John T. Butler
Assistant General Counsel – Regulatory
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5639
(561) 691-7135 (Facsimile)
John.Butler@fpl.com

March 3, 2014

-VIA ELECTRONIC FILING -

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 140001-EI

Dear Ms. Stauffer:

I enclose for electronic filing in the above docket (i) Florida Power & Light Company's ("FPL") Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery True-Ups for the Period Ending December 2013, (ii) the prefiled testimony and exhibits of FPL witness Terry J. Keith and (iii) the prefiled testimony and exhibit of FPL witness Gerard J. Yupp.

Exhibit TJK-2 to Mr. Keith's testimony and Exhibit GJY-1 to Mr. Yupp's testimony contain confidential information. This electronic filing includes only the redacted version of Exhibits TJK-2 and GJY-1. Contemporaneous herewith, FPL will file via hand-delivery a Request for Confidential Classification.

If there are any questions regarding this transmittal, please contact me at (561) 304-5639.

Sincerely,

s/ John T. Butler
John T. Butler

Enclosures
cc: Counsel for Parties of Record (w/encl.)

1290255_1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 140001-EI Filed: March 3, 2014

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY NET TRUE-UPS FOR THE PERIOD ENDING DECEMBER 2013, AND 2013 INCENTIVE MECHANISM RESULTS

Florida Power & Light Company ("FPL") hereby petitions this Commission for approval of (1) FPL's Net Fuel and Purchased Power Cost Recovery ("FCR") true-up amount of $98,482 under-recovery, and (2) Net Capacity Cost Recovery ("CCR") true-up amount of $11,054,159 over-recovery, both for the period ending December 2013. Additionally, FPL is including the results for the period January 2013 through December 2013 of its Incentive Mechanism that was approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013 in Docket No. 120015-EI. FPL incorporates the prepared written testimony and exhibits of FPL witnesses Terry J. Keith and Gerard J. Yupp and states as follows:

1. The $98,482 net FCR true-up under-recovery for the period January 2013 through December 2013 was calculated in accordance with the methodology set forth in Schedule 1, page 2 of 2, attached to Order No. 10093, dated June 19, 1981. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of Mr. Keith.

2. By Order No. PSC-13-0665-FOF-EI, the Commission approved FCR Factors for the period commencing January 2, 2014. These factors reflected an actual/estimated true-up under-recovery, including interest, for the period January 2013 through December 2013 of $143,214,959, which was also approved in Order No. PSC-13-0665-FOF-EI. The actual under-

recovery, including interest, for the period January 2013 through December 2013 is $143,313,441. The $143,313,441 actual under-recovery, less the actual/estimated under-recovery of $143,214,959, which is currently reflected in charges for the period beginning January 2, 2014, results in a net FCR true-up under-recovery of $98,482 that is to be included in the calculation of the FCR factors for the period beginning January 2015.

3. The $11,054,159 net CCR true-up over-recovery for the period January 2013 through December 2013 was calculated in accordance with the methodology set forth in Order No. 25773, dated February 24, 1992. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of Mr. Keith.

4. By Order No. PSC-13-0665-FOF-EI, the Commission approved CCR Factors for the period commencing January 2, 2014. These factors reflected an actual/estimated true-up under-recovery, including interest, for the period January 2013 through December 2013 of $25,357,191, which was also approved in Order No. PSC-13-0665-FOF-EI. The actual under-recovery, including interest, for the period January 2013 through December 2013 is $14,303,032. The $14,303,032 actual under-recovery, less the actual/estimated under-recovery of $25,357,191, results in a net CCR true-up over-recovery of $11,054,159 that is to be included in the calculation of the CCR Factors for the period beginning January 2015.

5. By Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company, the Commission ordered that, as part of the fuel cost recovery clause, FPL annually file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization it undertook in that calendar year. Consistent with this order, the results of its Incentive Mechanism for the period January 2013 through December 2013 are provided in the testimony and exhibit of Mr. Yupp. The total gains

for the Incentive Mechanism during that period were $24,563,872. This does not exceed the sharing threshold of $46 million and so customers receive 100% of those gains.

WHEREFORE, Florida Power & Light Company respectfully requests the Commission to approve for the period ending December 2013: (1) FPL's net FCR true-up amount of $98,482 under-recovery and authorize the inclusion of this amount in the calculation of the FCR Factors for the period beginning January 2015, (2) FPL's net CCR true-up amount of $11,054,159 over-recovery and authorize the inclusion of this amount in the calculation of the CCR Factors for the period beginning January 2015, and (3) total gains of $24,563,872 for the Incentive Mechanism during the period January 2013 through December 2013.

Respectfully submitted,

R. Wade Litchfield, Esq.
Vice President and General Counsel
John T. Butler, Esq.
Assistant General Counsel – Regulatory
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5639
Facsimile: (561) 691-7135

By: *s/ John T. Butler*
John T. Butler
Fla. Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 140001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service / hand delivery / or the United States mail on this 3rd day of March, 2014, to the following persons:

Martha F. Barrera, Esq.
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd
Tallahassee, Florida 32399-0850
mbarrera@psc.state.fl.us

Jon C. Moyle, Esq.
Moyle Law Firm, P.A.
118 N. Gadsden St.
Tallahassee, FL 32301
Counsel for FIPUG
jmoyle@moylelaw.com

Beth Keating, Esq.
Gunster Law Firm
Attorneys for FPUC
215 South Monroe St., Suite 601
Tallahassee, Florida 32301- 1804
bkeating@gunster.com

John T. Burnett, Esq.
Dianne M. Triplett, Esq.
Attorneys for DEF
209 First Avenue North
St. Petersburg, Florida 33701
john.burnett@duke-energy.com
dianne.triplett@duke-energy.com

James D. Beasley, Esq
J. Jeffrey Wahlen, Esq.
Ashley M. Daniels
Ausley & McMullen
Attorneys for Tampa Electric
P.O. Box 391
Tallahassee, Florida 32302
jbeasley@ausley.com
jwahlen@ausley.com
adaniels@ausley.com

Jeffrey A. Stone, Esq.
Russell A. Badders, Esq.
Steven R. Griffin, Esq.
Beggs & Lane
Attorneys for Gulf Power
P.O. Box 12950
Pensacola, FL 32591-2950
jas@beggslane.com
rab@beggslane.com
srg@beggsland.com

