BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 2, 2013

IN RE: LEVELIZED FUEL COST RECOVERY AND CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP
JANUARY 2013 THROUGH DECEMBER 2013

TESTIMONY & EXHIBITS OF:

TERRY J. KEITH
DON GRISSETTE

2014 RISK MANAGEMENT PLAN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 130001-EI

AUGUST 2, 2013

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 2013 through December 2013. My testimony also presents FPL's request for recovery through the CCR Clause of incremental costs associated with new Nuclear Regulatory Commission (NRC) compliance requirements resulting from the Fukushima Daiichi event.

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

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

The FCR Schedules contained in Appendix I include Schedules E3 through E9 that provide revised estimates for the period July 2013 through December 2013. FCR Schedules A1 through A9 provide actual data for the period January 2013 through June 2013. They are filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

The CCR Schedules contained in Appendix II provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2013 through December 2013.

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

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

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

A. The FCR and CCR true-up calculations compare actual/estimated data consisting of actuals for January 2013 through June 2013 and revised estimates for July 2013 through December 2013 to original projections for 2013.

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

A. The calculation of the interest provision follows the same methodology used in calculating the interest provision for the cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount times the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published in the Federal Reserve website on the first business day of the current and the subsequent month. The average interest rate for the projected months is the actual rate published as of the first business day in July 2013 reflecting the last business day in June 2013.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the 2013 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 2013 through December 2013.

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

A. Appendix I, Page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The end-of-period net true-up amount to be carried forward to the 2014 FCR factor is an under-recovery of $153,456,602 (Appendix I, Page 1, Column 14, Line 42). This $153,456,602 under-recovery includes the 2012 final true-up under-recovery of $4,550,654 (Appendix I, Page 1, Column 14, Line 40), filed with the Commission on March 1, 2013, and the actual/estimated true-up under-recovery, including interest, of $148,905,948 (Appendix I, Page 1, Column 14, Lines 37 plus 38) for the period January 2013 through December 2013.

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

A. Yes, they were.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and original projections for 2013?

A. Yes. Appendix I, Page 2 provides a comparison of jurisdictional revenues and costs on a dollar per MWh basis. Appendix I, Page 3 provides a variance calculation that compares the actual/estimated period data to the data from the original projections for the January 2013 through December 2013 period.

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

A. Appendix I, Page 2 provides a comparison of Jurisdictional Total Fuel Revenues and Jurisdictional Total Fuel Costs and Net Power Transactions on a dollar per MWh basis. The $153,456,602 variance is primarily due to an increase in fuel costs per MWh of $31.53/MWh vs. $30.46/MWh that results in a cost variance of $110,227,434, and a decrease in fuel revenues per MWh of $29.69/MWh vs. $30.07/MWh that results in a cost variance of $38,881,836, for a total variance due to cost of $149,109,270.

The impact of the variance due to consumption is mostly offset between costs per

MWh and revenues per MWh, netting to a variance due to consumption of $238,791. The total variance due to cost of $149,109,270 less the total variance due to consumption of $238,791 results in the 2013 actual/estimated true-up variance of $148,870,479. When the interest amount of $35,469 associated with the 2013 actual/estimated true-up amount and the 2012 final true-up under-recovery amount of $4,550,654 are added to the calculation, the total amount of the variance is $153,456,602.

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

A. FPL originally projected Jurisdictional Total Fuel Costs and Net Power Transactions to be $3.204 billion for 2013 (Appendix I, Page 3, Column 3, Line 21). The Actual/Estimated Jurisdictional Total Fuel Costs and Net Power Transactions are now projected to be $3.298 billion for that period (actual data for January 2013 through June 2013 and revised estimates for July 2013 through December 2013) (Appendix I, Page 3, Column 2, Line 21). Therefore, Jurisdictional Total Fuel Costs and Net Power Transactions are $93.3 million, or 2.9% higher than the original projections (Appendix I, Page 3, Column 4, Line 21). Jurisdictional Fuel Revenues, net of revenue taxes for 2013 are projected to be $57.2 million, or 1.8% lower than the original projections (Appendix I, Page 3, Column 4, Line 29).

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

A. The primary reasons for the $93.3 million variance are higher than projected Fuel Cost of System Net Generation ($246.7 million), partially offset by lower than projected Energy Payments to Qualifying Facilities ($39.4 million), lower than projected Energy Cost of Economy Purchases ($36.4 million), higher than projected Fuel Cost of Power Sold ($35.6 million), lower than projected Fuel Cost of Purchased Power ($31.8 million), higher than projected Gains from Off-System Sales ($7.0 million),lower than projected Nuclear Fuel Disposal Costs ($1.0 million) and a $0.1 million decrease associated with coal cars.

<u>Fuel Cost of System Net Generation ($246.7 million increase)</u>

Natural gas costs are currently projected to be $273.7 million (11.5%) higher than the original projections. Although the unit cost of natural gas in the actual/estimated period is projected to be only 0.3% higher than what was included in the original projections ($4.8940 per MMBTU vs. $4.8815 per MMBTU), consumption of natural gas in the actual/estimated period is projected to be 544,295,269 MMBTUs, which is approximately 11.2% higher than the 489,626,432 MMBTUs included in the original projections.

Light oil costs are currently projected to be $9.7 million (1592.5%) higher than the original projections. Light oil burn in the actual/estimated period is projected to be 503,298 MMBTUs, which is approximately 1801.6% higher than the 26,467 MMBTUs included in the original projections. The unit cost of light oil in the actual/estimated period is projected to be $20.56 per MMBTU, which is 11.0% lower than the $23.10 per MMBTU included in the original projections.

Heavy oil costs are currently projected to be $3.2 million (4.8%) higher than the original projections. Heavy oil burn in the actual/estimated period is projected to be 4,693,368 MMBTUs, which is 13.6% higher than the 4,129,865 MMBTUs included in the original projections. The unit cost of heavy oil in the actual/estimated period is projected to be $14.77 per MMBTU, which is 7.8% lower than the $16.02 per MMBTU included in the original projections.

Nuclear generation costs are currently projected to be $27.1 million (112.8%) lower than the original projections. The unit cost of nuclear fuel in the actual/estimated period is projected to be $0.69 per MMBTU, which is 7.7% lower than the $0.74 per MMBTU included in the original projections. Nuclear consumption in the actual/estimated period is projected to be 269,522,718 MMBTUs, which is 5.5% lower than the 285,258,283 MMBTUs included in the original projections.

Coal costs are currently projected to be $12.8 million (7.7%) lower than the original projections. The unit cost of coal in the actual/estimated period is projected to be $2.65 per MMBTU, which is 5.2% lower than the $2.79 per MMBTU included in the original projections. Coal consumption in the actual/estimated period is projected to be 58,243,399 MMBTUs, which is 2.6% lower than the 59,813,211 MMBTUs included in the original projections.

Generation data by fuel type for the actual/estimated period January 2013 through December 2013 are included in Appendix I, Schedule E3.

Fuel Cost of Purchased Power ($31.8 million decrease)

The variance for the Fuel Cost of Purchased Power is primarily attributable to both volume and cost variances for UPS and SJRPP purchases. FPL now projects to purchase approximately 686,000 MWh less from its UPS PPA, which results in a variance of approximately $24.4 million. This is partially off-set by higher than projected unit fuel costs of approximately $4.48/MWh, or $9.0 million. FPL also projects to purchase approximately 153,000 MWh less from SJRPP at a cost of approximately $5.28/MWh lower than originally projected, resulting in variances of approximately $6.5 million and $9.9 million, respectively.

Energy Cost of Economy Purchases ($36.4 million decrease)

The variance for the Energy Cost of Economy Purchases is attributable to significantly lower than projected economy purchases. FPL projects that it will purchase approximately 928,000 MWh less of economy energy than its original projections. Lower economy purchases results in a volume variance of approximately $36.8 million, which is slightly offset by higher than originally projected costs for economy purchases of approximately $0.44 million. The combination of lower purchases and slightly higher costs results in a total variance of $36.4 million for the Energy Cost of Economy Purchases.

Energy Payments to Qualifying Facilities ($39.4 million decrease)

The variance for Energy Payments to Qualifying Facilities is primarily attributable to lower than projected QF purchases. FPL now estimates that it will purchase approximately 798,000 MWh less from QF facilities. Lower purchases result in a variance of approximately \$35.7 million, or 91.0% of the total variance. Additionally, FPL now estimates that the unit cost of QF purchases will be approximately \$1.53/MWh less than originally projected, resulting in a variance of approximately \$3.7 million, or 9% of the total variance. The combination of lower purchases and lower fuel costs results in a total variance of \$39.4 million for Energy Payments to Qualifying Facilities.

<u>Nuclear Fuel Disposal Costs (\$1 million decrease)</u>

The Nuclear Fuel Disposal Costs were \$1.0 million lower than projected primarily due to lower generation that was driven by the Turkey Point Unit 4 EPU outage duration, which was longer than assumed in the projections and unplanned outages at St. Lucie Unit 1 and Turkey Unit 3 that occurred in March and April, respectively.

<u>Fuel Cost of Power Sold (\$35.6 million increase)</u>

The variance for the Fuel Cost of Power Sold is primarily attributable to higher than projected power sales. FPL projects that it will sell approximately 1.27 million MWh more power than originally projected, resulting in a variance of approximately \$26.9 million, or 76% of the total variance. Additionally, FPL projects that its average fuel costs attributable to power sales will be approximately \$3.87/MWh higher than originally projected, resulting in a variance of approximately \$8.7 million, or 24% of the total variance. The combination of higher sales and higher fuel costs results in a total variance of \$35.6 million for the Fuel Cost of Power Sold.

Gains from Off-System Sales ($7.0 million increase)

The variance for Gains from Off-System Sales is primarily attributable to higher than projected economy sales. FPL now projects to sell approximately 1.29 million MWh more economy power than its original projections, resulting in a variance of approximately $13.2 million. This is partially off-set by a lower than projected average margin on economy sales of approximately $3.67/MWh, which results in a variance of approximately $6.3 million. The combination of higher sales and lower margins results in a total variance of $7.0 million for Gains from Off-System Sales.

Coal Cars Depreciation and Return ($0.1 million decrease)

The variance in coal cars depreciation and return is due to proceeds received from the rail company for damaged rail cars.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the CCR 2013 actual/estimated true-up amount you are requesting this Commission to approve.

A. Appendix II, Page 1 shows the calculation of the CCR actual/estimated true-up amount. The calculation of the actual/estimated true-up for the period January 2013 through December 2013 is an under-recovery of $24,042,297 including interest (Appendix II, Page 1, Column 14, Lines 18 plus 19).

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 2013?

A. Yes. Appendix II, Page 2 shows the actual/estimated capacity charges and applicable revenues (January 2013 through June 2013 reflects actual data and the data for July 2013 through December 2013 is based on updated estimates) compared to the original projections for the January 2013 through December 2013 period, filed on November 1, 2012.

Q. Please explain the variances related to capacity charges.

A. As shown in Appendix II, Page 2, Column 4, Line 14, the variance related to jurisdictional capacity charges is $6.2 million, a 0.9% decrease from original projections. The primary reason for this variance is a $6.3 million or 1.2% decrease in total system capacity costs (Page 2, Column 4, Line 10).

The $6.3 million decrease is due to a decrease in the SJRPP Suspension Accrual ($11.3 million), an increase in Transmission Revenues from Capacity Sales ($2.8 million), a decrease in Payments to Non-cogenerators ($2.0 million), partially offset by an increase in Payments to Cogenerators ($7.9 million), an increase in Incremental Plant Security Costs ($0.8 million), and an increase in Transmission of Electricity by Others ($0.5 million). Additionally, there is an increase of $83,000 of O&M estimates and $17,587 of return requirements on Construction Work In Progress (CWIP) related to compliance with new Nuclear Regulatory Commission requirements resulting from the Fukushima Daiichi event, which FPL is requesting recovery of in this docket. These costs were not included in the original CCR projections.

SJRPP Suspension Accrual ($11.3 million decrease)

The variance of approximately $11.3 million is due to lower than projected accrual amounts when compared to original calculations. The suspension date, the point at which it is projected that FPL will no longer be able to take power purchased from Units 1 and 2 due to IRS regulations, has been extended into November of 2017. Additionally, the current reserve fund balance exceeds the remaining debt service. Therefore, pursuant to the SJRPP Bond Resolution, the reserve fund balance has been applied to existing suspension accrual amounts, resulting is a reduction to previously projected accrual values.

Transmission Revenues from Capacity Sales ($2.8 million increase)

Approximately $2.2 million of the total variance is due to higher than projected economy power sales in the first half of the year. FPL sold approximately 969,000 MWh more economy power than projected during the first six months of 2013. For the full year, FPL now projects to sell over 1,290,000 MWh more of economy power than originally projected. The variance attributable to the July through December period is projected to be approximately $0.6 million.

Payments to Non-cogenerators ($2.0 million decrease)

The primary cause of the total variance is due to a reduction of approximately $2.0 million in costs associated with the SJRPP agreement. Approximately $1.25 million of the SJRPP variance was due to lower costs for Debt Service and

Cumulative Capital Recovery Amount (CCRA) payments, offset by approximately $0.5 million in higher than originally projected payments for Transmission Service, Property Taxes, JEA O&M expense charges to FPL, and Inventory costs. The remaining variance of approximately $1.3 million is due to lower than projected costs during the balance of the year for SJRPP in most categories. The primary driver is a projected reduction of approximately $1.2 million in JEA O&M expense charges to FPL during the period.

There was an increase of approximately $50,000 in costs due to Change In Law (CIL) payments related to the Scherer unit in the UPS agreement, during the January to June period. Additionally, there is a projected increase of approximately $29,000 in costs due to CIL payments for the balance of the year.

Payments to Cogenerators ($7.9 million increase)

The $7.9 million variance is primarily due to higher than projected capacity payments to cogenerators in the first half of the year. There was an approximately $4.9 million increase in payments to cogenerators resulting from better availability performance during the first six months of the year, and, therefore, higher than projected capacity payments to Indiantown (ICL) and Cedar Bay (CB). This increase was partially offset by an approximately $244,000 reduction in costs associated with the Broward North and Solid Waste Authority facilities.

Approximately 41.0%, or $3.2 million of the total variance is due to higher than originally projected capacity payments to ICL and CB resulting from anticipated better availability performance during the July to December period.

Incremental Plant Security Costs ($0.8 million increase)

The $0.8 million or 1.7% increase in incremental plant security costs is primarily due to higher than projected costs associated with the implementation of Critical Infrastructure Protection (CIP) Version 5 compliance standards at three new power plant sites as well as one existing compliant site. Also, related revisions to processes and procedures were affected by the implementation of the CIP Version 5 compliance standards. Additionally, costs associated with preparations for the Florida Reliability Coordinating Council's (FRCC) audit of the NERC CIP Standards for 2013 were higher than projected. These activities account for $1.6 million of the total variance.

The $1.6 million variance was partially offset by an $0.8 million decrease in nuclear incremental security costs primarily due to less than projected installation costs for the Ballistic Bullet Resistant Enclosure by the low level waste facility and less than projected costs incurred for contracted security services.

Transmission of Electricity by Others ($0.5 million increase)

The approximate $0.5 million variance is primarily due to lower than projected UPS power purchases, resulting in higher than projected unutilized transmission costs. FPL purchased approximately 318,000 MWh less than originally projected from the UPS units for the first six months of 2013. For the full year, FPL now projects to purchase approximately 686,000 MWh less than originally projected from the UPS units. The total increase in unutilized transmission, approximately $2.1 million, is partially offset by a credit of approximately $1.5 million that FPL received from Southern Company. The credit was part of an annual true-up of estimated versus actual costs for firm point-to-point transmission service associated with the UPS power purchase agreements.

