lateral, and 200,000 MMBtu/day (January through March and November through December) to 345,000 MMBtu/day (April through October) of firm transport 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 for up to 1,046,500 MMBtu/day during the summer season of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply.

Q. Please describe FPL's natural gas storage position.

A. FPL currently holds 4.0 BCF of firm natural gas storage capacity in Bay Gas Storage, located in southwest Alabama. While the acquisition of upstream transportation capacity (i.e., SESH) has helped mitigate a large portion of risk associated with off-shore natural gas supply, natural gas storage capacity remains an important part of FPL's gas portfolio. Approximately 17% of FPL's supply continues to be sourced from off-shore sources. Additionally, as FPL's reliance on natural gas has increased, the importance of natural gas storage in helping balance consumption "swings" due to weather and unit availability has also increased. Storage capacity improves reliability by providing a relatively inexpensive insurance policy against supply and infrastructure problems while also increasing FPL's ability to manage supply and demand on a daily basis.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2017 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.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2017 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 its 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 higher in 2017 compared with projected 2016 average levels primarily due to the assumed increase in the global crude oil price. The recent global crude oil price increases reflect global consumption growth remaining relatively solid in 2017, while supply remains roughly unchanged. In its August 2016 Short-Term Energy Outlook report, the EIA forecasts West Texas Intermediate ("WTI") crude oil prices will average approximately $41 per barrel in 2016 and $52 per barrel in 2017. The EIA anticipates global crude oil and other liquid fuels production to grow by 0.4 million barrels per day in 2016 and 0.5 million barrels per day in 2017, with consumption growing by approximately 1.5 million barrels per day in 2016 and 2017. U.S. crude oil and liquid fuels production is projected to decrease by roughly 0.4 million barrels per day in 2016 and 0.2 million barrels per day in 2017. 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 2017 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 2017 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 2017 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. Do the fuel costs reflected on Schedule E3 for heavy oil, light oil and coal differ from the dispatch costs shown on page 3 of Appendix I?

A. Yes. FPL maintains inventories of those fuels and runs its plants out of that inventory. The dispatch costs reflect what FPL would pay to replace fuel that is removed from inventory to run the plants. On the other hand, the "charge out" costs for heavy oil, light oil and coal that are reflected on Schedule E3 are based on FPL's weighted average inventory cost, by month, for each fuel type.

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

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

A. The projected Average Net Heat Rates were calculated by the GenTrader 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 GenTrader 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 2017?

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 2017.

Q. Please describe the significant planned outages for the January through December 2017 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 February 20, 2017 until March 28, 2017, or 36 days during the period. Turkey Point Unit 3 is scheduled to be out of service from March 27, 2017 until April 27, 2017, or 31 days during the period. Turkey Point Unit 4 is scheduled to be out of service from October 2, 2017 until November 1, 2017, or 30 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2017 period.

A. As shown in FPL's 2016 Ten Year Power Plant Site Plan (Table ES-1, page 10), FPL projects a reduction in its 2017 summer firm capacity of 465 MW. Significant changes include the replacement of 48 gas turbines with 7 combustion turbines, the conversion of Turkey Point Unit 1 to a synchronous condenser, and the retirement of the Cedar Bay unit.

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 2017?

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. For 2017, the FCBBS will be comprised of 9 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, fuel 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 2,095,700 MWh of wholesale (off-system) power sales for the period of January through December 2017. The projected fuel cost related to these sales is $55,389,097. The projected transaction revenue from these sales is $73,615,072. After taking into account the transmission costs for those sales, the projected gain is $12,443,512.

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 2017 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 1,332,100 MWh at a cost of $36,493,143. If FPL generated this energy, FPL estimates that it would cost $44,654,443. Therefore, these purchases are projected to result in savings of $8,161,300.

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 two contracts with the Solid Waste Authority of Palm Beach County ("SWA"). 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 2017 period.

A. Energy purchases under the SWA agreements are projected to be 911,040 MWh for the period at an energy cost of $30,814,561. Energy purchases from the JEA-owned portion of SJRPP are projected to be 1,858,787 MWh for the period at an energy cost of $70,917,684. 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 468,335 MWh at a cost of $3,521,842. 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 1,066,468 MWh at a cost of $45,826,252.

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 GenTrader 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 614,604 MWh of energy at a cost of $4,235,814. 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. This objective was clearly defined in Item 1 of the Proposed Resolution of Issues that was approved in Order No. PSC-02-1484-FOF-EI, dated October 30, 2002, which states, "Each investor-owned utility recognizes the importance of managing price volatility in the fuel and purchased power it purchases to provide electric service to its customers. Further, each investor-owned electric utility recognizes that the greater proportion of a particular fuel or purchased power it relies upon to provide electric service to its customers, the greater the importance of managing price volatility associated with that energy source."

Q. On what fuel does FPL rely for the greatest proportion of the electric service that it provides to customers?

A. FPL is projecting that roughly 70% of the electricity it produces in 2017 will be generated with natural gas.

Q. Does FPL engage in speculative hedging strategies aimed at "out guessing" the market?

A. Absolutely not. FPL's hedging program is consistent with the guiding principles contained in Section IV of the Hedging Order Clarification Guidelines that the Commission approved in Order No. PSC-08-0667-PAA-EI, dated October 8, 2008. Section IV, part b, states that, "The Commission finds that a well-managed hedging program does not involve speculation or attempting to anticipate the most favorable point in time to place hedges." This point is further substantiated in Section IV, part d, which states, "The Commission does not expect an IOU to predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place."

Q. Is the purpose of hedging to reduce fuel costs over time?

A. No. In fact, in the same Hedging Order Clarification Guidelines (Section IV, part d), the Commission acknowledged that, "hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers, if fuel prices actually settle at lower levels than at the time that hedges were placed." The Commission went on to state that it "recognizes this as a reasonable trade-off for reducing customers' exposure to fuel cost increases that would result if fuel prices actually settle at higher levels than when the hedges were placed." These statements clearly underscore the fact that hedging is not designed to reduce fuel costs. Rather, hedging is a tool that is utilized to control volatility, specifically the volatility of fuel adjustment charges.

Q. Does FPL's hedging program balance the goal of reducing customers' exposure to fuel cost increases against the goal of allowing customers to benefit from falling prices?

A. Yes. This goal is achieved by limiting hedging to only a portion of the total expected fuel consumption.

Q. Has FPL filed a comprehensive Risk Management Plan for 2017, consistent with the Hedging Order Clarification Guidelines as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2017 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up filing on August 4, 2016. The 2017 Risk Management Plan was included as Exhibit GJY-5.

Q. Please provide an overview of FPL's 2017 Risk Management Plan.

A. FPL's 2017 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 2017 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2017 for its projected natural gas requirements in 2018. FPL plans to hedge the percentages of its 2018 projected natural gas requirements over the time periods in 2017 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 2018 heavy fuel oil requirements.

Q. Are there any changes to FPL's 2017 Risk Management Plan compared to prior years?

A. Yes. FPL's 2017 Risk Management Plan has been modified to reduce FPL's overall hedging target by 25% compared to prior years.

Q. Has FPL also filed a revised 2016 Risk Management Plan?

A. Yes. FPL has revised the 2016 Risk Management Plan to remove the provisions related to the use of gas reserves projects as part of FPL's hedging strategy, consistent with the Florida Supreme Court's May 19, 2016 order reversing the Commission's earlier approval of the Woodford gas reserves project.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2016, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2016 (January through July) on August 18, 2016. The Hedging Activity Supplemental Report is identified as Exhibit GJY-6.

Q. Have FPL's 2016 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, while also allowing FPL's customers to benefit from falling fuel prices.

<u>THE INCENTIVE MECHANISM</u>

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2015?

A. FPL's asset optimization activities in 2015 delivered total benefits of $46,884,377. The total gains exceeded the sharing threshold of $46 million and, therefore, the gains above $46 million will be shared between customers and FPL on a 40%/60% basis, respectively. In total, customers will receive $45,880,201 (net of FPL's share of the gain above the $46 million threshold, and after incremental personnel, software, and hardware expenses are removed), and FPL will receive $530,626. FPL's share of the gain is included for recovery in FPL's 2017 FCR Clause factors.

Q Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2015?

A. Yes. I have compared how customers would have fared under the prior wholesale-sales sharing mechanism with the results FPL has achieved under the Incentive Mechanism. For the purpose of this comparison, I have included the same savings of $37.6 million from optimization activities for power sales, power purchases and releases of electric transmission capacity under both mechanisms, as FPL was engaging in those activities prior to the Commission's approval of the Incentive Mechanism. For those savings, the previous sharing mechanism would have yielded net benefits to FPL's customers of $36.6 million, while FPL would have retained $1 million because the three-year rolling average threshold for wholesale sales would have been exceeded.

In contrast, under the Incentive Mechanism, FPL also is incented to pursue beneficial natural gas transportation, storage and trading activities. These activities generated slightly more than $11.8 million of additional savings in 2015. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received $45.9 million of savings under the Incentive Mechanism. This is $9.3 million more than customers would have received if the prior sharing mechanism were still in effect, clear proof that the Incentive Mechanism is working to deliver added value for customers as FPL and the Commission envisioned when it was approved.

Q. Is the Incentive Mechanism set to expire at the end of 2016?

A. Yes. As part of FPL's 2012 rate case settlement, the Commission approved the Incentive Mechanism as a pilot program for the four years of the settlement term. Therefore, FPL's authority to operate under the Incentive Mechanism will expire at the end of 2016.

Q. Is FPL seeking to modify and continue the Incentive Mechanism?

A. Yes. On April 15, 2016, FPL filed a petition to modify and continue the Incentive Mechanism for a four-year term from 2017 through 2020.

Q. What is the status of FPL's petition to modify and continue the Incentive Mechanism?

A. The petition to modify and continue the Incentive Mechanism (Docket No. 160088-EI) was consolidated with FPL's rate case (Docket No. 160021-EI) and is being evaluated as part of the rate case proceedings.

Q. Has FPL included in its 2017 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism if the continuation of the program is approved by the Commission?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E3) for 2017.

Q. Has FPL included in its 2017 FCR factors, projections of the Incremental Optimization Costs that it will incur if the continuation of the program is approved by the Commission?

A. Yes. FPL has included in its 2017 FCR factors, 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 ("VOM") costs associated with wholesale economy sales and purchases. These are the same Incremental Optimization Cost categories that were described in Paragraph 12 (b) of FPL's 2012 rate case settlement.

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 $423,445 in 2017 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism. FPL is also projecting to incur $53,263 in expenses for the licensing and maintenance of OATI WebTrader software.

Q. Please describe the costs that are included in FPL's projections for VOM expenses.

A. Consistent with its petition to modify and continue the Incentive Mechanism in Docket No. EI-160088, FPL has included for recovery in its 2017 FCR factors, VOM expenses that reflect the netting of economy sales and purchases. As shown on Schedules E6 and E9 of Appendix II, FPL projects to sell 2,095,700 MWh and purchase 1,332,100 MWh of economy power. Therefore, applying FPL's proposed VOM rate of $0.65/MWh, FPL projects to incur VOM expenses of $1,362,205 associated with its economy sales and to avoid ($865,865) with its economy purchases. FPL has included for recovery the net of these two figures, $496,340 (Schedule E2, Line No. 11), in its 2017 FCR factors.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 160001-EI

MARCH 2, 2016

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

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

Q. Please state your education and business experience.

A. I graduated from North Carolina Agricultural & Technical State University with a Bachelor's degree in Accounting in 1977. I subsequently earned a Master of Business Administration degree from the University of Wisconsin in 1982. Prior to joining FPL in 2006, I held various accounting positions at Phillips Petroleum Company and later Centel Corporation. At FPL, I held positions of increasing responsibility in the Accounting Department, including various supervision assignments relating to accounting research, financial reporting, development and application of overhead rates, and property accounting. I spent ten years in the Regulatory Affairs Department as Principal Regulatory Coordinator and later as Regulatory Issues Manager primarily responsible for managing and coordinating regulatory accounting and finance dockets. In 2008, I assumed my current position as Director, Cost Recovery Clauses, where I am responsible for providing direction as to cost recovery through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery.

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

A. Yes.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause net true-up amounts for the period January 2015 through December 2015.

