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August 30, 2013

-VIA ELECTRONIC FILING -

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 130001-EI

Dear Ms. Cole:

I enclose for electronic filing in the above docket the prefiled testimony and exhibits of Florida Power and Light Company witnesses Gerard J. Yupp, Don Grissette and Terry J. Keith, as well as affidavits and supporting schedules of Tiffany Cohen and Kim Ousdahl.

Consistent with the directions provided by Staff to parties, FPL will deliver separately five (5) copies of the prefiled testimony and exhibits of the witnesses, as well as the affidavits and supporting schedules, to Martha Barrera, the lead Staff attorney for the above docket.

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

Sincerely,

s/ John T. Butler
John T. Butler

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

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 30, 2013

IN RE: LEVELIZED FUEL COST RECOVERY
AND CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2014 THROUGH DECEMBER 2014

TESTIMONY & EXHIBITS OF:

GERARD J. YUPP
DON GRISSETTE
TERRY J. KEITH

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 130001-EI

AUGUST 30, 2013

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power and purchased power transactions. I also review the interim results of FPL's 2013 hedging program and its 2014 Risk Management Plan. Additionally, I describe the Incremental Optimization Costs included in FPL's 2014 projection filing that are associated with the Incentive Mechanism that was approved in Order No. PSC-13-0023-S-EI, dated January 14, 2013. Lastly, I present the projected fuel savings resulting from the operation of the Riviera Beach Next Generation Clean Energy Center (RBEC) from June through December 2014.

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

A. Yes, I am sponsoring the following exhibits:

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

FUEL PRICE FORECAST

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

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

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2014 period?

A. The key factors that could affect FPL’s price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to their quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the supply and demand for heavy oil in the domestic market; (8) the terms of FPL's supply and fuel transportation contracts; and (9) domestic and global inventory.

Average heavy oil prices are forecasted to be slightly lower in 2014 compared with projected 2013 average levels primarily due to the assumed reduction in the global crude oil price. Crude oil prices are expected to remain strong over the next few months due to OPEC supply disruptions in Iraq and Libya, as well as a reduction in the inventories of the Organisation for Economic Co-operation and Development (OECD) member countries. This is despite a strong surge in non-OPEC supply and North American shale oil production that is expected to grow by 1.1 million barrels per day in 2013. The United States Strategic Petroleum Reserve will also act as a deterrent to prices moving up significantly in the short-term. By mid-

2014, oil inventories should stabilize as OPEC supply improves and North American supply growth continues. The International Energy Agency (IEA) anticipates non-OPEC supply to grow by 1.5 million barrels per day in 2014, of which North American shale oil is expected to contribute 0.9 million barrels per day. While projected growth in non-OECD demand of 1.4 million barrels per day should boost global demand in 2014, the increase in non-OPEC supply will help reduce the call on OPEC supply in 2014 and stabilize prices at a lower level. As always, an increase in geopolitical concerns could create upward pressure on oil prices.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2014 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors are similar to those described for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2014 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal for St. Johns' River Power Park (SJRPP) and Plant

Scherer?

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal, delivered to the plants.

Q. Please provide FPL's projection for the dispatch cost of coal at SJRPP and Plant Scherer for the January through December 2014 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by plant and by month, is shown on page 3 of Appendix I.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2014 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) LNG and Canadian natural gas imports; and (3) the terms of FPL's natural gas supply and transportation contracts.

Natural gas prices are projected to remain fairly stable throughout 2014. Although working natural gas rigs are down approximately 76% since the peak in August 2008 and 20% year-on-year, efficiency improvements in the shale regions are leading to record levels of production of natural gas. However, growth has slowed in 2013 and this trend will continue into 2014. Forecast lower 48 production growth of 0.5 - 1.0 BCF/day will be led by increased contributions from byproduct wet gas plays, while non-associated gas declines continue. Stronger residential/commercial demand, especially in the Northeast due to heating oil-to-natural gas switching and new gas pipelines, could partly mitigate lackluster gas demand for power generation and the slow pace of demand expansion from the industrial sector; nonetheless, year-on-year demand growth in 2014 is expected to be lower by approximately 0.6 BCF/Day. Natural gas storage levels, a key benchmark for supply/demand balance, are projected to be approximately 0.2 TCF higher, year-on-year, by the end of March 2014. Thereafter, narrower production gains, coupled with larger import losses, could pull storage back down to current levels.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2014 period?

A. The key factors mainly relate to the balance of gas transportation and demand in Florida, specifically, (1) the capacity of the Florida Gas Transmission (FGT) pipeline into Florida; (2) the capacity of the Gulfstream Natural Gas System (Gulfstream) pipeline into Florida; (3) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; and (4) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is approximately 3,100,000 MMBtu/day and the current capacity of Gulfstream is approximately 1,260,000 MMBtu/day. FPL's total firm transportation capacity on FGT ranges from 1,150,000 to 1,324,000 MMBtu/day, depending on the month. FPL has firm transportation capacity on Gulfstream of 695,000 MMBtu/day.

Additionally, FPL has firm transportation capacity on several upstream pipelines that provide FPL access to on-shore gas supply. FPL has 580,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline, 200,000 MMBtu/day of firm transport on the Transcontinental Pipe Line Gas Company, LLC (Transco) Zone 4A lateral, and 145,000 MMBtu/day (April through October) on the Gulf South Pipeline Company, LP (Gulf South) pipeline. The firm transportation on the SESH, Transco, and Gulf South pipelines does not increase transportation capacity into the state, however FPL's firm transportation rights on these pipelines provide access to 925,000 MMBtu/day of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2014 period, 30,000 MMBtu/day to 150,000 MMBtu/day of non-firm natural gas transportation capacity will be available into the state, depending on the month. FPL projects that it could acquire some of this capacity, if economic, to supplement FPL’s firm allocation on FGT and Gulfstream.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2014 period?

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

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

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

A. The projected Average Net Heat Rates were calculated by the POWRSYM model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to POWRSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2014?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2014.

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

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

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

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

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2014?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. FPL's customers benefit from both purchases and sales as savings on purchases and gains on sales are credited to customers through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction. Additionally, FPL is a member of the Florida Cost-Based Broker System (FCBBS). The FCBBS matches hourly cost-based bids and offers to maximize savings for all participants. Currently, the FCBBS is comprised of 11 members, including FPL. FPL can also purchase and sell power during emergency conditions under several types of Emergency Interchange agreements that are in place with other utilities within Florida.

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

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

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

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

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2014 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 278,500 MWh at a cost of $13,403,538. If FPL generated this energy, FPL estimates that it would cost $18,526,538. Therefore, these purchases are projected to result in savings of $5,123,000.

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

A. Yes. FPL purchases energy under three Unit Power Sales Agreements (UPS) with the Southern Companies. The agreements are comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 165 MW of coal generation (Scherer Unit 3). The UPS agreements have a term that runs through December 31, 2015. FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units. Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2014 period.

A. UPS energy purchases for the period are projected to be 1,875,616 MWh at an energy cost of $73,825,771. The UPS energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of SJRPP are projected to be 1,737,760 MWh for the period at an energy cost of $67,452,000. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 488,814 MWh at a cost of $3,045,725. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 2,940,405 MWh at a cost of $126,567,361.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the POWRSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

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

HEDGING/ RISK MANAGEMENT PLAN

Q. Please describe FPL's hedging objectives.

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

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

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

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

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

A. FPL's 2014 Risk Management Plan remains consistent with FPL's overall objectives that I previously described. It addresses Items 1-9 and 13-15 of Exhibit TFB-4, which is required per the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOF-EI dated October 30, 2002. FPL's 2014 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2014 for its projected natural gas requirements in 2015. FPL plans to hedge the percentages of its 2015 projected natural gas requirements over the time periods in 2014 that are described in the plan. As described in the plan, FPL discontinued heavy fuel oil hedging in 2013 and does not intend to execute hedges for its 2015 heavy fuel oil requirements.

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

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

Supplemental Report is included as Exhibit GJY-3.

Q. Have FPL's 2013 hedging strategies been successful in achieving FPL's hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers. At the time FPL was placing its hedges for its 2013 projected natural gas and heavy oil requirements, market prices were different than the actual settlement prices that have occurred in 2013.

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

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

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

INCREMENTAL OPTIMIZATION COSTS ASSOCIATED WITH THE INCENTIVE MECHANISM

Q. Is FPL seeking to recover through the FCR Clause projected incremental operating and maintenance expenses (Incremental Optimization Costs) during the January through December 2014 period with respect to implementing its program for expanded short-term wholesale purchases and sales, as well as asset optimization measures (the Incentive Mechanism) that was approved in Order No. PSC-13-0023-S-EI, dated January 14, 2013?

A. Yes. FPL has included projected Incremental Optimization Costs associated with the Incentive Mechanism in its projections for 2014.

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

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

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

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

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

A. FPL projects to incur incremental expenses related to variable power plant O&M of $1,722,910 in 2014. FPL projects to sell 1,655,000 MWh of economy power (Schedule E6) in 2014 which is 1,141,000 MWh above the 514,000 MWh of such sales that were projected in FPL's 2013 Test Year and used as a threshold for power sales in the Incentive Mechanism. Based on data provided as part of the 2013 Test Year projections, FPL has determined that its incremental variable power plant O&M cost is $1.51/MWh. Applying this rate to projected excess sales of 1,141,000 MWh above the threshold yields total variable power plant O&M of $1,722,910 in 2014.