Q. Please explain the variance in CCR Revenues.

A. The variance in CCR revenues of $30.2 million represents an under-recovery primarily resulting from a difference between the basis on which recoverable revenue requirements for West County Energy Center 3 (WCEC-3) were initially projected vs. the recovery that was subsequently approved in Docket No. 120015-EI. The approved 2013 CCR factors were limited to the annual fuel savings as prescribed in Order No. PSC-12-0664-FOF-EI, Docket No. 120001-EI. However, the Commission recognized in that same order that a decision in Docket No. 120015-EI, which addressed the future recovery of WCEC-3, would not be reached until after a decision was rendered in Docket No. 120001-EI. The order went on to state that any over or under recovery as a result of the decision in Docket No. 120015-EI would be handled through the regular CCR true-up process. Per Order No. PSC-13-0023-S-EI, the Commission approved the rate case settlement in which FPL is entitled to recover the full WCEC-3 non-fuel revenue requirements, rather than limiting that recovery to the projected annual fuel savings. Because FPL is now authorized to recover the full annual non-fuel revenue requirements for WCEC-3, it has included the difference between the originally projected WCEC-3 recovery (limited to fuel savings of $133 million) and the annual non-fuel revenue requirements for WCEC-3 of $165.0 million in its

2013 actual/estimated CCR true-up amount.

INCREMENTAL NRC COMPLIANCE COSTS - FUKUSHIMA

Q. Is FPL requesting to recover in its CCR 2013 actual/estimated true-up incremental costs associated with new Nuclear Regulatory Commission (NRC) compliance requirements resulting from the Fukushima Daiichi event?

A. Yes. As discussed in the testimony of FPL witness Don Grissette, the NRC has issued three Orders and three Requests for Information (RFIs) resulting from the Fukushima event that define, at a high level, what is to be changed at U.S. nuclear power plants and when the expected changes are to be completed. FPL will be required to make plant modifications and enhancements to support beyond design basis mitigation strategies submitted to the NRC.

FPL submitted its proposed implementation plan to the NRC on February 28, 2013 associated with the Orders requiring immediate action. In order to ensure FPL complies with the current regulatory deadlines, FPL has had to begin the engineering phase of the implementation plan, with the assumption that the NRC will accept the plan as submitted.

Q. Did FPL include any costs associated with NRC compliance requirements resulting from the Fukushima event in its 2013 Test Year Forecast revenue requirements that were filed in Docket No. 120015-EI?

A. Yes. FPL included \$10.0 million of capital expenditures and \$144,000 of O&M

expenses for the 2013 Test Year in Docket No. 120015-EI. At that time, not enough information was available to estimate the full impact of the Fukushima event. We now know that the required scope of Fukushima-related actions will be substantially greater than FPL was in a position to estimate at the time that the 2013 Test Year Forecast was developed.

Q. Why does FPL believe it is appropriate to recover through the CCR prudently incurred NRC compliance costs related to the Fukushima event that are incremental to what was included in its 2013 Test Year Forecast revenue requirements?

A. NRC compliance costs associated with the Fukushima event will be incurred in order to allow FPL's nuclear plants to continue operating and saving FPL customers substantial fossil fuel costs. The level of NRC compliance costs associated with the Fukushima event included in base rates does not address either (a) the increase in the compliance costs that FPL expects in 2013 and beyond; or (b) the high degree of uncertainty that exists as to the ultimate level of compliance costs. Both of these considerations make base rate recovery problematic and clause recovery appropriate. In the absence of CCR recovery, FPL will have no opportunity to recover Fukushima compliance costs that are incremental to the small level that is reflected in the 2013 test year forecast. Therefore, FPL is requesting to recover through the CCR incremental NRC compliance costs above the amounts included in the 2013 test year forecast.

Q. Has the Commission previously approved clause recovery for analogous types of compliance costs?

A. Yes, in Order No. PSC-01-2516-FOF-EI, issued in Docket No. 010001-EI on

December 26, 2001, the Commission approved recovery of FPL's incremental post-9/11 power plant security costs associated with the events of September 11, 2001 through the fuel clause. As with NRC compliance costs related to the Fukushima event, the incremental post-9/11 power plant security costs related to unanticipated, substantial new regulatory requirements that emerged following a disaster (in that instance, the 9/11 terrorist attacks). Those costs were expected to be volatile over time, and they have proven to be so. NRC compliance costs associated with the Fukushima event were also completely unexpected prior to the earthquake and tsunami in 2011.

In Order No. PSC-05-0748-FOF-EI, the Commission states:

> "Cost recovery clauses were designed to recover costs which are volatile and unpredictable. We also agree that all four current clauses address costs that are unpredictable, volatile and irregular, due to forces outside the utility's control. The original purpose of recovery clauses was to address on-going costs which could fluctuate between rate cases and unduly penalize either the utility or customers, if such costs were included in base rates."

In the same order, the Commission indicated that clause recovery was based on an immediate need to protect the health, safety and welfare of the utility and its customers, and there was a basis for believing the costs would be recurring on some level.

In Order No. PSC-01-2516-FOF-EI, the Commission states:

"We find that recovery of this incremental cost through the fuel clause is appropriate in this instance because there is a nexus between protection of FPL's nuclear generation facilities and the fuel cost savings that result from the continued operation of those facilities. Further, we believe that this type of cost is a potentially volatile cost, making it appropriate for recovery through a cost recovery clause. We are comforted that the true-up mechanism inherent in the fuel clause will ensure that ratepayers pay no more than the actual costs incurred. In addition, we find that recovery of this cost through the fuel clause provides a good match between the timing of the incurrence and recovery of the cost."

Because the NRC compliance costs associated with the Fukushima event are related to operating generating capacity, the same logic that led the Commission to move the power plant security cost recovery from the FCR to the CCR in 2002 would suggest that CCR recovery would be appropriate here as well.

Q. What is FPL's current estimate of 2013 O&M and capital costs associated with NRC requirements resulting from the Fukushima event?

A. FPL's actual 2013 NRC compliance costs resulting from the Fukushima event through June 2013 and current estimate for the remainder of the year total $227,000 of O&M expenses and $13.2 million of capital expenditures.

Q. Did FPL include any incremental O&M or capital costs associated with NRC requirements resulting from the Fukushima event in its projected 2013 CCR costs that were approved last year in Docket No. 120001-EI (Order No. PSC-

12-0664-FOF-EI)?

A. No. At the time those projections were made, FPL did not yet have enough information on the NRC requirements to accurately forecast the 2013 Fukushima-related costs.

Q. Has FPL included in its calculation of the 2013 CCR Actual/Estimated True-Up amount any incremental O&M costs associated with NRC requirements resulting from the Fukushima event?

A. Yes. FPL has included $83,000 of incremental O&M expenses associated with NRC compliance resulting from the Fukushima event. This amount is the difference between projected 2013 O&M expenses of $227,000 and the $144,000 included in FPL's base rates.

Q. Has FPL included in its calculation of the 2013 Actual/Estimated True-Up amount any incremental capital costs associated with NRC requirements resulting from the Fukushima event?

A. Yes. FPL has included in the calculation of the 2013 CCR Actual/Estimated True-Up amount $17,587 of return requirements on Construction Work in Progress (CWIP) related to this project. This $17,587 is based on 2013 capital expenditures of $3.2 million, which is the difference between projected 2013 capital expenditures of $13.2 million and the $10.0 million included in FPL's base rates. The capital recovery schedule providing the calculation of 2013 return requirements is provided on page 3 of Appendix II.

Q. Is FPL's determination of incremental costs consistent with the methodology established for incremental security costs?

A. Yes. As described above, FPL identified the O&M and capital costs included in its last rate case MFR's (Docket 120015-EI). Those amounts reduced the amounts FPL is requesting to recover through the CCR.

Q. How is FPL's recovery request for costs associated with NRC requirements resulting from the Fukushima event different from its current recovery of incremental security costs?

A. For incremental security costs, Order No. PSC-01-2516-FOF-EI did not make a distinction between capital items and expense items; thus, all costs were treated as current year expense. FPL is not requesting to recover its Fukushima-related capital costs as a current year expense, but rather to recover such costs consistent with the Company's normal accounting treatment. Therefore, capital costs will be recorded in CWIP until investments are put in service, at which time FPL will recover depreciation expense and return on the average net book value of the plant-in service balance at FPL's overall weighted average cost of capital. This approach is consistent with how the costs for capital projects are recovered in the Environmental Cost Recovery Clause.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DON GRISSETTE

DOCKET NO. 130001-EI

AUGUST 2, 2013

Q. Please state your name and address.

A. My name is Don Grissette. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light as General Manager of Organizational Effectiveness in the Nuclear Business Unit.

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

A. I am currently responsible for the daily and strategic activities for the nuclear fleet's Training, Licensing, Performance Improvement, and Nuclear Security organizations.

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

A. I hold a Master of Science degree in Radiation Toxicology from Auburn University, and a Bachelor of Science degree in Chemistry from Troy State University. I also earned a Senior Reactor Operator License at Farley Nuclear Plant.

I have spent 32 years in the nuclear industry in increasingly responsible positions at Southern Nuclear, FPL and TVA including Operations Manager, Plant General Manager and Corporate and Site Vice President.

I have served as an industry advisor at Auburn University, North Carolina State University and for several Institute of Nuclear Power Operations (INPO) and World Association of Nuclear Operators (WANO) evaluations.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of the 2013 costs incurred in response to new Nuclear Regulatory Commission (NRC) requirements resulting from the events that occurred at the Fukushima Daiichi nuclear power station in Japan (Fukushima).

Q. Please describe the natural disaster that occurred in Japan in 2011 and its impact on nuclear power plants.

A. On March 11, 2011, an earthquake occurred off the coast of Japan, which resulted in a tsunami. The earthquake and tsunami caused significant damage to the units at Fukushima. Following the earthquake and tsunami, off-site power was lost and cooling water systems were damaged, resulting in difficulties in cooling all of the units' reactor cores and spent fuel pools, and leading to explosions and radiation leaks from the site. The events at Fukushima raised questions about nuclear safety, which have been explored by all US nuclear plant sites, the NRC and INPO.

Q. What changes has the NRC implemented as a result of the Fukushima events?

A. Even though the NRC has concluded that all U.S. plants are safe, the impact on NRC licensees, such as FPL, of the lessons learned from the Fukushima event is expected to be significant. In March 2012, the NRC issued three Orders and three Requests for Information (RFIs) which define, at a high level, what is to be changed and when the expected changes are to be completed. It should be noted the NRC has yet to specifically define the criteria or parameters to implement.

The NRC Orders address Mitigation Strategies, Hardened Vent (not applicable to FPL nuclear sites) and Spent Fuel Pool Instrumentation. The RFIs address Seismic and Flooding Walkdowns, Seismic and Flooding Re-evaluations and Emergency Planning Communications and Staffing. The required responses to the Orders and RFIs follow varying schedules from 60 days to several years, but can be broadly grouped into immediate, short and long term requirements.

Q. Is FPL's exposure to Fukushima response costs analogous to the exposure that FPL has had to post-9/11 power plant security costs?

A. Yes. Both events were unanticipated disasters that are having significant impacts on regulatory requirements and resulting in additional costs for operating nuclear power plants. Both events fundamentally have changed the landscape of expectations for the protection of nuclear plants. In 2001, it was the nature and scope of terrorist threats. In 2012, it was the nature and scope of potential seismic and flooding events. In both instances, there has been substantial uncertainty as to the ongoing cost impacts.

Q. What steps has FPL already implemented as a result of the new NRC Fukushima-related Orders and RFIs?

A. To date, the majority of the actions taken by FPL have been associated with re-evaluation of existing design features and development of strategies and conceptual design of modifications needed to satisfy the immediate term NRC Orders and RFIs. This included acquiring additional diesel generators and water pumps, initiating seismic and flooding walkdowns and responding to all information requests.

Q. What types of further steps does FPL anticipate taking as a result of the new NRC Orders and RFIs?

A. FPL will be required to make plant modifications and enhancements to support "beyond design basis" mitigation strategies submitted to the NRC. The project scope is still evolving based on NRC interaction and is currently expected to include but not be limited to the following:

- Modifications and interim actions needed to satisfy re-evaluated seismic analysis. Modifications and interim actions needed to satisfy re-evaluated flooding analysis. Modifications to existing plant equipment to support beyond design basis station blackout mitigation strategies.
- Hardened storage, equipment and modifications needed to mitigate beyond design basis events using portable equipment stored on site.
- Equipment and modifications needed to mitigate beyond design basis events using portable equipment stored off-site.
- Additional Spent Fuel Pool Instrumentation.
- Upgraded Onsite Emergency Response Capabilities.
- Training associated with beyond design basis procedures and emergency plan requirements.

FPL submitted its proposed implementation plan to the NRC on February 28, 2013 associated with the two Regulatory Orders requiring immediate action: Spent Fuel Instrumentation Upgrades and Station Black-out Mitigation Strategies. To ensure FPL complies with the current regulatory deadlines, FPL has begun the engineering phase of the implementation plan with the assumption that the NRC will accept the plan as submitted. Any revisions that are needed will be addressed through the RFI process. Progress updates must be provided to the NRC every six months until all required actions are complete.

Q. Please describe the RFI process in more detail.

A. The RFI process is an iterative process following the NRC issuing specific criteria and parameters that must be satisfied. FPL then submits its proposal to the NRC to address these items. The NRC and FPL teams begin to exchange information as both move toward a mutually acceptable understanding of appropriate mitigating strategies. There is a high likelihood that additional scope changes will result from this interaction. Since the NRC final decisions will be ongoing for a number of years, the costs are unpredictable and are likely to be volatile and irregular.

Q. Please provide a brief description of the Fukushima-related activities that are being pursued in 2013.

A. FPL is currently pursuing or expects to pursue the following activities in 2013:

- Seismic Re-evaluations: FPL will perform comparisons of plant design curves to new curves endorsed by the NRC.
- Flooding Re-evaluation: FPL completed the re-evaluation in 2013 and has begun a flooding integrated assessment based on re-evaluation results.
- Station Black Out Mitigation: FPL has begun the engineering design of the modifications based on the proposed plan

submitted to the NRC earlier this year. Additionally, FPL will incur costs associated with the Regional Response Centers (a warehouse of off-site portable equipment shared by the industry that was established in 2013 and will be functional in 2014).

- Spent fuel Instrumentation: FPL has begun the engineering design and procurement of equipment to support instrumentation that will be installed in 2014.
- Emergency Preparedness Staffing studies.
- Payment of NRC fees associated with these efforts.

Q. Does FPL have enough information currently to project with confidence the cost to complete all Fukushima-related modifications and enhancements that may be required by the NRC?

A. No. Until the NRC endorses the proposed mitigation strategies, cost projections will remain uncertain. However, FPL has engaged a third party cost estimating expert, High Bridge Associates, Inc. (HBA) to prepare a parametric analysis based on FPL implementation plan submittals provided to the NRC, and on HBA's knowledge of the other licensees' approaches to providing additional Spent Fuel Pool Instrumentation and Station Blackout Mitigation. The parametric analysis will provide a range of costs likely to be incurred for the expected scope of work.

Q. Will the use of HBA provide other benefits to the project?

A. Yes. HBA is also proving to be an invaluable source of industry-wide information that FPL is using to refine its analysis of compliance alternatives. This analysis supports FPL's identification of least-cost compliance strategies. For example, FPL submitted a conceptual design to the NRC for using quick electrical connections vice running cables to portable generator breakers. HBA's valuation for this design was substantially greater than FPL's. Consequently, FPL re-evaluated the design to determine whether there was an alternative strategy that could be implemented at a lower cost. Ultimately, FPL and HBA identified an alternative approach that will accomplish the same outcome for a third of the cost.

Q. When does FPL currently expect to complete the Fukushima-related modifications and enhancements?

A. The NRC has established completion dates of late 2015 and mid 2016 for the immediate-term Spent Fuel Instrumentation Upgrades and Station Black-out Mitigation Strategies Orders. Modifications required because of seismic and flooding re-evaluations may extend beyond 2017. Actions and dates associated with the short and long term actions have not been established.

Q. Did FPL include any costs to comply with the Fukushima requirements in the Rate Case Forecast that was filed in Docket No. 120015-EI?

A. Yes. FPL included a total of approximately $10 million of capital expenditures for 2012 and 2013 and $144,000 of O&M expenses for 2013. However, at the time the Rate Case Forecast was developed in the Fall of 2011, not enough information was available to estimate the full impact of the Fukushima event.

Q. Does FPL expect to incur Fukushima-related costs well in excess of the Rate Case Forecast levels in 2013 and beyond?

A. Yes. It has become apparent that the required scope of Fukushima-related actions will be substantially greater than FPL was in a position to estimate at the time that the Rate Case Forecast was developed.