Robert Scheffel Wright, Esq.
John T. LaVia, III, Esq.
Gardner, Bist, Wiener, et al
Attorneys for Florida Retail Federation
1300 Thomaswood Drive
Tallahassee, Florida 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

James W. Brew, Esq
F. Alvin Taylor, Esq.
Attorney for White Springs
Brickfield, Burchette,Ritts & Stone, P.C
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, DC 20007-5201
jbrew@bbrslaw.com
ataylor@bbrslaw.com

J. R. Kelly, Esq.
Patricia Christensen, Esq.
Charles Rehwinkel, Esq.
Joseph A. McGlothlin, Esq.
Erik L. Sayler, Esq.
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, Florida 32399
Kelly.jr@leg.state.fl.us
Christensen.patty@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us
mcglothlin.joseph@leg.state.fl.us
sayler.erik@leg.state.ft.us

Michael Barrett
Division of Economic Regulation
Florida Public Service Commission
2540 Shumard Oak Blvd
Tallahassee, Florida 32399-0850
mbarrett@psc.state.fl.us

By: *s/ John T. Butler*
John T. Butler
Fla. Bar No. 283479

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI
FLORIDA POWER & LIGHT COMPANY

MARCH 3, 2014

IN RE: LEVELIZED FUEL COST RECOVERY
AND CAPACITY COST RECOVERY
FINAL TRUE-UP

JANUARY 2013 THROUGH DECEMBER 2013

TESTIMONY & EXHIBITS OF:

TERRY J. KEITH
GERARD J. YUPP

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 140001-EI

MARCH 3, 2014

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

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

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

A. Yes.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery (FCR) Clause and Capacity Cost Recovery (CCR) Clause Net True-Up amounts for the period January 2013 through December 2013. The Net True-Up for the FCR is an under-recovery, including interest, of $98,482. The Net True-Up for the CCR is an over-recovery, including interest, of $11,054,159. FPL is requesting Commission approval to include the FCR true-up under-recovery of $98,482 in the calculation of the FCR factor for the period January 2015 through December 2015. FPL is also requesting Commission approval to include the CCR true-up over-recovery of $11,054,159 in the calculation of the CCR factor for the period January 2015 through December 2015.

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

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. In addition, FCR Schedules A1 through A12 for the January 2013 through December 2013 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

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

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

FUEL COST RECOVERY CLAUSE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Turning to page 4 in Appendix I, what was the variance in Adjusted Total Fuel Costs and Net Power Transactions?

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

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

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

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

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

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

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

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

million decrease due to lower than projected unit costs.

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

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

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

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

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

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

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

Energy Cost of Economy Purchases ($1.2 million increase)

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

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

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

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

<u>Fuel Cost of Power Sold ($0.9 million decrease)</u>

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

<u>Energy Payments to Qualifying Facilities ($10.2 million decrease)</u>

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

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

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

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

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

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

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

CAPACITY COST RECOVERY CLAUSE (CCR)

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

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

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

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

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

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

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

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

A. Yes. Appendix II, page 3, titled “Calculation of Final True-up Variances,” shows the actual capacity charges and applicable revenues compared to actual/estimated capacity charges and applicable revenues for the period January 2013 through December 2013.

Q. What was the variance in net capacity charges?

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

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

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

Transmission of Electricity by Others ($2.1 million decrease)

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

Transmission Revenues from Capacity Sales ($0.5 million increase)

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

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

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

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

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

Payments to Non-Cogenerators ($1.2 million increase)

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

Payments to Co-generators ($0.7 million increase)

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

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

Q. What was the variance in CCR revenues?

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

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

A. Yes. Schedule A12 consists of two pages that are included in Appendix II as pages 4 and 5. Page 4 shows the actual capacity payments for QFs, the Southern Company UPS contract and the SJRPP contract for the period January 2013 through December 2013. Page 5 provides the Short Term Capacity Payments for the period January 2013 through December 2013.

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

FUEL COST RECOVERY

2013 FINAL TRUE UP CALCULATION

TJK-1
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-4
EXHIBIT ____
MARCH 3, 2014

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP

FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	Total
1. End of Period True-up [1]	($143,313,441)
2. Less: Actual Estimated True-up for the same period [2]	($143,214,959)
3. Net True-up for the period	($98,482)

[1] Page 2, Column (14) Lines 37 & 38

[2] Approved in FPSC Order PSC-13-0665-FOF-EI

Note: Totals may not add due to rounding.