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

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

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF RBEC

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

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

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

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

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DON GRISSETTE

DOCKET NO. 130001-EI

AUGUST 30, 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 Security organizations.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy (MMBtu) to be produced by our nuclear units and the costs of disposal of spent nuclear fuel. Both nuclear fuel and disposal of spent nuclear fuel costs were input values to the POWERSYM model that is used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2014 through December 2014. I am also updating the status of certain litigation that affects FPL’s nuclear fuel costs; plant security costs; new NRC requirements resulting from Fukushima; and outage events.

<u>Nuclear Fuel Costs</u>

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

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and current operating schedules, for the period January 2014 through December 2014.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2014 through December 2014.

A. FPL projects the nuclear units will produce 297,384,483 MMBtu of energy at a cost of $0.6383 per MMBtu, excluding spent fuel disposal costs, for the period January 2014 through December 2014.

Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 16.

Spent Nuclear Fuel Disposal Costs

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2014 through December 2014 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $26.1 million are provided in Appendix II, on Schedule E-2, starting on page 12. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9387 mills per net kWh generated, including transmission and distribution line losses.

Litigation Status Update

Q. Is there currently an unresolved dispute relating to the spent fuel disposal fee?

A. Yes. On June 1, 2012, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit ruled that the DOE failed to perform a valid evaluation of whether the spent fuel disposal fee should be adjusted in light of the Federal Government's decision not to develop the Yucca Mountain site as the disposal location for spent nuclear fuel from nuclear power plants. The Court did not grant the requested relief -- suspension of the fee -- but remanded the matter to DOE with directions to perform a valid evaluation of a potential fee adjustment within six months. The D.C. Circuit retained jurisdiction over the case so that any further review of DOE's revised analysis can be expedited. This ruling came in response to a petition filed by FPL and other utilities that was supported by a joint filing by this Commission and the Office of Public Counsel. DOE submitted a revised fee adequacy evaluation to the Court on January 16, 2013. On January 31, the National Association of Regulatory Utility Commissioners (NARUC) and Nuclear Energy Institute (NEI) filed a motion asking the Court to reopen the proceeding for review of the revised evaluation and to order the suspension of the fee as originally requested. The Court agreed to reopen the proceedings on February 27, 2013, and both parties have filed additional briefs as directed by the Court. Oral arguments are scheduled for September 25, 2013.

<u>Nuclear Plant Security Costs</u>

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2014 through December 2014?

A. FPL projects that it will incur $44.2 million in incremental nuclear power plant security costs in 2014. The costs consist of $7.0 million of capital expenditures and $37.2 million of O&M expenses.

Q. Please provide a brief description of the items included in this projection.

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

<u>Fukushima Costs</u>

Q. What is FPL's projection of Fukushima costs at FPL's nuclear power plants for the period January 2014 through December 2014?

A. FPL's current projection of Fukushima-related costs for 2014 is approximately $27.5 million of capital expenditures and $400,000 of

O&M expenses. These estimates are for total expenditures, reflecting both the amounts that were included in the 2013 base rate test year and the increments above those amounts. FPL witness Keith discusses the calculation of the 2014 Fukushima-related recovery amount that FPL seeks to include in the Capacity Clause.

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

A. FPL expects to pursue the following activities in 2014:

- Seismic Re-evaluation: FPL will compare current design basis curves to new Seismic Curves. FPL will also incur EPRI fees associated with seismic re-evaluations.
- Flooding Re-evaluation: FPL will complete a flooding integrated assessment based on re-evaluation results obtained in 2013.
- Station Black out Mitigation: FPL will implement its Station Black-out mitigation strategies. The implementation will include:
  - design and implementation of hardened storage for portable equipment
  - engineering and purchase of equipment to install low leakage Reactor Coolant Pump Seals in 2015 and 2016
  - purchase of portable equipment

- modifications to existing plant equipment that upgrades protection or provide a means to tie portable equipment into existing electrical and fluid systems
- procedure and training development and
- FPL's share of costs for the Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).

- Spent fuel Instrumentation: FPL will procure and install two new level instruments in each Spent Fuel Pool.
- Station Black-out preliminary staffing studies
- Emergency Preparedness facility and procedure upgrades
- Payment of NRC fees associated with these efforts

<u>2013 Outage Events</u>

St. Lucie

Q. Has FPL experienced any unplanned outages at St. Lucie Unit 1 in 2013?

A. Yes. In March 2013, Unit 1 automatically shut down due to the malfunction of the 1B Main Steam Isolation Valve (MSIV), which reduced steam flow to the secondary plant.

Q. What caused the malfunction of the MSIV?

A. Disassembly of 1B MSIV (HCV-08-1B,1B MSIV) revealed unexpected contact between the check valve and the valve body that is part of the MSIV. This prevented the valve, when open, from fully seating on the surfaces designed to absorb the forces from the valve actuator. Without the check valve fully seating, forces exceeding design loads were transmitted through the actuator linkage and caused the failure of the valve.

Q. What corrective actions have been initiated to address these events?

A. FPL replaced the damaged internal valve parts and eliminated the area of unexpected contact that caused the valve failure. Additionally, FPL revised the maintenance procedure and vendor manual to include steps to ensure the valve opens completely without contacting the valve body after any maintenance has been performed on it.

Q. How many days was St. Lucie Unit 1 out of service due to this issue?

A. The Unit 1 outage due to the MSIV was approximately 20 days.

Q. Has St. Lucie Unit 2 experienced any unplanned outages in 2013?

A. Yes. In May 2013, Unit 2 was operating at 88 percent power with the 2A2 Condenser Waterbox and 2A2 Circulating Water Pump removed from service due to a suspected condenser tube leak. During a very large algae intrusion event, the unit experienced high differential pressure on the debris filter for the 2A1 Condenser Waterbox, which required the 2A1 Circulating Water Pump to be removed from service as well. With both the 2A1 and 2A2 Circulating Water Pumps removed from service, FPL had to manually shut down the unit.

Q. What caused the high differential pressure on the debris filter system?

A. FPL determined internal binding of the flush water check valve caused a false low debris filter system (DFS) transmitter differential pressure. This false signal, in conjunction with a very large algae intrusion, prevented the DFS strainer from properly backwashing to avoid clogging of the DFS filter and resulted in the subsequent high differential pressure that led to manual shutdown of the unit.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. The flush water check valves were replaced with new check valves and a procedure for preventative maintenance checks was added to help ensure the check valves operate properly with no binding.

Additionally, FPL plans to replace the flush water check valves with a design that is not susceptible to similar binding and has a higher opening pressure.

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

A. The Unit 2 outage due to the 2A1 Condenser Waterbox was approximately 3 days.

Q. Has St. Lucie Unit 2 experienced any other unplanned outages in 2013?

A. Yes. In May, while Unit 2 was returning to service from the algae intrusion event, the turbine # 9 bearing experienced vibrations at levels that required FPL to manually shut down the unit.

Q. What caused the high vibrations in the turbine?

A. Prior to the shutdown, the turbine #9 bearing had been experiencing acceptable but higher than desired vibrations. To reduce the vibrations and thus optimize the long term health of the turbine, FPL installed an exciter balance weight on the turbine when the unit was offline for the algae intrusion event discussed above. As is often the case with turbine balancing, the initial adjustment did not resolve the vibration issue and it took several iterations before the vibration was reduced to acceptable levels that allowed the unit to return to service.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. In the future, to minimize the number of turbine balance adjustments needed, FPL revised the unit restart readiness procedure to include additional reviews of planned turbine balance adjustments. These reviews will be performed prior to unit shut down and performance of the balance adjustments. Performing outside technical reviews upfront will allow for improved accuracy in the calculations and less field adjustments should be needed.

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

A. The Unit 2 outage due to turbine # 9 bearing vibration was approximately 2 days.

<u>Turkey Point</u>

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2013?

A. Yes. In February 2013, Unit 3 automatically shut down due to an unexpected loss of condenser vacuum.

Q. What caused the loss of condenser vacuum?

A. The Gland Seal Spillover Control Valve CV-3-3725 was being bypassed in preparation for diagnostic testing. While executing the preparation for testing, the open bypass valve allowed a significant reduction in gland sealing steam pressure and a loss of main condenser vacuum. The main condenser vacuum declined to the system set point, which caused an automatic reactor and turbine shut down. The system responded as designed.

Q. What corrective actions has FPL initiated to avoid this problem in the future?

A. FPL revised guidelines to add additional steps for bypassing spillover valves to include additional communication with the control room and monitoring so as to reduce the possibility for automatic shutdowns when the condenser pressure is reduced.

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

A. The Unit 3 outage due to loss of condenser vacuum was approximately 3 days.

Q. Has Turkey Point Unit 3 experienced any other unplanned outages in 2013?

A. Yes. In February, Unit 3 was manually shut down due to a malfunction of the 3A Reactor Coolant Pump (RCP) #1 seal. During normal plant operations, leak-off from the RCP #1 seal increased to an unexpectedly high level that was not consistent with the 3B or 3C RCP seals. The seal leak-off increased to a level that required the 3A RCP to be secured, which mandates a manual unit shutdown per plant operating procedures. The seal leak-off must be maintained within the vendor recommended band to avoid damage to the seal.

Q. What caused the 3A RCP #1 seal malfunction?

A. The 3A RCP seal was disassembled, inspected and found to have a damaged #1 seal ring and runner O-ring. The damaged O-ring appeared to have been "pinched," which led to its degradation. The root cause has not been definitively established; however, FPL believes that conditions associated with the installation of the O-ring and preparation of contact surfaces between the RCP shoulder shaft and the seal by AREVA personnel during maintenance of the RCP in the prior outage likely contributed to the excessive seal leakage In addition, it has become clear that the design of the current seal makes it difficult to assemble properly and to verify proper assembly.