Q. What is FPL's current projection of Fukushima-related costs at FPL's nuclear power plants for the period January 2013 through December 2013?

A. FPL's current projection of Fukushima-related costs for 2013 is approximately $13.2 million of capital expenditures and $227,000 of O&M expenses. As described in FPL witness Keith's testimony, FPL is only requesting recovery of the incremental amount of these costs in excess of what FPL included in its Rate Case Forecast.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

FUEL COST RECOVERY

ACTUAL/ESTIMATED TRUE UP CALCULATION

TJK-3
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
August 2, 2013

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE

SCHEDULE: E1-B

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) 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	$299,597,033	$301,405,743	$286,677,773	$267,474,908	$214,522,470	$219,862,398	$3,082,868,833
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	$2,341,856	$2,341,856	$2,244,819	$1,675,564	$2,260,197	$2,403,658	$23,793,433
4	Scherer Coal Cars Depreciation & Return	$0	($181)	($46,136)	($207)	($416)	($416)	($53,088)	$0	$0	$0	$0	$0	($100,444)
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)	($4,247,107)	($4,826,707)	($2,968,118)	($1,792,000)	($3,741,229)	($5,638,407)	($56,324,203)
6	Gains from Off-System Sales (Per A6)	($876,040)	($1,741,631)	($2,183,089)	($1,053,380)	($1,015,087)	($688,662)	($516,250)	($588,750)	($278,750)	($312,500)	($675,000)	($1,277,500)	($11,206,639)
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	$17,098,920	$16,190,014	$17,178,160	$14,461,104	$9,027,553	$8,443,059	$155,005,864
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	$14,320,667	$14,505,666	$15,353,663	$10,077,669	$5,485,671	$3,385,672	$103,986,176
9	Energy Cost of Economy Purchases (Per A9)	$98,806	$63,673	$148,556	$1,639,283	$121,100	$186,471	$250,000	$500,000	$1,350,000	$1,225,000	$56,000	$44,000	$5,682,889
10	Total Fuel Costs & Net Power Transactions	$226,713,811	$208,908,774	$234,022,458	$288,124,017	$299,970,871	$321,120,295	$328,792,030	$329,527,820	$319,557,546	$292,809,745	$226,935,661	$227,222,880	$3,303,705,908
11														
12	**Incremental Optimization Costs**													
13	Incremental Personnel, Software, and Hardware Costs	$0	$0	$0	$20,622	$21,401	$28,231	$33,672	$32,288	$30,904	$33,672	$30,904	$32,288	$263,980
14	Variable Power Plant O&M Costs over 514,000 MW Threshold (Per A6)	$0	$0	$364,700	$315,395	$227,805	$125,549	$98,150	$113,250	$52,850	$60,400	$151,000	$286,900	$1,795,999
15	Total	$0	$0	$364,700	$336,017	$249,206	$153,780	$131,822	$145,538	$83,754	$94,072	$181,904	$319,188	$2,059,979
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	($3,845,522)
18	Energy Imbalance Fuel Revenues	$56,481	$82,535	$48,854	$75,548	$65,257	$47,061	$0	$0	$0	$0	$0	$0	$375,736
19	Inventory Adjustments	($106,047)	($4,083,681)	$168,325	($88,560)	($285,132)	($28,899)	$0	$0	$0	$0	$0	$0	($4,423,994)
20	Non Recoverable Oil/Tank Bottoms	$0	($718,392)	$452,505	$0	$189	($189)	$0	$0	$0	$0	$0	$0	($265,887)
21	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,013	$287,849,940	$299,311,180	$320,490,802	$328,923,851	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,297,606,220
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	10,150,088,249	10,080,997,264	9,763,403,645	9,104,618,770	8,255,228,566	8,067,004,659	102,590,262,282
24	Sale for Resale (excluding CKW) [2]	148,696,550	152,935,981	143,064,345	153,595,635	171,792,467	176,313,367	191,752,025	209,487,317	208,827,684	192,550,041	174,526,607	149,677,379	2,073,219,398
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	10,341,840,274	10,290,484,581	9,972,231,329	9,297,168,811	8,429,755,173	8,216,682,038	104,663,481,680
26														
27	**Jurisdictional % of Total Sales (Line 23/25)**	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.14586%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01916%
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	$299,212,015	$297,175,299	$287,813,033	$268,392,872	$243,353,902	$237,805,294	$3,045,673,611
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)	($641,531)	($641,531)	($641,531)	($641,531)	($641,531)	($641,531)	($7,698,365)
33	Jurisdictional Fuel Revenues Applicable to Period	$238,729,088	$219,447,095	$215,290,215	$232,869,851	$254,920,867	$270,857,549	$302,577,593	$300,540,876	$291,178,610	$271,758,449	$246,719,479	$241,170,871	$3,086,060,542
34	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,013	$287,849,940	$299,311,180	$320,490,802	$328,923,851	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,297,606,220
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.14586%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01916%
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$221,888,753	$199,492,191	$230,007,841	$282,428,776	$293,697,828	$314,660,568	$323,086,631	$323,223,665	$313,201,211	$287,069,941	$222,595,570	$223,578,045	$3,234,931,021
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	$16,840,334	$19,954,904	($14,717,626)	($49,558,925)	($38,776,961)	($43,803,020)	($20,509,038)	($22,682,789)	($22,022,601)	($15,311,492)	$24,123,908	$17,592,827	($148,870,479)
38	Interest Provision for the Month	$2,912	$5,096	$4,722	$1,789	($1,335)	($3,612)	($5,141)	($6,421)	($7,740)	($8,874)	($8,854)	($8,012)	($35,469)
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$60,921,435	$76,874,326	$58,154,314	$4,590,070	($38,195,333)	($86,009,073)	($110,530,361)	($137,226,679)	($163,264,127)	($182,591,601)	($162,483,655)	$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 [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)
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	$56,370,780	$72,323,673	$53,603,660	$39,416	($42,745,988)	($90,559,727)	($115,081,014)	($141,777,333)	($167,814,782)	($187,142,255)	($167,034,309)	($153,456,602)	($153,456,602)
43														

44 [1] January through June actuals include various adjustments as noted on the A-Schedules.

45 [2] Billed KWH includes all wholesale customers except CKW.

46 [3] Prior Period 2011/2012 True-up.

47 [4] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.

48 [5] Deferred 2012 Final True-up.

FLORIDA POWER & LIGHT COMPANY
REVENUE/COST VARIANCE ANALYSIS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)
Line No.	Revenue/Cost Variance Analysis Schedule	ACTUAL/ESTIMATED	ORIGINAL PROJECTION	Difference
1	Jurisdictional Fuel Revenues			
2	Revenues	$3,045,673,611	$3,102,901,635	($57,228,024)
3	MWH	102,590,262	103,200,444	(610,182)
4	$ per MWH	29.68775	30.06675	(0.37900)
5				
6	Variance due to Consumption			($18,346,188)
7	Variance due to Cost			($38,881,836)
8	Total Variance			($57,228,024)
9				
10	Jurisdictional Total Fuel Costs			
11	Costs	$3,234,931,021	$3,143,288,566	$91,642,455
12	MWH	102,590,262	103,200,444	(610,182)
13	$ per MWH	31.53253	30.45809	1.07444
14				
15	Variance due to Consumption			($18,584,980)
16	Variance due to Cost			$110,227,434
17	Total Variance			$91,642,455
18				
19	Total Variance			
20	Variance due to Consumption			$238,791
21	Variance due to Cost			($149,109,270)
22	Total Variance			($148,870,479)
23	Interest			($35,469)
24	Prior Year True-up			($4,550,654)
25	Total True-up			($153,456,602)
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL/ESTIMATED vs. ORIGINAL PROJECTION

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)
Line No.		FCR - 2013 Actual Estimated	FCR - 2013 Original Projection - Jun - Dec	Dif. FCR - 2013 Original Projection - Jun - Dec	% Dif. FCR - 2013 Original Projection - Jun - Dec
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3) [1]	$3,082,868,833	$2,836,155,287	$246,713,546	8.7%
3	Nuclear Fuel Disposal Costs (Per A2)	$23,793,433	$24,785,825	($992,393)	(4.0%)
4	Scherer Coal Cars Depreciation & Return	($100,444)	$0	($100,444)	N/A
5	Fuel Cost of Power Sold (Per A6)	($56,324,203)	($20,692,255)	($35,631,948)	172.2%
6	Gains from Off-System Sales (Per A6)	($11,206,639)	($4,238,116)	($6,968,523)	164.4%
7	Fuel Cost of Purchased Power (Per A7)	$155,005,864	$186,831,284	($31,825,420)	(17.0%)
8	Energy Payments to Qualifying Facilities (Per A8)	$103,986,176	$143,346,388	($39,360,212)	(27.5%)
9	Energy Cost of Economy Purchases (Per A9)	$5,682,889	$42,063,927	($36,381,038)	(86.5%)
10	Total Fuel Costs & Net Power Transactions	$3,303,705,908	$3,208,252,341	$95,453,568	3.0%
11					
12	**Incremental Optimization Costs**				
13	Incremental Personnel, Software, and Hardware Costs	$263,980	$0	$263,980	N/A
14	Variable Power Plant O&M Costs over 514,000 MW Threshold (Per A6)	$1,795,999	$0	$1,795,999	N/A
15	Total	$2,059,979	$0	$2,059,979	N/A
16	**Adjustments to Fuel Cost**				
17	Sales to City of Key West (CKW)	($3,845,522)	($3,946,028)	$100,506	(2.5%)
18	Energy Imbalance Fuel Revenues	$375,736	$0	$375,736	N/A
19	Inventory Adjustments	($4,423,994)	$0	($4,423,994)	N/A
20	Non Recoverable Oil/Tank Bottoms	($265,887)	$0	($265,887)	N/A
21	Adjusted Total Fuel Costs & Net Power Transactions	$3,297,606,220	$3,204,306,313	$93,299,907	2.9%
22	**Jurisdictional kWh Sales**				
23	Jurisdictional kWh Sales	102,590,262,282	103,200,444,298	(610,182,016)	(0.6%)
24	Sale for Resale (excluding CKW) [2]	2,073,219,398	2,099,817,776	(26,598,378)	(1.3%)
25	Sub-Total Sales (excluding CKW)	104,663,481,680	105,300,262,074	(636,780,394)	(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)	$3,045,673,611	$3,102,901,635	($57,228,024)	(1.8%)
30	**Fuel Adjustment Revenues Not Applicable to Period**				
31	Prior Period True-up (Collected)/Refunded This Period [3]	$48,085,296	$48,085,296	$0	0.0%
32	GPIF, Net of Revenue Taxes [4]	($7,698,365)	($7,698,365)	$0	(0.0%)
33	Jurisdictional Fuel Revenues Applicable to Period	$3,086,060,542	$3,143,288,566	($57,228,024)	(1.8%)
34	Adjusted Total Fuel Costs & Net Power Transactions	$3,297,606,220	$3,204,306,313	$93,299,907	2.9%
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)	$3,234,931,021	$3,143,288,566	$91,642,455	2.9%
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	($148,870,479)	$0	($148,870,479)	N/A
38	Interest Provision for the Month	($35,469)	$0	($35,469)	N/A
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 [5]	($4,550,654)	$0	($4,550,654)	N/A
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)	($153,456,602)	$0	($153,456,602)	0.0%
43					
44	[1] January through June actuals include various adjustments as noted on the A-Schedules.				
45	[2] Billed KWH includes all wholesale customers except CKW.				
46	[3] Prior Period 2011/2012 True-up.				
47	[4] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.				
48	[5] Deferred 2012 Final True-up.				

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	**Fuel Cost of System Net Generation ($)**													
2	Heavy Oil	175,248	186,272	675,248	1,879,167	1,003,094	2,077,583	11,478,041	14,834,877	25,791,995	7,743,199	3,485,913	0	69,330,637
3	Light Oil	251,735	385,253	1,980,262	819,242	1,436,080	643,242	1,319,040	1,219,949	1,679,321	172,655	442,783	0	10,349,563
4	Coal	14,022,984	12,321,270	13,281,549	14,446,074	11,447,914	16,062,546	13,498,000	12,623,100	12,978,900	11,968,900	11,262,900	10,358,700	154,272,836
5	Gas	192,662,133	185,486,609	210,891,468	236,851,196	242,398,178	257,113,182	253,719,552	253,145,418	227,446,256	233,259,354	180,876,975	189,909,498	2,663,759,820
6	Nuclear	12,925,680	9,671,348	7,804,464	13,220,456	14,674,532	16,534,210	19,582,400	19,582,400	18,781,300	14,330,800	18,453,900	19,594,200	185,155,690
7	**Total Fuel Cost of System Net Generation ($)**	220,037,780	208,050,752	234,632,991	267,216,135	270,959,798	292,430,763	299,597,033	301,405,743	286,677,773	267,474,908	214,522,470	219,862,398	3,082,868,545
8														
9	**System Net Generation (MWH)**													
10	Heavy Oil	(1,808)	478	3,369	11,065	5,173	12,646	71,698	96,168	166,016	50,008	21,904	0	436,717
11	Light Oil	1,611	2,232	12,026	5,254	8,529	4,445	3,478	3,411	4,625	584	1,179	0	47,374
12	Coal	510,895	433,608	492,845	517,541	409,849	513,860	507,361	471,101	487,647	448,460	429,825	392,328	5,615,319
13	Gas	5,472,419	5,580,054	6,216,826	6,179,442	6,450,621	6,774,561	7,415,511	7,495,878	6,616,348	6,925,212	5,170,684	5,398,736	75,696,293
14	Nuclear	1,988,376	1,513,557	1,216,458	1,941,110	2,144,047	2,409,561	2,501,181	2,501,181	2,397,542	1,789,559	2,413,967	2,567,188	25,383,727
15	Solar	4,495	4,975	6,976	6,353	7,233	5,860	18,954	17,826	15,611	14,225	9,132	7,915	119,555
16	**Total System Net Generation (MWH)**	7,975,989	7,534,903	7,948,500	8,660,765	9,025,452	9,720,933	10,518,183	10,585,565	9,687,789	9,228,048	8,046,691	8,366,167	107,298,985
17														
18	**Units of Fuel Burned (Unit)** [a]													
19	Heavy Oil	1,952	1,966	7,126	20,217	10,864	22,347	116,455	157,007	275,152	83,186	37,337	0	733,609
20	Light Oil	2,224	3,676	15,757	6,850	12,084	5,876	11,052	10,180	13,938	1,433	3,675	0	86,745
21	Coal [b]	53,239	43,028	32,203	44,860	44,860	73,525	60,168	57,219	56,474	50,828	40,533	39,205	596,142
22	Gas	39,361,833	39,766,367	43,503,736	46,454,547	47,200,994	50,409,689	52,395,885	53,075,883	47,023,895	48,591,932	35,761,121	36,985,563	540,531,444
23	Nuclear	20,147,225	15,616,107	12,640,147	20,859,112	22,905,284	24,990,594	27,094,244	27,094,244	25,977,833	19,579,677	25,508,266	27,109,985	269,522,718
24	**Total Units of Fuel Burned (Unit)**													
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	12,443	12,527	45,414	129,147	69,089	142,278	745,307	1,004,842	1,760,971	532,392	238,957	0	4,693,368
28	Light Oil	12,857	21,250	90,722	39,545	70,007	34,097	64,434	59,348	81,257	8,353	21,427	0	503,298
29	Coal	5,157,669	4,534,830	5,186,087	5,398,841	4,083,642	5,849,037	5,179,619	4,818,901	4,985,251	4,606,534	4,410,244	4,032,742	58,243,399
30	Gas	39,936,356	40,305,984	44,131,313	47,087,749	47,880,284	51,119,304	52,395,885	53,075,883	47,023,895	48,591,932	35,761,121	36,985,563	544,295,269
31	Nuclear	20,147,225	15,616,107	12,640,147	20,859,112	22,905,284	24,990,594	27,094,244	27,094,244	25,977,833	19,579,677	25,508,266	27,109,985	269,522,718
32	**Total BTU Burned (MMBTU)**	65,266,550	60,490,699	62,093,684	73,514,395	75,008,307	82,135,311	85,479,489	86,053,218	79,829,207	73,318,888	65,940,015	68,128,290	877,258,052
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	89.7788	94.7468	94.7583	92.9499	92.3320	92.9692	98.5620	94.4854	93.7373	93.0830	93.3635	0.0000	94.5063
36	Light Oil	113.1903	104.8022	125.6751	119.5974	118.8414	109.4694	119.3485	119.8378	120.4851	120.4851	120.4851	0.0000	119.3102
37	Coal	78.8383	79.0800	80.0861	78.0173	78.0173	73.6463	76.9412	76.9779	76.9044	77.2330	77.2334	77.1738	77.2506
38	Gas	4.8946	4.6644	4.8477	5.0986	5.1354	5.1005	4.8424	4.7695	4.8368	4.8004	5.0579	5.1347	4.9280
39	Nuclear	0.6416	0.6193	0.6174	0.6338	0.6407	0.6616	0.7228	0.7228	0.7230	0.7319	0.7234	0.7228	0.6870
40	**Total Fuel Cost per Unit ($/Unit)**													
41														