The net true-up for the FCR is an over-recovery, including interest, of $29,767,250. On February 2, 2016, FPL filed a petition with the Commission requesting a mid-course correction to its currently effective FCR factors that would refund to its customers FPL's projected 2016 end-of-period true-up over-recovery of $285,525,014. This $285,525,014 over-recovery is made up of the projected 2016 end-of period over-recovery, including interest, of $255,757,764 and the 2015 net true-up over-recovery of $29,767,250 that I present in this testimony. Consistent with the Commission's approval of FPL's petition at the March 1, 2016 agenda conference, FPL will refund this FCR net true-up over-recovery of $29,767,250 via the mid-course correction FCR factors starting when the Port Everglades Energy Center ("PEEC") goes into commercial operation, which is expected to be April 1, 2016.

The net true-up for the CCR is an over-recovery, including interest, of

$5,938,824. FPL is requesting Commission approval to include the CCR true-up over-recovery of $5,938,824 in the calculation of the CCR factors for the period January 2017 through December 2017.

Finally, FPL is requesting Commission approval to include $530,626 in the calculation of the FCR factors for the period January 2017 through December 2017, which represents FPL's share of the 2015 Incentive Mechanism gain described in the testimony of FPL witness Yupp.

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

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. In addition, FCR Schedules A1 through A12 for the January 2015 through December 2015 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

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

FUEL COST RECOVERY CLAUSE

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

A. Appendix I, page 1, titled "Summary of Net True-Up," shows the calculation of the net true-up for the period January 2015 through December 2015, an over-recovery of $29,767,250.

The summary of the net true-up amount shows the actual end-of-period true-up under-recovery for the period January 2015 through December 2015 of $37,050,993 on line 1. The actual/estimated true-up under-recovery for the same period of $66,818,243 is shown on line 2. Line 1 less line 2 results in the net final true-up for the period January 2015 through December 2015, an over-recovery of $29,767,250 on line 3.

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

Q. Have you provided a schedule showing the calculation of the 2015 FCR actual true-up by month?

A. Yes. Appendix I, page 2, titled "Calculation of Final True-up Amount," shows the calculation of the FCR actual true-up by month for January 2015 through December 2015.

Q. Have you provided schedules showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2015?

A. Yes. Appendix I, page 3, provides a comparison of jurisdictional fuel costs and revenues on a dollar per MWh basis. Appendix I, page 4, compares the actual end-of-period true-up under-recovery of $37,050,993 to the actual/estimated end-of-period true-up under-recovery of $66,818,243. Both comparisons result in a net over-recovery of $29,767,250.

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

A. Appendix I, page 3, provides a comparison of jurisdictional total fuel revenues and jurisdictional total fuel costs (including net power transactions) on a dollar per MWh basis.

The $29,767,250 over-recovery is primarily due to a decrease in fuel prices resulting in a variance of $27,944,959 and an increase in consumption resulting in a variance of $1,833,710.

Actual jurisdictional fuel revenues collected were $32,878,266 higher than projected, actual consumption was 989,462 MWh higher than projected, and revenues collected per MWh were $0.012 higher than projected. Of the $32,878,266 increase in fuel revenues collected, $31,594,423 was due to the increase in consumption and $1,283,843 was due to the increase in revenues per MWh resulting from the variation in the proportion by which the rate classes use energy.

Actual jurisdictional fuel costs were $3,099,597 higher than projected, actual consumption was 989,462 MWh higher than projected, yet jurisdictional fuel costs per MWh were $0.243 lower than projected. Of the $3,099,597 increase in jurisdictional fuel costs, $29,760,713 was due to the increase in consumption, partially offset by a decrease in price (fuel costs incurred per MWh) of $26,661,116.

The increase in fuel revenues due to consumption of $31,594,423 minus the increase in jurisdictional fuel costs due to consumption of $29,760,713 resulted in a total variance due to consumption of $1,833,710. The increase in fuel revenues due to price of $1,283,843 minus the decrease in fuel costs due to price of $26,661,116 resulted in a total variance due to price of $27,944,959. The total variance due to consumption of $1,833,710 and the total variance due to price of $27,944,959 resulted in an over-recovery of $29,778,669. This over-recovery of $29,778,669 plus the decrease of $11,419 in interest associated with the 2015 final true-up amount resulted in a total true up over-recovery of $29,767,250.

Q. Turning to page 4 in Appendix I, what was the variance in adjusted total fuel costs and net power transactions?

A. The variance in adjusted total fuel costs and net power transactions was an increase of $11,221,284. This increase was primarily due to a $13.8 million increase in Fuel Cost of Purchased Power, a $5.9 million decrease in Fuel Cost of Power Sold, a $5.0 million increase in Energy Cost of Economy Purchases, a $1.5 million decrease in Gains from Off-System Sales and a $1.2 million increase in Non-recoverable Tank Bottoms. These amounts were partially offset by a $7.3 million decrease in Energy Payments to Qualifying Facilities ("QFs"), a $6.7 million decrease in Fuel Cost of System Net Generation, a $1.8 million decrease in Inventory Adjustments, and a $0.4

million increase in Energy Imbalance Fuel Revenues.

Fuel Cost of Purchased Power ($13.8 million increase)

The variance for the Fuel Cost of Purchased Power is primarily attributable to higher than originally projected purchases and costs under the UPS agreements. FPL purchased 316,288 MWh more than originally projected from its UPS agreements. In addition, the cost of power under the UPS agreements averaged $3.27/MWh higher than projected. The higher volume and costs resulted in a total variance for UPS purchases of $20.8 million. This variance was partially offset by lower than projected purchases and costs under the SWA contracts. FPL purchased 88,191 MWh less from SWA at a cost that averaged $8.34/MWh less than originally projected. This resulted in a variance for SWA purchases of $6.5 million. In addition, FPL experienced a variance of $0.5 million due to a drop in the average cost of purchases from SJRPP of $6.76/MWh that was almost fully offset by an increase in SJRPP purchases of 251,255 MWh. Finally, purchases under the St. Lucie Reliability Exchange added a variance of $33,356 due to a lower average cost that was partially offset by higher purchases. The combination of these variances resulted in a total net variance for the Fuel Cost of Purchased Power of $13.8 million.

Fuel Cost of Power Sold ($5.9 million decrease)

The variance for the Fuel Cost of Power Sold is primarily attributable to lower than projected economy sales coupled with lower fuel costs. FPL sold 129,619 less MWh of economy power than originally projected with associated fuel costs that averaged $1.16/MWh less than originally projected, resulting in a variance on economy sales of $5.7 million. The remaining variance of $0.2 million is attributable to lower than originally projected fuel costs on St. Lucie Plant Reliability Exchange sales, partially offset by higher than originally projected St. Lucie Plant Reliability Exchange sales.

<u>Energy Cost of Economy Purchases ($5.0 million increase)</u>

The variance for the Energy Cost of Economy Purchases is primarily attributable to higher than projected economy purchases. FPL purchased 100,963 MWh more of economy energy, resulting in a variance of $4.1 million. Additionally, the average cost of economy purchases was $1.71/MWh higher than projected resulting in a variance of $0.9 million. The combination of higher economy purchases and costs resulted in a total variance of $5.0 million for the Energy Cost of Economy Purchases.

<u>Gains from Off-System Sales ($1.5 million decrease)</u>

The variance for Gains from Off-System Sales is primarily attributable to lower than projected economy sales. FPL sold 129,619 MWh less of economy power than originally projected, resulting in a variance of $1.5 million.

<u>Non-recoverable Tank Bottoms ($1.2 million increase)</u>

Non-recoverable Tank Bottoms of $1.1 million were inadvertently reported as Inventory Adjustments in the actual/estimated filing, creating this variance. The remaining variance represents actual non-recoverable tank bottoms expenses incurred in 2015.

Energy Payments to Qualifying Facilities ($7.3 million decrease)

The variance for Energy Payments to Qualifying Facilities is primarily attributable to lower purchases and costs. In total, FPL purchased 171,891 MWh less than projected from these facilities. Lower purchases combined with lower costs resulted in a total variance for these facilities of $9.6 million. This variance was offset by $2.3 million from higher than projected purchases and costs from the Cedar Bay facility, which resulted in a total net variance for Energy Payments to Qualifying Facilities of $7.3 million.

Fuel Cost of System Net Generation ($6.7 million decrease)

FPL's natural gas cost averaged $4.45 per MMBtu, which was $0.13 per MMBtu lower than projected during the period. However, FPL consumed 11,139,639 more MMBtus than projected during the period. Of the total $34.6 million decrease for natural gas, $85.8 million was due to lower than projected unit costs, partially offset by a $51.1 million increase due to higher than projected consumption.

FPL's nuclear fuel cost averaged $0.64 per MMBtu, which was $0.004 per MMBtu lower than projected during the period. However, FPL consumed 95,537 more MMBtus than projected during the period. Of the total $1.2 million decrease for nuclear fuel, $1.3 million was due to lower than projected unit costs, partially offset by a $0.1 million increase due to higher than projected consumption.

FPL’s coal cost averaged $2.70 per MMBtu, which was $0.004 per MMBtu lower than projected during the period. However, FPL consumed 6,779,159 more MMBtus than projected during the period. Of the total $18.1 million increase for coal, $18.3 million was due to higher than projected consumption, partially offset by a $0.2 million decrease due to lower than projected unit costs.

FPL’s heavy oil cost averaged $14.64 per MMBtu, which was $0.06 per MMBtu higher than projected during the period. Additionally, FPL consumed 449,262 more MMBtus than projected during the period. Of the total $6.8 million increase for heavy oil, $6.5 million was due to higher than projected consumption and $0.2 million was due to higher than projected unit costs.

FPL’s light oil cost averaged $20.68 per MMBtu, which was $1.04 per MMBtu higher than projected during the period. Additionally, FPL consumed 142,398 more MMBtus than projected during the period. Of the total $4.3 million increase for light oil, $2.8 million was due to higher than projected consumption and $1.5 million was due to higher than projected unit costs.

<u>Inventory Adjustments ($1.8 million decrease)</u>

Non-recoverable Tank Bottoms of $1.1 million were inadvertently reported as Inventory Adjustments in the actual/estimated filing, creating this variance. Additionally, there were $0.7 million in actual inventory adjustments related to temperature calibration adjustments.

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

A. As shown on Appendix I, page 4, line 31, actual jurisdictional FCR revenues, net of revenue taxes, were approximately $32.9 million higher than the actual/estimated projection. This was primarily due to higher than projected jurisdictional sales, which were approximately 989,462,455 kWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $530,626 as its 60% share of 2015 Incentive Mechanism gains over the $46 million threshold. When is FPL requesting to recover its share of the gains, and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2015 Incentive Mechanism gains through the 2017 FCR factors, consistent with its treatment of approved Generating Performance Incentive Factor ("GPIF") amounts. FPL will include the approved jurisdictionalized Incentive Mechanism amount in the calculation of the 2017 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2017 through December 2017 as a reduction to jurisdictional fuel revenues applicable to each period.

Q. What is the status of the replacement power issue arising from the April 2014 outage extension at St. Lucie Unit 2 raised by the Office of Public Counsel ("OPC") in testimony filed in the 2015 fuel docket?

A. FPL remains in discussions with OPC regarding this issue and will provide an update no later than its 2016 Actual/Estimated True-up filing.

CAPACITY COST RECOVERY CLAUSE

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

A. Appendix II, page 1, titled "Summary of Net True-Up" shows the calculation of the CCR net true-up for the period January 2015 through December 2015, an over-recovery of $5,938,824, which FPL is requesting to be included in the calculation of the CCR factors for the January 2017 through December 2017 period.

The actual end-of-period over-recovery for the period January 2015 through December 2015 of $13,638,140 shown on line 1 less the actual/estimated end-of-period over-recovery for the same period of $7,699,316 shown on line 2 that was approved by the Commission in Order No. PSC-15-0586-FOF-EI, results in the net true-up over-recovery for the period January 2015 through December 2015 of $5,938,824 on line 3.

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

A. Yes. Appendix II, page 2, titled "Calculation of Final True-up" shows the calculation of the CCR end-of-period true-up for the period January 2015 through December 2015 by month.

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

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2

"Calculation of True-Up and Interest Provision" for the FCR clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity charges and applicable revenues for 2015?

A. Yes. Appendix II, page 3, titled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to actual/estimated capacity charges and applicable revenues for the period January 2015 through December 2015.

Q. What was the variance in net capacity charges?

A. Appendix II, page 3, line 17 provides the variance in jurisdictional capacity charges, which is a decrease of $2,810,641. This $2.8 million decrease was primarily due to a $2.6 million decrease in Transmission of Electricity by Others, a $1.8 million decrease in Incremental Plant Security Costs - O&M, a $1.4 million decrease in Payments to Cogenerators and a $0.1 million decrease in Incremental Plant Security Costs - Capital.