Q. What corrective actions has FPL initiated to avoid this problem in the future?

A. FPL and AREVA replaced the seal. Additionally, FPL revised the RCP seal maintenance and assembly procedure to include a hold point that ensures a check is performed any time a RCP shoulder shaft is machined. FPL also plans to replace all three RCP seals with a new seal design that is more robust and easier to maintain. This replacement will occur during the Fall 2015 outage that FPL will conduct in order to implement Fukushima response requirements.

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

A. The Unit 3 outage due to the RCP #1 seal malfunction was approximately 22 days.

Q. Has Turkey Point Unit 3 experienced any other unplanned outages in 2013?

A. Yes. In March, while Unit 3 was returning to service from the RCP seal event, the Turbine Lower Left Control Valve (LLCV) closed unexpectedly causing a loss of power. FPL manually shut down the turbine to investigate and perform repairs to the LLCV. The reactor was maintained at 3% power to support the LLCV repair. Following the repair, a reactor protection signal was initiated while testing the LLCV that caused an automatic shutdown of the reactor.

Q. What caused the manual shut down of the turbine and automatic shut down of the reactor?

A. The Turbine Control Valves are controlled by the new Turbine Control System (TCS) that was installed during the Extended Power Uprate (EPU) outage. Each Turbine Control Valve utilizes two Linear Variable Differential Transformers (LVDTs) that provide valve position feedback to the TCS. The TCS sends an electrical signal to the control valve to position them as required. FPL determined that one of the connectors contained in one LVDT for the #3 Turbine Control Valve was loose and the signal cable appeared to be burnt and discolored.

When the #3 Control Valve was stroked for post maintenance testing, steam entered the turbine through open upstream isolation valves (MSIVs), causing the steam pressure indicator to spike. The pressure indicator, sensing a steam pressure value that was consistent with power operation, activated the "At-Power" reactor trip programs in the Reactor Protection System, one of which functioned as designed to initiate an automatic reactor shutdown. .

Q. What corrective actions has FPL initiated to avoid these problems in the future?

A. To address the loose connector, the affected LVDT and cable were replaced and calibrated before returning to service. Additionally, FPL revised the applicable maintenance procedures to direct the use of dielectric gel to improve conductivity of the LVDT cable connections and protect them from exposure to outdoor elements.

To help avoid the type of automatic shutdown of the reactor that occurred during post-maintenance testing of the LVDT repair, a change to the Turbine Operating Procedure was made that requires the upstream isolation valves to be closed whenever testing of the Turbine Control Valves is performed.

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

A. The Unit 3 outage due to the Turbine # 3 control valve and reactor shut down was approximately 3 days.

Q. Has Turkey Point Unit 3 experienced any other unplanned outages in 2013?

A. Yes. In May, Unit 3 reduced power to 50% to perform repairs of the 3B Steam Generator Feed Pump (SGFP). After it was identified that the pump could not be isolated due to inlet isolation valve leakage, a unit shutdown was performed to facilitate safe access for disassembly of the 3B SGFP.

Q. What caused the 3B SGFP performance degradation?

A. FPL found that the 3B SGFP suction strainer had become disassembled while in service. Pieces became trapped inside of the 3B SGFP, adversely affecting its performance. Normally a SGFP can be taken out of service and isolated with the unit operating at reduced power, but a shutdown of Unit 3 was required due to 3B SGFP inlet isolation valve leakage. Failure of the 3B SGFP suction strainer required the unit to be reduced to below 50% power, but subsequently Unit 3 had to be taken offline due to the inability of the 3B SGFP inlet isolation valve to maintain a safe pressure boundary for workers repairing the suction strainer. The new suction strainers were installed on the 3A, 3B, 4A, and 4B SGFPs during the Unit 3 and Unit 4 EPU outages. Analysis determined that the installed strainers were not structurally sufficient for the service.

Q. What corrective actions has FPL initiated to avoid this problem in the future?

A. FPL removed the damaged strainer material from the 3A, 3B, and 4A SGFPs. FPL then permanently removed the suction strainers from the 3A, 3B, 4A, and 4B SGFPs to avoid the possibility of future problems with the strainers becoming disassembled while in service. FPL plans to repair the 3B SGFP inlet isolation valve in the spring 2014 refueling outage, which will allow adequate time to prepare for efficient implementation of the required scope of work and thus minimize the time the unit is offline for the repair.

Q. How many days was the Turkey Point Unit 3 outage due to this issue?

A. The Unit 3 outage due to the 3B SGFP was approximately 6 days.

Q. Has Turkey Point Unit 4 experienced any unplanned outages in 2013?

A. Yes. In April, while Unit 4 was shut down for the planned EPU outage, duration extensions associated with EPU modifications, post-maintenance testing, and several emergent component deficiencies delayed the restart of the unit.

Q. What caused the Unit 4 duration extensions?

A. The extensions were needed to address issues of the type that typically arise during one-time, first-of-their-kind implementations of major projects.

Q. Do these duration extensions indicate a problem with the implementation of those projects?

A. No. The EPU projects were one of the largest and most complex nuclear design, engineering and construction projects undertaken in the nuclear industry since the construction of the previous generation of U.S. nuclear plants. The long duration outages involved significant engineering, equipment modifications and upgrades, most of which have no industry counterparts. As with any projects of such extraordinary magnitude, one has to expect the unexpected, including the high likelihood that some task durations will require more time then anticipated.

Q. How many additional days was the Turkey Point Unit 4 out of service due to these implementation issues?

A. The Unit 4 outage extension was approximately 6 days. The extension is based on the revised outage schedule that was changed after the fuel projection filing was filed in Docket No. 120001-EI.

Q. Has Turkey Point Unit 4 experienced any other unplanned outages in 2013?

A. Yes. In April, while Unit 4 was in power ascension at 30% power from the planned EPU outage, Unit 4 automatically shut down while performing an electrical generator relay protection test (Harmonic Relay Ascension Testing).

Q. What occurred during the electrical generator relay protection testing that caused the unit to shut down?

A. The generator relay protection testing captures the performance of the new Unit 4 generator installed during the EPU outage at various power levels during power ascension. While performing the testing, a degraded voltage condition was created on the safety related 480V Load Centers, which initiated 4A and 4B 4kV bus stripping from the 4A and 4B sequencers. The 4A and 4B Emergency Diesel Generators automatically started in response to the condition and energized the 4A and 4B 4kV busses. The 4A and 4B Sequencers performed as designed and sequenced loads onto the 4A and 4B 4kV busses. As designed, the reactor automatically shut down due to the stripping of the Reactor Coolant Pumps off of the 4A and 4B 4kV busses.

Q. What corrective actions has FPL initiated to avoid this problem in the future?

A. Changes to risk recognition procedures were incorporated to explicitly identify the potential for Load Centers to be subject to degraded voltage conditions during testing and to spell out precautions that are to be taken to monitor Load Center voltage during any future generator testing that may be performed

Q. How many days was Turkey Point Unit 4 out of service due to this issue?

A. The Unit 4 outage due to the harmonic relay ascension testing was approximately 2 days.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 130001-EI

AUGUST 30, 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 what is your position?

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

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present a revised 2013 Fuel Cost Recovery (FCR) actual/estimated true-up amount, which has been updated to include July 2013 actual data and which is incorporated into the calculation of the 2014 FCR factors.
- I present FCR factors for the period January 2014 through May 2014 and June 2014 through December 2014 that reflect the Riviera Beach Next Generation Energy Center (RBEC) fuel savings in the period after the unit goes into service (projected

to be June 1, 2014). I also present for informational purposes, 2014 FCR factors based on the traditional factor calculation methodology, which spreads the fuel savings associated with RBEC over the entire calendar year.

- I present a revised 2013 Capacity Cost Recovery (CCR) actual/estimated true-up amount, which has been updated to include July 2013 actual data and which is incorporated into the calculation of the 2014 CCR factors.
- I present the CCR factors for the period January 2014 through December 2014. I also provide CCR factors for the period January 2014 through December 2014 including an adjustment to recover the projected non-fuel revenue requirements associated with West County Energy Center Unit 3 (WCEC-3) for the period January 2014 through December 2014, as approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.
- I present FPL's Nuclear Power Plant Cost Recovery amount to be recovered through the CCR Clause in 2014.
- I present for Commission review and approval through the CCR incremental NRC compliance costs resulting from the Fukushima Daiichi event.
- I present the WCEC-3 revenue requirement calculation for the January 2014 through December 2014 period.
- Finally, I provide on pages 76-77 of Appendix II FPL's

proposed COG tariff sheets, which reflect 2014 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten-year projection of FPL's annual generation mix and fuel prices.

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

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

TJK-5 (Appendix II)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 provide the calculation of FCR factors for January 2014 through May 2014, which exclude RBEC fuel savings.
- Schedule E1-A, a revised Schedule E1-B, which includes July 2013 actual data, Schedules E1-C, E1-D, and H1, which pertain to the entire 2014 calendar year.
- Pages 9 through 11, which provide the 2014 Projected Energy Losses by Rate Class.
- Pages 76 and 77, which provide updated COG tariff sheets.

TJK-6 (Appendix III)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 for the period June 2014 through December 2014, which include RBEC fuel savings.

TJK-7 (Appendix IV)

- Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 that provide the calculation of FCR factors for the period January 2014 through December 2014 based on the traditional factor calculation methodology, which spreads the RBEC fuel savings over the entire calendar year.