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Generation Mix (%)													
2	Heavy Oil	(0.02%)	0.01%	0.04%	0.13%	0.06%	0.13%	0.68%	0.91%	1.71%	0.54%	0.27%	0.00%	0.41%
3	Light Oil	0.02%	0.03%	0.15%	0.06%	0.09%	0.05%	0.03%	0.03%	0.05%	0.01%	0.01%	0.00%	0.04%
4	Coal	6.41%	5.75%	6.20%	5.98%	4.54%	5.29%	4.82%	4.45%	5.03%	4.86%	5.34%	4.69%	5.23%
5	Gas	68.61%	74.06%	78.21%	71.35%	71.47%	69.69%	70.50%	70.81%	68.30%	75.05%	64.26%	64.53%	70.55%
6	Nuclear	24.93%	20.09%	15.30%	22.41%	23.76%	24.79%	23.78%	23.63%	24.75%	19.39%	30.00%	30.69%	23.66%
7	Solar	0.06%	0.07%	0.09%	0.07%	0.08%	0.06%	0.18%	0.17%	0.16%	0.15%	0.11%	0.09%	0.11%
8	**Total Generation Mix (%)**	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
9														
10	Fuel Cost per MMBTU ($/MMBTU)													
11	Heavy Oil	14.0839	14.8693	14.8687	14.5506	14.5188	14.6023	15.4004	14.7634	14.6465	14.5442	14.5880	0.0000	14.7720
12	Light Oil	19.5803	18.1296	21.8277	20.7166	20.5133	18.8650	20.4712	20.5558	20.6668	20.6698	20.6647	0.0000	20.5635
13	Coal	2.7189	2.7170	2.5610	2.6758	2.8034	2.7462	2.6060	2.6195	2.6035	2.5982	2.5538	2.5686	2.6488
14	Gas	4.8242	4.6020	4.7787	5.0300	5.0626	5.0297	4.8424	4.7695	4.8368	4.8004	5.0579	5.1347	4.8940
15	Nuclear	0.6416	0.6193	0.6174	0.6338	0.6407	0.6616	0.7228	0.7228	0.7230	0.7319	0.7234	0.7228	0.6870
16														
17	BTU Burned per KWH (BTU/KWH)													
18	Heavy Oil	(6,883)	26,211	13,481	11,671	13,356	11,251	10,395	10,449	10,607	10,646	10,909	0	10,747
19	Light Oil	7,978	9,522	7,544	7,527	8,208	7,670	18,526	17,399	17,569	14,303	18,174	0	10,624
20	Coal	10,095	10,458	10,523	10,432	9,964	11,383	10,209	10,229	10,223	10,272	10,261	10,279	10,372
21	Gas	7,298	7,223	7,099	7,620	7,423	7,546	7,066	7,081	7,107	7,017	6,916	6,851	7,191
22	Nuclear	10,133	10,317	10,391	10,746	10,683	10,371	10,833	10,833	10,835	10,941	10,567	10,560	10,618
23														
24	Generated Fuel Cost per KWH (cents/KWH)													
25	Heavy Oil	(9.6942)	38.9740	20.0448	16.9824	19.3916	16.4285	16.0089	15.4260	15.5358	15.4839	15.9145	0.0000	15.8754
26	Light Oil	15.6218	17.2625	16.4668	15.5930	16.8377	14.4701	37.9252	35.7651	36.3096	29.5642	37.5558	0.0000	21.8464
27	Coal	2.7448	2.8416	2.6949	2.7913	2.7932	3.1259	2.6604	2.6795	2.6615	2.6689	2.6203	2.6403	2.7474
28	Gas	3.5206	3.3241	3.3923	3.8329	3.7577	3.7953	3.4215	3.3771	3.4376	3.3683	3.4981	3.5177	3.5190
29	Nuclear	0.6501	0.6390	0.6416	0.6811	0.6844	0.6862	0.7829	0.7829	0.7834	0.8008	0.7645	0.7633	0.7294
30	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.7588	2.7612	2.9519	3.0854	3.0022	3.0083	2.8484	2.8473	2.9592	2.8985	2.6660	2.6280	2.8732
31														
32														
33	[a] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
34	[b] Scherer coal is not reported in Tons, excludes Scherer coal													
35														
36														
37														
38														
39														
40														
41														

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jul - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		813,641					5,357,824	1,000,000	5,357,824	25,476,171	3.13	4.75
5	Plant Unit Info	1,210	813,641	90.4%	94.7%	90.4%	6,585			5,357,824	25,476,171	3.13	
6	*Desoto Solar*												
7	Solar		5,118					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,118	27.5%		27.5%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		3,478					11,052	5,830,076	64,434	1,319,040	37.93	119.35
15	Plant Unit Info	648	3,478	0.7%	93.5%	35.8%	18,526			64,434	1,319,040	37.93	
16	*Fort Myers 2*												
17	Gas		571,383					4,093,583	1,000,000	4,093,583	19,710,804	3.45	4.82
18	Plant Unit Info	1,349	571,383	56.9%	94.2%	94.8%	7,164			4,093,583	19,710,804	3.45	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		30,608					335,418	1,000,000	335,418	1,663,245	5.43	4.96
22	Plant Unit Info	296	30,608	27.8%	95.1%	98.1%	10,958			335,418	1,663,245	5.43	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		802					13,373	1,000,000	13,373	66,893	8.34	5.00
26	Plant Unit Info	684	802	0.2%	93.5%	58.6%	16,681			13,373	66,893	8.34	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		89,940					736,327	1,000,000	736,327	3,666,759	4.08	4.98
30	Plant Unit Info	438	89,940	27.6%	94.6%	94.6%	8,187			736,327	3,666,759	4.08	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		99,821					816,477	1,000,000	816,477	4,066,132	4.07	4.98
34	Plant Unit Info	438	99,821	30.6%	94.1%	94.6%	8,179			816,477	4,066,132	4.07	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1	Plant Unit Info	788	0	0.0%	0.0%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		32,900					58,502	6,399,952	374,410	5,772,718	17.55	98.68
4	Gas		22,141					227,822	1,000,000	227,822	1,140,228	5.15	5.00
5	Plant Unit Info	788	55,041	9.4%	95.0%	67.2%	10,941			602,232	6,912,945	12.56	
6	*Manatee 3*												
7	Gas		724,543					4,965,805	1,000,000	4,965,805	24,049,728	3.32	4.84
8	Plant Unit Info	1,058	724,543	92.1%	94.9%	92.0%	6,854			4,965,805	24,049,728	3.32	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		28,505					42,476	6,399,920	271,843	4,147,239	14.55	97.64
15	Gas		71,454					803,494	1,000,000	803,494	3,989,806	5.58	4.97
16	Plant Unit Info	802	99,959	16.8%	95.0%	62.6%	10,758			1,075,337	8,137,045	8.14	
17	*Martin 3*												
18	Gas		113,991					852,460	1,000,000	852,460	4,101,615	3.60	4.81
19	Plant Unit Info	431	113,991	35.6%	94.3%	94.8%	7,478			852,460	4,101,615	3.60	
20	*Martin 4*												
21	Gas		127,848					950,250	1,000,000	950,250	4,572,199	3.58	4.81
22	Plant Unit Info	431	127,848	39.9%	94.8%	94.8%	7,433			950,250	4,572,199	3.58	
23	*Martin 8*												
24	Gas		666,633					4,670,255	1,000,000	4,670,255	22,559,325	3.38	4.83
25	Plant Unit Info	1,052	666,633	85.2%	94.9%	92.4%	7,006			4,670,255	22,559,325	3.38	
26	*Martin 8 Solar*												
27	Solar		12,062					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	12,062	21.6%		21.6%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		44,514					399,414	1,000,000	399,414	1,985,906	4.46	4.97
32	Plant Unit Info	239	44,514	25.0%	95.0%	95.0%	8,973			399,414	1,985,906	4.46	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		43,833					394,257	1,000,000	394,257	1,956,551	4.46	4.96
36	Plant Unit Info	239	43,833	24.7%	94.4%	95.0%	8,995			394,257	1,956,551	4.46	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		522,818					3,694,662	1,000,000	3,694,662	17,823,762	3.41	4.82
2	Plant Unit Info	905	522,818	77.7%	95.8%	97.7%	7,067			3,694,662	17,823,762	3.41	
3	*Sanford 5*												
4	Gas		362,203					2,622,195	1,000,000	2,622,195	12,635,478	3.49	4.82
5	Plant Unit Info	901	362,203	54.0%	89.4%	89.5%	7,240			2,622,195	12,635,478	3.49	
6	*Scherer 4*												
7	Coal		376,675					226,818	17,000,022	3,855,911	8,868,600	2.35	39.10
8	Plant Unit Info	629	376,675	80.5%	93.8%	91.8%	10,237			3,855,911	8,868,600	2.35	
9	*St Johns 10*												
10	Coal		63,939					29,598	22,000,135	651,160	2,277,300	3.56	76.94
11	Plant Unit Info	124	63,939	69.3%	94.1%	69.3%	10,184			651,160	2,277,300	3.56	
12	*St Johns 20*												
13	Coal		66,747					30,570	22,000,262	672,548	2,352,100	3.52	76.94
14	Plant Unit Info	124	66,747	72.4%	94.0%	72.3%	10,076			672,548	2,352,100	3.52	
15	*St Lucie 1*												
16	Nuclear		711,622					7,514,567	1,000,000	7,514,567	5,251,600	0.74	0.70
17	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	5,251,600	0.74	
18	*St Lucie 2*												
19	Nuclear		609,333					6,369,659	1,000,000	6,369,659	4,568,800	0.75	0.72
20	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	4,568,800	0.75	
21	*Space Coast*												
22	Solar		1,774					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,774	23.9%		23.9%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		10,293					15,477	6,400,078	99,054	1,558,084	15.14	100.67
26	Gas		27,285					289,195	1,000,000	289,195	1,442,719	5.29	4.99
27	Plant Unit Info	378	37,578	13.4%	94.5%	80.8%	10,332			388,249	3,000,803	7.99	
28	*Turkey Point 3*												
29	Nuclear		586,125					6,560,405	1,000,000	6,560,405	5,120,200	0.87	0.78
30	Plant Unit Info	808	586,125	97.5%	97.8%	97.5%	11,193			6,560,405	5,120,200	0.87	
31	*Turkey Point 4*												
32	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,641,800	0.78	0.70
33	Plant Unit Info	819	594,101	97.5%	98.0%	97.5%	11,193			6,649,613	4,641,800	0.78	
34	*Turkey Point 5*												
35	Gas		625,451					4,348,502	1,000,000	4,348,502	21,217,048	3.39	4.88
36	Plant Unit Info	1,053	625,451	79.8%	85.7%	84.0%	6,953			4,348,502	21,217,048	3.39	
37	*WCEC 01*												

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		806,204					5,551,013	1,000,000	5,551,013	27,063,187	3.36	4.88
2	Plant Unit Info	1,219	806,204	88.9%	94.7%	88.9%	6,885			5,551,013	27,063,187	3.36	
3	*WCEC 02*												
4	Gas		814,466					5,608,966	1,000,000	5,608,966	27,509,258	3.38	4.90
5	Plant Unit Info	1,219	814,466	89.8%	94.7%	89.8%	6,887			5,608,966	27,509,258	3.38	
6	*WCEC 03*												
7	Gas		835,934					5,664,595	1,000,000	5,664,595	27,022,740	3.23	4.77
8	Plant Unit Info	1,219	835,934	92.2%	94.4%	92.2%	6,776			5,664,595	27,022,740	3.23	
9	**System Totals**												
10	Plant Unit Info	23,364	10,518,183				8,127			85,479,489	299,597,033	2.85	
11													
12													
13													
14													
15													
16													
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ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Aug - 2013**												
2	CCEC 3												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		825,520					5,432,642	1,000,000	5,432,642	25,331,539	3.07	4.66
5	Plant Unit Info	1,210	825,520	91.7%	94.7%	91.7%	6,581			5,432,642	25,331,539	3.07	
6	Desoto Solar												
7	Solar		4,864					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,864	26.2%		26.2%	0			0	0	0.00	
9	Everglades 1-12												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	Fort Myers 1-12												
14	Light Oil		3,411					10,180	5,829,862	59,348	1,219,949	35.77	119.84
15	Plant Unit Info	648	3,411	0.7%	93.5%	29.2%	17,399			59,348	1,219,949	35.77	
16	Fort Myers 2												
17	Gas		619,611					4,426,031	1,000,000	4,426,031	21,000,221	3.39	4.74
18	Plant Unit Info	1,349	619,611	61.7%	94.2%	93.9%	7,143			4,426,031	21,000,221	3.39	
19	Fort Myers 3A_B												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		29,303					321,504	1,000,000	321,504	1,573,646	5.37	4.89
22	Plant Unit Info	296	29,303	26.6%	95.1%	98.1%	10,972			321,504	1,573,646	5.37	
23	Lauderdale 1-24												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		2,387					37,134	1,000,000	37,134	184,082	7.71	4.96
26	Plant Unit Info	684	2,387	0.5%	93.5%	87.2%	15,557			37,134	184,082	7.71	
27	Lauderdale 4												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		109,689					895,535	1,000,000	895,535	4,410,502	4.02	4.92
30	Plant Unit Info	438	109,689	33.7%	94.6%	94.5%	8,164			895,535	4,410,502	4.02	
31	Lauderdale 5												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		126,971					1,035,223	1,000,000	1,035,223	5,108,221	4.02	4.93
34	Plant Unit Info	438	126,971	39.0%	94.1%	94.4%	8,153			1,035,223	5,108,221	4.02	
35	Manatee 1												
36	Heavy Oil		27,149					47,238	6,399,953	302,321	4,460,965	16.43	94.44
37	Gas		18,099					186,425	1,000,000	186,425	924,167	5.11	4.96

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	788	45,248	7.7%	59.4%	79.8%	10,801			488,746	5,385,132	11.90	
2	*Manatee 2*												
3	Heavy Oil		28,470					49,291	6,399,951	315,460	4,654,877	16.35	94.44
4	Gas		19,187					197,757	1,000,000	197,757	981,275	5.11	4.96
5	Plant Unit Info	788	47,657	8.1%	95.0%	81.7%	10,769			513,217	5,636,152	11.83	
6	*Manatee 3*												
7	Gas		729,091					4,994,304	1,000,000	4,994,304	23,743,480	3.26	4.75
8	Plant Unit Info	1,058	729,091	92.6%	94.9%	92.6%	6,850			4,994,304	23,743,480	3.26	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		26,127					38,797	6,400,082	248,304	3,610,750	13.82	93.07
15	Gas		64,475					727,390	1,000,000	727,390	3,581,837	5.56	4.92
16	Plant Unit Info	802	90,602	15.2%	95.0%	58.8%	10,769			975,694	7,192,587	7.94	
17	*Martin 3*												
18	Gas		133,193					991,887	1,000,000	991,887	4,703,196	3.53	4.74
19	Plant Unit Info	431	133,193	41.5%	94.3%	94.8%	7,447			991,887	4,703,196	3.53	
20	*Martin 4*												
21	Gas		133,158					988,688	1,000,000	988,688	4,687,975	3.52	4.74
22	Plant Unit Info	431	133,158	41.5%	94.8%	94.8%	7,425			988,688	4,687,975	3.52	
23	*Martin 8*												
24	Gas		677,626					4,739,668	1,000,000	4,739,668	22,512,947	3.32	4.75
25	Plant Unit Info	1,052	677,626	86.6%	94.9%	92.9%	6,995			4,739,668	22,512,947	3.32	
26	*Martin 8 Solar*												
27	Solar		11,278					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	11,278	20.2%		20.2%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		47,012					421,156	1,000,000	421,156	2,069,962	4.40	4.91
32	Plant Unit Info	239	47,012	26.4%	95.0%	95.0%	8,958			421,156	2,069,962	4.40	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		46,331					416,044	1,000,000	416,044	2,035,916	4.39	4.89
36	Plant Unit Info	239	46,331	26.1%	94.4%	95.0%	8,980			416,044	2,035,916	4.39	
37	*Sanford 4*												