( ) Reflects Underrecovery

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF FINAL TRUE-UP AMOUNT

SCHEDULE: E1-B

FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3) [1]	$220,037,900	$208,050,632	$234,633,600	$267,219,326	$276,720,275	$286,666,776	$280,951,961	$293,440,680	$264,285,265	$271,357,868	$227,446,862	$239,845,999	$3,070,657,144
3	Nuclear Fuel Disposal Costs (Per A2)	$1,880,395	$1,417,734	$1,144,529	$1,819,397	$2,007,177	$2,256,251	$2,453,484	$2,421,839	$2,299,690	$1,713,969	$2,032,223	$2,264,192	$23,710,879
4	Scherer Coal Cars Depreciation & Return (Per A2)	$0	($181)	($46,136)	($207)	($416)	($416)	($53,299)	($53,089)	$0	$0	$0	$0	($153,745)
5	Fuel Cost of Power Sold (Per A6)	($3,701,519)	($6,549,357)	($8,851,076)	($6,190,755)	($4,716,820)	($3,101,107)	($3,484,994)	($2,681,851)	($2,955,570)	($2,535,310)	($4,702,354)	($5,148,525)	($54,619,237)
6	Gains from Off-System Sales (Per A6)	($876,040)	($1,741,631)	($2,183,089)	($1,053,380)	($1,015,087)	($688,662)	($793,680)	($558,376)	($610,581)	($689,423)	($1,258,111)	($1,445,536)	($12,913,597)
7	Fuel Cost of Purchased Power (Per A7)	$7,594,732	$6,358,940	$3,174,645	$14,997,896	$15,862,340	$24,618,502	$21,479,018	$22,953,577	$19,429,563	$21,478,113	$12,128,752	$8,867,546	$178,943,623
8	Energy Payments to Qualifying Facilities (Per A8)	$1,679,537	$1,308,964	$6,001,429	$9,692,457	$10,992,302	$11,182,480	$9,314,906	$10,913,363	$10,145,088	$5,729,241	$7,446,607	$4,332,450	$88,738,823
9	Energy Cost of Economy Purchases (Per A9)	$98,806	$63,673	$148,556	$1,639,283	$121,100	$186,471	$137,962	$1,169,468	$1,273,625	$1,746,818	$174,561	$18,068	$6,778,391
10	Total Fuel Costs & Net Power Transactions	$226,713,812	$208,908,773	$234,022,459	$288,124,015	$299,970,870	$321,120,295	$310,005,357	$327,605,611	$293,867,080	$298,801,275	$243,268,540	$248,734,194	$3,301,142,281
11														
12	**Incremental Optimization Costs**													
13	Incremental Personnel, Software, and Hardware Costs (Per A2)	$0	$0	$0	$20,622	$21,401	$28,231	$33,219	$32,033	$30,798	$33,542	$30,658	$32,904	$263,407
14	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$0	$0	$364,700	$315,395	$227,805	$125,549	$155,543	$127,118	$132,895	$145,729	$262,136	$303,582	$2,160,452
15	Total	$0	$0	$364,700	$336,017	$249,206	$153,780	$188,762	$159,151	$163,693	$179,271	$292,794	$336,486	$2,423,859
16	**Adjustments to Fuel Cost**													
17	Sales to City of Key West (CKW)	($664,908)	($570,246)	($522,829)	($597,082)	($689,211)	($801,246)	$0	$0	$0	$0	$0	$0	($3,845,521)
18	Energy Imbalance Fuel Revenues	$56,481	$82,535	$48,854	$75,548	$65,257	$47,061	$47,948	$55,449	$75,579	($28,592)	$26,696	$3,066	$555,882
19	Inventory Adjustments	($106,047)	($4,083,681)	$168,325	($88,560)	($285,132)	($28,899)	($78,905)	($130,403)	($246,658)	($145,605)	$188,446	($172,902)	($5,010,021)
20	Non Recoverable Oil/Tank Bottoms	$0	($718,392)	$452,505	$0	$189	($189)	$1,663,517	$465,892	$0	$0	$0	$1,183,800	$3,047,322
21	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,014	$287,849,938	$299,311,179	$320,490,803	$311,826,680	$328,155,699	$293,859,694	$298,806,349	$243,776,475	$250,084,645	$3,298,313,803
22	**Jurisdictional kWh Sales**													
23	Jurisdictional kWh Sales	7,684,412,091	7,108,916,875	6,977,292,798	7,671,972,198	8,616,263,762	9,110,063,405	9,724,266,549	10,261,768,851	10,390,746,922	9,076,196,297	8,227,451,350	7,934,506,213	102,783,857,311
24	Sales for Resale (excluding CKW) [2]	148,696,550	152,935,981	143,064,345	153,595,635	171,792,467	176,313,367	189,064,624	194,252,476	204,570,260	183,181,514	181,301,034	157,135,776	2,055,904,029
25	Sub-Total Sales (excluding CKW)	7,833,108,641	7,261,852,856	7,120,357,143	7,825,567,833	8,788,056,229	9,286,376,772	9,913,331,173	10,456,021,327	10,595,317,182	9,259,377,811	8,408,752,384	8,091,641,989	104,839,761,340
26														
27	**Jurisdictional % of Total Sales (Line 23/25)**	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	98.14220%	98.06924%	98.02166%	97.84390%	98.05805%	98.03900%
28	**True-up Calculation**													
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$235,363,510	$216,081,517	$211,924,637	$229,504,273	$251,555,289	$267,491,971	$287,935,348	$305,667,934	$309,014,768	$266,585,140	$240,723,076	$230,792,575	$3,052,640,037
30	**Fuel Adjustment Revenues Not Applicable to Period**													
31	Prior Period True-up (Collected)/Refunded This Period [3]	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$48,085,296
32	GPIF, Net of Revenue Taxes [4]	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($7,698,365)
33	Jurisdictional Fuel Revenues Applicable to Period	$238,729,087	$219,447,095	$215,290,214	$232,869,851	$254,920,866	$270,857,548	$291,300,926	$309,033,512	$312,380,346	$269,950,718	$244,088,653	$234,158,152	$3,093,026,968
34	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,014	$287,849,938	$299,311,179	$320,490,803	$311,826,680	$328,155,699	$293,859,694	$298,806,349	$243,776,475	$250,084,645	$3,298,313,803
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	98.14220%	98.06924%	98.02166%	97.84390%	98.05805%	98.03900%
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$221,888,754	$199,492,191	$230,007,842	$282,428,775	$293,697,827	$314,660,569	$306,127,346	$322,320,090	$288,419,400	$293,132,189	$238,713,612	$245,426,761	$3,236,315,354
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	$16,840,334	$19,954,904	($14,717,628)	($49,558,924)	($38,776,960)	($43,803,021)	($14,826,420)	($13,286,578)	$23,960,946	($23,181,471)	$5,375,041	($11,268,608)	($143,288,386)
38	Interest Provision for the Month	$2,912	$5,096	$4,722	$1,789	($1,335)	($3,612)	($4,579)	($5,406)	($5,346)	($5,018)	($6,103)	($8,175)	($25,055)
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$60,921,434	$76,874,326	$58,154,312	$4,590,069	($38,195,333)	($86,009,075)	($104,847,182)	($122,146,275)	($102,197,783)	($129,391,380)	($128,029,550)	$48,085,296
40	Deferred True-up Beginning of Period - Over/(Under) Recovery [5]	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)
41	Prior Period True-up Collected/(Refunded) This Period	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($48,085,296)
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	$56,370,780	$72,323,672	$53,603,658	$39,415	($42,745,987)	($90,559,729)	($109,397,836)	($126,696,929)	($106,748,437)	($133,942,034)	($132,580,204)	($147,864,095)	($147,864,095)
43														
44														

45 [1] Actuals include various adjustments as noted on the A-Schedules.