TJK-8 (Appendix V)

- Page 1 provides the calculation of the revised 2013 Actual/Estimated CCR True-Up amount, which includes July 2013 actual data.
- Pages 2 through 4 provide the calculation of the 2014 CCR factors.
- Pages 5 through 7 provide the calculation of depreciation and return on incremental power plant security and incremental nuclear NRC compliance capital investments.
- Pages 10 through 12 provide the calculation of the CCR factors that recover the non-fuel revenue requirements associated with WCEC-3 for the period January 2014 through December 2014.
- Page 13 provides the calculation of the 2014 CCR factors including the calculation of the non-fuel revenue requirements associated with WCEC-3 for the period January 2014 through December 2014.

TJK-9 (Appendix VI)

- Pages 1 and 2 provide the calculation of the WCEC-3 revenue requirement for January 2014 through December 2014.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2013 FCR Actual/Estimated True-up amount that was filed on August 2, 2013 to reflect July actual data?

A. Yes. The 2013 FCR actual/estimated true-up amount has been revised to an under-recovery of $143,214,959, reflecting July 2013 actual data, plus interest. This $143,214,959 under-recovery, plus the 2012 final true-up under-recovery of $4,550,654, results in a net under-recovery of $147,765,613 (see Schedule E1-b, Page 3, Appendix II). This $147,765,613 under-recovery is to be included in the FCR factor for the January 2014 through December 2014 period.

Q What adjustments are included in the calculation of the 2014 FCR factors shown on Schedules E1 included in Appendices II, III and IV?

A. The total net true-up to be included in the 2014 FCR factors is an under-recovery of $147,765,613. This amount, divided by the projected retail sales of 105,843,225 MWh for January 2014 through December 2014, results in an increase of 0.1396¢ per kWh before applicable revenue taxes, as shown on Line 26 of Schedule E1. The Generating Performance Incentive Factor (GPIF) testimony of witness J. Carine Bullock (adopted by FPL witness Charles Rote), filed on March 15, 2013 and revised on May 13, 2013, proposes a reward of $20,679,970 for the period ending December 2012. This $20,679,970 reward, divided by the projected retail sales of 105,843,225 MWh during the projected period, results in an increase of 0.0195¢ per kWh, as shown on line 30 of Schedule E1.

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2014 through December 2014.

A. In Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013, the Commission approved FPL's recovery of annualized revenue requirements associated with RBEC with the in-service date of the unit, which is projected for June 1, 2014. FPL proposes that the corresponding fuel savings associated with RBEC be reflected in fuel factors to become effective when the unit goes in-service. Implementing the fuel factors reflecting those savings concurrent with the step base rate increase better aligns costs with the fuel savings benefits, consistent with the past practice approved by the Commission when new units come into service during the year.

Q. What are the projected jurisdictional fuel savings associated with the RBEC from June 1, 2014 through the balance of 2014?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings for that period are $82,000,000. The jurisdictional portion of those fuel savings is $78,543,407. The calculation of this jurisdictional amount is shown on Page 2 of Appendix III.

Q. Has FPL calculated 2014 FCR factors reflecting the RBEC fuel savings commencing with the unit's in-service date?

A. Yes. FPL has prepared two E-1 Schedules to calculate average "Step

1" fuel factors to be applied during the period before RBEC goes into service, assumed to be January 2014 through May 2014, (Page 1 of Appendix II) and separate average "Step 2" fuel factors to be applied during the period after RBEC goes into service, assumed to be June 2014 through December 2014 (Page 1 of Appendix III).

Q. Please explain this calculation.

A. FPL first calculates the Step 1 fuel factors assuming RBEC is not operating in 2014, meaning that the total jurisdictional fuel savings are excluded from the calculation of the levelized fuel factor on both E-1 Schedules. This adjustment is shown on Line 2. This results in a levelized fuel factor of 3.383 cents per kWh for the period January 2014 through May 2014. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $30.67 during this period.

Next, FPL adjusts the Step 2 fuel factors for the period June 2014 through December 2014 by crediting the fuel savings associated with RBEC during this period. The total jurisdictional fuel savings of $78,543,407, divided by the projected sales for June 2014 through December 2014 of 65,556,788 MWh results in a downward adjustment of 0.1198 cents per kWh, including revenue taxes (Schedule E-1, Line 31, Page 1 of Appendix III). This downward adjustment results in a lower levelized FCR factor of 3.263 cents per kWh for the period June 2014 through December 2014, which reflects a reduction in the levelized fuel factor of 0.120 cents per kWh. For FPL's residential

1,000 kWh bill, this represents a fuel charge of $29.47 for this period.

Schedule E2 provides the monthly fuel factors and also the levelized FCR factor. Schedule E-1E provides the calculation of the FCR factors by rate group for each period.

Q. Has FPL also calculated levelized FCR factors that would apply uniformly throughout calendar year 2014?

A. Yes. Although FPL requests approval of its “Step 1” and “Step 2” FCR factors for 2014, FPL has also provided fuel factors using the traditional methodology for informational purposes. Appendix IV includes Schedules El, El-E, E2, RS-1 Inverted Rate Calculation and E10, which calculate a twelve-month levelized fuel factor of 3.308¢ per kWh, based on the traditional methodology. This twelve-month levelized fuel factor spreads the RBEC fuel savings throughout the twelve months of 2014.

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

A. Yes.

Q. Is FPL proposing to discontinue calculating its Time of Use (TOU) rates based on seasonal differentiation?

A. Yes. FPL has not found that TOU rates based on seasonal differentiation have been beneficial for its customers.

Q. Please explain.

A. In Order No. PSC-11-0216-PAA-EI, issued in Docket No. 100358-EI on May 11, 2011, the Commission directed FPL to investigate whether TOU fuel factors based on seasonal differentiation would benefit its customers. While FPL believed that its current methodology for calculating TOU fuel factors was reasonable, FPL nonetheless implemented TOU fuel factors based on seasonal differentiation in January 2012 to determine whether customers would change their usage patterns.

There was not a significant change in either usage or customer bills as a result of these seasonal differentiation factors. In addition, the use of seasonal differentiation factors, with multiple rate changes throughout the year, adds a layer of complexity to the billing process that, absent any identified customer benefits, should be eliminated. Therefore, FPL has calculated its 2014 TOU fuel factors based on marginal fuel costs with on-peak and off-peak fuel factors that will apply to the entire calendar year.

Schedule E1-D, Page 1 of 2 in Appendix II provides the calculation of FPL's TOU multipliers. FPL's TOU on-peak and off-peak multipliers are 1.431 and 0.816, respectively. These on-peak and off-peak multipliers are first applied to the levelized fuel factor to arrive at the average on-peak and off-peak TOU factors. Loss multipliers for each rate group are then applied to the average on-peak and off-peak TOU factors to arrive at the final TOU FCR factors for each rate group.

Schedule E1-D, Page 2 of 2 in Appendix II provides the calculation of TOU on-peak and off-peak multipliers of 1.839 and 0.851, respectively for the Seasonal Demand Time of Use Rider (SDTR).

Schedule E-1E, Page 1 of 2 in Appendices II and III presents 2014 FCR factors for FPL's non TOU and TOU rates. Schedule E-1E, Page 2 of 2 in Appendices II and III presents FPL's 2014 FCR factors for its SDTR rates.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2013 CCR Actual/Estimated True-up amount that was filed on August 2, 2013 to reflect July 2013 actual data?

A. Yes. The 2013 CCR actual/estimated true-up amount has been revised to an under-recovery of $25,357,191, reflecting July 2013 actual data, plus interest. This $25,357,191 under-recovery, plus the 2012 final true-up under-recovery of $7,913,484 results in a net under-recovery of $33,270,675 (see Page 1 of Appendix V). This $33,270,675 net under-recovery is to be included for recovery in the CCR factor for the January 2014 through December 2014 period.

Q. Have you prepared a summary of the requested capacity payments for the projected period of January 2014 through December 2014?

A. Yes. Page 2 of Appendix V provides this summary. Total Recoverable Capacity Payments for the period January 2014 through December 2014 are $535,688,312 (line 11). This $535,688,312 is then increased by the net under-recovery for 2012 and 2013 of $33,270,675 (line 14 plus line 15) and the Nuclear Power Plant Cost Recovery Clause amount of $43,461,246 (line 16) for which FPL has sought approval in Docket No. 130009-EI. The total CCR jurisdictional amount to be recovered in 2014, including taxes but excluding WCEC-3 revenue requirements is $587,166,525.

Q. When will the Commission approve FPL's Nuclear Power Plant Cost Recovery amount to be included in the CCR for 2014?

A. The Commission is scheduled to approve the Nuclear Power Plant Cost Recovery amount to be included in FPL's 2014 CCR factors at its October 1, 2013 Agenda Conference. If the Commission makes any changes to FPL's requested recovery amount of $43,461,246 on October 1, FPL will submit to the Commission, with copies to all parties, revised schedules showing the calculation of the 2014 CCR factors. Commission staff has been granted administrative authority to verify that the schedules are consistent with the Commission's vote on October 1, 2013.

Q. Are you proposing any changes to the recovery of capital costs associated with incremental power plant security?

A. Yes. Beginning in January 2014, instead of treating all costs as O&M, FPL is proposing to recover capital related incremental power plant security costs associated with new capital investments including return requirements on Construction Work in Progress (CWIP) consistent with the Company's normal accounting treatment. FPL will record capital costs in CWIP and recover a return on CWIP until investments are put in service, at which time FPL will recover depreciation expense and return on average net book value of the plant-in-service balance at FPL's overall weighted average cost of capital. This is consistent with the manner in which investments in capital projects are recovered and it better matches recovery of the assets with the period in which customers receive the benefit of those assets.