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		547,338					3,858,615	1,000,000	3,858,615	18,322,824	3.35	4.75
2	Plant Unit Info	905	547,338	81.3%	95.8%	98.3%	7,050			3,858,615	18,322,824	3.35	
3	*Sanford 5*												
4	Gas		295,456					2,178,745	1,000,000	2,178,745	10,339,862	3.50	4.75
5	Plant Unit Info	901	295,456	44.1%	81.8%	83.4%	7,374			2,178,745	10,339,862	3.50	
6	*Scherer 4*												
7	Coal		347,643					209,417	17,000,010	3,560,091	8,218,500	2.36	39.24
8	Plant Unit Info	629	347,643	74.3%	93.8%	90.8%	10,241			3,560,091	8,218,500	2.36	
9	*St Johns 10*												
10	Coal		58,406					27,353	22,000,073	601,768	2,105,600	3.61	76.98
11	Plant Unit Info	124	58,406	63.3%	94.1%	63.3%	10,303			601,768	2,105,600	3.61	
12	*St Johns 20*												
13	Coal		65,052					29,866	21,999,665	657,042	2,299,000	3.53	76.98
14	Plant Unit Info	124	65,052	70.5%	94.0%	70.5%	10,100			657,042	2,299,000	3.53	
15	*St Lucie 1*												
16	Nuclear		711,622					7,514,567	1,000,000	7,514,567	5,251,600	0.74	0.70
17	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	5,251,600	0.74	
18	*St Lucie 2*												
19	Nuclear		609,333					6,369,659	1,000,000	6,369,659	4,568,800	0.75	0.72
20	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	4,568,800	0.75	
21	*Space Coast*												
22	Solar		1,684					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,684	22.6%		22.6%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		14,422					21,681	6,399,935	138,757	2,108,284	14.62	97.24
26	Gas		31,572					335,134	1,000,000	335,134	1,657,467	5.25	4.95
27	Plant Unit Info	378	45,994	16.4%	94.5%	80.1%	10,303			473,891	3,765,750	8.19	
28	*Turkey Point 3*												
29	Nuclear		586,125					6,560,405	1,000,000	6,560,405	5,120,200	0.87	0.78
30	Plant Unit Info	808	586,125	97.5%	97.8%	97.5%	11,193			6,560,405	5,120,200	0.87	
31	*Turkey Point 4*												
32	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,641,800	0.78	0.70
33	Plant Unit Info	819	594,101	97.5%	98.0%	97.5%	11,193			6,649,613	4,641,800	0.78	
34	*Turkey Point 5*												
35	Gas		572,984					3,993,957	1,000,000	3,993,957	19,160,368	3.34	4.80
36	Plant Unit Info	1,053	572,984	73.1%	82.6%	82.8%	6,970			3,993,957	19,160,368	3.34	
37	*WCEC 01*												

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		811,664					5,588,350	1,000,000	5,588,350	26,886,284	3.31	4.81
2	Plant Unit Info	1,219	811,664	89.5%	94.7%	89.5%	6,885			5,588,350	26,886,284	3.31	
3	*WCEC 02*												
4	Gas		817,923					5,634,468	1,000,000	5,634,468	27,343,810	3.34	4.85
5	Plant Unit Info	1,219	817,923	90.2%	94.7%	90.2%	6,889			5,634,468	27,343,810	3.34	
6	*WCEC 03*												
7	Gas		837,290					5,675,225	1,000,000	5,675,225	26,585,838	3.18	4.68
8	Plant Unit Info	1,219	837,290	92.3%	94.4%	92.3%	6,778			5,675,225	26,585,838	3.18	
9	**System Totals**												
10	Plant Unit Info	23,364	10,585,565				8,129			86,053,218	301,405,743	2.85	
11													
12													
13													
14													
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16													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Sep - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		799,314					5,261,193	1,000,000	5,261,193	25,036,797	3.13	4.76
5	Plant Unit Info	1,210	799,314	91.8%	94.7%	91.7%	6,582			5,261,193	25,036,797	3.13	
6	*Desoto Solar*												
7	Solar		4,325					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,325	24.0%		24.0%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		4,625					13,938	5,829,890	81,257	1,679,321	36.31	120.49
15	Plant Unit Info	648	4,625	1.0%	93.5%	29.7%	17,569			81,257	1,679,321	36.31	
16	*Fort Myers 2*												
17	Gas		116,600					880,297	1,000,000	880,297	4,258,867	3.65	4.84
18	Plant Unit Info	1,349	116,600	12.0%	25.2%	54.0%	7,550			880,297	4,258,867	3.65	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		33,220					364,448	1,000,000	364,448	1,779,363	5.36	4.88
22	Plant Unit Info	296	33,220	31.2%	95.1%	98.1%	10,971			364,448	1,779,363	5.36	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		1,675					26,321	1,000,000	26,321	128,483	7.67	4.88
26	Plant Unit Info	684	1,675	0.3%	93.5%	81.6%	15,710			26,321	128,483	7.67	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		106,104					868,167	1,000,000	868,167	4,241,273	4.00	4.89
30	Plant Unit Info	438	106,104	33.7%	94.6%	94.6%	8,182			868,167	4,241,273	4.00	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		111,101					907,688	1,000,000	907,688	4,441,341	4.00	4.89
34	Plant Unit Info	438	111,101	35.2%	94.1%	94.6%	8,170			907,688	4,441,341	4.00	
35	*Manatee 1*												
36	Heavy Oil		59,142					102,069	6,400,004	653,242	9,601,219	16.23	94.07
37	Gas		39,428					406,870	1,000,000	406,870	2,000,460	5.07	4.92

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	788	98,570	17.4%	96.9%	83.4%	10,755			1,060,112	11,601,678	11.77	
2	*Manatee 2*												
3	Heavy Oil		58,212					100,688	6,399,988	644,402	9,419,286	16.18	93.55
4	Gas		39,222					404,953	1,000,000	404,953	1,996,927	5.09	4.93
5	Plant Unit Info	788	97,434	17.2%	95.0%	85.3%	10,770			1,049,355	11,416,214	11.72	
6	*Manatee 3*												
7	Gas		705,812					4,834,856	1,000,000	4,834,856	23,426,280	3.32	4.85
8	Plant Unit Info	1,058	705,812	92.7%	94.9%	92.7%	6,850			4,834,856	23,426,280	3.32	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		32,698					48,450	6,400,000	310,080	4,464,909	13.65	92.15
15	Gas		78,160					874,250	1,000,000	874,250	4,285,839	5.48	4.90
16	Plant Unit Info	802	110,858	19.2%	95.0%	62.3%	10,683			1,184,330	8,750,749	7.89	
17	*Martin 3*												
18	Gas		120,119					896,158	1,000,000	896,158	4,334,713	3.61	4.84
19	Plant Unit Info	431	120,119	38.7%	94.3%	94.8%	7,461			896,158	4,334,713	3.61	
20	*Martin 4*												
21	Gas		112,735					840,052	1,000,000	840,052	4,063,293	3.60	4.84
22	Plant Unit Info	431	112,735	36.3%	94.8%	94.8%	7,452			840,052	4,063,293	3.60	
23	*Martin 8*												
24	Gas		550,823					3,877,795	1,000,000	3,877,795	18,782,510	3.41	4.84
25	Plant Unit Info	1,052	550,823	72.7%	94.9%	93.7%	7,040			3,877,795	18,782,510	3.41	
26	*Martin 8 Solar*												
27	Solar		9,794					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	9,794	18.1%		18.1%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		51,327					460,712	1,000,000	460,712	2,249,361	4.38	4.88
32	Plant Unit Info	239	51,327	29.8%	95.0%	95.0%	8,976			460,712	2,249,361	4.38	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		26,459					281,037	1,000,000	281,037	1,371,966	5.19	4.88
36	Plant Unit Info	239	26,459	15.4%	53.6%	51.0%	10,622			281,037	1,371,966	5.19	
37	*Sanford 4*												

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		384,510					2,747,634	1,000,000	2,747,634	13,294,958	3.46	4.84
2	Plant Unit Info	905	384,510	59.0%	95.8%	99.7%	7,146			2,747,634	13,294,958	3.46	
3	*Sanford 5*												
4	Gas		255,198					1,888,306	1,000,000	1,888,306	9,137,019	3.58	4.84
5	Plant Unit Info	901	255,198	39.3%	84.5%	84.8%	7,399			1,888,306	9,137,019	3.58	
6	*Scherer 4*												
7	Coal		365,534					220,167	16,999,991	3,742,837	8,635,800	2.36	39.22
8	Plant Unit Info	629	365,534	80.7%	93.8%	91.2%	10,239			3,742,837	8,635,800	2.36	
9	*St Johns 10*												
10	Coal		58,485					27,299	21,999,890	600,575	2,099,400	3.59	76.90
11	Plant Unit Info	124	58,485	65.5%	94.1%	65.5%	10,269			600,575	2,099,400	3.59	
12	*St Johns 20*												
13	Coal		63,628					29,175	21,999,623	641,839	2,243,700	3.53	76.90
14	Plant Unit Info	124	63,628	71.3%	94.0%	71.3%	10,087			641,839	2,243,700	3.53	
15	*St Lucie 1*												
16	Nuclear		665,710					7,029,762	1,000,000	7,029,762	4,912,800	0.74	0.70
17	Plant Unit Info	981	665,710	94.3%	94.3%	97.5%	10,560			7,029,762	4,912,800	0.74	
18	*St Lucie 2*												
19	Nuclear		589,677					6,164,182	1,000,000	6,164,182	4,421,400	0.75	0.72
20	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,453			6,164,182	4,421,400	0.75	
21	*Space Coast*												
22	Solar		1,492					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,492	20.7%		20.7%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		15,964					23,945	6,399,958	153,247	2,306,581	14.45	96.33
26	Gas		11,160					121,489	1,000,000	121,489	594,362	5.33	4.89
27	Plant Unit Info	378	27,124	10.0%	85.1%	89.7%	10,129			274,736	2,900,943	10.70	
28	*Turkey Point 3*												
29	Nuclear		567,218					6,348,776	1,000,000	6,348,776	4,955,000	0.87	0.78
30	Plant Unit Info	808	567,218	97.5%	97.8%	97.5%	11,193			6,348,776	4,955,000	0.87	
31	*Turkey Point 4*												
32	Nuclear		574,937					6,435,113	1,000,000	6,435,113	4,492,100	0.78	0.70
33	Plant Unit Info	819	574,937	97.5%	98.0%	97.5%	11,193			6,435,113	4,492,100	0.78	
34	*Turkey Point 5*												
35	Gas		684,949					4,718,934	1,000,000	4,718,934	22,945,112	3.35	4.86
36	Plant Unit Info	1,053	684,949	90.3%	94.9%	92.4%	6,889			4,718,934	22,945,112	3.35	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		785,325					5,408,174	1,000,000	5,408,174	26,239,421	3.34	4.85
2	Plant Unit Info	1,219	785,325	89.5%	94.7%	89.5%	6,887			5,408,174	26,239,421	3.34	
3	*WCEC 02*												
4	Gas		791,942					5,455,571	1,000,000	5,455,571	26,598,551	3.36	4.88
5	Plant Unit Info	1,219	791,942	90.2%	94.7%	90.2%	6,889			5,455,571	26,598,551	3.36	
6	*WCEC 03*												
7	Gas		811,166					5,498,992	1,000,000	5,498,992	26,239,360	3.23	4.77
8	Plant Unit Info	1,219	811,166	92.4%	94.4%	92.4%	6,779			5,498,992	26,239,360	3.23	
9	**System Totals**												
10	Plant Unit Info	23,364	9,687,789				8,240			79,829,207	286,677,773	2.96	
11													
12													
13													
14													
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ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Oct - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		808,202					5,323,299	1,000,000	5,323,299	25,124,918	3.11	4.72
5	Plant Unit Info	1,210	808,202	89.8%	94.7%	89.8%	6,587			5,323,299	25,124,918	3.11	
6	*Desoto Solar*												
7	Solar		4,176					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,176	22.5%		22.5%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		584					1,433	5,829,030	8,353	172,655	29.56	120.49
15	Plant Unit Info	648	584	0.1%	93.5%	15.0%	14,303			8,353	172,655	29.56	
16	*Fort Myers 2*												
17	Gas		193,218					1,493,926	1,000,000	1,493,926	7,142,577	3.70	4.78
18	Plant Unit Info	1,349	193,218	19.3%	46.5%	46.1%	7,732			1,493,926	7,142,577	3.70	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		22,195					243,547	1,000,000	243,547	1,198,650	5.40	4.92
22	Plant Unit Info	296	22,195	20.2%	95.1%	98.1%	10,973			243,547	1,198,650	5.40	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	684	0	0.0%	93.5%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		82,714					677,195	1,000,000	677,195	3,331,345	4.03	4.92
30	Plant Unit Info	438	82,714	25.4%	94.6%	94.4%	8,187			677,195	3,331,345	4.03	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		90,735					741,615	1,000,000	741,615	3,654,274	4.03	4.93
34	Plant Unit Info	438	90,735	27.8%	94.1%	94.6%	8,173			741,615	3,654,274	4.03	
35	*Manatee 1*												
36	Heavy Oil		24,234					42,224	6,399,986	270,233	3,949,560	16.30	93.54
37	Gas		16,592					171,264	1,000,000	171,264	845,692	5.10	4.94

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	788	40,826	7.0%	96.9%	76.2%	10,814			441,497	4,795,253	11.75	
2	*Manatee 2*												
3	Heavy Oil		10,526					18,060	6,399,945	115,583	1,689,310	16.05	93.54
4	Gas		7,017					72,508	1,000,000	72,508	358,396	5.11	4.94
5	Plant Unit Info	788	17,543	3.0%	95.0%	92.8%	10,721			188,091	2,047,706	11.67	
6	*Manatee 3*												
7	Gas		725,855					4,973,463	1,000,000	4,973,463	23,900,893	3.29	4.81
8	Plant Unit Info	1,058	725,855	92.2%	94.9%	92.2%	6,852			4,973,463	23,900,893	3.29	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		15,248					22,902	6,400,140	146,576	2,104,328	13.80	91.88
15	Gas		39,665					464,342	1,000,000	464,342	2,279,303	5.75	4.91
16	Plant Unit Info	802	54,913	9.2%	95.0%	49.6%	11,125			610,918	4,383,632	7.98	
17	*Martin 3*												
18	Gas		75,177					560,241	1,000,000	560,241	2,678,374	3.56	4.78
19	Plant Unit Info	431	75,177	23.4%	54.8%	94.8%	7,452			560,241	2,678,374	3.56	
20	*Martin 4*												
21	Gas		110,693					822,068	1,000,000	822,068	3,930,185	3.55	4.78
22	Plant Unit Info	431	110,693	34.5%	94.8%	94.8%	7,427			822,068	3,930,185	3.55	
23	*Martin 8*												
24	Gas		667,402					4,667,863	1,000,000	4,667,863	22,393,320	3.36	4.80
25	Plant Unit Info	1,052	667,402	85.3%	94.9%	92.6%	6,994			4,667,863	22,393,320	3.36	
26	*Martin 8 Solar*												
27	Solar		8,611					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	8,611	15.4%		15.4%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		37,019					332,186	1,000,000	332,186	1,632,331	4.41	4.91
32	Plant Unit Info	239	37,019	20.8%	95.0%	95.0%	8,973			332,186	1,632,331	4.41	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		16,579					180,313	1,000,000	180,313	886,976	5.35	4.92
36	Plant Unit Info	239	16,579	9.3%	47.2%	47.5%	10,876			180,313	886,976	5.35	
37	*Sanford 4*												