46 [2] Billed KWH includes all wholesale customers except CKW.

47 [3] Prior Period 2011/2012 Net True-up.

48 [4] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.

49 [5] Deferred 2012 Final True-up.

50

51 Note: Amounts may not agree to Actual/Estimated Filing or A-Schedules due to rounding.

FLORIDA POWER & LIGHT COMPANY
REVENUE/COST VARIANCE ANALYSIS

FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)
Line No.	Revenue/Cost Final Variance Analysis	FINAL TRUE-UP	ACTUAL/ESTIMATED	DIFFERENCE
1	**Jurisdictional Total Fuel Revenues**			
2	Revenues	$3,052,640,037	$3,034,396,944	$18,243,093
3	MWH	102,783,857	102,164,441	619,417
4	$ per MWH	29.69961	29.70111	(0.00150)
5				
6	Variance due to Consumption			$18,397,362
7	Variance due to Price			($154,269)
8	Total Variance			$18,243,093
9				
10	**Jurisdictional Total Fuel Costs**			
11	Costs	$3,236,315,354	$3,217,971,736	$18,343,618
12	MWH	102,783,857	102,164,441	619,417
13	$ per MWH	31.48661	31.49796	(0.01135)
14				
15	Variance due to Consumption			$19,510,365
16	Variance due to Price			($1,166,747)
17	Total Variance			$18,343,618
18				
19	**Total Variance**			
20	Variance due to Consumption			($1,113,003)
21	Variance due to Price			$1,012,478
22	Total Variance			($100,525)
23	Interest			$2,043
24	Total True-up			($98,482)
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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - FINAL TRUE-UP VS. ACTUAL/ESTIMATED TRUE-UP

FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)
Line No.		FCR - 2013 Final True-up	FCR - 2013 Actual/Estimated True-up	Dif. FCR - 2013 Actual/Estimated True-up	% Dif. FCR - 2013 Actual/Estimated True-up
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3)	$3,070,657,144	$3,064,223,762	$6,433,383	0.2%
3	Nuclear Fuel Disposal Costs (Per A2)	$23,710,879	$23,905,061	($194,182)	(0.8%)
4	Scherer Coal Cars Depreciation & Return (Per A2)	($153,745)	($100,655)	($53,090)	52.7%
5	Fuel Cost of Power Sold (Per A6)	($54,619,237)	($55,562,090)	$942,853	(1.7%)
6	Gains from Off-System Sales (Per A6)	($12,913,597)	($11,484,069)	($1,429,528)	12.4%
7	Fuel Cost of Purchased Power (Per A7)	$178,943,623	$159,385,962	$19,557,661	12.3%
8	Energy Payments to Qualifying Facilities (Per A8)	$88,738,823	$98,980,415	($10,241,592)	(10.3%)
9	Energy Cost of Economy Purchases (Per A9)	$6,778,391	$5,570,851	$1,207,540	21.7%
10	Total Fuel Costs & Net Power Transactions	$3,301,142,281	$3,284,919,237	$16,223,045	0.5%
11					
12	**Incremental Optimization Costs**				
13	Incremental Personnel, Software, and Hardware Costs (Per A2)	$263,407	$263,527	($120)	(0.0%)
14	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$2,160,452	$1,853,392	$307,060	16.6%
15	Total	$2,423,859	$2,116,919	$306,940	14.5%
16	**Adjustments to Fuel Cost**				
17	Sales to City of Key West (CKW)	($3,845,521)	($3,845,522)	$1	(0.0%)
18	Energy Imbalance Fuel Revenues	$555,882	$423,684	$132,198	31.2%
19	Inventory Adjustments	($5,010,021)	($4,502,899)	($507,122)	11.3%
20	Non Recoverable Oil/Tank Bottoms	$3,047,322	$1,397,630	$1,649,692	118.0%
21	Adjusted Total Fuel Costs & Net Power Transactions	$3,298,313,803	$3,280,509,049	$17,804,754	0.5%
22	**Jurisdictional kWh Sales**				
23	Jurisdictional kWh Sales	102,783,857,311	102,164,440,582	619,416,729	0.6%
24	Sales for Resale (excluding CKW)	2,055,904,029	2,070,531,997	(14,627,968)	(0.7%)
25	Sub-Total Sales (excluding CKW)	104,839,761,340	104,234,972,579	604,788,761	0.6%
26					
27	**Jurisdictional % of Total Sales (Line 23/25)**	N/A	N/A	N/A	N/A
28	**True-up Calculation**				
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$3,052,640,037	$3,034,396,944	$18,243,093	0.6%
30	**Fuel Adjustment Revenues Not Applicable to Period**				
31	Prior Period True-up (Collected)/Refunded This Period	$48,085,296	$48,085,296	$0	0.0%
32	GPIF, Net of Revenue Taxes [(1)]	($7,698,365)	($7,698,365)	($0)	0.0%
33	Jurisdictional Fuel Revenues Applicable to Period	$3,093,026,968	$3,074,783,875	$18,243,093	0.6%
34	Adjusted Total Fuel Costs & Net Power Transactions	$3,298,313,803	$3,280,509,049	$17,804,754	0.5%
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	N/A	N/A	N/A	N/A
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$3,236,315,354	$3,217,971,736	$18,343,618	0.6%
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	($143,288,386)	($143,187,861)	($100,525)	0.1%
38	Interest Provision for the Month	($25,055)	($27,098)	$2,043	(7.5%)
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$48,085,296	$0	0.0%
40	Deferred True-up Beginning of Period - Over/(Under) Recovery [(2)]	($4,550,654)	($4,550,654)	$0	0.0%
41	Prior Period True-up Collected/(Refunded) This Period [(3)]	($48,085,296)	($48,085,296)	$0	0.0%
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	($147,864,095)	($147,765,613)	($98,482)	0.1%
43					
44	[(1)] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.				
45	[(2)] Deferred 2012 Final True-up.				
46	[(3)] Prior Period 2011/2012 Net True-up.				
47					
48	Note: Amounts may not agree to Actual/Estimated Filing or A-Schedules due to rounding.				