These decreases were partially offset by a $1.4 million increase in Incremental Nuclear NRC Compliance Costs (Fukushima) - O&M, a $1.2 million increase in Payments to Non-cogenerators and a $0.3 million decrease in Transmission Revenues from Capacity Sales.

<u>Transmission of Electricity by Others ($2.6 million decrease)</u>

The variance for Transmission of Electricity by Others is primarily due to higher than projected utilization of the UPS power agreements, resulting in lower than projected unutilized transmission costs. FPL utilized approximately 316,000 more MWh than projected for the last five months of 2015, which resulted in a variance of approximately $1.3 million. Lower than projected revenues associated with capacity resales resulted in a variance of approximately $0.2 million. Additionally, $1.1 million in costs associated with SWA Unit No. 1 were inadvertently booked to this category in July and reclassed to Payments to Non-Cogenerators in August after the actual/estimated filing had been made.

Incremental Plant Security Costs - O&M ($1.8 million decrease)

The variance for Incremental Plant Security Costs was primarily due to less Cyber Security costs incurred due to extended contract negotiations for engineering support, which caused planned work to begin later than originally estimated. Work has been extended into 2016. Additionally, there were less NRC Part 171 Homeland Security costs than originally estimated for licensing inspection fees associated with the Force on Force drills.

Payments to Cogenerators ($1.4 million decrease)

The variance for Payments to Cogenerators was primarily due to decreased payments to certain Cogenerators. Approximately $1.1 million of the net variance was attributable to lower than projected capacity payments to Broward North. Approximately $0.3 million of the variance was due to lower than projected capacity payments to Cedar Bay. The remaining variance was due to slightly lower than projected payments of $50,000 to the Indiantown facility.

Incremental Plant Security Costs - Capital ($0.1 million decrease)

The variance for Incremental Plant Security Costs was primarily due to a change in the in-service dates for the Turkey Point Force-on-Force modifications from August and September 2015 to March 2016. The modifications were delayed due to resources being dedicated to the Turkey Point Unit 3 Refueling outage.

Incremental Nuclear NRC Compliance Costs (Fukushima) – O&M ($1.4 million increase)

The variance for Incremental Nuclear NRC Compliance Costs was primarily due to engineering costs associated with the Plant St. Lucie flooding and seismic hazard re-evaluation. These costs were originally projected as capital costs, but were reclassified as O&M.

Payments to Non-Cogenerators ($1.2 million increase)

The variance for Payments to Non-Cogenerators was primarily due to costs associated with the SJRPP agreement. Approximately $1.3 million of the total variance was attributable to the SJRPP agreement. An increase in FPL's portion of costs of approximately $2.5 million for Cumulative Capital Recovery Amount ("CCRA") payments and $64,000 for property taxes were partially offset by lower payments for debt service of $0.2 million, transmission capability and service costs of $25,000, and O&M and inventory costs of $1.0 million. There was a small increase in costs of approximately $52,000 due to a Capacity Availability Performance Adjustment ("CAPA") true-up payment and Change in Law costs related to the Scherer unit in the UPS agreement.

The balance of the variance, approximately $152,000, was attributable to two factors. Approximately $1.25 million was due to a projection error associated with the new SWA agreements. While capacity costs for the new unit were not actually recovered through the CCR during the period, the August to December 2015 projections included amortization amounts. These projected costs were largely offset by an August accounting correction of $1.11 million to reclass the costs associated with SWA Unit No. 1 which were inadvertently recorded to Transmission of Electricity by Others.

<u>Transmission Revenues from Capacity Sales ($0.3 million decrease)</u>

The variance for Transmission Revenues from Capacity Sales was primarily due to lower than projected economy sales. FPL sold approximately 130,000 MWh less of economy power than projected, resulting in lower transmission revenues.

Q. What was the variance in CCR revenues?

A. As shown on page 3, line 18, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes) were $3,123,430 higher than the actual/estimated projection. This was primarily due to higher than projected jurisdictional sales, which were approximately 989,462,455 kWh, higher than the actual/estimated projection.

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

A. Yes. Schedule A12 consists of two pages that are included in Appendix II as pages 4 and 5. Page 4 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2015 through December 2015. Page 5 provides the Short Term Capacity Payments for the period January 2015 through

December 2015.

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

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2015 through December 2015 are included on pages 12 and 13 of Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 160001-EI

AUGUST 4, 2016

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company ("FPL") as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the Actual/Estimated True-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2016 through December 2016.

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

A. Yes, I have. It consists of various schedules included in Appendices I and II. Exhibit TJK-3, included in Appendix I contains the FCR related schedules, and Exhibit TJK-4, included in Appendix II contains the CCR related schedules.

The FCR Schedules contained in Appendix I include Schedules E3 through E9 that provide revised estimates for the period July 2016 through December 2016. FCR Schedules A1 through A9 provide actual data for the period January 2016 through June 2016. The A-Schedules are filed monthly with the Commission, are served on all parties and are incorporated herein by reference. The FCR Schedules contained in Appendix I also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2016 through December 2016.

The CCR Schedules contained in Appendix II provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2016 through December 2016.

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

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

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

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2016 through June 2016 and revised estimates for July 2016 through December 2016 to the data reflected in the midcourse correction that was approved by Order No. PSC-16-0120-PCO-EI, issued on March 21, 2016.

The CCR true-up calculation compares actual/estimated data consisting of actuals for January 2016 through June 2016 and revised estimates for July 2016 through December 2016 to the data reflected in FPL's original projections for the period January 2016 through December 2016 filed on September 21, 2015.

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

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the projected months is the actual rate published on the first business day in July 2016, which reflects the interest rate from the last business day in June 2016.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2016 actual/estimated true-up by month?

A. Yes. Appendix I, Page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2016 through December 2016.

Q. Please explain the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to

approve.

A. Appendix I, Page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2016 end-of-period net true-up amount to be carried forward to the 2017 FCR factors is an over-recovery of $3,276,633 (Column 14, Line 49). This $3,276,633 over-recovery is comprised of the actual/estimated true-up under-recovery of $4,402,573 for the period January 2016 through December 2016 (Column 14, Line 42) plus associated interest of $137,694 (Column 14, Line 43) and the jurisdictional portion of FPL's vendor settlement refund including interest of $7,541,512 (Column 14, Line 47), which is consistent with the terms of the settlement agreement between FPL and the Office of Public Counsel ("OPC") approved by Order No. PSC-16-0298-FOF-EI, issued on July 27, 2016. Pursuant to Order No. PSC-16-0120-PCO-EI, issued on March 21, 2016, FPL is refunding the 2015 final true-up over-recovery of $29,767,250 (Column 14, Line 45) in its midcourse correction fuel factors for the period April 2016 through December 2016.

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

A. Yes, they were.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the projections in the midcourse correction for 2016?

A. Yes. Appendix I, Page 2 provides a variance calculation that compares the actual/estimated period data by component to the projected data by component from the midcourse correction filing.

Q. Please summarize the variance schedule on Page 2 of Appendix I.

A. FPL's midcourse correction filing projected Jurisdictional Total Fuel Costs and Net Power Transactions to be $2.701 billion for 2016 (Appendix I, Page 2, Column 3, Line 41). The Actual/Estimated Jurisdictional Total Fuel Costs and Net Power Transactions are now projected to be $2.692 billion for that period (actual data for January 2016 through June 2016 and revised estimates for July 2016 through December 2016) (Appendix I, Page 2, Column 2, Line 41). Therefore, Jurisdictional Total Fuel Costs and Net Power Transactions are projected to be $8.4 million, or 0.3% lower than the midcourse correction estimates (Appendix I, Page 2, Column 4, Line 41) and Jurisdictional Fuel Revenues, net of revenue taxes for 2016 are projected to be $12.8 million, or 0.5% lower than the midcourse correction estimates (Appendix I, Page 2, Column 4, Line 32).

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

A. Below are the primary reasons for the $8.4 million variance.

<u>Energy Cost of Economy Purchases ($33.0 million increase)</u>

The variance for the Energy Cost of Economy Purchases is attributable to higher than projected economy purchases and energy costs. FPL now projects to purchase 891,184 MWh more economy power than projected, resulting in a variance of $26.3 million. FPL also projects that the cost of economy power will be $3.66/MWh higher than projected resulting in a variance of $6.7 million.

Fuel Cost of Power Sold ($1.0 million decrease)

The variance for the Fuel Cost of Power Sold is primarily attributable to lower than projected fuel costs of economy sales, partially offset by higher than projected economy sales. FPL now projects to sell 612,456 MWh more economy power at an average associated fuel cost that is $8.47/MWh less than projected. The combination of lower fuel costs associated with economy sales and higher economy sales results in a variance for economy sales of $0.9 million. The remaining variance of $0.1 million is primarily attributable to lower than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

Variable Power Plant O&M Costs over 514,000 MWh Threshold ($0.8 million increase)

The variance of $0.8 million is primarily attributable to higher than projected economy sales.

Cedar Bay – Rail Coal Cars Lease ($0.3 million increase)

The variance for the Cedar Bay – Rail Coal Cars Lease is attributable to additional costs for rail car maintenance and storage when the cars are not in use.

Gas Reserves Refund ($21.3 million decrease)

In response to the Florida Supreme Court's May 19, 2016 order reversing the Commission's approval of FCR recovery for the Woodford Project, FPL has included a refund of $24,532,560 (Exhibit GJY-3, Table 3, Line 3) including associated interest of $38,999 (Exhibit GJY-3, Table 3, Line 5) calculated from March 2015 through June 2016. This $24,532,560 consists of $21,294,315 (Exhibit GJY-3, Table 3, Line 6) credited to customers in June 2016 plus $3,238,245 (Exhibit GJY-3, Table 3, Lines 7 and 8) that is already reflected in the monthly true-up amounts. The calculation of the refund is presented and explained in the 2016 Actual/Estimated testimony and exhibits of FPL witness Yupp.

<u>Fuel Cost of System Net Generation ($16.0 million decrease)</u>

Coal costs are currently projected to be $15.6 million (11.9%) lower than the midcourse correction estimates. Coal consumption in the actual/estimated period is projected to be 42,964,895 MMBtu, which is 7.7% lower than the 46,537,748 MMBtu included in the midcourse correction estimates. The unit cost of coal in the actual/estimated period is projected to be $2.70 per MMBtu, which is 4.6% lower than the $2.83 per MMBtu included in the midcourse correction estimates.

Of the $15.6 million projected decrease in coal costs, $10.1 million is attributable to lower consumption and $5.5 million is attributable to lower costs.

Heavy oil costs are currently projected to be $1.9 million (5.0%) lower than the midcourse correction estimates. Heavy oil burn in the actual/estimated period is projected to be 2,529,323 MMBtu, which is 3.6% lower than the 2,624,228 MMBtu included in the midcourse correction estimates. The unit cost of heavy oil in the actual/estimated period is projected to be $14.15 per MMBtu, which is 1.5% lower than the $14.36 per MMBtu included in the midcourse correction estimates. Of the $1.9 million projected decrease in heavy oil costs, $1.4 million is attributable to lower consumption and $0.5 million is attributable to lower costs.

Nuclear generation costs are currently projected to be $1.2 million (0.6%) lower than the midcourse correction estimates. Nuclear consumption in the actual/estimated period is projected to be 317,410,552 MMBtu, which is 0.7% higher than the 315,332,825 MMBtu included in the midcourse correction estimates. The unit cost of nuclear fuel in the actual/estimated period is projected to be $0.64 per MMBtu, which is 1.2% lower than the $0.65 per MMBtu included in the midcourse correction estimates. Of the $1.2 million projected decrease in nuclear generation costs, $2.6 million is attributable to lower costs, partially offset by a $1.4 million increase attributable to higher consumption.

Natural gas costs are currently projected to be $0.4 million (0.02%) lower than the midcourse correction estimates. Natural gas consumption in the actual/estimated period is projected to be 601,614,410 MMBtu, which is approximately 1.4% higher than the 593,083,490 MMBtu included in the midcourse correction estimates. The unit cost of natural gas in the actual/estimated period is projected to be $3.94 per MMBtu, which is 1.4% lower than the $3.99 per MMBtu included in the midcourse correction estimates. Of the $0.4 million projected decrease in natural gas costs, $34.5 million is attributable to lower costs, partially offset by a $34.1 million increase attributable to higher consumption.