Q. Have you included in the calculation of your 2014 CCR factors any projected costs that are associated with Nuclear Regulatory Commission (NRC) compliance requirements resulting from the Fukushima Daiichi event?

A. Yes. FPL has included in the calculation of its 2014 CCR factors $256,000 of projected O&M costs and $1.4 million of projected return requirements for 2014 associated with Fukushima compliance. Projected 2014 O&M expenses of $400,000 less $144,000 of Fukushima compliance related O&M expenses included in FPL's base rates results in the $256,000 of incremental O&M included in the 2014 CCR factors. The $1.4 million represents return on CWIP, which is based on incremental 2014 capital investments of $27.5 million. This $27.5 million is the difference between projected 2014 capital expenditures of $37.5 and the $10.0 million included in FPL's base rates. The capital recovery schedule providing the calculation of 2014 return requirements is provided on page 7 of Appendix V.

A description of activities associated with FPL's 2014 Fukushima compliance cost projections are provided in the testimony of FPL witness Don Grissette. Previously, Mr. Grissette and I have explained in our 2013 actual/estimated true-up testimony why recovery of Fukushima compliance costs in the CCR is appropriate.

Q. What is the projected WCEC-3 jurisdictional non-fuel revenue requirement for the January 2014 through December 2014 period?

A. The projected jurisdictional non-fuel revenue requirement for January 2014 through December 2014 is $159,210,391. The calculation of this amount is shown in my Exhibit TJK-9, which is included in Appendix VI. Per Order No. PSC-13-0023-EI, issued in Docket No. 120015-EI on January 14, 2013 approving FPL's Settlement Agreement, the annual revenue requirement for WCEC-3 will continue to be recovered through the CCR but will no longer be limited to the projected annual fuel cost savings for WCEC-3. The $159,210,391 reflects the projected plant-in-service balance and operating expenses for WCEC-3 that were included in the determination of need for the unit in Docket No. 080203-EI, with the return on equity (ROE) of 10.5%, as approved in the Settlement Agreement.

Q. Have you provided a calculation of 2014 CCR factors by rate

class including an adjustment to recover the projected non-fuel revenue requirements associated with WCEC-3 for the period January 2014 through December 2014?

A. Yes. As approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013, FPL has included in Appendix VI the 2014 non-fuel revenue requirements of $159.2 million. Accordingly, Exhibit TJK-8, which is Appendix V to my testimony, shows the calculation of 2014 CCR factors including the projected non-fuel revenue requirements associated with WCEC-3 for the period January 2014 through December 2014.

Q. What is the total CCR jurisdictional amount to be recovered in 2014?

A. The total CCR jurisdictional amount to be recovered in 2014, including taxes and WCEC-3 revenue requirements is $746,376,916.

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

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

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

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2014 (cycle day 1, which will be January 2, 2014) and that they remain effective until cycle day 21 of December 2014, or until they are modified by the Commission. This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

Q. What is FPL's proposed preliminary residential 1,000 kWh bill for the period beginning January, 2014?

A. Based on FPL's requests in its cost recovery clause filings, its preliminary residential 1,000 kWh bill for January 2014 through May 2014 is $100.26. Of this amount, the base rate charges are $52.48, the FCR charge is $30.67, the CCR charge is $7.86, the Environmental charge is $2.30, the Conservation charge is $3.37, the Storm charge is $1.07 and the amount of Gross Receipts Tax is $2.51.

Once RBEC becomes operational, which is projected to be on June 1, 2014, FPL's base rate charges will increase to $54.88 and its FCR charge will decrease to $29.47. The base rate change reflects the application of a Generation Base Rate Adjustment ("GBRA") for RBEC consistent with the Stipulation and Settlement that was approved in Order No. PSC-13-0023-S-EI. Appendix VII contains the affidavit and supporting schedules of Kim Ousdahl, which present the base revenue requirement of $233.6 million for the first twelve months of operation for FPL's RBEC. Appendix VIII contains the affidavit of Tiffany Cohen and GBRA supporting schedules for RBEC. FPL's preliminary Residential 1,000 kWh bill for the period June 2014 through December 2014, including an increase in the amount of Gross Receipts Tax of $0.03, will be $101.49, which is an increase of $1.23, from its January 2014 through May 2014 bill. FPL's proposed preliminary Residential 1,000 kWh bills for 2014 are provided on Schedule E-10, which is page 7 of Exhibit TJK-6, Appendix III.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

FUEL COST RECOVERY

EXHIBIT GJY-4

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AUGUST 30, 2013

APPENDIX I

FUEL COST RECOVERY

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Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2014

Heavy Oil	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
0.7% Sulfur Grade ($/Bbl)	102.49	102.49	102.49	102.07	102.08	102.08	101.07	101.07	101.07	101.06	101.06	101.06
0.7% Sulfur Grade ($/mmBtu)	16.01	16.01	16.01	15.95	15.95	15.95	15.79	15.79	15.79	15.79	15.79	15.79
Light Oil	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
0.05% Sulfur Grade ($/Bbl)	139.20	138.88	138.16	137.35	136.67	135.99	135.58	135.24	135.06	134.85	134.53	134.21
0.05% Sulfur Grade ($/mmBtu)	23.88	23.82	23.70	23.56	23.44	23.33	23.26	23.20	23.17	23.13	23.08	23.02
Natural Gas Transportation	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Firm FGT (mmBtu/Day)	1,150,000	1,150,000	1,150,000	1,239,000	1,324,000	1,324,000	1,324,000	1,324,000	1,324,000	1,239,000	1,150,000	1,150,000
Firm Gulfstream (mmBtu/Day)	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000
Non-Firm FGT (mmBtu/Day)	100,000	100,000	100,000	100,000	75,000	30,000	30,000	30,000	30,000	75,000	100,000	100,000
Non-Firm Gulfstream (mmBtu/Day)	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	-	50,000	50,000
Total Projected Daily Availability (mmBtu/Day)	1,995,000	1,995,000	1,995,000	2,084,000	2,144,000	2,099,000	2,049,000	2,049,000	2,049,000	2,009,000	1,995,000	1,995,000
Southeast Supply Header (SESH)**	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000
Transcontinental Pipe Line (Transco)**	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Gulf South Pipeline Company (Gulf South)**	-	-	-	145,000	145,000	145,000	145,000	145,000	145,000	145,000	-	-
**Note: SESH,Transco and Gulf South firm transportation does not provide increased capacity to FPL's plants but does increase FPL's access to on-shore supply.												
Natural Gas Dispatch Price	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Firm FGT ($/mmBtu)	3.97	3.97	3.94	4.03	4.06	4.09	4.12	4.14	4.15	4.17	4.11	4.29
Firm Gulfstream ($/mmBtu)	3.92	3.92	3.89	3.98	4.00	4.03	4.07	4.08	4.09	4.11	4.06	4.23
Non-Firm FGT ($/mmBtu)	4.58	4.58	4.55	4.64	4.66	4.70	4.73	4.75	4.75	4.78	4.72	4.90
Non-Firm Gulfstream ($/mmBtu)	4.51	4.52	4.49	4.57	4.59	4.63	4.66	4.68	4.68	4.71	4.65	4.82
Coal	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Scherer ($/mmBtu)	2.29	2.31	2.32	2.31	2.32	2.33	2.36	2.39	2.41	2.41	2.42	2.43
SJRPP ($/mmBtu)	3.27	3.29	3.29	3.31	3.32	3.36	3.40	3.45	3.45	3.46	3.46	3.48

FLORIDA POWER AND LIGHT COMPANY
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2014