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		541,317					3,816,578	1,000,000	3,816,578	18,271,290	3.38	4.79
2	Plant Unit Info	905	541,317	80.4%	95.8%	97.9%	7,051			3,816,578	18,271,290	3.38	
3	*Sanford 5*												
4	Gas		356,448					2,558,560	1,000,000	2,558,560	12,254,873	3.44	4.79
5	Plant Unit Info	901	356,448	53.2%	94.8%	94.2%	7,178			2,558,560	12,254,873	3.44	
6	*Scherer 4*												
7	Coal		340,506					205,194	17,000,039	3,488,306	8,043,300	2.36	39.20
8	Plant Unit Info	629	340,506	72.8%	93.8%	89.5%	10,244			3,488,306	8,043,300	2.36	
9	*St Johns 10*												
10	Coal		49,677					23,780	22,000,042	523,161	1,836,600	3.70	77.23
11	Plant Unit Info	124	49,677	53.9%	94.1%	53.8%	10,531			523,161	1,836,600	3.70	
12	*St Johns 20*												
13	Coal		58,277					27,048	22,000,407	595,067	2,089,000	3.58	77.23
14	Plant Unit Info	124	58,277	63.2%	94.0%	63.2%	10,211			595,067	2,089,000	3.58	
15	*St Lucie 1*												
16	Nuclear		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	981	0	0.0%	0.0%	0.0%	0			0	0	0.00	
18	*St Lucie 2*												
19	Nuclear		609,333					6,369,659	1,000,000	6,369,659	4,568,800	0.75	0.72
20	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	4,568,800	0.75	
21	*Space Coast*												
22	Solar		1,438					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,438	19.3%		19.3%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	378	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Turkey Point 3*												
29	Nuclear		586,125					6,560,405	1,000,000	6,560,405	5,120,200	0.87	0.78
30	Plant Unit Info	808	586,125	97.5%	97.8%	97.5%	11,193			6,560,405	5,120,200	0.87	
31	*Turkey Point 4*												
32	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,641,800	0.78	0.70
33	Plant Unit Info	819	594,101	97.5%	98.0%	97.5%	11,193			6,649,613	4,641,800	0.78	
34	*Turkey Point 5*												
35	Gas		700,817					4,834,076	1,000,000	4,834,076	23,428,963	3.34	4.85
36	Plant Unit Info	1,053	700,817	89.5%	94.9%	91.5%	6,898			4,834,076	23,428,963	3.34	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		793,263					5,458,612	1,000,000	5,458,612	26,338,334	3.32	4.83
2	Plant Unit Info	1,219	793,263	87.5%	94.7%	87.5%	6,881			5,458,612	26,338,334	3.32	
3	*WCEC 02*												
4	Gas		806,193					5,549,172	1,000,000	5,549,172	26,866,649	3.33	4.84
5	Plant Unit Info	1,219	806,193	88.9%	94.7%	88.9%	6,883			5,549,172	26,866,649	3.33	
6	*WCEC 03*												
7	Gas		834,112					5,651,106	1,000,000	5,651,106	26,742,011	3.21	4.73
8	Plant Unit Info	1,219	834,112	92.0%	94.4%	92.0%	6,775			5,651,106	26,742,011	3.21	
9	**System Totals**												
10	Plant Unit Info	23,364	9,228,048				7,945			73,318,888	267,474,908	2.90	
11													
12													
13													
14													
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ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Nov - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		607,325					3,986,251	1,000,000	3,986,251	19,945,981	3.28	5.00
5	Plant Unit Info	1,355	607,325	62.3%	72.6%	82.4%	6,564			3,986,251	19,945,981	3.28	
6	*Desoto Solar*												
7	Solar		3,596					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,596	20.0%		20.0%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	383	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,179					3,675	5,830,476	21,427	442,783	37.56	120.49
15	Plant Unit Info	690	1,179	0.2%	93.5%	34.2%	18,174			21,427	442,783	37.56	
16	*Fort Myers 2*												
17	Gas		267,875					1,966,298	1,000,000	1,966,298	9,961,028	3.72	5.07
18	Plant Unit Info	1,440	267,875	25.8%	61.5%	66.2%	7,340			1,966,298	9,961,028	3.72	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		5,550					59,908	1,000,000	59,908	305,757	5.51	5.10
22	Plant Unit Info	314	5,550	4.9%	95.1%	98.1%	10,794			59,908	305,757	5.51	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	766	0	0.0%	93.5%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		25,065					203,908	1,000,000	203,908	1,040,771	4.15	5.10
30	Plant Unit Info	447	25,065	7.8%	94.6%	90.4%	8,135			203,908	1,040,771	4.15	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	447	0	0.0%	3.1%	0.0%	0			0	0	0.00	
35	*Manatee 1*												
36	Heavy Oil		11,355					19,512	6,399,856	124,874	1,753,445	15.44	89.86
37	Gas		10,022					104,607	1,000,000	104,607	532,959	5.32	5.09

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	798	21,377	3.7%	96.9%	57.0%	10,735			229,481	2,286,404	10.70	
2	*Manatee 2*												
3	Heavy Oil		7,855					13,877	6,400,014	88,813	1,369,709	17.44	98.70
4	Gas		5,237					53,769	1,000,000	53,769	274,466	5.24	5.10
5	Plant Unit Info	798	13,092	2.3%	95.0%	68.4%	10,891			142,582	1,644,176	12.56	
6	*Manatee 3*												
7	Gas		582,589					3,987,761	1,000,000	3,987,761	20,252,373	3.48	5.08
8	Plant Unit Info	1,117	582,589	72.4%	94.9%	91.7%	6,845			3,987,761	20,252,373	3.48	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		2,694					3,948	6,400,709	25,270	362,758	13.47	91.88
15	Gas		6,286					69,911	1,000,000	69,911	356,690	5.67	5.10
16	Plant Unit Info	808	8,980	1.5%	95.0%	69.5%	10,600			95,181	719,448	8.01	
17	*Martin 3*												
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	462	0	0.0%	0.0%	0.0%	0			0	0	0.00	
20	*Martin 4*												
21	Gas		52,716					388,223	1,000,000	388,223	1,965,496	3.73	5.06
22	Plant Unit Info	462	52,716	15.9%	94.8%	93.5%	7,364			388,223	1,965,496	3.73	
23	*Martin 8*												
24	Gas		612,749					4,227,860	1,000,000	4,227,860	21,430,087	3.50	5.07
25	Plant Unit Info	1,112	612,749	76.5%	89.4%	87.5%	6,900			4,227,860	21,430,087	3.50	
26	*Martin 8 Solar*												
27	Solar		4,308					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	4,308	8.0%		8.0%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		9,434					84,673	1,000,000	84,673	432,085	4.58	5.10
32	Plant Unit Info	248	9,434	5.3%	87.1%	86.5%	8,975			84,673	432,085	4.58	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		3,914					43,235	1,000,000	43,235	220,468	5.63	5.10
36	Plant Unit Info	248	3,914	2.2%	63.0%	43.8%	11,046			43,235	220,468	5.63	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		299,389					2,144,434	1,000,000	2,144,434	10,862,812	3.63	5.07
2	Plant Unit Info	955	299,389	43.5%	95.8%	93.0%	7,163			2,144,434	10,862,812	3.63	
3	*Sanford 5*												
4	Gas		207,493					1,496,219	1,000,000	1,496,219	7,580,878	3.65	5.07
5	Plant Unit Info	952	207,493	30.3%	94.8%	92.4%	7,211			1,496,219	7,580,878	3.65	
6	*Scherer 4*												
7	Coal		345,398					206,972	16,999,976	3,518,519	8,132,400	2.35	39.29
8	Plant Unit Info	635	345,398	75.6%	93.8%	86.2%	10,187			3,518,519	8,132,400	2.35	
9	*St Johns 10*												
10	Coal		40,067					19,469	21,999,743	428,313	1,503,600	3.75	77.23
11	Plant Unit Info	124	40,067	44.9%	94.1%	44.9%	10,690			428,313	1,503,600	3.75	
12	*St Johns 20*												
13	Coal		44,360					21,064	22,000,190	463,412	1,626,900	3.67	77.24
14	Plant Unit Info	124	44,360	49.7%	94.0%	49.7%	10,447			463,412	1,626,900	3.67	
15	*St Lucie 1*												
16	Nuclear		633,695					6,544,958	1,000,000	6,544,958	4,574,000	0.72	0.70
17	Plant Unit Info	1,003	633,695	87.8%	87.8%	97.5%	10,328			6,544,958	4,574,000	0.72	
18	*St Lucie 2*												
19	Nuclear		603,721					6,173,813	1,000,000	6,173,813	4,428,300	0.73	0.72
20	Plant Unit Info	860	603,721	97.5%	97.5%	97.5%	10,226			6,173,813	4,428,300	0.73	
21	*Space Coast*												
22	Solar		1,228					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,228	17.1%		17.1%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	380	0	0.0%	12.6%	0.0%	0			0	0	0.00	
28	*Turkey Point 3*												
29	Nuclear		584,765					6,356,602	1,000,000	6,356,602	4,961,100	0.85	0.78
30	Plant Unit Info	833	584,765	97.5%	97.8%	97.5%	10,870			6,356,602	4,961,100	0.85	
31	*Turkey Point 4*												
32	Nuclear		591,786					6,432,893	1,000,000	6,432,893	4,490,500	0.76	0.70
33	Plant Unit Info	843	591,786	97.5%	98.0%	97.5%	10,870			6,432,893	4,490,500	0.76	
34	*Turkey Point 5*												
35	Gas		443,948					3,092,876	1,000,000	3,092,876	15,765,692	3.55	5.10
36	Plant Unit Info	1,114	443,948	55.4%	94.9%	91.0%	6,967			3,092,876	15,765,692	3.55	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1	Gas		767,985					5,226,203	1,000,000	5,226,203	26,553,987	3.46	5.08
2	Plant Unit Info	1,335	767,985	79.9%	94.7%	80.9%	6,805			5,226,203	26,553,987	3.46	
3	WCEC 02												
4	Gas		806,986					5,498,434	1,000,000	5,498,434	27,731,060	3.44	5.04
5	Plant Unit Info	1,335	806,986	84.0%	94.7%	84.0%	6,814			5,498,434	27,731,060	3.44	
6	WCEC 03												
7	Gas		456,122					3,126,553	1,000,000	3,126,553	15,664,386	3.43	5.01
8	Plant Unit Info	1,335	456,122	47.5%	70.3%	72.8%	6,855			3,126,553	15,664,386	3.43	
9	**System Totals**												
10	Plant Unit Info	24,641	8,046,691				8,195			65,940,015	214,522,470	2.67	
11													
12													
13													
14													
15													
16													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Dec - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		796,375					5,231,007	1,000,000	5,231,007	26,568,402	3.34	5.08
5	Plant Unit Info	1,355	796,375	79.0%	94.7%	79.0%	6,569			5,231,007	26,568,402	3.34	
6	*Desoto Solar*												
7	Solar		3,265					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,265	17.6%		17.6%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	383	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	93.5%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		360,324					2,568,647	1,000,000	2,568,647	13,217,974	3.67	5.15
18	Plant Unit Info	1,440	360,324	33.6%	94.2%	90.3%	7,129			2,568,647	13,217,974	3.67	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		1,233					13,357	1,000,000	13,357	69,158	5.61	5.18
22	Plant Unit Info	314	1,233	1.1%	95.1%	98.1%	10,831			13,357	69,158	5.61	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	766	0	0.0%	93.5%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		28,005					225,452	1,000,000	225,452	1,167,714	4.17	5.18
30	Plant Unit Info	447	28,005	8.4%	94.6%	81.4%	8,050			225,452	1,167,714	4.17	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		15,899					128,809	1,000,000	128,809	667,069	4.20	5.18
34	Plant Unit Info	447	15,899	4.8%	82.0%	86.8%	8,102			128,809	667,069	4.20	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	798	0	0.0%	96.9%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	798	0	0.0%	95.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		460,112					3,170,581	1,000,000	3,170,581	16,362,188	3.56	5.16
8	Plant Unit Info	1,117	460,112	55.4%	94.9%	91.3%	6,891			3,170,581	16,362,188	3.56	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	808	0	0.0%	64.3%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	462	0	0.0%	39.5%	0.0%	0			0	0	0.00	
20	*Martin 4*												
21	Gas		56,820					416,947	1,000,000	416,947	2,143,930	3.77	5.14
22	Plant Unit Info	462	56,820	16.5%	94.8%	91.8%	7,338			416,947	2,143,930	3.77	
23	*Martin 8*												
24	Gas		607,254					4,175,367	1,000,000	4,175,367	21,496,419	3.54	5.15
25	Plant Unit Info	1,112	607,254	73.4%	94.9%	90.9%	6,876			4,175,367	21,496,419	3.54	
26	*Martin 8 Solar*												
27	Solar		3,564					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	3,564	6.4%		6.4%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		8,989					83,717	1,000,000	83,717	433,185	4.82	5.17
32	Plant Unit Info	248	8,989	4.9%	95.0%	72.5%	9,313			83,717	433,185	4.82	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		4,563					42,418	1,000,000	42,418	219,389	4.81	5.17
36	Plant Unit Info	248	4,563	2.5%	94.4%	73.6%	9,296			42,418	219,389	4.81	
37	*Sanford 4*												

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		263,918					1,883,556	1,000,000	1,883,556	9,688,024	3.67	5.14
2	Plant Unit Info	955	263,918	37.1%	95.8%	92.7%	7,137			1,883,556	9,688,024	3.67	
3	_Sanford 5_												
4	Gas		138,301					993,726	1,000,000	993,726	5,112,131	3.70	5.14
5	Plant Unit Info	952	138,301	19.5%	94.8%	92.5%	7,185			993,726	5,112,131	3.70	
6	_Scherer 4_												
7	Coal		311,998					186,484	17,000,005	3,170,229	7,333,100	2.35	39.32
8	Plant Unit Info	635	311,998	66.0%	93.8%	93.1%	10,161			3,170,229	7,333,100	2.35	
9	_St Johns 10_												
10	Coal		38,629					19,032	22,000,420	418,712	1,468,800	3.80	77.18
11	Plant Unit Info	124	38,629	41.9%	94.1%	41.9%	10,839			418,712	1,468,800	3.80	
12	_St Johns 20_												
13	Coal		41,701					20,173	21,999,752	443,801	1,556,800	3.73	77.17
14	Plant Unit Info	124	41,701	45.2%	94.0%	45.2%	10,642			443,801	1,556,800	3.73	
15	_St Lucie 1_												
16	Nuclear		727,574					7,514,567	1,000,000	7,514,567	5,251,600	0.72	0.70
17	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	5,251,600	0.72	
18	_St Lucie 2_												
19	Nuclear		623,845					6,379,606	1,000,000	6,379,606	4,575,900	0.73	0.72
20	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,226			6,379,606	4,575,900	0.73	
21	_Space Coast_												
22	Solar		1,086					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,086	14.6%		14.6%	0			0	0	0.00	
24	_Turkey Point 1_												
25	Heavy Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	380	0	0.0%	94.5%	0.0%	0			0	0	0.00	
28	_Turkey Point 3_												
29	Nuclear		604,258					6,568,489	1,000,000	6,568,489	5,126,500	0.85	0.78
30	Plant Unit Info	833	604,258	97.5%	97.8%	97.5%	10,870			6,568,489	5,126,500	0.85	
31	_Turkey Point 4_												
32	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,640,200	0.76	0.70
33	Plant Unit Info	843	611,511	97.5%	98.0%	97.5%	10,870			6,647,323	4,640,200	0.76	
34	_Turkey Point 5_												
35	Gas		385,253					2,684,060	1,000,000	2,684,060	13,869,342	3.60	5.17
36	Plant Unit Info	1,114	385,253	46.5%	94.9%	88.4%	6,967			2,684,060	13,869,342	3.60	
37	_WCEC 01_												