Light oil costs are currently projected to be $3.2 million (14.3%) higher than the midcourse correction estimates. Light oil burn in the actual/estimated period is projected to be 1,112,165 MMBtu, which is 12.7% lower than the 1,273,943 MMBtu included in the midcourse correction estimates. The unit cost of light oil in the actual/estimated period is projected to be $22.72 per MMBtu, which is 30.9% higher than the $17.36 per MMBtu included in the midcourse correction estimates. Of the $3.2 million projected increase in light oil costs, $6.0 million is attributable to higher costs, partially offset by a $2.8 million decrease attributable to lower consumption.

Generation data by fuel type for the actual/estimated period January 2016 through December 2016 are included in Appendix I, Schedule E3.

<u>Gains from Off-System Sales ($2.2 million increase)</u>

The variance for Gains from Off-System Sales is primarily attributable to higher than projected economy sales. FPL now projects to sell 612,456 MWh more economy power than projected, resulting in a variance of $5.5 million. This variance is partially offset by $3.3 million due to lower than projected margins on economy power sales. FPL now expects an average economy sales margin of $7.35/MWh, or $1.55/MWh lower than projected.

<u>Fuel Cost of Purchased Power ($1.1 million decrease)</u>

The variance for the Fuel Cost of Purchased Power is primarily attributable to lower than projected SJRPP purchases and costs, partially offset by higher energy costs for Solid Waste Authority ("SWA") purchases. FPL now projects to purchase 73,358 MWh less from SJRPP at an average cost that is $1.57 lower than projected. The combination of lower SJRPP purchases and costs results in a variance of $5.2 million.

This variance is partially offset by higher than projected energy costs of SWA purchases. FPL now projects that its energy purchases from SWA will average $5.40/MWh higher than projected, resulting in a variance of $4.7 million.

The remaining variance of $0.6 million is primarily attributable to lower than projected energy purchases from SWA and prior period adjustments for energy costs under the expired UPS contracts, partially offset by higher than projected purchases under the St. Lucie Reliability Exchange.

<u>Energy Payments to Qualifying Facilities ($1.1 million decrease)</u>

The variance for Energy Payments to Qualifying Facilities is primarily attributable to lower than projected purchases and costs from Firm and As-Available Co-Generation ("Co-Gen") facilities, partially offset by higher than projected purchases from the Indiantown Co-Gen ("ICL") facility. In total, FPL now projects to purchase 204,828 MWh less from Firm and As-Available Co-Gen Facilities at $9.13/MWh and $5.14/MWh less than projected energy costs, respectively. The combination of lower purchases and lower energy costs from Firm and As-Available Co-Gen facilities results in a variance of $7.5 million. This variance is partially offset by the combination of higher than projected purchases and lower than projected costs from ICL. FPL now projects to purchase 259,358 MWh more from ICL resulting in a variance of $17.3 million, partially offset by a variance of $10.9 million due to lower than projected costs from ICL of $19.54/MWh.

Variable Power Plant O&M Correction ($0.8 million decrease)

As presented and explained in the 2016 Actual/Estimated testimony and exhibits of FPL witness Yupp, FPL has included a refund of $832,856, including interest, resulting from the application of a corrected variable power plant O&M rate to wholesale economy energy sales for the period January 2013 through April 2016.

Q. Is FPL including an additional adjustment in the calculation of the FCR 2016 end-of-period net true-up amount?

A. Yes. In addition to the adjustments for the Woodford Project and Variable Power Plant O&M discussed above, FPL is including a refund of $7,541,512 in the calculation of its 2016 end-of-period net true-up amount, which represents the jurisdictional portion of FPL's vendor settlement of $8 million, pursuant to the settlement agreement approved in Order No. PSC-16-0298-FOF-EI, issued on July 27, 2016. This will reduce FPL's 2017 fuel factors.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2016 actual/estimated true-up by month?

A. Yes. Appendix II, Page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2016 through December 2016.

Q. Please explain the calculation of the CCR 2016 end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Appendix II, Page 1 shows the calculation of the CCR end-of-period net true-up and actual/estimated true-up amounts. The 2016 end-of period true up amount to be carried forward to the 2017 CCR factors is an over-recovery of $10,069,299 (Column 14, Line 26). This $10,069,299 net over-recovery is comprised of the 2015 Final True-up over-recovery of $5,938,824 filed with the Commission on March 2, 2016 (Column 14, Line 24) and the actual/estimated true-up over-recovery of $4,104,229 for the period January 2016 through December 2016 (Column 14, Line 21) plus associated interest of $26,246 (Column 14, Line 22).

The CCR Revenues (Net of Revenue Taxes) are projected to be $5,413,578 lower than originally estimated. The $9,517,807 decrease in costs (Appendix II, Page 2, Column 4, Line 17) less the $5,413,578 million decrease in revenues results in the 2016 actual/estimated true-up over-recovery amount of $4,130,475, including interest (Appendix II, Page 2, Column 4, Lines 21 plus 22).

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

A. Yes, it is.

Q. Have you provided a schedule showing the variances between the actual/estimated and the original projections for 2016?

A. Yes. Appendix II, Page 2 shows the actual/estimated capacity charges and applicable revenues (January 2016 through June 2016 reflects actual data and the data for July 2016 through December 2016 is based on updated estimates) compared to the original projections for the January 2016 through December 2016 period.

Q. Please explain the variances related to capacity charges.

A. As shown in Appendix II, Page 2, Column 4, Line 17, the variance related to jurisdictional capacity charges is $9.5 million, a 2.7% decrease from original projections. The primary reason for this variance is a $10.1 million or 3.0% decrease in total system capacity costs (Page 2, Column 4, Line 13).

Below are the primary reasons for the $10.1 million decrease in total system capacity costs.

Payments to Co-Generators ($4.5 million decrease)

The variance for Payments to Co-Generators is primarily due to the termination of the Broward North contract in November, 2015. Termination of this contract resulted in a variance of approximately $4.1 million, or approximately 91% of the total variance. Approximately 9% or $0.4 million of the variance was attributable to lower than projected capacity payments to ICL.

Incremental Plant Security O&M Costs ($2.5 million decrease)

The variance for Incremental Plant Security O&M costs is primarily due to the implementation of cost savings initiatives at St. Lucie and Turkey Point. Additionally, the NRC Homeland Security fees were less than originally projected.

Finally, as a result of NERC Critical Infrastructure Protection ("CIP") Version 5 implementation date changes from April 1 to June 1, 2016, there was a change in scope of work. Based on the changes in NERC categories at Turkey Point Unit 5, certain NERC CIP activities are no longer required at the plant. This variance was partially offset by additional costs at the West County plant for consulting work to support the Version 5 readiness assessments and unanticipated expenses for the Emerson Ovation Security Center revision upgrade.

<u>Payments to Non-Cogenerators ($2.3 million decrease)</u>

The variance for Payments to Non-Cogenerators (UPS, SJRPP & SWA) is primarily due to a projection error that included the amortization of prepayments (approximately $3.0 million) associated with the new SWA agreement. Slightly lower payments related to the SWA 40MW unit resulted in a variance of approximately $0.1 million.

Additionally, higher than projected costs associated with the SJRPP agreement resulted in an offsetting variance of approximately $0.9 million. This $0.9 million variance consists of approximately $1.3 million from higher than projected costs for Cumulative Capital Recovery Amount ("CCRA") payments, partially offset by lower than projected costs for Debt Service of $0.2 million, Transmission Capability & Service of $0.02 million, Property Taxes of $0.05 million, and

O&M/Inventory of $0.2 million.

Finally, approximately $0.05 million was due to prior period adjustments associated with the UPS agreement which expired at the end of 2015.

Transmission Revenues from Capacity Sales ($1.5 million increase)

The variance for Transmission Revenues from Capacity Sales is attributable to higher than projected economy sales. FPL now projects to sell 612,456 MWh more economy power than originally projected, resulting in higher transmission revenues.

Transmission of Electricity By Others ($0.4 million decrease)

The variance for Transmission of Electricity By Others is due to higher than projected revenues associated with capacity resales.

Incremental Plant Security Capital Costs ($0.1 million decrease)

The variance for Incremental Plant Security depreciation and return is primarily due a change in the in-service dates for the Turkey Point Force-on-Force modifications from August and September 2015 to July 2016. The modifications were delayed due to extended contract negotiations for engineering support, which caused planned work to begin later than originally estimated.

Incremental NRC Compliance O&M Costs ($0.9 million increase)

The variance for Incremental NRC Compliance O&M Costs is primarily attributable to engineering costs associated with the Turkey Point Plant flooding evaluation. These costs were accumulated in deferred accounts pending NRC guidance and then were determined to be O&M costs in 2016.

Incremental NRC Compliance Capital Costs ($0.3 million increase)

The variance for Incremental NRC Compliance depreciation and return is primarily due to a change in the in-service date for the Turkey Point Unit 4 low leakage Reactor Cooling Pump Seals from October 2016 to April 2016.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 160001-EI

SEPTEMBER 2, 2016

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company ("FPL") as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present a revised 2016 Fuel Cost Recovery ("FCR") actual/estimated true-up amount, which has been updated to include July 2016 actual data that is incorporated into the calculation of the 2017 FCR factors.
- I present FCR factors for the period January 2017 through December 2017.
- I present the calculation of the jurisdictional amount of FPL's portion of the 2015 incentive mechanism gains for recovery through the 2017 FCR factors.

- I present a revised 2016 Capacity Cost Recovery ("CCR") actual/estimated true-up amount, which has been updated to include July 2016 actual data that is incorporated into the calculation of the 2017 CCR factors.
- I present the CCR factors that FPL is requesting the Commission to approve for the period January 2017 through December 2017, which were calculated based on a 12 CP and 25% cost allocation methodology for production plant and do not include the non-fuel revenue requirement for West County Energy Center Unit 3 ("WCEC-3"). These adjustments reflect FPL's request in its current rate case proceeding in Docket No. 160021-EI.
- I present alternative CCR factors for the period January 2017 through December 2017 that were calculated based on the current cost allocation methodology of 12 CP and 1/13th, should the Commission not approve FPL's request in Docket No. 160021-EI.
- I present the WCEC-3 revenue requirement calculation for the January 2017 through December 2017 period should the Commission not approve FPL's request in Docket No. 160021-EI.
- I identify additional issues from FPL's current base rate proceeding that may impact the FCR and CCR clauses beginning in 2017.
- Finally, I provide on pages 91-92 of Appendix II FPL's proposed cogeneration ("COG") tariff sheets, which reflect 2017 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten-year projection of FPL's annual

generation mix and fuel prices.

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

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

TJK-5 (Appendix II)

- Schedules E1, E1-A, a revised Schedule E1-B, which includes July 2016 actual data, Schedules E1-C, E1-D, E1-E, E2, RS-1 Inverted Rate Calculation, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion, H1 and E10 provide the calculation of FCR factors for January 2017 through December 2017.
- Pages 10 through 13, which provide the 2017 Projected Energy Losses by Rate Class.
- Pages 91 and 92, which provide updated COG tariff sheets.

TJK-6 (Appendix III)

- Page 1 provides the calculation of the revised 2016 actual/estimated CCR True-Up amount, which reflects July 2016 actual data.
- Pages 2 through 4 provide the calculation of the 2017 CCR factors that FPL is requesting that this Commission approve. These factors were calculated based on a 12 CP and 25% cost allocation methodology for production plant and exclude recovery of the WCEC-3 non-fuel revenue requirement for January 2017 through December 2017.
- Pages 5 through 12 provide the calculation of depreciation and

return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments.

- Pages 15 and 16 provide the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction.
- Pages 17 and 18 provide the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction.
- Page 19 provides the capital structure components and cost rates relied upon to calculate the revenue requirement, rate of return applied to capital investments and working capital amounts included for recovery through the CCR clause for the period January 2017 through December 2017.
- Pages 20 through 22 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirement associated with WCEC-3 for the period January 2017 through December 2017.
- Page 23 combines the results from pages 2 through 4 and pages 20 through 22 to provide the total 2017 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2017 through December 2017.

TJK-7 (Appendix IV)

- Pages 1 through 3 provide the calculation of the 2017 CCR factors based on the current cost allocation methodology of 12 CP and 1/13th for January 2017 through December 2017, should the Commission not approve FPL's request in Docket No. 160021-EI.

- Pages 4 through 6 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirement associated with WCEC-3 for the period January 2017 through December 2017 based on the current cost allocation methodology of 12 CP and 1/13th.
- Page 7 combines the results from pages 1 through 3 and pages 4 through 6 to provide the total 2017 CCR factors including the non-fuel revenue requirement associated with WCEC-3 for the period January 2017 through December 2017.