APPENDIX II

CAPACITY COST RECOVERY

2013 FINAL TRUE UP CALCULATION

TJK-2
DOCKET NO. 140001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-8
EXHIBIT ____
MARCH 3, 2014

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

Line No.		Total
1	End of Period True-up for the period (1)	($14,303,032)
2	Less - Estimated/Actual True-up for the same period (2)	($25,357,191)
3	Net True-up for the period	$11,054,159
4		
5	(1) From Page 2, Column (14), Lines 18+19	
6	(2) Approved in FPSC Order No. 13-0665-FOF-EI	
7		
8	Note: total may not add due to rounding	
9		
10	( ) Reflects Under-recovery	
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Total
1	Payments to Non-cogenerators	$16,437,513	$16,618,240	$17,107,824	$16,482,672	$16,487,283	$16,076,979	$15,714,068	$16,059,963	$18,026,852	$16,583,199	$16,367,344	$16,510,438	$198,472,373
2	Payments to Co-generators	$25,038,297	$25,205,917	$20,512,305	$23,359,041	$22,728,373	$23,148,194	$23,388,910	$23,174,685	$23,193,201	$23,275,962	$23,207,885	$23,270,698	$279,503,468
3	SJRPP Suspension Accrual	$0	$0	($2,582,946)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return on SJRPP Suspension Liability	($445,444)	($445,444)	($435,246)	($421,647)	($414,848)	($408,049)	($405,655)	($398,781)	($391,907)	($385,034)	($378,160)	($371,286)	($4,901,501)
5	Incremental Plant Security PSC Order No. 02-1761-FOF-EI	$2,742,107	$3,070,332	$3,468,119	$3,248,334	$2,732,257	$3,485,081	$2,485,373	$3,728,780	$4,144,063	$3,209,604	$3,161,608	$4,801,912	$40,277,571
6	Incremental Nuclear NRC Compliance Costs O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Incremental Nuclear NRC Compliance Costs Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,859	$8,859
8	Transmission of Electricity by Others	$2,270,836	$2,203,512	$2,161,119	$1,343,872	$1,441,836	($627,741)	$1,138,719	$784,731	$930,009	$882,320	$1,856,565	$2,130,914	$16,516,689
9	Transmission Revenues from Capacity Sales	($329,135)	($578,809)	($845,612)	($380,813)	($477,335)	($249,378)	($294,350)	($214,153)	($213,798)	($318,520)	($375,425)	($406,877)	($4,684,204)
10	Total (Lines 1 through 9)	$45,714,174	$46,073,747	$39,385,564	$42,770,476	$41,636,583	$40,564,103	$41,166,083	$42,274,242	$44,827,438	$42,386,550	$42,978,834	$45,083,677	$514,861,472
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%
12	Jurisdictional CCR Charges	$44,786,322	$45,138,597	$38,586,163	$41,902,373	$40,791,494	$39,740,782	$40,330,543	$41,416,210	$43,917,584	$41,526,239	$42,106,501	$44,168,623	$504,411,431
13	Nuclear Cost Recovery Costs [a]	$12,249,674	$14,229,199	$14,667,616	$13,013,524	$12,802,720	$12,659,892	$12,293,132	$12,185,111	$12,000,151	$11,888,604	$11,726,916	$11,774,862	$151,491,400
14	Jurisdictional CCR Charges	$57,035,996	$59,367,796	$53,253,780	$54,915,896	$53,594,213	$52,400,674	$52,623,675	$53,601,321	$55,917,735	$53,414,842	$53,833,418	$55,943,485	$655,902,832
15	CCR Revenues (Net of Revenue Taxes)	$52,434,454	$49,413,054	$49,832,052	$53,331,531	$58,351,845	$61,903,701	$65,986,930	$69,005,856	$69,298,105	$62,290,497	$56,640,817	$53,736,697	$702,225,539
16	Prior Period True-up Provision	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($60,583,035)
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$47,385,867	$44,364,468	$44,783,466	$48,282,945	$53,303,259	$56,855,115	$60,938,344	$63,957,270	$64,249,519	$57,241,910	$51,592,231	$48,688,111	$641,642,504
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($9,650,129)	($15,003,328)	($8,470,314)	($6,632,952)	($290,954)	$4,454,441	$8,314,669	$10,355,949	$8,331,783	$3,827,068	($2,241,187)	($7,255,375)	($14,260,328)
19	Interest Provision for Month	($4,127)	($6,184)	($6,358)	($5,822)	($5,356)	($4,259)	($3,075)	($2,417)	($1,758)	($1,136)	($981)	($1,231)	($42,704)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($65,188,705)	($75,149,631)	($78,577,717)	($80,167,904)	($75,415,629)	($65,916,860)	($52,556,681)	($37,154,562)	($23,775,950)	($14,901,432)	($12,095,013)	($60,583,035)
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$60,583,035
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($73,102,189)	($83,063,115)	($86,491,201)	($88,081,388)	($83,329,113)	($73,830,344)	($60,470,165)	($45,068,046)	($31,689,434)	($22,814,916)	($20,008,497)	($22,216,516)	($22,216,516)
24														
25	[a] As approved on Order No PSC-12-0664-FOF-EI													
26														
27	Total may not add due to rounding													
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)
Line No.	CCR - Final True-up Variance	CCR - 2013 Final True-up	CCR - 2013 Actual/Estimated	Dif. CCR - 2013 Actual/Estimated	% Dif. CCR - 2013 Actual/Estimated
1	Payments to Non-cogenerators	$198,472,373	$197,237,197	$1,235,176	0.6%
2	Payments to Co-generators	$279,503,468	$278,819,477	$683,991	0.2%
3	SJRPP Suspension Accrual	($10,331,784)	($10,331,784)	$0	0.0%
4	Return on SJRPP Suspension Liability	($4,901,501)	($4,901,525)	$24	(0.0%)
5	Incremental Plant Security PSC Order No. 02-1761-FOF-EI	$40,277,571	$46,426,048	($6,148,477)	(13.2%)
6	Incremental Nuclear NRC Compliance Costs O&M	$0	$98,678	($98,678)	(100.0%)
7	Incremental Nuclear NRC Compliance Costs Capital	$8,859	$17,587	($8,727)	(49.6%)
8	Transmission of Electricity by Others	$16,516,689	$18,578,470	($2,061,781)	(11.1%)
9	Transmission Revenues from Capacity Sales	($4,684,204)	($4,157,931)	($526,272)	12.7%
10	Total (Lines 1 through 9)	$514,861,472	$521,786,216	($6,924,745)	(1.3%)
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	0.00000%	(0.0%)
12	Jurisdictional CCR Charges	$504,411,431	$511,195,626	($6,784,195)	(1.3%)
13	Nuclear Cost Recovery Costs [a]	$151,491,400	$151,506,739	($15,339)	(0.0%)
14	Jurisdictional CCR Charges	$655,902,832	$662,702,365	($6,799,533)	(1.0%)
15	CCR Revenues (Net of Revenue Taxes)	$702,225,539	$697,971,665	$4,253,873	0.6%
16	Prior Period True-up Provision	($60,583,035)	($60,583,035)	$0	0.0%
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$641,642,504	$637,388,630	$4,253,873	0.7%
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($14,260,328)	($25,313,735)	$11,053,407	(43.7%)
19	Interest Provision for Month	($42,704)	($43,456)	$752	(1.7%)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($60,583,035)	$0	0.0%
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	($7,913,484)	$0	0.0%
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$60,583,035	$60,583,035	$0	0.0%
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($22,216,516)	($33,270,675)	$11,054,159	(33.2%)
24					
25	[a] As approved on Order No PSC-12-0664-FOF-EI				
26					
27	Columnns and rows may not add due to rounding				
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For the Month of **Dec-13**