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral Energy Center	1.3	2.7	2.6	02/22/14 - 02/28/14	03/01/14 - 03/07/14 *			
Ft. Myers 2	0.8	4.0	4.5	11/01/14 - 11/07/14	11/08/14 - 11/14/14 *	11/15/14 - 11/21/14 *		
Ft. Myers 3	0.4	4.0	1.9	05/31/14 - 06/06/14 *	06/08/14 - 06/14/14 *			
Ft. Myers GTs	0.2	3.5	1.0					
Lauderdale 4	1.4	4.0	10.7	02/17/14 - 02/20/14	08/30/14 - 10/03/14			
Lauderdale 5	1.3	4.0	1.1	02/24/14 - 02/27/14				
Lauderdale GTs	0.2	3.5	1.0					
Manatee 1	0.6	4.0	2.7	11/15/14 - 11/24/14				
Manatee 2	1.3	4.0	11.5	02/15/14 - 03/28/14				
Manatee 3	0.9	4.0	9.1	05/23/14 - 06/14/14 *	05/27/14 - 06/18/14 *	05/30/14 - 06/17/14	06/11/14 - 07/03/14 *	07/07/14 - 08/05/14 *
Martin 1	0.5	4.0	38.6	01/01/14 - 05/21/14				
Martin 2	0.1	4.0	77.3	03/25/14 - 12/31/14				
Martin 3	1.1	4.0	1.9	10/18/14 - 10/24/14				
Martin 4	1.1	4.0	15.6	06/30/14 - 08/25/14				
Martin 8	1.0	4.0	1.9	02/15/14 - 02/21/14 *	03/08/14 - 03/21/14 *	03/22/14 - 03/28/14 *		
Port Everglades GTs	0.2	3.5	1.0					
Putnam 1	0.7	4.0	19.0	02/28/14 - 04/03/14	02/28/14 - 05/14/14 *	03/03/14 - 05/15/14 *		
Putnam 2	0.7	4.0	10.4	02/28/14 - 03/29/14	02/28/14 - 04/03/14	10/27/14 - 11/01/14 *		
Riviera 5	2.3	2.7	3.3	12/06/14 - 12/12/14				
Sanford 4	1.0	4.0	5.5	04/24/14 - 04/30/14 *	04/25/14 - 04/30/14	07/12/14 - 08/22/14 *	12/06/14 - 12/12/14 *	12/13/14 - 12/19/14 *
Sanford 5	1.0	4.0	3.3	06/07/14 - 06/13/14	06/07/14 - 06/16/14 *	11/08/14 - 11/17/14 *	11/15/14 - 11/21/14 *	
Scherer 4	1.8	4.0	15.9	02/22/14 - 04/20/14				
St. Johns 1	1.9	4.0	2.2	02/15/14 - 02/22/14				
St. Johns 2	1.7	4.0	15.9	03/01/14 - 04/27/14				
St. Lucie 1	1.2	1.2	0.0	NONE				
St. Lucie 2	1.1	1.1	9.3	03/03/14 - 04/06/14				
Turkey Point 1	0.6	4.0	2.7	12/08/14 - 12/17/14				
Turkey Point 3	1.1	1.1	9.0	03/17/14 - 04/19/14				
Turkey Point 4	1.1	1.1	9.9	09/24/14 - 10/30/14				
Turkey Point 5	0.9	4.0	15.6	02/01/14 - 03/02/14 *	02/15/14 - 02/26/14	02/15/14 - 03/16/14 *	04/25/14 - 06/29/14 *	11/17/14 - 12/07/14
West County 1	1.3	2.7	11.4	09/27/14 - 11/05/14 *	10/01/14 - 11/09/14 *	10/15/14 - 11/09/14	10/15/14 - 11/24/14 *	
West County 2	1.4	2.7	4.7	06/14/14 - 06/29/14 *	06/18/14 - 07/03/14 *	06/23/14 - 06/29/14	06/23/14 - 07/12/14 *	
West County 3	1.5	2.7	6.9	02/15/14 - 03/13/14 *	03/04/14 - 03/30/14 *	03/14/14 - 03/24/14		

* Partial Planned Outage

APPENDIX II
FUEL COST RECOVERY
2014 E-SCHEDULES

FOR THE PERIOD JANUARY 2014 THROUGH MAY 2014

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FUEL COST RECOVERY
2014 E SCHEDULES
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FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

	(1)	(2)	(3)	(4)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,248,141,556	112,677,379	2.8827
2	Riviera Beach Energy Center (RBEC) Savings	$82,000,000	112,677,379	0.0728
3	Nuclear Fuel Disposal Costs (E2)	$26,064,319	27,766,399	0.0939
4	TOTAL COST OF GENERATED POWER	$3,356,205,875	112,677,379	2.9786
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$144,323,495	4,102,190	3.5182
6	Energy Cost of Economy Purchases (E9)	$13,403,538	278,500	4.8128
7	Payments to Qualifying Facilities (E8)	$126,567,361	2,940,405	4.3044
8	TOTAL COST OF PURCHASED POWER	$284,294,395	7,321,095	3.8832
9	TOTAL AVAILABLE MWH (LINE 4 + LINE 8)		119,998,473	
10	Fuel Cost of Economy Sales (E6)	($65,345,750)	(1,655,000)	3.9484
11	Gain from Off-System Sales (E6)	($11,080,000)	N/A	N/A
12	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,342,565)	(629,817)	0.6895
13	TOTAL FUEL COST AND GAINS OF POWER SALES	($80,768,315)	(2,284,817)	3.5350
14	Incremental Personnel, Software, and Hardware Costs	$389,472	N/A	N/A
15	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,722,910	N/A	N/A
16	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,112,382	N/A	N/A
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 4 + 8 + 13 + 16)	$3,561,844,337	117,713,657	3.0259
18	Net Unbilled Sales (1)	($32,030,707)	(1,058,567)	(0.0289)
19	Company Use (1)	$10,685,533	353,141	0.0096
20	T & D Losses (1)	$231,519,882	7,651,388	0.2090
21	SYSTEM MWH SALES	$3,561,844,337	110,767,695	3.2156
22	Wholesale MWH Sales	$158,351,051	4,924,470	3.2156
23	Jurisdictional MWH Sales	$3,403,493,286	105,843,225	3.2156
24	Jurisdictional Loss Multiplier	$5,751,904		1.00169
25	Jurisdictional MWH Sales Adjusted for Line Losses	$3,409,245,189	105,843,225	3.2210
26	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$147,765,613	105,843,225	0.1396
27	TOTAL JURISDICTIONAL FUEL COST	$3,557,010,803	105,843,225	3.3606
28	Revenue Tax Factor	$2,561,048		1.00072
29	Fuel Factor Adjusted for Taxes	$3,559,571,851	105,843,225	3.3630
30	GPIF (2)	$20,679,970	105,843,225	0.0195
31	Fuel Factor including GPIF (Line 29 + Line 30)	$3,580,251,821	105,843,225	3.3825
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.383
33				
34	(1) For Informational Purposes Only			
35	(2) Calculation Based on Jurisdictional KWH Sales			
36				
37	Note: Totals may not add due to rounding.			
38				

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)

SCHEDULE: E1-A

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.		Annual Total
1	Actual/Estimated over/(under) recovery [1]	($143,214,959)
2	Final over/(under) recovery [2]	($4,550,654)
3	Total over/(under) recovery to be included in projected period [3]	($147,765,613)
4		
5	Total Jurisdictional Sales (MWH)	105,843,225
6		
7	True-Up Factor (cents/kWh)	(0.1396)
8		
9	[1] Actual/Estimated over/(under) recovery for January 2013 - December 2013	
10	[2] Final over/(under) recovery for January 2012 - December 2012	
11	[3] Projected Period January 2014 - December 2014 (Schedule E1, Line 26)	
12		
13	Note: Totals may not add due to rounding.	
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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

FOR THE 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 Actual	(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	$280,951,961	$301,405,743	$286,677,773	$267,474,908	$214,522,470	$219,862,398	$3,064,223,762
3	Nuclear Fuel Disposal Costs (Per A2)	$1,880,395	$1,417,734	$1,144,529	$1,819,397	$2,007,177	$2,256,251	$2,453,484	$2,341,856	$2,244,819	$1,675,564	$2,260,197	$2,403,658	$23,905,061
4	Scherer Coal Cars Depreciation & Return	$0	($181)	($46,136)	($207)	($416)	($416)	($53,299)	$0	$0	$0	$0	$0	($100,655)
5	Fuel Cost of Power Sold (Per A6)	($3,701,519)	($6,549,357)	($8,851,076)	($6,190,755)	($4,716,820)	($3,101,107)	($3,484,994)	($4,826,707)	($2,968,118)	($1,792,000)	($3,741,229)	($5,638,407)	($55,562,090)
6	Gains from Off-System Sales (Per A6)	($876,040)	($1,741,631)	($2,183,089)	($1,053,380)	($1,015,087)	($688,662)	($793,680)	($588,750)	($278,750)	($312,500)	($675,000)	($1,277,500)	($11,484,069)
7	Fuel Cost of Purchased Power (Per A7)	$7,594,732	$6,358,940	$3,174,645	$14,997,896	$15,862,340	$24,618,502	$21,479,018	$16,190,014	$17,178,160	$14,461,104	$9,027,553	$8,443,059	$159,385,962
8	Energy Payments to Qualifying Facilities (Per A8)	$1,679,537	$1,308,964	$6,001,429	$9,692,457	$10,992,302	$11,182,480	$9,314,906	$14,505,666	$15,353,663	$10,077,669	$5,485,671	$3,385,672	$98,980,415
9	Energy Cost of Economy Purchases (Per A9)	$98,806	$63,673	$148,556	$1,639,283	$121,100	$186,471	$137,962	$500,000	$1,350,000	$1,225,000	$56,000	$44,000	$5,570,851
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	$310,005,358	$329,527,820	$319,557,546	$292,809,745	$226,935,661	$227,222,880	$3,284,919,237
11														
12	**Incremental Optimization Costs**													
13	Incremental Personnel, Software, and Hardware Costs	$0	$0	$0	$20,622	$21,401	$28,231	$33,219	$32,288	$30,904	$33,672	$30,904	$32,288	$263,527
14	Variable Power Plant O&M Costs over 514,000 MW Threshold (Per A6)	$0	$0	$364,700	$315,395	$227,805	$125,549	$155,543	$113,250	$52,850	$60,400	$151,000	$286,900	$1,853,392
15	Total			364,700	336,017	249,206	153,780	188,762	145,538	83,754	94,072	181,904	319,188	2,116,919
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	$47,948	$0	$0	$0	$0	$0	$423,684
19	Inventory Adjustments	($106,047)	($4,083,681)	$168,325	($88,560)	($285,132)	($28,899)	($78,905)	$0	$0	$0	$0	$0	($4,502,899)
20	Non Recoverable Oil/Tank Bottoms	$0	($718,392)	$452,505	$0	$189	($189)	$1,663,517	$0	$0	$0	$0	$0	$1,397,630
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	$311,826,680	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,280,509,049
22	**Jurisdictional kWh Sales**													
23	Jurisdictional kWh Sales	7,684,412,091	7,108,916,875	6,977,292,798	7,671,972,198	8,616,263,762	9,110,063,405	9,724,266,549	10,080,997,264	9,763,403,645	9,104,618,770	8,255,228,566	8,067,004,659	102,164,440,582
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	189,064,624	209,487,317	208,827,684	192,550,041	174,526,607	149,677,379	2,070,531,997
25	Sub-Total Sales (excluding CKW)	7,833,108,641	7,261,852,856	7,120,357,143	7,825,567,833	8,788,056,229	9,286,376,772	9,913,331,173	10,290,484,581	9,972,231,329	9,297,168,811	8,429,755,173	8,216,682,038	104,234,972,579
26														
27	**Jurisdictional % of Total Sales (Line 23/25)**	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01359%
28	**True-up Calculation**													
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$235,363,510	$216,081,517	$211,924,637	$229,504,273	$251,555,289	$267,491,971	$287,935,348	$297,175,299	$287,813,033	$268,392,872	$243,353,902	$237,805,294	$3,034,396,944
30	**Fuel Adjustment Revenues Not Applicable to Period**													
31	Prior Period True-up (Collected)/Refunded This Period [3]	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$48,085,296
32	GPIF, Net of Revenue Taxes [4]	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,531)	($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	$291,300,926	$300,540,876	$291,178,610	$271,758,449	$246,719,479	$241,170,871	$3,074,783,875
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	$311,826,680	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,280,509,049
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01359%
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	$306,127,346	$323,223,665	$313,201,211	$287,069,941	$222,595,570	$223,578,045	$3,217,971,736
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)	($14,826,420)	($22,682,789)	($22,022,601)	($15,311,492)	$24,123,908	$17,592,827	($143,187,861)
38	Interest Provision for the Month	$2,912	$5,096	$4,722	$1,789	($1,335)	($3,612)	($4,579)	($5,118)	($6,218)	($7,164)	($7,147)	($6,445)	($27,098)
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)	($104,847,181)	($131,542,196)	($157,578,123)	($176,903,887)	($156,794,234)	$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)	($109,397,834)	($136,092,850)	($162,128,777)	($181,454,541)	($161,344,888)	($147,765,614)	($147,765,613)
43	% Net (Under)/Over Recovery													
44														