TJK-8 (Appendix VII)

- Pages 1 and 2 provide the calculation of the WCEC-3 revenue requirement for January 2017 through December 2017.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2016 FCR actual/estimated true-up amount that was filed on August 4, 2016 to reflect July actual data?

A. Yes. The 2016 FCR actual/estimated true-up amount has been revised to an under-recovery of $26,483,684, incorporating July 2016 actual data, plus interest. This revised 2016 FCR actual/estimated under-recovery of $26,483,684 is included in the calculation of the FCR factors for the January 2017 through December 2017 period.

Q What adjustments are included in the calculation of the 2017 FCR factors shown on Schedules E1 included in Appendix II?

A. The total net true-up to be included in the 2017 FCR factors is an under-recovery of $26,483,684. This amount, divided by the projected retail sales of 107,335,994 MWh for January 2017 through December 2017, results in an increase of 0.0247¢ per kWh before applicable revenue taxes, as shown on Line 26 of Schedule E1. The Generating Performance Incentive Factor ("GPIF") testimony of witness Charles R. Rote, filed on March 16, 2016, proposes a reward of $31,658,059 for the period ending December 2015. This $31,658,059 reward, divided by the projected retail sales of 107,335,994 MWh for January 2017 through December 2017, results in an increase of 0.0295¢ per kWh, as shown on Line 30 of Schedule E1.

Q. Please explain the adjustment included in the calculation of 2017 FCR factors to recover FPL's portion of 2015 Incentive Mechanism Gains.

A. FPL is including $500,861 in the calculation of its 2017 FCR factors, which represents the jurisdictional amount associated with its share of 2015 Incentive Mechanism Gains that FPL is allowed to retain per the settlement agreement approved in Order No. PSC. 13-0023-S-EI and which is being treated consistent with FPL's recovery methodology of approved GPIF amounts.

As presented and explained in the direct testimony and exhibits of FPL witness Yupp filed on March 2, 2016 in this docket, FPL's activities under the Incentive Mechanism during 2015 delivered $46,884,377 in total gains. Of these total gains, FPL is allowed to retain $530,626 (system amount). FPL will reflect recovery of one-twelfth of the approved jurisdictional amount of $500,861, net of revenue taxes, in each month's Schedule A2 for the period January 2017 through December 2017 as a reduction to jurisdictional fuel revenues applicable to each period.

Q. How has FPL calculated the jurisdictional share of the 2015 Incentive Mechanism Gains?

A. As shown on Page 5 of Appendix II, FPL calculated an average jurisdictional separation factor of 94.32276%, which is based on actual 2015 sales. This separation factor is applied to the $530,626 resulting in a jurisdictional amount of $500,501. This amount is then adjusted for revenue taxes resulting in $500,861, which is the total jurisdictional amount of FPL's share of the 2015 Incentive Mechanism Gains. The $500,861 is included in the calculation of the average FCR factor on Line 31 of Schedule E1.

Q. Please explain the adjustment included in the calculation of 2017 FCR factors associated with FPL's vendor settlement refund.

A. FPL is including a refund of $7,573,924 in the calculation of its 2017 FCR factors which represents the jurisdictional portion of FPL's vendor settlement of $8 million, pursuant to the Settlement Agreement approved in Order No. PSC-16-0298-FOF-EI, issued on July 27, 2016. The Settlement Agreement addressed the resolution of two issues concerning the recovery of replacement power costs incurred during outage events that occurred at FPL's St. Lucie Unit 2 in 2014 and 2015. This refund represents the amount associated with FPL's confidential agreement with one of the vendors that performed work at St. Lucie Unit 2 during the March 2014 planned outage.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2016 CCR actual/estimated true-up amount that was filed on August 4, 2016 to reflect July 2016 actual data?

A. Yes. The 2016 CCR actual/estimated true-up amount has been revised to an over-recovery of $9,639,909 (Appendix III, Page 1, Line 21 plus Line 22), incorporating July 2016 actual data, plus interest and updated capital schedules for the depreciation and return on incremental power plant security and incremental nuclear NRC compliance capital investments. The $9,639,909 over-recovery, plus the 2015 final true-up over-recovery of $5,938,824 results in a net over-recovery of $15,578,733 (Appendix III, Page 1, Line 26). This $15,578,733 net over-recovery is included in the calculation of the CCR factors for the January 2017 through December 2017 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2017 through December 2017?

A. Yes. Page 2 of Appendix III provides this summary. Total Recoverable Capacity Payments for the period January 2017 through December 2017 are $296,120,626 (Line 21). This $296,120,626 includes the net over-recovery for 2015 and 2016 of $15,578,733 (Line 15 plus Line 16), the Cape Canaveral Energy Center GBRA True-up refund amount of $1,890,528, and revenue taxes but excludes the 2017 WCEC-3 non-fuel revenue requirement.

Q. Has FPL included Nuclear Power Plant Cost Recovery ("NCR") Clause project costs in the calculation of its 2017 CCR factors?

A. No. By Order No. PSC-16-0266-PCO-EI issued in Docket No. 160009-EI on

July 12, 2016, the Commission granted FPL's motion to defer all issues in the 2016 NCR docket to the 2017 NCR docket and to defer recovery of its requested 2017 NCR amount of $22,081,049.

Q. Has FPL included an adjustment to its 2017 CCR factors resulting from the Cedar Bay Settlement Agreement between FPL and the Office of Public Counsel ("OPC") approved in Order No. PSC-15-0401-AS-EI issued in Docket No. 150075-EI on September 23, 2015?

A. As discussed in the direct testimony of Kim Ousdahl in Docket No. 160021-EI, FPL removed all Cedar Bay amounts from FPL's base rate filing. The unamortized amounts previously classified as base rates and transferred to the CCR as of January 1, 2017 are $73 million for the purchase price and $46 million for its associated income tax gross up.

Q. Has FPL included an adjustment associated with its Generating Base Rate Adjustment ("GBRA") for the Cape Canaveral Energy Center?

A. Yes. Pursuant to Order No. PSC-13-0023-S-EI, Docket No. 120015-EI, a true-up of the Cape Canaveral Energy Center GBRA is required if the actual costs are lower than projected. As reflected in the declaration of Liz Fuentes, the projected capital costs included in the GBRA were $946.42 million and the actual costs are $942.95 million, resulting in a revised GBRA revenue requirement of $163.20 million. As such, FPL has included a credit of $1,890,528, including interest, (Appendix III, page 3, Line 18) for the true-up of Cape Canaveral costs for the period April 24, 2013 through December 31, 2016 as a reduction in the calculation of its CCR factors. The calculation of this credit is discussed in the declaration and attachments of Tiffany C.

Cohen.

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

A. Yes. Page 3 of Appendix III provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. What effective date is FPL requesting for the new FCR and CCR factors?

A. FPL is requesting that the FCR and CCR factors become effective with meter readings scheduled to be read in January 2017 and that they remain effective until they are modified by the Commission. This will provide for 12 months of billing on the FCR and CCR factors for all customers.

PENDING BASE RATE CASE ISSUES IMPACTING FCR AND CCR CLAUSES BEGINNING IN 2017

Q. How is FPL currently recovering the non-fuel revenue requirement associated with FPL's West County Energy Center Unit 3 ("WCEC-3")?

A. Pursuant to the 2012 Rate Settlement approved in Order No. PSC-13-0023-S-EI, the non-fuel revenue requirement associated with WCEC-3 is currently being recovered through the CCR clause. WCEC-3 revenues collected through the CCR clause are reclassified on FPL's books and records from

CCR revenues to base revenues.

Q. Is FPL requesting to recover the WCEC-3 revenue requirement in its base rates as part of the current base rate proceeding in Docket No. 160021-EI?

A. Yes. In its current base rate proceeding, FPL is proposing to move recovery of the WCEC-3 revenue requirement from the CCR clause to base rates beginning in 2017. If the Commission approves FPL's request, the WCEC-3 revenue requirement will not be included in FPL's CCR factors beginning January 1, 2017.

Q. If the Commission does not approve recovery of the WCEC-3 revenue requirement through base rates in Docket No. 160021-EI, should FPL be permitted to continue recovery through the CCR clause?

A. Yes. Should FPL's request to move recovery of the WCEC-3 revenue requirement from the CCR clause to base rates beginning in January 2017 not be approved, FPL requests the Commission to approve the continuation of recovery through the CCR clause. The calculation of the projected WCEC-3 jurisdictional non-fuel revenue requirement for the January 2017 through December 2017 period is provided in Exhibit TJK-6, which is included in Appendix III.

Q. Is FPL proposing any adjustments in its current base rate proceeding that impact the FCR and CCR clauses?

A. Yes. As discussed in the direct testimony of Tiffany C. Cohen filed in Docket No. 160021-EI on March 15, 2016, FPL is proposing two new lighting rate schedules: Metered Customer-Owned Street Lights (SL-1M) and Metered

Traffic Signals (SL-2M).

Q. Has FPL calculated FCR and CCR factors for the proposed metered lighting rate schedules?

A. Yes. The FCR and CCR factors for the proposed new metered lighting rate schedules are included in the schedules calculating 2017 factors.

Q. Is FPL proposing an adjustment in its current base rate proceeding in Docket No. 160021-EI that would impact the allocation of 2017 CCR cost projections to customer classes?

A. Yes. As explained in the direct testimony of Renae B. Deaton filed in Docket No. 160021-EI on March 15, 2016, FPL is proposing to utilize a 12 Coincident Peak ("CP") and 25% methodology for production plant, rather than the 12 CP and 1/13th method used in prior rate cases. The 12 CP and 25% methodology classifies 75% of costs on the basis of CP demand and 25% of costs on the basis of energy.

Q. Has FPL calculated 2017 CCR factors based on the proposed change in cost allocation methodology?

A. Yes. FPL has calculated 2017 CCR factors based on the 12 CP and 25% cost allocation methodology and is requesting the Commission to approve these factors, which are included in Exhibit TJK-6 provided in Appendix III. In the alternative, FPL has also provided 2017 CCR factors based on the current cost allocation methodology of 12 CP and 1/13th, which are included in Exhibit TJK-7 provided in Appendix IV.

Q. Is FPL proposing an adjustment to move costs related to clause recoverable projects currently being recovered in both base rates and clauses to solely clause recoverable?

A. Yes. As explained in the direct testimony of Kim Ousdahl, filed in Docket No. 160021-EI on March 15, 2016, FPL is proposing to transfer the portion of Incremental Nuclear Regulatory Commission ("NRC") Fukushima-related compliance costs currently recovered in FPL's base rates to the CCR Clause. This adjustment will ensure that all costs related to the Fukushima project will be reflected and recovered solely through the CCR, which will serve to reduce complexity in accounting and ratemaking.

Q. Has FPL included this proposed adjustment in the calculation of its 2017 CCR factors?

A. No. FPL has not included this adjustment in the calculation of its 2017 CCR factors. Should the Commission approve this adjustment in Docket No. 160021-EI, FPL will reflect this adjustment in the true-up process for 2017.

<u>Impact of Indiantown Cogeneration Transaction on FCR and CCR Factors</u>

Q. Please provide a brief description of FPL's petition in Docket No. 160154-EI.

A. On June 20, 2016, FPL filed a petition requesting approval of its proposed Agreement with Calypso Energy Holdings, LLC to assume ownership of the Indiantown Cogeneration L.P. ("ICL") facility and the related Power Purchase Agreement ("PPA") between FPL and ICL ("ICL Transaction").

Q. If approved, how will the ICL transaction impact FPL's FCR and CCR clauses?

A. If approved by this Commission, FPL will recover through the CCR clause the amortization of the regulatory asset associated with the loss on the ICL investment and recover a return on the unamortized balance of the regulatory asset calculated at FPL's weighted average cost of capital.

Q. Has FPL included in the calculation of its 2017 FCR and CCR factors the impact of the ICL Transaction?

A. No. FPL has not included the impact of the ICL Transaction in the calculation of its 2017 FCR and CCR factors. Should the Commission approve this Petition in Docket No. 160154-EI, FPL will reflect this adjustment in the true-up process for 2017.