Contract	Capacity MW	Term Start	Term End	Contract Type
Cedar Bay	250	1/25/1994	12/31/2024	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
SWAPC	40	1/1/2012	4/1/2032	QF

QF = Qualifying Facility

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	12,096,169	12,274,083	7,575,325	10,422,060	9,829,336	10,226,750	10,377,201	10,201,288	10,221,794	10,192,154	10,209,504	10,274,578	123,900,241
ICL	11,521,003	11,510,708	11,515,856	11,515,856	11,502,091	11,508,973	11,536,485	11,536,485	11,536,485	11,536,485	11,543,106	11,539,795	138,303,327
BN-NEG '91	317,350	317,350	317,350	317,350	293,172	308,696	301,049	297,937	295,947	408,349	316,300	317,350	3,808,200
BS-NEG '91	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	1,211,700
SWAPC	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,073,200	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	12,280,000
Total	25,038,297	25,205,917	20,512,305	23,359,041	22,728,373	23,148,194	23,388,910	23,174,685	23,193,201	23,275,962	23,207,885	23,270,698	279,503,468

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 2 of 2

For the Month of Dec-13

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	Southern Co. - UPS Scherer	Other Entity	June, 2010	December 31, 2015
2	Southern Co. - UPS Harris	Other Entity	June, 2010	December 31, 2015
3	Southern Co. - UPS Franklin	Other Entity	June, 2010	December 31, 2015
4	JEA - SJRPP	Other Entity	April, 1982	September 30, 2021

2013 Capacity in MW

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	163	163	163	163	163	163	163	163	163	163	163	163
2	600	600	600	600	600	600	600	600	600	600	600	600
3	190	190	190	190	190	190	190	190	190	190	190	190
4	375	375	375	375	375	375	375	375	375	375	375	375
Total	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328

2013 Capacity in Dollars

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total	16,437,513	16,618,240	17,107,824	16,482,672	16,487,283	16,076,979	15,714,068	16,059,963	18,026,852	16,583,199	16,367,344	16,510,438

Year-to-date Short Term Capacity Payments	198,472,373

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

True ups												
1		[redacted]			[redacted]							
2												
3										[redacted]		
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

INCREMENTAL NUCLEAR NRC COMPLIANCE FOR THE PERIOD JANUARY THROUGH DECEMBER 2013

INCREMENTAL NUCLEAR NRC COMPLIANCE	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,219,384	$12,219,384
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base (1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,219,384	N/A
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,219,384	N/A
6. Total Estimated Capital Expenditures Included in Base Rates (2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	
7. Base Rate Capital Expenditures Closed to Plant-in-Service (3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	
9. Adjusted Net Investment (Lines 5 - 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,219,384	
10. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,109,692	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes (4)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,411	$7,411
b. Debt Component (Line 6 x debt rate x 1/12) (5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,448	$1,448
12. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,859	$8,859

(1) Represents nuclear NRC Compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year base (Docket No.120015) on line 6

(2) Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI)

(3) Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service

(4) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9230%, which is based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU

(5) The Debt Component is 1.5658%, which is based on the May 2013 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER 2012 RATE CASE (a)
Docket No 120015-EI Order No PSC-13-0023-S-EI

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	6,253,556,649	29.470%	5.19%	1.53%	1.53%
SHORT TERM DEBT	363,682,507	1.714%	2.11%	0.04%	0.04%
PREFERRED STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	430,247,132	2.028%	1.99%	0.04%	0.04%
COMMON EQUITY	9,768,463,093	46.034%	10.50%	4.83%	7.87%
DEFERRED INCOME TAX	4,403,202,920	20.750%	0.00%	0.00%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	930,822	0.004%	8.43%	0.00%	
TOTAL	$21,220,083,124	100.00%		6.44%	9.48%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (b)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$6,253,556,649	39.03%	5.19%	2.03%	2.03%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	9,768,463,093	60.97%	10.50%	6.40%	10.42%
TOTAL	$16,022,019,743	100.00%		8.43%	12.45%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.5301%
SHORT TERM DEBT	0.0361%
CUSTOMER DEPOSITS	0.0404%
TAX CREDITS -WEIGHTED	0.0001%
TOTAL DEBT	**1.6067%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8336%
TAX CREDITS -WEIGHTED	0.0003%
TOTAL EQUITY	**4.8339%**
TOTAL	6.4406%
PRE-TAX EQUITY	7.8695%
PRE-TAX TOTAL	9.4762%

Note:

(a) Reflects approved capital structure and ROE reflected in Docket No 120015-EI Order No PSC-13-0023-S-EI.
The above capital structure started effective January 2013.