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

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

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

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

49 [5] Deferred 2012 Final True-up.

50

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR

SCHEDULE: E1-C

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	Annual Total
1. TOTAL AMOUNT OF ADJUSTMENTS	$168,445,583
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$20,679,970
B. TRUE-UP (OVER)/UNDER RECOVERED	$147,765,613
2. TOTAL JURISDICTIONAL SALES (MWH)	105,843,225
3. ADJUSTMENT FACTORS (cents/kWh)	0.1591
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0195
B. TRUE-UP FACTOR	0.1396

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF MARGINAL TIME OF USE MULTIPLIERS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	E1-D Schedule - Marginal	Jan - 2014	Feb - 2014	Mar - 2014	Apr - 2014	May - 2014	Jun - 2014	Jul - 2014	Aug - 2014	Sep - 2014	Oct - 2014	Nov - 2014	Dec - 2014	Total
1	Full Year (January - December)													
2	On-Peak Period													
3	System MWH Requirements	2,412,752	2,106,898	2,054,363	2,998,055	3,315,018	3,438,876	3,919,931	3,653,625	3,742,709	3,378,511	1,978,702	2,359,988	35,359,428
4	Marginal Cost	$81,719,910	$70,370,393	$61,610,346	$184,920,032	$138,468,302	$304,031,027	$360,516,054	$342,746,561	$329,470,673	$190,615,591	$63,239,316	$74,103,623	$2,201,811,830
5	Average Marginal Cost (¢/kWh)	3.387	3.340	2.999	6.168	4.177	8.841	9.197	9.381	8.803	5.642	3.196	3.140	6.227
6	Off-Peak Period													
7	System MWH Requirements	6,370,148	5,774,237	6,795,526	5,978,958	6,993,994	7,361,504	7,758,024	8,064,526	7,191,462	6,907,162	6,790,379	6,592,659	82,578,579
8	Marginal Cost	$181,421,815	$161,909,605	$228,601,495	$189,353,600	$224,157,508	$328,764,769	$330,026,341	$313,064,899	$318,366,023	$261,021,652	$201,470,545	$193,758,248	$2,931,916,499
9	Average Marginal Cost (¢/kWh)	2.848	2.804	3.364	3.167	3.205	4.466	4.254	3.882	4.427	3.779	2.967	2.939	3.550
10	Total Period													
11	System MWH Requirements	8,782,900	7,881,135	8,849,889	8,977,013	10,309,012	10,800,380	11,677,955	11,718,151	10,934,171	10,285,673	8,769,081	8,952,647	117,938,007
12	Marginal Cost	$263,141,725	$232,279,999	$290,211,841	$374,273,632	$362,625,810	$632,795,796	$690,542,395	$655,811,461	$647,836,696	$451,637,243	$264,709,861	$267,861,871	$5,133,728,329
13	Average Marginal Cost (¢/kWh)	2.996	2.947	3.279	4.169	3.518	5.859	5.913	5.597	5.925	4.391	3.019	2.992	4.353
14														
15	Full Year Multiplier													
16	On-Peak Period													
17	Marginal Fuel Cost Weighting Multiplier													1.431
18	Off-Peak Period													
19	Marginal Fuel Cost Weighting Multiplier													0.816
20	Average													
21	Marginal Fuel Cost Weighting Multiplier													1.000
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FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF TIME OF USE MULTIPLIERS FOR SEASONAL DEMAND TIME OF USE RIDER

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.		Jun - 2014	Jul - 2014	Aug - 2014	Sep - 2014	Total
1	June - September					
2	*On-Peak Period*					
3	System MWH Requirements	1,576,655	1,801,555	1,676,044	1,734,431	6,788,685
4	Marginal Cost	$143,617,504	$178,894,412	$175,230,400	$174,206,250	$671,948,565
5	Average Marginal Cost (¢/kWh)	9.109	9.930	10.455	10.044	9.898
6	*Off-Peak Period*					
7	System MWH Requirements	9,223,725	9,876,400	10,042,107	9,199,740	38,341,972
8	Marginal Cost	$449,564,357	$457,178,556	$424,078,179	$425,763,967	$1,756,585,058
9	Average Marginal Cost (¢/kWh)	4.874	4.629	4.223	4.628	4.581
10	*Total Period*					
11	System MWH Requirements	10,800,380	11,677,955	11,718,151	10,934,171	45,130,657
12	Marginal Cost	$593,181,860	$636,072,968	$599,308,579	$599,970,217	$2,428,533,624
13	Average Marginal Cost (¢/kWh)	5.492	5.447	5.114	5.487	5.381
14						
15	June - September Multiplier					
16	*On-Peak Period*					
17	Marginal Fuel Cost Weighting Multiplier					1.839
18	*Off-Peak Period*					
19	Marginal Fuel Cost Weighting Multiplier					0.851
20	*Average*					
21	Marginal Fuel Cost Weighting Multiplier					1.000
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24	Note: Totals may not add due to rounding.					
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FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

(1)	(2)	(3)	(4)	(5)
		JANUARY - DECEMBER		
GROUPS	RATE SCHEDULE	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	3.383	1.00293	3.067
A	RS-1 all additional kWh	3.383	1.00293	4.067
A	GS-1, SL-2, GSCU-1, WIES-1	3.383	1.00293	3.393
A-1	SL-1, OL-1, PL-1 [1]	3.093	1.00293	3.102
B	GSD-1	3.383	1.00284	3.393
C	GSLD-1, CS-1	3.383	1.00186	3.389
D	GSLD-2, CS-2, OS-2, MET	3.383	0.99253	3.358
E	GSLD-3, CS-3	3.383	0.96479	3.264
A	GST-1 On-Peak	4.841	1.00293	4.855
	GST-1 Off-Peak	2.761	1.00293	2.769
A	RTR-1 On-Peak	-	-	1.462
	RTR-1 Off-Peak	-	-	(0.624)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.841	1.00283	4.855
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.761	1.00283	2.769
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.841	1.00186	4.850
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.761	1.00186	2.766
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.841	0.99328	4.808
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.761	0.99328	2.742
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.841	0.96479	4.671
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.761	0.96479	2.664
F	CILC-1(D), ISST-1(D) On-Peak	4.841	0.99253	4.805
	CILC-1(D), ISST-1(D) Off-Peak	2.761	0.99253	2.740

[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	6.221	1.00284	6.239
	GSD(T)-1 Off-Peak	2.879	1.00284	2.887
C	GSLD(T)-1 On-Peak	6.221	1.00186	6.233
	GSLD(T)-1 Off-Peak	2.879	1.00186	2.884
D	GSLD(T)-2 On-Peak	6.221	0.99328	6.179
	GSLD(T)-2 Off-Peak	2.879	0.99328	2.860