Proposed 2017 Residential Bill

Q. What is FPL's proposed preliminary residential 1,000 kWh bill for the period beginning January 2017?

A. FPL's preliminary residential 1,000 kWh bill for January 2017 through December 2017 is $102.28. This preliminary bill includes a base rate charge of $67.00, which reflects FPL's request in its current rate case proceeding in Docket No. 160021-EI. The preliminary bill also includes an FCR charge of $24.91, a CCR charge of $2.98, an Environmental Cost Recovery clause charge of $2.41, an Energy Conservation Cost Recovery clause charge of $1.25, a Storm Surcharge of $1.17 and a Gross Receipts Tax charge of

$2.56. FPL's proposed preliminary Residential 1,000 kWh bill for 2017 is provided on Schedule E-10, which is page 88 of Exhibit TJK-5, Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 160001-EI

MARCH 16, 2016

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL") and I am the Business Services Manager in the Power Generation Division of FPL.

Q. Please summarize your educational background and professional experience.

A. I graduated from DePauw University with a Bachelor's degree in Industrial Psychology in 1991. I subsequently earned a Master of Business Administration from Pace University in New York in 1994. I am a Certified Public Accountant in the state of New York. Prior to joining FPL in 2009, I held various auditing positions at Price Waterhouse LLP and Pfizer Inc. From 1999 to 2009, I worked for Rinker Materials (acquired by Cemex in 2008) in various audit, accounting and development capacities. I have been in my current role at FPL since 2009 where I have responsibility for all Budgeting, Forecasting, Regulatory and Internal Controls activities for FPL's fossil generating assets. I have previously testified as a Generating Performance Incentive Factor ("GPIF") witness and since January 2013, I have also overseen the overall preparation and filing of GPIF documents including testimony, exhibits, audits and discovery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report actual 2015 performance for Equivalent Availability Factor ("EAF") and Average Net Operating Heat Rate ("ANOHR") for the eleven generating units used to determine the GPIF and to calculate the resulting GPIF reward. I have compared the performance of each unit to the revised targets approved in the final Commission Order No. PSC-15-0038-FOF-EI issued January 12, 2015, for the period January through December 2015, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $64,959,390 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $31,658,059.

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

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

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

A. The steps involved in making this calculation are provided in Exhibit CRR-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +5.6041, $64,959,390 in fuel savings and a GPIF reward of $31,658,059. Page 3 provides the revised calculation of the maximum allowed incentive dollars as approved by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's performance indicators (EAF and ANOHR), the weighting factors, and the associated GPIF unit points.

Page 5 is the actual EAF and adjustments summary. This page, in columns 1 through 5, lists each of the eleven GPIF units, the actual outage factors and the actual EAF for each unit. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 18. These tables are based on the targets and target ranges previously submitted to, and approved by, the Commission.

Continuing with Exhibit CRR-1, page 7 shows the adjustments to ANOHR. For each GPIF unit it shows, in columns 2 through 4, the target heat rate formula, and the actual net output factor ("NOF") and ANOHR for all units. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 18. These tables are based on the targets and target ranges submitted to, and approved by, the Commission.

Q. Please explain the primary reason why FPL will receive a reward under the GPIF for the January through December 2015 period.

A. The primary reason that FPL will receive a reward for the period is that adjusted actual EAFs for all of the GPIF units were better than target and the Ft. Myers Unit 2 ANOHR was better than target.

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

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 90.3%, compared to its target of 83.5%. This results in +10.0 points, which corresponds to a GPIF reward of $5,022,040.

St. Lucie Unit 2 operated at an adjusted actual EAF of 86.8%, compared to its target of 84.8%. This results in +6.67 points, which corresponds to a GPIF reward of $2,757,885.

Turkey Point Unit 3 operated at an adjusted actual EAF of 91.5% compared to its target of 83.2%. This results in +10.0 points, which corresponds to a GPIF reward of $4,123,835.

Turkey Point Unit 4 operated at an adjusted actual EAF of 99.2% compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $4,541,868.

In total, the combined nuclear units' EAF performance resulted in a GPIF reward of $16,445,628.

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

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,400 Btu/kWh compared to its target of 10,405 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The St. Lucie Unit 2 adjusted actual ANOHR is 10,239 Btu/kWh compared to its target of 10,288 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The Turkey Point Unit 3 adjusted actual ANOHR is 11,126 Btu/kWh compared to its target of 11,143 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

Turkey Point Unit 4 adjusted actual ANOHR results in 10,994 Btu/kWh compared to its target of 11,002 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

In total, the combined nuclear units' heat rate performance resulted in no GPIF reward or penalty.

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

A. $16,445,628.

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

A. Regarding EAF performance, each of the seven fossil generating units performed better than their availability targets resulting in a reward of $14,767,283.

Regarding ANOHR, one out of the seven fossil units (Ft. Myers 2) operated with an ANOHR that was below the ±75 Btu/kWh dead band, resulting in a reward of $1,553,499. Out of the remaining six fossil units, four operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties while the other two operated above the dead band so they received a combined penalty of $1,108,351. Thus, the total fossil units' heat rate performance results in a net GPIF reward of $445,148.

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

A. The net GPIF availability performance reward of $14,767,283 plus the net GPIF heat rate performance reward of $445,148 results in a total GPIF reward for FPL's fossil units of $15,212,431.

Q. To recap, what is the total GPIF result for the period January through December 2015?

A. The total GPIF result for the period January through December 2015 is $64,959,390 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $31,658,059.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 160001-EI

SEPTEMBER 2, 2016

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as the Business Services Manager in the Power Generation Division of FPL, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil generating assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor (EAF) targets and average net operating heat rate (ANOHR) targets used in determining the Generating Performance Incentive Factor (GPIF) for the period January through December 2017.

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

A. Yes, I am sponsoring exhibit CRR-2. This exhibit supports the development of the 2017 GPIF targets EAF and ANOHR. The first page of this exhibit is an index to the contents of the corresponding exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2017 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December 2017, FPL projects a weighted system equivalent planned outage factor of 6.5% and a weighted system equivalent unplanned outage factor of 7.3%, which yield a weighted system EAF target of 86.2%. The targets for this period reflect planned refuelings for St. Lucie Unit 2, Turkey Point Unit 3, and Turkey Point Unit 4. FPL also projects a weighted system ANOHR target of 7,275 Btu/kWh for the period January through December 2017. As discussed later in my testimony, these targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

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

A. Yes, I have. Exhibit CRR-2, pages 6 and 7, contains the information summarizing the individual targets and ranges for EAF and ANOHR for each of the twelve generating units that FPL proposes to be considered as GPIF units for the period January through December 2017. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

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

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the equivalent planned outage factor

(EPOF) and the equivalent unplanned outage factor (EUOF). The EPOF for each unit is determined by the duration and magnitude of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor (EFOF) and the equivalent maintenance outage factor (EMOF). The EUOF is then adjusted to reflect recent or projected unit overhauls following the projection period.

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

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

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

A. In accordance with the GPIF Manual, the GPIF units selected are responsible for no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the GenTrader model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the twelve units which FPL proposes to use for the period January through December 2017 represent the top 80.2% of the total forecasted system net generation for this period excluding the Riviera Beach Next Generation Clean Energy Center and the Port Everglades Next Generation Clean Energy Center. These units came into service in 2014 and 2016, respectively, and were excluded from the GPIF calculation because there is insufficient historical data to include them. Consistent with the GPIF Manual, these units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2017 EAF and ANOHR performance targets represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL KILEY

DOCKET NO. 160001-EI

SEPTEMBER 2, 2016

Q. Please state your name and address.

A. My name is Michael Kiley. My business address is 15430 Endeavor Drive, Jupiter, FL 33478.

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

A. I am employed by Florida Power & Light Company ("FPL") as Vice President of Project Controls and Strategic Alliances as of August 2016. My previous position was Vice President of Organizational Support in the Nuclear Business Unit.

Q. Please describe your duties and responsibilities.

A. I am responsible for the Nuclear fleet functional area of Project Controls. My previous position was responsible for the Nuclear fleet functional area of Security, Training, Nuclear Licensing and Regulatory Compliance, Performance Improvement and Organizational Development. In addition, I provided executive oversight for Organizational and Strategic initiatives for the NextEra Nuclear Fleet.

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

A. I hold a Master of Business Administration degree from Southern New Hampshire University, and a Bachelor of Science degree in Marine Engineering from Massachusetts Maritime Academy. I also earned a Senior Reactor Operator License at Seabrook Nuclear Plant.

I have spent 29 years in the nuclear industry in increasingly responsible positions at NextEra and FPL including Control Room Operator to Plant General Manager at two separate NextEra locations, to Site Vice President at Turkey Point, Corporate Vice President for Organizational Support, to my current role of Vice President of Project Controls and Strategic Alliances.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy ("MMBtu") to be produced by our nuclear units. Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2017 through December 2017. I am also supporting FPL's projected 2017 incremental plant security and Fukushima costs. Finally, I address 2016 outage events at FPL's nuclear units.

Nuclear Fuel Costs

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

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and current operating schedules, for the period January 2017 through December 2017.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2017 through December 2017.

A. FPL projects the nuclear units will produce 302,416,541 MMBtu of energy at a cost of $0.6396 per MMBtu, excluding spent fuel disposal costs, for the period January 2017 through December 2017. Projections by nuclear unit and by month are listed in Appendix II, on Schedule E-4, starting on page 18, which is attached as an exhibit to FPL witness Keith's testimony.

Nuclear Plant Incremental Security Costs

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2017 through December 2017?

A. FPL projects that it will incur $46.2 million in incremental nuclear power plant security costs in 2017. The costs consist of $10.7 million of capital expenditures and $35.5 million of O&M expenses.

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

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

<u>Fukushima-Related Costs</u>

Q. What is FPL's projection of Fukushima-related costs at FPL's nuclear power plants for the period January 2017 through December 2017?

A. FPL's current projection of Fukushima-related costs for 2017 is approximately $485,000 of capital expenditures and $1.5 million of O&M expenses.

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

A. FPL expects to pursue the following activities in 2017:

- FPL will complete a flooding integrated assessment to determine the challenge a beyond design basis flood hazard could possibly pose to existing safety systems.
- Modifications identified in the mitigation strategy assessment conducted in 2016, that are expected to protect existing safety systems.
- Emergency procedure upgrades.
- Payment of NRC fees charged for NRC work-hours for site inspections related to Station Blackout Mitigation Actions implemented in 2016, and for reviewing FPL's responses associated with the various regulatory orders and information requests.

<u>**2016 Outage Events**</u>

Q. Has FPL experienced any unplanned outages at its Turkey Point plants in 2016?

A. Yes. In late July 2016, Unit 3 reduced power to perform repairs to a tube leak on the 3B Feedwater Heater. While preparing the unit for maintenance activities, FPL had challenges with isolating the 3B Feedwater Heater on both the condensate side and extraction steam, which caused FPL to manually shut down the unit to safely repair the tube leak. Upon returning the unit to service from the repair, the turbine tripped due to the malfunction of a control system card. FPL replaced the affected control system card and then returned the unit to service. FPL is currently in the process of investigating and evaluating this outage.

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

A. The Unit 3 outage time due to the 3B Feedwater Heater tube leak and control system card malfunction was approximately 3 days.

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2016?

A. Yes. In August 2016, Unit 1 was manually shut down to investigate a leak in the Reactor Coolant System (RCS). FPL identified a leak in a flow element and conducted repairs to address the issue. While the unit was in preparation for power ascension following the repairs, FPL observed evidence of seat leakage within the 1A2 RCS Pressure isolation check valve V3217 that exceeded specified limits. Consequently, FPL returned the unit to a safe condition to perform additional testing and repairs. The outage duration for this event was approximately 27 days. FPL is currently in the process of investigating and evaluating this outage.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 160001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2015 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 2015 through December 2015.

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

A. Yes. Exhibit________ (CDY-1) consists of Schedules A, C1 and E1-B for the Consolidated Electric Division. 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 2015 through December 2015?

A. For the Consolidated Electric Division the final remaining true-up amount is an under recovery of $28,109.

Q. How was this amount calculated?

A. It is the difference between the actual end of period true-up amount for the January through December 2015 period and the total true-up amount to be collected or refunded during the January - December 2016 period.

Q. What was the actual end of period true-up amount for January - December 2015?

A. For the Consolidated Electric Division it was $1,610,257 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2016 period?

A. A consolidated over-recovery of $1,582,148 to be refunded.

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.

Q. What are the costs outside of purchased fuel costs, included in the 2015 final true up for Florida Public Utilities Company?

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

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

Additionally, the Consultants provided services related to reviewing and evaluating the impact of the new Generation facility at Rayonier on our purchased power costs, and the impact from the loss, or possible increase, of the purchased power from Rayonier. They assisted in the negotiations and review of the Purchased power agreements between the Company and Eight Flags Energy LLC ("Eight Flags") as well as the existing renewable energy power purchase contract with Rayonier Performance Fibers. The Consultants also assisted the Company in its evaluation of alternatives on what could be done to protect fuel savings to our customers, and what can be done to further reduce the Company's costs for purchased power.