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		737,587					5,012,518	1,000,000	5,012,518	25,851,948	3.50	5.16
2	Plant Unit Info	1,335	737,587	74.3%	94.7%	78.7%	6,796			5,012,518	25,851,948	3.50	
3	*WCEC 02*												
4	Gas		805,267					5,476,523	1,000,000	5,476,523	28,214,436	3.50	5.15
5	Plant Unit Info	1,335	805,267	81.1%	94.7%	81.1%	6,801			5,476,523	28,214,436	3.50	
6	*WCEC 03*												
7	Gas		728,835					4,878,879	1,000,000	4,878,879	24,828,187	3.41	5.09
8	Plant Unit Info	1,335	728,835	73.4%	90.4%	88.6%	6,694			4,878,879	24,828,187	3.41	
9	**System Totals**												
10	Plant Unit Info	24,641	8,366,167				8,143			68,128,290	219,862,398	2.63	

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.		Jul - 2013	Aug - 2013	Sep - 2013	Oct - 2013	Nov - 2013	Dec - 2013	Jul:Dec - 2013
1	**#6 Heavy Oil (BBLS)**							
2	Purchases							
3	Units	0	255,000	145,000	0	0	0	400,000
4	Unit Cost	0.0000	97.3768	96.0864	0.0000	0.0000	0.0000	96.9090
5	Amount	$0	$24,831,082	$13,932,528	$0	$0	$0	$38,763,610
6	Burned							
7	Units	116,455	157,007	275,152	83,186	37,337	0	669,137
8	Unit Cost	92.8088	93.3017	93.4663	93.0830	93.3635	0.0000	93.2599
9	Amount	$10,808,051	$14,649,027	$25,717,445	$7,743,199	$3,485,913	$0	$62,403,634
10	Ending Inventory							
11	Units	2,801,231	2,899,224	2,769,072	2,685,886	2,648,549	2,648,549	2,648,549
12	Unit Cost	92.6609	93.0410	93.1582	93.1605	93.1577	93.1577	93.1577
13	Amount	$259,564,639	$269,746,694	$257,961,776	$250,218,578	$246,732,665	$246,732,665	$246,732,665
14	**#2 Light Oil (BBLS)**							
15	Purchases							
16	Units	60,848	13,905	19,950	0	150,000	0	244,703
17	Unit Cost	128.5550	132.3334	132.5602	0.0000	132.0769	0.0000	131.2551
18	Amount	$7,822,313	$1,840,096	$2,644,576	$0	$19,811,535	$0	$32,118,521
19	Burned							
20	Units	11,052	10,180	13,938	1,433	3,675	0	40,278
21	Unit Cost	119.3485	119.8378	120.4851	120.4851	120.4851	0.0000	120.0096
22	Amount	$1,319,040	$1,219,949	$1,679,321	$172,655	$442,783	$0	$4,833,747
23	Ending Inventory							
24	Units	1,300,500	1,300,500	1,300,500	1,299,067	1,445,392	1,445,392	1,445,392
25	Unit Cost	115.5428	115.6407	115.7701	115.7649	117.4457	117.4457	117.4457
26	Amount	$150,263,473	$150,390,678	$150,558,981	$150,386,326	$169,755,079	$169,755,079	$169,755,079
27	**Coal - SJRPP (TONS)**							
28	Purchases							
29	Units	60,168	57,218	56,473	50,829	40,532	39,204	304,424
30	Unit Cost	76.9346	76.9863	76.9040	77.2394	77.2229	77.1860	77.0603
31	Amount	$4,629,000	$4,405,000	$4,343,000	$3,926,000	$3,130,000	$3,026,000	$23,459,000
32	Burned							
33	Units	60,168	57,218	56,473	50,829	40,532	39,204	304,424
34	Unit Cost	76.9346	76.9863	76.9040	77.2394	77.2229	77.1860	77.0603
35	Amount	$4,629,000	$4,405,000	$4,343,000	$3,926,000	$3,130,000	$3,026,000	$23,459,000
36	Ending Inventory							
37	Units	91,000	91,000	91,000	91,000	91,000	90,999	90,999
38	Unit Cost	76.6593	76.6593	76.6593	76.6593	76.6593	76.6602	76.6602
39	Amount	$6,976,000	$6,976,000	$6,976,000	$6,976,000	$6,976,000	$6,976,000	$6,976,000
40								

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.		Jul - 2013	Aug - 2013	Sep - 2013	Oct - 2013	Nov - 2013	Dec - 2013	Jul:Dec - 2013
1	**Coal - Scherer (MMBTU)**							
2	Purchases							
3	Units	3,855,906	3,560,089	3,742,839	3,488,298	3,518,524	3,170,228	21,335,884
4	Unit Cost	2.3001	2.3084	2.3073	2.3057	2.3112	2.3131	2.3074
5	Amount	$8,869,000	$8,218,000	$8,636,000	$8,043,000	$8,132,000	$7,333,000	$49,231,000
6	Burned							
7	Units	3,855,906	3,560,089	3,742,839	3,488,298	3,518,524	3,170,228	21,335,884
8	Unit Cost	2.3001	2.3084	2.3073	2.3057	2.3112	2.3131	2.3074
9	Amount	$8,869,000	$8,218,000	$8,636,000	$8,043,000	$8,132,000	$7,333,000	$49,231,000
10	Ending Inventory							
11	Units	5,035,417	5,035,417	5,035,417	5,035,417	5,035,418	5,035,417	5,035,417
12	Unit Cost	2.3066	2.3066	2.3066	2.3066	2.3066	2.3066	2.3066
13	Amount	$11,614,941	$11,614,941	$11,614,941	$11,614,941	$11,614,941	$11,614,941	$11,614,941
14	**Gas (MCF)**							
15	Burned							
16	Units	52,395,885	53,075,883	47,023,895	48,591,932	35,761,121	36,985,563	273,834,279
17	Unit Cost	4.8424	4.7695	4.8368	4.8004	5.0579	5.1347	4.8875
18	Amount	$253,719,552	$253,145,418	$227,446,256	$233,259,354	$180,876,975	$189,909,498	$1,338,357,053
19	**Nuclear (Other)**							
20	Burned							
21	Units	27,094,244	27,094,244	25,977,833	19,579,677	25,508,266	27,109,985	152,364,249
22	Unit Cost	0.7228	0.7228	0.7230	0.7319	0.7235	0.7228	0.7241
23	Amount	$19,583,000	$19,583,000	$18,781,000	$14,331,000	$18,454,000	$19,594,000	$110,326,000
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FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	SOLD TO	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total $ for Fuel Adjustment (Col(4) * Col(5))	Total Cost ($) (Col(4) * Col(6))	Gain from Off System Sales ($)
1									
2	July Estimated								
3	Off System	OS	65,000	65,000	5.932	6.971	$3,855,900	$4,530,900	$516,250
4	St Lucie Reliability Sales		52,999	52,999	0.738	0.738	$391,207	$391,207	$0
5	**Total July Estimated**		117,999	117,999	3.599	4.171	$4,247,107	$4,922,107	$516,250
6									
7	August Estimated								
8	Off System	OS	75,000	75,000	5.914	6.934	$4,435,500	$5,200,500	$588,750
9	St Lucie Reliability Sales		52,999	52,999	0.738	0.738	$391,207	$391,207	$0
10	**Total August Estimated**		127,999	127,999	3.771	4.369	$4,826,707	$5,591,707	$588,750
11									
12	September Estimated								
13	Off System	OS	35,000	35,000	7.435	8.478	$2,602,150	$2,967,150	$278,750
14	St Lucie Reliability Sales		49,580	49,580	0.738	0.738	$365,968	$365,968	$0
15	**Total September Estimated**		84,580	84,580	3.509	3.941	$2,968,118	$3,333,118	$278,750
16									
17	October Estimated								
18	Off System	OS	40,000	40,000	4.480	5.493	$1,792,000	$2,197,000	$312,500
19	St Lucie Reliability Sales		0	0	0.000	0.000	$0	$0	$0
20	**Total October Estimated**		40,000	40,000	4.480	5.492	$1,792,000	$2,197,000	$312,500
21									
22	November Estimated								
23	Off System	OS	100,000	100,000	3.401	4.301	$3,400,500	$4,300,500	$675,000
24	St Lucie Reliability Sales		47,197	47,197	0.722	0.722	$340,729	$340,729	$0
25	**Total November Estimated**		147,197	147,197	2.542	3.153	$3,741,229	$4,641,229	$675,000
26									
27	December Estimated								
28	Off System	OS	190,000	190,000	2.762	3.656	$5,247,200	$6,947,200	$1,277,500
29	St Lucie Reliability Sales		54,189	54,189	0.722	0.722	$391,207	$391,207	$0
30	**Total December Estimated**		244,189	244,189	2.309	3.005	$5,638,407	$7,338,407	$1,277,500
31									
32	Period Total								
33	Off System	OS	505,000	505,000	4.224	5.177	$21,333,250	$26,143,250	$3,648,750
34	St Lucie Reliability Sales		256,964	256,964	0.732	0.732	$1,880,319	$1,880,319	$0
35	**Total Period Total**		761,964	761,964	3.047	3.678	$23,213,569	$28,023,569	$3,648,750
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	July Estimated					
3	UPS		253,643	253,643	3.725	$9,448,739
4	SJRPP		206,596	206,596	3.537	$7,308,000
5	St Lucie Reliability		45,379	45,379	0.754	$342,181
6	**Total July Estimated**		505,618	505,618	3.382	$17,098,920
7						
8	August Estimated					
9	UPS		238,070	238,070	3.685	$8,771,832
10	SJRPP		198,991	198,991	3.556	$7,076,000
11	St Lucie Reliability		45,379	45,379	0.754	$342,181
12	**Total August Estimated**		482,440	482,440	3.356	$16,190,014
13						
14	September Estimated					
15	UPS		270,887	270,887	3.660	$9,914,998
16	SJRPP		195,418	195,418	3.547	$6,932,000
17	St Lucie Reliability		43,920	43,920	0.754	$331,162
18	**Total September Estimated**		510,225	510,225	3.367	$17,178,160
19						
20	October Estimated					
21	UPS		216,942	216,942	3.691	$8,007,054
22	SJRPP		174,397	174,397	3.621	$6,315,000
23	St Lucie Reliability		45,379	45,379	0.306	$139,050
24	**Total October Estimated**		436,718	436,718	3.311	$14,461,104
25						
26	November Estimated					
27	UPS		93,686	93,686	3.900	$3,653,925
28	SJRPP		136,866	136,866	3.684	$5,042,000
29	St Lucie Reliability		44,965	44,965	0.738	$331,628
30	**Total November Estimated**		275,517	275,517	3.277	$9,027,553
31						
32	December Estimated					
33	UPS		82,813	82,813	3.976	$3,292,376
34	SJRPP		128,257	128,257	3.749	$4,808,000
35	St Lucie Reliability		46,464	46,464	0.738	$342,682
36	**Total December Estimated**		257,534	257,534	3.278	$8,443,059
37						
38	Period Total					
39	UPS		1,156,041	1,156,041	3.727	$43,088,923
40	SJRPP		1,040,525	1,040,525	3.602	$37,481,000
41	St Lucie Reliability		271,487	271,487	0.674	$1,828,885
42	**Total Period Total**		2,468,053	2,468,053	3.339	$82,398,809
43						
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	Transaction Cost (cents/KWH)	Total $ for Fuel Adj (Col(3) * Col(4))	Cost if Generated (cents/KWH)	Cost if Generated ($) (Col(3) * Col(6))	Fuel Savings ($) (Col(7) - Col(5))
1								
2	**July Estimated**							
3	Economy	OS	5,000	5.000	$250,000	7.210	$360,500	$110,500
4	Total July Estimated		5,000	5.000	$250,000	7.210	$360,500	$110,500
5								
6	**August Estimated**							
7	Economy	OS	10,000	5.000	$500,000	7.784	$778,400	$278,400
8	Total August Estimated		10,000	5.000	$500,000	7.784	$778,400	$278,400
9								
10	**September Estimated**							
11	Economy	OS	30,000	4.500	$1,350,000	9.237	$2,771,100	$1,421,100
12	Total September Estimated		30,000	4.500	$1,350,000	9.237	$2,771,100	$1,421,100
13								
14	**October Estimated**							
15	Economy	OS	35,000	3.500	$1,225,000	5.838	$2,043,300	$818,300
16	Total October Estimated		35,000	3.500	$1,225,000	5.838	$2,043,300	$818,300
17								
18	**November Estimated**							
19	Economy	OS	2,000	2.800	$56,000	4.121	$82,420	$26,420
20	Total November Estimated		2,000	2.800	$56,000	4.121	$82,420	$26,420
21								
22	**December Estimated**							
23	Economy	OS	2,000	2.200	$44,000	3.008	$60,160	$16,160
24	Total December Estimated		2,000	2.200	$44,000	3.008	$60,160	$16,160
25								
26	**Period Total**							
27	Economy	OS	84,000	4.077	$3,425,000	7.257	$6,095,880	$2,670,880
28	Total Period Total		84,000	4.077	$3,425,000	7.257	$6,095,880	$2,670,880
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APPENDIX II

CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP CALCULATION

TJK-4
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
August 2, 2013

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual
1	Payments to Non-cogenerators	$16,437,513	$16,618,240	$17,107,824	$16,482,672	$16,487,283	$16,076,979
2	Payments to Co-generators	$25,038,297	$25,205,917	$20,512,305	$23,359,041	$22,728,373	$23,148,194
3	SJRPP Suspension Accrual	$0	$0	($2,582,946)	($860,982)	($860,982)	($860,982)
4	Return on SJRPP Suspension Liability	($445,444)	($445,444)	($435,246)	($421,647)	($414,848)	($408,049)
5	Incremental Plant Security PSC Order No. 02-1761	$2,742,107	$3,070,332	$3,468,119	$3,248,334	$2,732,257	$3,485,081
6	Incremental Nuclear NRC Compliance Costs O&M	$25,179	$174,820	($37,256)	($3,346)	$23,650	($83,471)
7	Incremental Nuclear NRC Compliance Costs Capital	$0	$0	$0	$0	$0	$0
8	Transmission of Electricity by Others	$2,270,836	$2,203,512	$2,161,119	$1,343,872	$1,441,836	($627,741)
9	Transmission Revenues from Capacity Sales	($329,135)	($578,809)	($845,612)	($380,813)	($477,335)	($249,378)
10	Total (Lines 1 through 9)	$45,739,352	$46,248,567	$39,348,308	$42,767,130	$41,660,233	$40,480,632
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%
12	*Jurisdictional CCR*	*$44,810,990*	*$45,309,869*	*$38,549,663*	*$41,899,094*	*$40,814,664*	*$39,659,005*
13	Nuclear Cost Recovery Costs	$12,249,674	$14,229,199	$14,667,616	$13,013,524	$12,802,720	$12,659,892
14	Jurisdictional CCR	$57,060,664	$59,539,068	$53,217,280	$54,912,618	$53,617,383	$52,318,897
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
16	Prior Period True-up Provision	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)
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
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($9,674,797)	($15,174,600)	($8,433,814)	($6,629,673)	($314,124)	$4,536,218
19	Interest Provision for Month	($4,128)	($6,193)	($6,371)	($5,832)	($5,367)	($4,266)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($65,213,374)	($75,345,580)	($78,737,179)	($80,324,099)	($75,595,003)
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)
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
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($73,126,858)	($83,259,064)	($86,650,663)	($88,237,583)	($83,508,487)	($73,927,950)