(b) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

This Capital Structure and Cost Rates was used during the period January through June 2013

FLORIDA POWER & LIGHT COMPANY					
COST RECOVERY CLAUSES					
Equity @ 10.50%	**CAPITAL STRUCTURE AND COST RATES PER MAY 2013 EARNINGS SURVEILLANCE REPORT**				
					PRE-TAX
	ADJUSTED		MIDPOINT	WEIGHTED	WEIGHTED
	RETAIL	RATIO	COST RATES	COST	COST
LONG_TERM_DEBT	6,416,467,850	29.591%	4.981%	1.474%	1.474%
SHORT_TERM_DEBT	431,179,727	1.989%	1.833%	0.036%	0.036%
PREFERRED_STOCK	0	0.000%	0.000%	0.000%	0.000%
CUSTOMER_DEPOSITS	428,779,347	1.977%	2.796%	0.055%	0.055%
COMMON_EQUITY	10,165,729,253	46.882%	10.500%	4.923%	8.014%
DEFERRED_INCOME_TAX	4,240,131,465	19.555%	0.000%	0.000%	0.000%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.000%	0.000%	0.000%
WEIGHTED COST	1,324,684	0.006%	8.364%	0.001%	0.001%
TOTAL	$21,683,612,327	100.00%		6.489%	9.580%

	CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)				
	ADJUSTED		COST	WEIGHTED	PRE TAX
	RETAIL	RATIO	RATE	COST	COST
LONG TERM DEBT	$6,416,467,850	38.69%	4.981%	1.927%	1.927%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	10,165,729,253	61.31%	10.500%	6.437%	10.480%
TOTAL	$16,582,197,103	100.00%		8.364%	12.407%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.4740%
SHORT TERM DEBT	0.0364%
CUSTOMER DEPOSITS	0.0553%
TAX CREDITS -WEIGHTED	0.0001%
TOTAL DEBT	**1.5658%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9226%
TAX CREDITS -WEIGHTED	0.0004%
TOTAL EQUITY	**4.9230%**
TOTAL	6.4889%
PRE-TAX EQUITY	8.0147%
PRE-TAX TOTAL	9.5805%

Note:

(a) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

This Capital Structure and Cost Rates was used during the period July through December 2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 140001-EI

MARCH 3, 2014

Q. Please state your name and address.

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

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

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

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

A. Yes.

Q. What is the purpose of your testimony?

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

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

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

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

Q. Please provide an overview of the Incentive Mechanism.

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

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

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

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

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

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

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

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

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

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

2013.

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

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

Q. Does this conclude your testimony?

A. Yes it does.

APPENDIX III

FUEL COST RECOVERY

2013 INCENTIVE MECHANISM RESULTS

GJY-1
DOCKET NO. 140001-EI
FPL WITNESS: GERARD J. YUPP
PAGES 1-4
EXHIBIT ____
MARCH 3, 2014

TOTAL GAINS SCHEDULE
Actual for the Period of: January 2013 through December 2013

TABLE 1

(1) Month	(2) Wholesale Sales Gains ($)	(3) Wholesale Purchases Savings ($)	(4) Asset Optimization Gains ($)	(5) Total Monthly Gains ($) (2)+(3)+(4)	(6) **Threshold 1** Gains ≤ $36M ($)	(7) **Threshold 2** $36M > Gains ≤ $46M ($)	(8) **Threshold 3** $46M > Gains ≤ $100M ($)	(9) **Threshold 4** Gains > $100M ($)
January	876,040	25,150	252,822	1,154,012	1,154,012	0	0	0
February	1,798,400	13,766	468,770	2,280,936	2,280,936	0	0	0
March	1,818,389	91,330	386,343	2,296,061	2,296,061	0	0	0
April	854,235	813,190	1,323,425	2,990,850	2,990,850	0	0	0
May	847,782	29,181	1,260,419	2,137,382	2,137,382	0	0	0
June	563,113	68,212	1,014,037	1,645,363	1,645,363	0	0	0
July	638,137	30,044	1,137,216	1,805,396	1,805,396	0	0	0
August	431,258	531,754	908,988	1,871,999	1,871,999	0	0	0
September	477,686	545,306	1,122,089	2,145,081	2,145,081	0	0	0
October	593,686	948,788	1,016,305	2,558,780	2,558,780	0	0	0
November	1,114,617	102,373	557,181	1,774,171	1,774,171	0	0	0
December	1,139,662	6,653	757,524	1,903,839	1,903,839	0	0	0
Total	**11,153,006**	**3,205,747**	**10,205,119**	**24,563,872**	**24,563,872**	**0**	**0**	**0**

TABLE 2

(1) Month	(2) **Threshold 1** Gains ≤ $36M 100% Customer Benefit ($)	(3) **Threshold 2** $36M > Gains ≤ $46M 100% Customer Benefit ($)	(4) **Threshold 3** $46M > Gains ≤ $100M 40% Customer Benefit ($)	(5) **Threshold 3** $46M > Gains ≤ $100M 60% FPL Benefit ($)	(6) **Threshold 4** Gains > $100M 50% Customer Benefit ($)	(7) **Threshold 4** Gains > $100M 50% FPL Benefit ($)	(8) **Total** Customer Benefits ($)	(9) **Total** FPL Benefits ($)
January	1,154,012	0	0	0	0	0	1,154,012	0
February	2,280,936	0	0	0	0	0	2,280,936	0
March	2,296,061	0	0	0	0	0	2,296,061	0
April	2,990,850	0	0	0	0	0	2,990,850	0
May	2,137,382	0	0	0	0	0	2,137,382	0
June	1,645,363	0	0	0	0	0	1,645,363	0
July	1,805,396	0	0	0	0	0	1,805,396	0
August	1,871,999	0	0	0	0	0	1,871,999	0
September	2,145,081	0	0	0	0	0	2,145,081	0
October	2,558,780	0	0	0	0	0	2,558,780	0
November	1,774,171	0	0	0	0	0	1,774,171	0
December	1,903,839	0	0	0	0	0	1,903,839	0
Total	**24,563,872**	**0**	**0**	**0**	**0**	**0**	**24,563,872**	**0**

WHOLESALE POWER DETAIL
Actual for the Period of: January 2013 through December 2013