The specified legal and consulting costs were not included in expenses during the last FPUC consolidated electric rate base proceeding and are not being recovered through base rates. While the purchased power agreements for the cogeneration project have been completed and approved by the Commission, the Company's efforts in this regard are ongoing until the plant is fully operational. The Company fully expects that the cogeneration project, with which these legal and consulting expenses are associated, will come to fruition and ultimately produce significant fuel savings for customers, as well as increased reliability. As such, consistent with past Commission precedent, these fuel-related costs should be deemed appropriately recoverable through the fuel clause.

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

A. Consistent with the Commission's policy, similar expenses paid in Docket No. 120001-EI, Docket No. 130001-EI, Docket No. 140001-EI and Docket No. 150001-EI, for legal and consulting costs associated with the review and analysis of the Company's existing purchase power agreements, as well as the development and negotiations for a renewable energy contract with Rayonier were determined to be appropriate and recoverable through the fuel clause.

Q. Which legal and consulting costs were allowed to be recovered through the fuel clause in 2012, 2013, 2014 and 2015?

A. In all four years, the Commission allowed FPUC to recover costs associated with work done by Christensen and Associates ("Christensen"), Gunster, Yoakley, & Stewart, ("Gunster") and Sterling Energy Services ("Sterling") pertaining to the Rayonier renewable energy contract, which was finalized in early 2012. This contract provides for the purchase of power at rates lower than the existing Purchase Power Agreement between FPUC and JEA. FPUC realized reduced fuel rates for the Northeast Division customers as a result of this agreement, beginning in mid-2012. The costs associated with the development, negotiation, and regulatory approvals for the contract had not been included in expenses during the last FPUC consolidated electric base rate proceeding; thus, they were not being recovered through the Company's base rates. Consequently, the Commission allowed these costs to be passed through the fuel clause. The Company believes that the costs addressed herein are similar to those allowed to be recovered through the fuel clause in 2012, 2013, 2014 and 2015. As such, the Company believes the costs addressed herein are likewise appropriate for recovery through the fuel clause.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 160001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Direct Testimony (Actual/Estimated True-Up) of
Michael Cassel
On Behalf of
Florida Public Utilities Company

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

A. My name is Michael Cassel. I am the Director of Regulatory and Governmental Affairs for Florida Public Utilities Company's ("FPUC" or "Company") Electric and Natural Gas Divisions, as well as the Florida Division of Chesapeake Utilities Corporation ("CHPK"). Our Companies' have their administrative offices at 1750 S. 14^{th} Street, Suite 200, Fernandina Beach, Florida 32034.

Q. Describe briefly your education and relevant professional background.

A. I received a Bachelor of Science Degree in Accounting from Delaware State University in Dover, Delaware in 1996. From 1996 to 1999, I was employed by J.P. Morgan, Inc., where I had various accounting/finance responsibilities for the firm's private banking clientele. Subsequently, I was employed by Computer Sciences Corporation as a Senior Finance Manager from 1999 to 2006. In this position, I was responsible for the financial operation of the company's chemical, oil and natural resources business. This included forecasting, financial close and reporting responsibility, as well as representing Computer Sciences Corporation's financial interests in contract/service negotiations with existing and potential clients. From 2006-2008, I was employed by J.P. Morgan Chase & Company, Inc. as a Financial Manager in their card finance group. My primary responsibility in this position was the development of client specific financial models and profit loss statements. In 2008, I was hired by Chesapeake Utilities Corporation (CUC) as a Senior Regulatory Analyst. In that position, I was primarily involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the CUC's Delaware and Maryland natural gas distribution companies. In 2010, I moved to Florida to assume the role of Senior Tax Accountant for CUC's Florida business units, which include FPUC and CHPK. Since that time, I have held various management roles including Manager of the Back Office in 2011, and Director of Business Management in 2012.

Q. What are your responsibilities in your current position?

A. As the Director of Regulatory and Governmental Affairs, my responsibilities include directing the regulatory and governmental affairs for the various business units under the Chesapeake Utilities Corporation umbrella in Florida, including, but not limited to, regulatory analysis, and reporting and filings before the Florida Public Service Commission (FPSC) for FPUC, FPUC-Indiantown, FPUC-Fort Meade, CHPK, and Peninsula Pipeline Company.

Q. Have you previously testified in this Docket?

A. No, I have not.

Q. Have you provided testimony in other proceedings?

A. Not in Florida. However, I did submit testimony in the Delaware Commission's annual Gas Sales Service Rate dockets (GSR) in 2008 and 2009, Docket Nos. 08-269F and 09-398F, respectively.

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 2017 – December 2017.

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

A. Yes, they were completed under my direction.

Q. Which schedules has the Company completed and filed?

A. With this filing, the Company is including Schedules E1-A, E1-B, and E1-B1. These schedules are included in the exhibit to my testimony, Exhibit MC-1. Schedule E1-B shows the Calculation of

Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2016 – December 2016 based on 6 Months Actual and 6 Months Estimated data.

Q. What was the final remaining true-up amount for the period January 2015 – December 2015?

A. The final remaining true-up amount was an under-recovery of $28,109.

Q. What is the estimated true-up amount for the period January 2016 – December 2016?

A. The estimated true-up amount is an under-recovery of $1,261,783.

Q. What is the total true-up amount to be collected or refunded during January 2017 – December 2017?

A. Based upon six months actual data and six months estimated data, the Company has determined that, at the end of December 2016, the Company will have under-recovered $1,289,892 in purchased power costs, which should be included in the calculation of FPUC's cost recovery factors to be applied in 2017.

Q. By Order No. PSC-15-0586-FOF-EI, issued in Docket No. 150001-EI, the FPSC approved the recovery by FPUC of depreciation expense, taxes other than income tax, and a return investment associated with a project to establish an interconnection between

FPUC's Northeast Division and Florida Power & Light Company ("FPL"). What is the status of that project?

A. Consistent with the arrangement between the two companies, FPL is responsible for construction and implementation of the interconnect between our Northeast Division and their facilities. It is my understanding that FPL is currently working on the final design for interconnecting with the FPU 138 KV transmission system. Early in the permit approval process, local concerns regarding the original design resulted in construction being postponed until alternative designs could be evaluated. As I understand it, an alternative design option has since been selected, but FPL is still working to obtain the necessary local approvals so that construction can begin. In spite of the delay, construction schedules still indicate that construction will be completed and the interconnection will be in place and operable prior to January 1, 2018.

Q. In Docket No. 150001-EI, the Commission also approved certain expenses associated with FPUC's purchased power agreement with Eight Flags Energy. Has Eight Flags initiated deliveries to FPUC under that contract?

A. The Eight Flags Energy facility began deliveries to FPUC in June 2016, which represents the start date for additional fuel savings for

FPUC's customers, as recognized by the FPSC in Docket No. 140185-EQ.

Q. Has FPUC included other costs in addition to the costs specific to fuel and purchased power amounts in its calculations?

A. Yes, as we have in the past, the Company has included charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery through the fuel clause.

Q. Please explain why these costs should be deemed recoverable through the fuel clause?

A. Consistent with the FPSC's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, these are fuel and purchased power–related costs that are not currently being recovered through FPUC's base rates. Similar expenses paid by FPUC to consultants and legal counsel have been determined by the FPSC to be recoverable by the Company through the fuel clause in Dockets Nos. 050001-EI, 120001-EI, 130001-EI, 140001-EI, and most recently in Docket No. 150001-EI. Consistent with the FPSC's prior decisions, the costs that we have included in 2016 reflect legal and consulting fees associated with projects designed to reduce fuel rates for our customers. These legal and consulting fees are not associated with "fuel procurement administrative functions," because they are not associated with the performance of the day-to-day administration of existing contracts for power purchases from FPUC's wholesale providers nor are these costs associated with internal staff responsible for fuel procurement. To the contrary, these costs were incurred specifically for the purpose of pursuing projects and contracts that will inure to the benefit of FPUC's ratepayers in the form of fuel savings. Moreover, these costs were not anticipated in the Company's last rate case and tend to fluctuate significantly from year to year. As such, recovery through the fuel clause is consistent with past FPSC decision, including the FPSC's policy set forth in Order No. 14546.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2017 Projection Testimony of
Michael Cassel
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Michael Cassel. I am the Director of Regulatory and Governmental Affairs for Florida Public Utilities Company (including both the electric and natural divisions), Florida Public Utilities Company – Indiantown Division, and Florida Public Utilities Company-Fort Meade (jointly, "FPUC"), the Florida Division of Chesapeake Utilities Corporation ("CFG"), Peninsula Pipeline, and Eight Flags Energy, LLC (Eight Flags), (herein, all FPUC divisions and CHPK, jointly, "Companies"). FPUC has its administrative offices at 1750 S. 14th Street, Suite 200, Fernandina Beach, Florida 32034

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

A. I received a Bachelor of Science Degree in Accounting from Delaware State University in Dover, Delaware in 1996. I was hired by Chesapeake Utilities Corporation (CUC) as a Senior Regulatory Analyst in March 2008. As a Senior Regulatory Analyst, I was primarily involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the CUC's Delaware and Maryland natural gas distribution companies. In

2010, I moved to Florida in the role of Senior Tax Accountant for CUC's Florida business units. Since that time, I have held various management roles including Manager of the Back Office in 2011, Director of Business Management in 2012. I am currently the Director of Regulatory and Governmental Affairs for CUC's Florida business units. In this role, my responsibilities include directing the regulatory and governmental affairs for the Companies in Florida including regulatory analysis, and reporting and filings before the Florida Public Service Commission (FPSC) for FPU, FPU-Indiantown, FPU-Fort Meade, Central Florida Gas, and Peninsula Pipeline Company. Prior to joining Chesapeake, I was employed by J.P. Morgan Chase & Company, Inc. from 2006 to 2008 as a Financial Manager in their card finance group. My primary responsibility in this position was the development of client-specific financial models and profit loss statements. I was also employed by Computer Sciences Corporation as a Senior Finance Manager from 1999 to 2006. In this position, I was responsible for the financial operation of the company's chemical, oil and natural resources business. This included forecasting, financial close and reporting responsibility, as well as representing Computer Sciences Corporation's financial interests in contract/service negotiations with existing and potential clients. From 1996 to 1999 I was employed by J.P. Morgan, Inc. where I had various accounting/finance responsibilities for the firm's private banking clientele.

Q. Have you previously testified in this Docket?

A. No, I have not, although I submitted prefiled testimony on August 4, 2016, in this proceeding addressing the Company's actual/estimated true-up.

Q. Have you provided testimony in other proceedings?

A. Not in Florida. However, I did submit testimony in the Delaware Commission's annual Gas Sales Service Rate dockets (GSR) in 2008 and 2009, Docket Nos. 08-269F and 09-398F, respectively.

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 2017 - December 2017 fuel cost recovery adjustments for its consolidated 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 2016 – December 2016 and to establish a "true-up" amount to be collected or refunded during January 2017 - December 2017.

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

A. Yes, they were completed under my direct supervision and review.

Q. Is FPUC providing the required schedules with this filing?

A. Yes. Included with this filing are Consolidated Electric Schedules E1, E1A, E2, E7, E8, E10 and Attachment A. These schedules are included in my Exhibit MC-2, which is appended to my testimony.

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. Mr. Cutshaw and Mr. Shelley address these projects more specifically in their testimonies.

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

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

Specifically, consistent with item 10 of Order 14546, the costs the Company has included are fuel-related costs that were not anticipated or included in the cost levels used to establish the current base rates. To be clear, these costs are not tied to the Company's internal staff involvement in fuel and purchased power procurement and administration. Instead, these costs are associated with external contracts which consequently, tend to be more volatile depending upon the issue. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of Fuel costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in more recent Docket Nos. 120001-EI, 130001-EI, 140001-EI, 150001-EI and 160001-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. As the Commission has recognized time and again, the Company simply does not have the internal resources to pursue projects and initiatives designed to produce fuel savings without engaging outside assistance for project analytics and due diligence, as well as negotiation and contract development expertise. Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. **Please explain what are the costs outside of purchased fuel costs included in the 2016 true-up for Florida Public Utilities Company?**

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. ("Gunster") King and Spalding ("King") and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their fuel rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2017 Projection factors, were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates. Pierpont has also been performing due diligence in its 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. Moreover, without this outside assistance, the Company would be unable to adequately analyze potential fuel savings opportunities, nor could we properly evaluate proposals to meet our generation needs. And, again, these costs are consistent with the standard set forth in Order No. 14546 in that they are incurred in the pursuit of fuel and purchased power savings for our customers and are not otherwise being recovered through the Company's base rates. The

Company will continue to engage legal and consulting assistance as it explores additional fuel related savings options including other CHP opportunities and solar/photovoltaic opportunities.