	(1)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1	Payments to Non-cogenerators	$16,301,176	$16,214,757	$17,059,834	$16,492,116	$16,259,876	$16,286,036	$197,824,305
2	Payments to Co-generators	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$278,518,255
3	SJRPP Suspension Accrual	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return on SJRPP Suspension Liability	($405,660)	($398,786)	($391,912)	($385,038)	($378,164)	($371,291)	($4,901,530)
5	Incremental Plant Security PSC Order No. 02-1761	$3,239,994	$5,208,263	$5,387,066	$4,104,789	$4,317,518	$6,176,809	$47,180,669
6	Incremental Nuclear NRC Compliance Costs O&M	$2,404	($3,127)	$46,873	($3,127)	($3,127)	($56,471)	$83,000
7	Incremental Nuclear NRC Compliance Costs Capital	$0	$0	$0	$0	$0	$17,587	$17,587
8	Transmission of Electricity by Others	$1,488,962	$1,541,868	$1,399,703	$1,613,647	$2,021,776	$2,069,324	$18,928,713
9	Transmission Revenues from Capacity Sales	($158,750)	($176,250)	($86,250)	($92,500)	($225,000)	($422,500)	($4,022,332)
10	Total (Lines 1 through 9)	$42,694,832	$44,613,432	$45,642,019	$43,956,593	$44,219,584	$45,926,201	$523,296,883
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	N/A
12	*Jurisdictional CCR*	*$41,828,264*	*$43,707,922*	*$44,715,632*	*$43,064,414*	*$43,322,068*	*$44,994,046*	*$512,675,631*
13	Nuclear Cost Recovery Costs	$12,277,795	$12,200,448	$12,000,152	$11,888,604	$11,726,916	$11,774,862	$151,491,402
14	Jurisdictional CCR	$54,106,058	$55,908,370	$56,715,784	$54,953,018	$55,048,985	$56,768,908	$664,167,034
15	CCR Revenues (Net of Revenue Taxes)	$68,768,050	$68,299,950	$66,148,216	$61,684,870	$55,930,151	$54,654,912	700,752,785
16	Prior Period True-up Provision	($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)	$63,719,463	$63,251,364	$61,099,629	$56,636,284	$50,881,565	$49,606,325	$640,169,750
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	$9,613,405	$7,342,994	$4,383,845	$1,683,266	($4,167,420)	($7,162,583)	($23,997,284)
19	Interest Provision for Month	($3,330)	($2,654)	($2,108)	($1,704)	($1,514)	($1,545)	($45,013)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($66,014,466)	($51,355,804)	($38,966,878)	($29,536,555)	($22,806,407)	($21,926,755)	($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)
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	$60,583,035
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($59,269,288)	($46,880,362)	($37,450,039)	($30,719,891)	($29,840,239)	($31,955,780)	($31,955,780)

25 [a] As approved on Order No PSC-12-0664-FOF-EI

27 Totals may not add up due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL VARIANCES
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)
Line No.	CCR - Actual Estimated Variance	CCR - 2013 Actual/Estimated	CCR - 2013 Original Projection	Dif. CCR - 2013 Original Projection	% Dif. CCR - 2013 Original Projection
1	Payments to Non-cogenerators	$197,824,305	$199,776,283	($1,951,978)	(1.0%)
2	Payments to Co-generators	$278,518,255	$270,601,412	$7,916,842	2.9%
3	SJRPP Suspension Accrual	($10,331,784)	$935,844	($11,267,628)	(1,204.0%)
4	Return on SJRPP Suspension Liability	($4,901,530)	($5,304,459)	$402,929	(7.6%)
5	Incremental Plant Security PSC Order No. 02-1761	$47,180,669	$46,396,506	$784,163	1.7%
6	Incremental Nuclear NRC Compliance Costs O&M	$83,000	$0	$83,000	N/A
7	Incremental Nuclear NRC Compliance Costs Capital	$17,587	$0	$17,587	N/A
8	Transmission of Electricity by Others	$18,928,713	$18,402,144	$526,569	2.9%
9	Transmission Revenues from Capacity Sales	($4,022,332)	($1,209,884)	($2,812,448)	232.5%
10	Total (Lines 1 through 9)	$523,296,883	$529,597,847	($6,300,963)	(1.2%)
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	0.00000%	0.0%
12	Jurisdictional CCR	$512,675,631	$518,848,705	($6,173,074)	(1.2%)
13	Nuclear Cost Recovery Costs	$151,491,402	$151,491,402	$0	0.0%
14	Jurisdictional CCR	$664,167,034	$670,340,107	($6,173,074)	(0.9%)
15	CCR Revenues (Net of Revenue Taxes)	$700,752,785	$730,923,142	($30,170,357)	(4.1%)
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)	$640,169,750	$670,340,107	($30,170,357)	(4.5%)
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($23,997,284)	$0	($23,997,284)	0.0%
19	Interest Provision for Month	($45,013)	$0	($45,013)	N/A
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)	$0	($7,913,484)	N/A
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)	($31,955,780)	$0	($31,955,780)	0.0%

[a] As approved in order no PSC-12-0664-FOF-EI

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$6,814,592	$1,955,779	$2,416,515	$2,031,919	$0
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 [a]	$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	$6,814,592	$8,770,372	$11,186,886	$13,218,806	N/A
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,814,592	$8,770,372	$11,186,886	$13,218,806	N/A
6. Total Estimated Capital Expenditures Included in Base Rates [b]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
7. Base Rate Capital Expenditures Closed to Plant-in-Service [c]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
9. Adjusted Net Investment (Lines 5 - 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,185,408)	($1,229,628)	$1,186,886	$3,218,806	N/A
10. Average Net Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,202,846	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,713	$14,713
b. Debt Component (Line 10 x debt rate x 1/12) [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,874	$2,874
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	$17,587	$17,587

[a] Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

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

[c] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

[d] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2013 actual period is 4.8339% based on rate case Order No. PSC-13-0023-S-EI and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2013 estimated period is 4.9230% 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.

APPENDIX III

FUEL COST RECOVERY

2014 RISK MANAGEMENT PLAN

GJY-2
DOCKET NO. 130001-EI
FPL WITNESS: G. J. YUPP
August 2, 2013

Florida Power and Light Company
2014 Risk Management Plan

Florida Power & Light ("FPL") recognizes the importance of managing price volatility in the fuel and power it purchases to provide electric service to its customers. Further, FPL recognizes that the greater the proportion of a particular energy source it relies upon to provide electric services to its customers, the greater the importance of managing price volatility associated with that energy source.

FPL's risk management plan is based on the following guiding principles:

a) A well-managed hedging program does not involve speculation or market timing. Its primary purpose is not to reduce FPL's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs over time.

b) 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 the hedges were placed. FPL does not 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.

c) Market prices and forecasts of market prices have experienced significant volatility and are expected to continue to be highly volatile and, therefore, FPL does not intend to "outguess the market" in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged.

d) In order to balance the goal of reducing customers' exposure to rising fuel prices against the goal of allowing customers to benefit from falling fuel prices, it is appropriate to limit hedging to a portion of the total expected volume of fuel purchases.

Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)

FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel hedging strategy to achieve the goal of fuel price stability (volatility minimization). FPL's fuel hedging strategy aims to reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

Fuel Procurement Risks (TFB-4, Item 3)

FPL encounters several potential risks when executing its fuel procurement activities. These risks are grouped into four categories as detailed below:

Market Risk

Market Risk is the risk of changes in economic fair value due to fluctuations in market prices, volatility, correlation, and interest rates. Market risk has a direct impact on any open or unhedged energy positions.

Limits ("Limits") are set by the President and Chief Executive Officer ("CEO") of NextEra Energy ("NEE") and delegated to the Exposure Management Committee ("EMC"). The EMC establishes a forum for discussion of NEE's energy risk profile and operations and develops guidelines required for an appropriate risk management control infrastructure, which includes implementation and monitoring of compliance with the NextEra Energy Trading and Risk Management Policy ("Policy"). The EMC has in turn delegated limits to FPL Energy Marketing and Trading ("EMT") for specific portfolios.

Limits (collectively referred to as "Limits") are generally expressed in terms of:

- Maximum portfolio tenor; and
- Open (un-hedged) positions (where appropriate)

The FPL hedging program Limits will be managed in accordance with established corporate guidance. During the ordinary course of business, EMT management will have regard to these NEE Limits, such that pre-approval will be obtained before committing to transactions or contracts which might otherwise cause them to be breached. Adherence to Limits is monitored by the Risk Management Department.

Credit Risk

Credit risk management includes appropriate creditworthiness review and monitoring processes, the request for collateral if deemed necessary, and the inclusion of contractual risk mitigation terms and conditions whenever possible. Such credit risk mitigations include collateral threshold amounts, cross default amounts, payment netting, and set-off agreements. Credit Limits are typically established for trading transactions and are designed to manage counterparty credit risk; and set appropriate levels at which to trigger communication concerning risk and strategy.

During the ordinary course of business, EMT management adheres to these credit limits, such that pre-approval is obtained before committing to transactions or contracts which might otherwise cause the credit limits to be breached. Adherence to limits is monitored by the Risk Management Department, as well as dealmakers.

Liquidity Risk

Transacting Liquidity: The availability of market participants willing to transact or having credit quality to transact will have an impact on the utility's ability to execute hedging and risk management strategies.

Short-Term Funding Liquidity: Changes in underlying market parameters may impact movements of cash in relation to business activities. Positions that are balanced for fair value purposes, but unbalanced for cash flow purposes, may give rise to large swings in cash balances. Risk Management assists the Finance Department by analyzing and monitoring the sufficiency of the allocated portions of the corporate facilities as they relate to EMT liquidity requirements.

Operational Risk

Operating risk is the physical risk associated with maintaining and operating generation assets. The potential risks that FPL encounters with its physical fuel procurement are fuel supply and transportation availability, product quality, delivery timing, weather, environmental, and supplier failure to deliver.

There is also operational risk specific to the wholesale trading activities, relating to inaccurate records of assets and transactions ("Administrative Operational Risk"). Certain personnel are authorized to transact on behalf of FPL and in so doing, can obligate the entity "instantaneously." FPL maintains sufficient controls to ensure that information relating to commitments, obligations and assets are captured accurately, completely and on a timely basis.

Fuel Procurement Oversight/Policies and Procedures (TFB-4, Items 4, 5, 6, 7 and 9)

FPL provides its fuel procurement activities with independent oversight.

The President of FPL is responsible for authorizing all hedging activities. Changes in strategies and any deviations from the program are approved by the President of FPL or his designee prior to execution. Program activity is included in the Monthly Operations Performance Review ("MOPR") chaired by the CEO of NEE. In addition, the EMC reviews performance and current procurement/hedging activities on a monthly basis.

The utility is supported by an independent middle office Risk Management department that provides oversight of fuel procurement activities. FPL has formal Policy and Procedures documents, signed by all employees, which include controls specifically related to the fuels hedging program. The Risk Management department ensures that the approved execution strategies are followed for each program. Daily and monthly reports are generated and reviewed by the Risk Management department and distributed to various groups, including executive management. Credit reviews are performed by the Risk Management department and included in the reporting mentioned above. Execution strategies must be approved prior to the execution of any transactions and documented as a Planned Position Strategy ("PPS"). All hedge transactions are to be addressed within this strategy document per the ranges and percentages defined in the Risk Management Plan and may be modified from time to time.

Policy and Procedures

As part of this Risk Management Plan, FPL is attaching the latest Policy and Trading and Risk Management Procedures Manual ("Procedures"). NEE updates the Policy and Procedures as necessary. For details that are not covered in this document, please refer to the Policy and Procedures. FPL considers its Policy and Procedures to be confidential.

The NEE corporate risk Policy delineates individual and group transaction limits and authorizations for all fuel procurement activities. The Policy sets out the NEE approach to energy risk and the management of risk, as follows:

- Identification and definition;
- Quantification and measurements;
- Reporting;
- Authority to transact; and
- Ownership and roles and responsibilities.

The Procedures Manual provides guidance that will promote efficient and accurate processing of transactions, effective preparation and distribution of information relating to trading and marketing activities, and efficient monitoring of the portfolio of risks, all within a well-controlled environment.

FPL's deal execution and capture functions coordinate activities across relevant departments, personnel, and systems. This framework of activity properly links the responsibilities of personnel and provides a sufficient medium to resolve issues.

The Procedures clearly list authorized trading personnel, trading limits, tenors, and acceptable instruments. Access to the data entry privileges in the deal capture system is limited to only those individuals who are formally granted permissions to enter trades. All transactions are entered and managed through a centralized deal capture system that supports routine reporting, settlements, and review. Transaction record editing is managed through acceptable authorizations and processes. Credit information is available to traders on a timely basis through daily reporting produced by the Risk Management department. Auditable records of all transactions are maintained and subject to review on a regular basis.

Deal Execution Details

FPL traders receive daily credit reports and credit watch lists from the Risk Management department to ensure that FPL does not enter into a trade with an unauthorized counterparty. FPL traders then select counterparties from this list to transact with as the hedging program is executed. FPL uses a market comparison approach to execute financial hedges. For natural gas, real-time prices can be observed by FPL through electronic tools, such as ICE ("InterContinental Exchange"), FutureSource, or over-the-counter brokers.

FPL traders generally execute trades with counterparties offering the best price for a given instrument. However, in a case where two or more counterparties are offering similar pricing, the traders will attempt to execute trades with the counterparty that has the least amount of credit exposure with FPL. This is done primarily to allow FPL to spread its risk among as many counterparties as possible, but also affords the advantage of preventing the inadvertent telegraphing of FPL's commercial intentions to the market, thus helping to ensure favorable pricing for FPL's hedges.

<u>**2014 Hedging Strategy (TFB-4, Items 2 and 8)**</u>

FPL plans to hedge a portion of its projected 2015 natural gas requirements during 2014. Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions); FPL will implement its hedging program within the following parameters:

Natural Gas

1) FPL will hedge approximately [redacted] of its projected 2015 natural gas requirements within the Hedging Window during 2014. This hedge percentage is consistent with 2014 hedge levels and is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements.
2) FPL will utilize [redacted] to hedge its projected natural gas requirements.
3) FPL will execute its natural gas hedges for 2015 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2015 natural gas requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) FPL intends to rebalance its natural gas hedge positions during the year based on changes in forecasted market prices, projected unit outage schedules or changes in FPL's load forecast. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. The monthly tolerance bands for natural gas are [redacted]. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

Heavy Fuel Oil

FPL does not intend to hedge heavy fuel oil for 2015. FPL discontinued fuel oil hedging in 2013 and the factors that influenced that decision still remain.

<u>Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)</u>

FPL reporting systems comprehensively identify, measure, and monitor all forms of risk associated with fuel procurement activities.

FPL's philosophy on reporting is that it should be timely, consistent, flexible, and transparent. Timely and consistent reporting of risk information is critical to the effective management of risk. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, current and historical pricing database, deal information, valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

Specifically, several reports are available at FPL to monitor risk:

<u>Daily Management Report</u>

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details the current energy, spot and forward, unrealized profit and loss, VaR, and position amounts. This report is published only after proper and thorough discussion between Risk Management and desk heads, if necessary for clarification, and resolution of any issues raised.

<u>Credit Exposure Reporting</u>

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details:

- Allowable deal types by counterparty
- Restrictions on counterparties

<u>EMC Update</u>

The Vice President Trading Risk Management provides a formal update to the EMC on a monthly basis. The agenda for the update will be agreed in advance with the EMC Chairman, but at a minimum contains the following items:

- Summary and explanation of significant changes in market risk and fair value;
- Summary and explanation of significant changes in credit risk;
- Exceptions to Risk Management Policy; and

- Minutes of previous EMC update for approval.

Hedge Program Limitations (TFB-4, Item 15)

FPL does not currently have any limitations on implementing certain hedging techniques that would provide a net benefit to customers.

Summary Update on Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) on Utility Hedgers

FPL is monitoring the development of rules related to the Dodd-Frank Act and is actively implementing those rules that affect its business. A number of rules have already been finalized and have become or will become effective over the next few months.

FPL is classified as a bona-fide hedger under the new rules and therefore, FPL will be able to transact swaps in the over-the-counter market without being subject to the mandatory clearing. FPL has signed up for the ISDA protocol 2.0 that became effective on July 1' 2013. This protocol updates agreements between swap dealers and their counterparties with respect to the swap trading relationship documentation and clearing status.

FPL cannot predict the impact that all of these new rules will have on its ability to hedge its commodity risk or on the OTC derivatives market as a whole, but these rules could have a material effect on FPL's risk exposure and financial results. If the still-to-be-finalized margin rules require FPL to post significant amounts of cash collateral with respect to swap transactions, FPL's liquidity could be materially affected and its ability to enter into OTC derivatives to hedge commodity risks could be significantly limited.

Energy Marketing & Trading

A division of Florida Power & Light Company

Trading and Risk Management

Procedures Manual

Revision: June 2013

Approved By the EMC on January 2, 2013
(If the original signature is needed, please contact Risk Management at 304-6028)

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 60]

Trading and Risk Management Procedures Manual

APPROVED BY THE EMC ON:

Last approved on January 3, 2013

(See EMC Emails noting approval. Please contact Risk Management at 304-6028)

NextEra Energy, Inc.
Energy Trading and Risk Management Policy

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 26]

Energy Trading and Risk Management Policy

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 1 through 5]

Planned Position Strategy