Wholesale Sales - Table 1

(1) Month	(2) OS Wholesale Sales (MWh)	(3) FCBBS Wholesale Sales (MWh)	(4) Total Wholesale Sales (MWh)	(5) OS Gross Gains ($)	(6) FCBBS Gross Gains ($)	(7) Incremental GT O&M Costs ($)	(8) Variable Power Plant O&M Costs ($)	(9) Power Option Premiums ($)	(10) Total Net Wholesale Sales Gains ($)
	Schedule A6	Schedule A6	(2) + (3)	Schedule A6	Schedule A6	Schedule A6	Schedule A6	*CCRC	(5)+(6)+(7)+(8)+(9)
January	142,553	1,358	143,911	867,833	8,207	0	0	0	876,040
February	272,757	4,864	277,621	1,723,631	20,639	(2,640)	0	56,769	1,798,400
March	332,474	6,778	339,252	2,148,552	34,537	0	(364,700)	0	1,818,389
April	202,954	656	203,610	1,054,648	4,668	(5,937)	(315,395)	116,250	854,235
May	150,596	268	150,864	1,021,644	1,627	(8,184)	(227,805)	60,500	847,782
June	82,966	179	83,145	696,460	878	(8,676)	(125,549)	0	563,113
July	100,994	2,015	103,009	782,141	11,539	0	(155,543)	0	638,137
August	83,551	633	84,184	564,544	3,442	(9,610)	(127,118)	0	431,258
September	87,192	818	88,010	612,371	5,213	(7,003)	(132,895)	0	477,686
October	96,375	134	96,509	698,737	707	(12,448)	(145,729)	52,419	593,686
November	184,762	570	185,332	1,257,203	3,060	(6,494)	(262,136)	122,984	1,114,617
December	188,634	682	189,316	1,377,367	3,378	0	(303,582)	62,500	1,139,662
Total	**1,925,808**	**18,955**	**1,944,763**	**12,805,132**	**97,895**	**(60,991)**	**(2,160,452)**	**471,422**	**11,153,006**

Wholesale Purchases - Table 2

(1) Month	(2) OS Wholesale Purchases (MWh)	(3) FCBBS Wholesale Purchases (MWh)	(4) Total Wholesale Purchases (MWh)	(5) OS Savings ($)	(6) FCBBS Savings ($)	(7) Total Schedule A9 Savings ($)	(8) Capacity Purchases (MWh)	(9) Net Capacity Purchases Savings ($)	(10) Total Wholesale Purchases Savings ($)
	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A7/A12		(7) + (9)
January	3,035	50	3,085	25,023	127	25,150	0	0	25,150
February	1,955	0	1,955	13,766	0	13,766	0	0	13,766
March	3,420	25	3,445	91,347	(17)	91,330	0	0	91,330
April	30,893	1,087	31,980	805,652	7,537	813,190	0	0	813,190
May	2,756	309	3,065	27,265	1,916	29,181	0	0	29,181
June	4,275	236	4,511	66,471	1,741	68,212	0	0	68,212
July	3,295	197	3,492	29,152	891	30,044	0	0	30,044
August	22,748	39	22,787	531,577	177	531,754	0	0	531,754
September	33,130	298	33,428	543,087	2,219	545,306	0	0	545,306
October	34,603	469	35,072	946,043	2,745	948,788	0	0	948,788
November	4,440	155	4,595	100,909	1,464	102,373	0	0	102,373
December	562	0	562	6,653	0	6,653	0	0	6,653
Total	**145,112**	**2,865**	**147,977**	**3,186,946**	**18,801**	**3,205,747**	**0**	**0**	**3,205,747**

*Capacity Cost Recovery Clause - Option premium gains are inlcuded under Transmission Revenues from Capacity Sales line item.

ASSET OPTIMIZATION DETAIL
Actual for the Period of: January 2013 through December 2013

(1) Month	(2) Natural Gas Delivered City-Gate Sales ($)	(3) Natural Gas Production Area Sales ($)	(4) Natural Gas Capacity Release Firm Transport ($)	(5) Natural Gas Option Premiums ($)	(6) Natural Gas Storage Optimization ($)	(7) Natural Gas AMA Gains ($)	(8) Electric Transmission Capacity Release Firm Transmission ($)	(9) Total Asset Optimization Gains ($)
January	[redacted]							252,822
February	[redacted]							468,770
March	[redacted]							386,343
April	[redacted]							1,323,425
May	[redacted]							1,260,419
June	[redacted]							1,014,037
July	[redacted]							1,137,216
August	[redacted]							908,988
September	[redacted]							1,122,089
October	[redacted]							1,016,305
November	[redacted]							557,181
December	[redacted]							757,524
Total	**908,857**	**2,649,611**	**678,798**	**3,162,795**	**158,513**	**1,569,554**	**1,076,991**	**10,205,119**

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 2013 through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Incremental O&M			Cumulative	Wholesale	Wholesale	Incremental	
	Personnel Expenses	Other Expenses*	Wholesale Sales	Wholesale Sales	Sales Threshold	Sales Above Threshold	Variable Power Plant O&M	Total Incremental O&M Expenses
Month	($)	($)	(MWh)	(MWh)	(MWh)	(MWh)	($)	($)
	Schedule A2	Schedule A2					Schedule A2/A6	(2) + (3) + (8)
January	0	0	143,911	143,911	514,000	0	0	0
February	0	0	277,621	421,532	514,000	0	0	0
March	0	0	339,252	760,784	514,000	246,784	364,700	364,700
April	20,622	0	203,610	964,394	514,000	203,610	315,395	336,017
May	21,401	0	150,864	1,115,258	514,000	150,864	227,805	249,206
June	28,231	0	83,145	1,198,403	514,000	83,145	125,549	153,780
July	33,219	0	103,009	1,301,412	514,000	103,009	155,543	188,762
August	32,033	0	84,184	1,385,596	514,000	84,184	127,118	159,151
September	30,798	0	88,010	1,473,606	514,000	88,010	132,895	163,693
October	33,542	0	96,509	1,570,115	514,000	96,509	145,729	179,271
November	30,658	0	185,332	1,755,447	514,000	185,332	262,136	292,794
December	32,904	0	189,316	1,944,763	514,000	189,316	303,582	336,486
Total	**263,407**	**0**	**1,944,763**			**1,430,763**	**2,160,452**	**2,423,859**

*Includes software and hardware expenses