Q. FPUC Witness Cutshaw addresses the status of the FPL Interconnect in his testimony. Does the Company continue to expect that this interconnect project will produce fuel and purchased power savings for FPUC's customers?

A. Absolutely. Consistent with the representations of FPUC's witnesses in Docket No. 150001-EI, the Company still adheres to its savings projections associated with the FPL interconnect project. While we cannot accurately quantify the full extent of the savings until our next purchase power agreement is in place, based upon the information currently available regarding purchased power rates available in the market as compared against payments made under our current purchased power agreement with JEA, we continue to believe that owe will see significant purchased power savings following the expiration of our current purchased power contract with JEA. Those savings will ultimately benefit our customers. I have included in my Exhibit MC-2 as additional Schedule A, which reflects our current projected savings associated with the project. Without the FPL Interconnection project, which will give the Company access to alternative power suppliers, we do not believe we would be able to attain savings near this level in our next purchased power agreement. Thus, the Company believes that recovery of the project through the Fuel Clause is appropriate in that the project is designed to achieve savings in the delivered price of purchased power for our customers and is not otherwise being recovered through our base rates. Moreover, it is my understanding that recovery of this project is not inconsistent with prior Commission decisions to allow cost recovery through the Fuel Clause of capital projects designed to produce fuel savings.

Summary Rates

Q. What are the final remaining true-up amounts for the period January – December 2015 for both Divisions?

A. The final remaining consolidated true-up amount was an under-recovery of $28,109.

Q. What are the estimated true-up amounts for the period of January – December 2016?

A. There is an estimated consolidated under-recovery of $1,261,783.

Q. Please address the calculation of the total true-up amount to be

collected or refunded during the January - December 2017 year?

A. The Company has determined that at the end of December 2016, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of $1,289,892.

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

A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is 6.593¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2017 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on consolidated Schedule E-10 in Composite Exhibit Number MC-2, a residential customer using 1,000 KWH will pay $138.97. This is a decrease of $1.37 under the previous period.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 160001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2017 Projection 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, 1750 South 14th Street, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

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

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida Divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues. During 2015 I moved into my current role as Director, Business Development and Generation.

Q. **Have you previously testified in this Docket?**

A. Yes. I have also testified in other proceedings before the Commission, including rate case and storm hardening proceedings.

Q. **Has the Company investigated means to reduce costs for its customers in its consolidated electric divisions?**

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

Company's purchased power contract with Gulf Power, which resulted in reduced costs to customers in its Northwest Florida Division.

These same focused and steady efforts are continuing today and, in our opinion, have resulted in a reduced rate of increase in fuel costs for FPUC and its customers.

The Company also continues to investigate other opportunities to reduce purchased power costs, including the contractual relationships with other wholesale power suppliers. As a result of this ongoing investigation into new opportunities, relationships were developed with other suppliers, informal studies of generation and transmission capacity arrangements were reviewed and contract possibilities were discussed. Although realization of some of these opportunities is not possible until the expiration of the existing contracts, the information gathered will provide FPUC with invaluable resources that will enhance the Company's ability to achieve further savings in the negotiation of its next purchased power agreements. For instance, among the notable information gleaned in the early stages of these discussions was the fact that a transmission system interconnection with Florida Power & Light ("FPL") in our Northeast Florida Division will provide enhanced opportunities to save customer fuel costs and increase the reliability in this division.

Most recently, FPUC provided a "Solicitation for Proposals to Provide Power Supply and Ancillary Services for Florida Public Utilities

Company" to selected wholesale power suppliers for the purpose of providing all requirements wholesale service to the Northeast Florida Division effective January 1, 2018. The Company anticipates a new contract to be in place by early 2017. Although these proposals have not yet been evaluated, it is anticipated that the new contract will provide benefits to all FPUC customers.

Q. Has the Company availed itself of other opportunities to produce fuel cost savings?

A. Yes. For instance, the Northeast Florida Division provides service to two paper mills on Amelia Island that have significant on site generation capabilities. Our relationships with these two large customers have created further opportunities for some limited purchased power for FPUC. FPUC has entered into arrangements with these alternative power providers that have thus far proven advantageous. FPUC is continuing to look at these types of arrangements and all other avenues for reducing purchased power costs.

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

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

Secondly, as discussed in the testimony of witness Drane Shelley, FPUC has completed the development of a partnership with Eight Flags Energy, LLC to provide additional, lower cost energy to its Northeast Florida Division customers, and that project is now delivering low cost energy to FPUC.

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

A. In addition to significant cost savings, these projects have been beneficial to the Company's electric customers by securing additional service reliability for the Northeast Florida Division. Also, due to the consolidated fuel factor, customers in both of the Company's electric divisions will benefit from the fuel and purchased power savings. Moreover, the Eight Flags project produces all these benefits, while doing so with a lower environmental profile than would be associated with locating traditional generation on the island or with FPUC's purchased power options.

Q. Can you provide background on the transmission interconnect project with FPL?

A. Yes. This is a significant project for FPUC, one that the Company has embarked upon specifically because we anticipate it will directly improve our ability to negotiate increased savings for our customers in our next purchased power agreement, as well as improve the system reliability in our Northeast Florida Division. Historically, FPUC's ability to secure competitive wholesale power quotations has been hindered by the limitation on the transmission interconnections providing power to FPUC's Northeast Florida Division (Amelia Island).

At present, the FPU 138 KV transmission is directly connected to the JEA 138 KV transmission system. Extending from the current interconnection with JEA, the FPUC 138 KV transmission line is a dual circuit, single pole line, which includes several miles of line located in relatively inaccessible marshy areas. This transmission line serves as the only off-island power supply to Amelia Island. In order to help mitigate the issues for upcoming wholesale power proposals, FPUC proposed an interconnection with the FPL transmission system, which is located in very close proximity to the existing FPUC transmission system. Not only will this additional interconnection provide access to more competitive wholesale power options, this will provide much needed redundancy to the power supply on Amelia Island which will have a positive impact on the overall system reliability.

Q. **Can you provide an update on the transmission interconnect project with FPL?**

A. Yes. The FPUC-owned 138 KV transmission line is located approximately 750 feet (0.14 miles) from the FPL substation and runs in the existing right-of-way along with the FPL 230 KV transmission line. Originally, the proposed construction was to include expansion of the existing FPL substation in which the necessary transmission and system protection equipment will be placed in order to allow for the interconnection of the FPUC 138 KV transmission line. The FPUC 138 KV transmission was to be re-routed to parallel the FPL 230 KV transmission line into the expanded substation. However, during the planning process, unexpected local opposition was raised based on the original design. As a result, numerous meetings and discussions occurred which identified other alternatives that would alleviate the public opposition. At present, the final design is nearing completion. We anticipate that the new design will be approved within a reasonable time frame, which will allow us to meet the goals and objectives of the interconnection.

As with the original design of the interconnect, the new design will provide for improved system reliability on the transmission system and will afford FPUC the opportunity to reach other less expensive generation sources while avoiding additional transmission wheeling costs.

Q. When will construction of the FPL transmission interconnection begin and what is the revised in service date?

A. Based on the most recent information construction will begin in fourth quarter of 2016 with the in-service date during the last quarter of 2017.

Q. Can you quantify or project the savings to be derived as a result of this new interconnect with FPL?

A. Consistent with my testimony in Docket No. 150001-EI, at this time, we cannot specifically define what those savings will be, nor will we be able to do so until the final design and negotiations for future agreements are completed. FPUC witness Mike Cassel addresses our continued faith in our projected savings associated with the FPL interconnection.

Q. Are there other efforts underway to identify projects that will lead to lower cost energy for FPUC customers?

A. Yes. FPUC continues to work with consultants, as well as project developers, to identify new projects and opportunities that can lead to reduced fuel costs for our customers. We also continue to analyze the feasibility of energy production and supply opportunities that have been on our planning horizon for some time and noted in prior fuel clause proceedings, namely additional Combined Heat and Power (CHP) projects and potential Solar Photovoltaic ("PV") projects.

Q. **Can you provide additional information on these CHP projects?**

A. Yes. The success of the Rayonier project and the Eight Flags project has sparked interest in other CHP opportunities on Amelia Island. When coupled with some anticipated industrial expansion in the area, the already quantifiable benefits of these existing projects has piqued the interest of others to contemplate partnering with a new CHP-based qualifying facility ("QF"). Given that FPUC would again be the recipient of any QF power generated by such project, FPUC has been involved in the analysis and feasibility study for this potential new project. The project is still in the planning stages, but the early indications are that the project would not only be feasible, but would provide benefits to all involved, including FPUC.

Q. **Can you provide additional information on the PV projects you referenced above?**

A. Yes. FPUC has determined that the development of smaller PV systems within the FPUC electric service territory may be economically feasible and could provide benefits to the rate payers. Based on this analysis, FPUC is working to acquire access to the necessary property to construct small scale (one to five megawatts) PV installations. Not only will this increase the renewable energy available to FPUC, the cost is expected to be less than the current wholesale power cost which will provide additional benefits to FPUC customers. Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. These projects are still in the early stages of analysis and development. At present, it is contemplated that any PV facility would be a utility asset and would not be in-service until after the relevant, existing full requirements purchase power agreements have expired. Nonetheless, even in these early analysis and planning stages, the potential benefits of the PV projects under consideration have been very encouraging.

Q. Does this include your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 160001-EI:
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2017 Projection Testimony of
Drane A. Shelley
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Drane A. Shelley, 1750 South 14th Street, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

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

A. I graduated from Murray State University in 1976 with a B.S. in Electrical Engineering Technology and began my career with Big Rivers Electric Company in May, 1976. I spent 15 years with Big Rivers Electric Company and held positions of increasing responsibility that involved substation, transmission, distribution and power plant electrical design, as well as operations and maintenance activities. After leaving Big Rivers, I worked 14 years for three (3) different Engineering Consultant Firms providing services to several Electric Utility Companies including IOU's, Municipals, and Cooperatives. I joined FPUC in December, 2006 as Operations Manager in the Marianna

(Northwest Florida) Division. In February, 2009, I was promoted to General Manager of the Northwest Florida Division, and in 2013, I moved into my current position of Director, Electric Operations. In my current position I am responsible for the Electric Operations of the Northwest and Northeast Divisions plus the Eight Flags CHP Generation Facility. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions.

Q. Have you previously testified in this Docket?

A. No, I have not.

Q. Have you provided testimony in other proceedings?

A. Yes, I submitted pre-filed testimony in the Company's last base rate proceeding, Docket No. 140025-EI.

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

A. To give an update on the Eight Flags, LLC ("Eight Flags") Combined Heat and Power ("CHP") project that was being developed between Rayonier Advance Materials ("Rayonier"), Eight Flags and FPUC.

Q. Could you provide a short background on this CHP project?

A. Yes. In Docket No. 140185-EQ, the Florida Public Service Commission reviewed and approved an agreement between Eight Flags and FPUC whereby a CHP facility was to be constructed on the Rayonier Site in

Fernandina Beach. This CHP facility, owned by Eight Flags, a subsidiary of Chesapeake Utilities Corporation (Chesapeake), is a FERC-certified qualifying facility that provides steam to Rayonier, as well as approximately 20 megawatts ("MW") of energy to FPUC's northeast electric division. This CHP generation facility provides lower cost energy to the Company's Northeast division electric customers on a more reliable basis given the location of the facility on Amelia Island.

Q. Has the project been completed?

A. Yes. The Eight Flags CHP facility began commercial operation in June 2016.

Q. What is the current electrical output associated with the Eight Flags Facility?

A. Currently the Eight Flags facility is putting out approximately 20MW of energy for use by FPUC Northeast division customers.

Q. Is the Eight Flags CHP facility producing the results that were anticipated?

A. Yes. Although the project is in the early stages of commercial operations, it is already operating at the output level planned and the Company anticipates that the both the savings and reliability will remain consistent with what was indicated in Docket No. 140085.

Q. Does this conclude your testimony?

A. Yes it does.

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

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 4th day of November, 2016.

Linda Boles

LINDA BOLES, CRR, RPR
Official FPSC Hearings Reporter
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