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
2014 PROJECTED ENERGY LOSSES BY RATE CLASS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS(T)-1						
2	Secondary	55,468,625	1.058576	58,717,738	0.944666	3,249,113	
3	**Total**	55,468,625	1.058576	58,717,738	0.944666	3,249,113	1.00293
4							
5	CILC-1D						
6	Primary	1,042,588	1.028631	1,072,438	0.972165	29,851	
7	Secondary	1,801,565	1.058576	1,907,093	0.944666	105,528	
8	**Total**	2,844,152	1.047599	2,979,531	0.954564	135,379	0.99253
9							
10	CILC-1G						
11	Primary	1,750	1.028631	1,800	0.972165	50	
12	Secondary	190,631	1.058576	201,798	0.944666	11,166	
13	**Total**	192,381	1.058303	203,598	0.944909	11,216	1.00267
14							
15	CILC-1T						
16	Transmission	1,314,661	1.018323	1,338,750	0.982006	24,089	
17	**Total**	1,314,661	1.018323	1,338,750	0.982006	24,089	0.96479
18							
19	GS(T)-1						
20	Secondary	6,127,209	1.058576	6,486,115	0.944666	358,905	
21	**Total**	6,127,209	1.058576	6,486,115	0.944666	358,905	1.00293
22							
23	GSCU-1						
24	Secondary	24,089	1.058576	25,500	0.944666	1,411	
25	**Total**	24,089	1.058576	25,500	0.944666	1,411	1.00293
26							
27	GSD(T)-1						
28	Primary	86,102	1.028631	88,567	0.972165	2,465	
29	Secondary	25,680,281	1.058576	27,184,521	0.944666	1,504,240	
30	**Total**	25,766,383	1.058476	27,273,088	0.944755	1,506,705	1.00284
31							
32	GSLD(T)-1						
33	Primary	399,862	1.028631	411,311	0.972165	11,449	
34	Secondary	10,207,414	1.058576	10,805,320	0.944666	597,906	
35	**Total**	10,607,276	1.057447	11,216,631	0.945674	609,355	1.00186
36							
37	GSLD(T)-2						
38	Primary	840,414	1.028631	864,477	0.972165	24,062	
39	Secondary	1,631,363	1.058576	1,726,921	0.944666	95,558	
40	**Total**	2,471,777	1.048395	2,591,398	0.953839	119,620	0.99328
41							
42	GSLD(T)-3						
43	Transmission	177,469	1.018323	180,721	0.982006	3,252	
44	**Total**	177,469	1.018323	180,721	0.982006	3,252	0.96479
45							
46	MET						
47	Primary	92,674	1.028631	95,327	0.972165	2,653	
48	**Total**	92,674	1.028631	95,327	0.972165	2,653	0.97456
49							
50	OL-1						
51	Secondary	98,770	1.058576	104,556	0.944666	5,786	
52	**Total**	98,770	1.058576	104,556	0.944666	5,786	1.00293
53							
54	OS-2						
55	Primary	11,761	1.028631	12,098	0.972165	337	

FLORIDA POWER & LIGHT COMPANY
2014 PROJECTED ENERGY LOSSES BY RATE CLASS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	**Total**	11,761	1.028631	12,098	0.972165	337	0.97456
2							
3	SL-1						
4	Secondary	531,937	1.058576	563,096	0.944666	31,159	
5	**Total**	531,937	1.058576	563,096	0.944666	31,159	1.00293
6							
7	SL-2						
8	Secondary	32,554	1.058576	34,461	0.944666	1,907	
9	**Total**	32,554	1.058576	34,461	0.944666	1,907	1.00293
10							
11	SST-DST						
12	Primary	9,858	1.028631	10,140	0.972165	282	
13	**Total**	9,858	1.028631	10,140	0.972165	282	0.97456
14							
15	SST-TST						
16	Transmission	88,606	1.018323	90,229	0.982006	1,624	
17	**Total**	88,606	1.018323	90,229	0.982006	1,624	0.96479
18							
19	Total Retail						
20	**Total**	105,860,183	1.057272	111,922,976	0.945831	6,062,793	1.00169
21							
22	FKEC						
23	Transmission	772,116	1.018323	786,264	0.982006	14,148	
24	**Total**	772,116	1.018323	786,264	0.982006	14,148	0.96479
25							
26	SEMINOLE						
27	Transmission	430,534	1.018323	438,423	0.982006	7,889	
28	**Total**	430,534	1.018323	438,423	0.982006	7,889	0.96479
29							
30	LCEC						
31	Transmission	3,787,145	1.018323	3,856,538	0.982006	69,393	
32	**Total**	3,787,145	1.018323	3,856,538	0.982006	69,393	0.96479
33							
34	WAUCHULA						
35	Transmission	65,911	1.018323	67,118	0.982006	1,208	
36	**Total**	65,911	1.018323	67,118	0.982006	1,208	0.96479
37							
38	Blountstown						
39	Transmission	40,814	1.018323	41,562	0.982006	748	
40	**Total**	40,814	1.018323	41,562	0.982006	748	0.96479
41							
42	Total Wholesale						
43	**Total**	5,096,520	1.018323	5,189,905	0.982006	93,385	0.96479
44							
45	Total Company						
46	**Total**	110,956,703	1.055483	117,112,881	0.947434	6,156,178	1.00000
47							
48	Company Use						
49	**Total**	129,213	1.058576	136,782	0.944666	7,569	1.00293
50							
51	Total FPL						
52	**Total**	111,085,916	1.055486	117,249,663	0.947431	6,163,747	1.00000
53							
54							
55							

FLORIDA POWER & LIGHT COMPANY
2014 PROJECTED ENERGY LOSSES BY RATE CLASS GROUP

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RATE CLASS GROUPS	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	GSD1/GSDT1/HLFT1	25,766,383	1.058476	27,273,088	0.944755	1,506,705	1.00284
2	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,607,276	1.057447	11,216,631	0.945674	609,355	1.00186
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,471,777	1.048395	2,591,398	0.953839	119,620	0.99328
4	GSLD3/GSLDT3/CS3/CST3	177,469	1.018323	180,721	0.982006	3,252	0.96479
5	CILC D/CILC G	3,036,534	1.048277	3,183,129	0.953946	146,595	0.99317
6	OL1/SL1/PL1	630,708	1.058576	667,652	0.944666	36,944	1.00293
7	SL2, GSCU1	56,643	1.058576	59,961	0.944666	3,318	1.00293
8	GSD-1/GSDT-1/HLFT-1/SDTR-1/CILC-1G	25,958,764	1.058474	27,476,686	0.944756	1,517,922	1.00283
9	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	2,576,212	1.047593	2,698,822	0.954569	122,611	0.99253
10	GSLD-3/GSLDT-3/CS-3/CST-3/CILC-1T	1,492,131	1.018323	1,519,471	0.982006	27,341	0.96479
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) January Estimated	(3) February Estimated	(4) March Estimated	(5) April Estimated	(6) May Estimated	(7) June Estimated	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) 12 Month Period
1	Fuel Cost of System Generation	$233,108,385	$213,044,367	$257,918,712	$259,343,506	$279,253,240	$295,856,825	$321,498,280	$321,451,323	$298,810,379	$291,192,917	$233,978,087	$242,685,535	$3,248,141,556
2	Nuclear Fuel Disposal	2,409,819	2,176,613	1,587,537	1,860,399	2,347,859	2,272,121	2,347,859	2,347,859	2,146,193	1,826,155	2,332,085	2,409,819	26,064,319
3	RBEC Fuel Savings	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	82,000,000
4	Fuel Cost of Power Sold	(5,739,770)	(9,106,079)	(10,893,920)	(7,980,423)	(5,760,820)	(5,833,323)	(6,602,020)	(4,047,920)	(1,737,073)	(1,970,620)	(3,479,923)	(6,536,420)	(69,688,315)
5	Gain on Economy Sales	(993,750)	(1,657,500)	(1,948,750)	(1,193,750)	(901,250)	(650,000)	(823,750)	(565,000)	(203,750)	(290,000)	(637,500)	(1,215,000)	(11,080,000)
6	Fuel Cost of Purchased Power	9,032,496	8,624,221	9,398,040	9,481,790	13,524,421	15,397,625	16,147,779	15,798,587	16,191,274	13,504,351	8,721,822	8,501,088	144,323,495
7	Qualifying Facilities	9,945,865	8,880,867	10,309,866	5,997,865	10,849,865	13,256,860	14,016,861	13,746,860	13,771,859	9,839,862	6,976,866	8,973,866	126,567,361
8	Energy Cost of Economy Purchases	197,461	85,278	86,206	519,450	155,794	3,005,537	3,824,412	2,947,914	1,805,718	715,344	29,606	30,818	13,403,538
9	Total Fuel & Net Power Transactions	$254,793,840	$228,881,101	$273,291,024	$274,862,170	$306,302,441	$330,138,979	$357,242,754	$358,512,956	$337,617,933	$321,651,343	$254,754,376	$261,683,039	$3,559,731,955
10														
11	Incremental Personnel, Software and Hardware Costs	33,432	29,280	31,536	32,961	32,961	31,536	34,387	31,536	32,961	34,387	30,110	34,387	389,472
12	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	0	326,160	279,350	203,850	128,350	143,450	105,700	37,750	60,400	151,000	286,900	1,722,910
13	Total	33,432	29,280	357,696	312,311	236,811	159,886	177,837	137,236	70,711	94,787	181,110	321,287	2,112,382
14	Adjusted Total Fuel & Net Power Transactions	254,827,272	228,910,381	273,648,719	275,174,481	306,539,252	330,298,864	357,420,590	358,650,191	337,688,644	321,746,129	254,935,486	262,004,326	3,561,844,337
15														
16	System MWH Sales	8,985,918	7,947,739	7,864,510	7,931,770	9,091,100	9,818,071	10,760,888	10,705,544	10,396,265	9,730,435	8,866,980	8,668,474	110,767,695
17														
18	Cost per KWH (¢/KWH)	2.8359	2.8802	3.4795	3.4693	3.3719	3.3642	3.3215	3.3501	3.2482	3.3066	2.8751	3.0225	3.2156
19	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
20	Jurisdictional Cost (¢/KWH)	2.8406	2.8851	3.4854	3.4751	3.3776	3.3699	3.3271	3.3558	3.2537	3.3122	2.8800	3.0276	3.2210
21	True-Up (¢/KWH)	0.1392	0.1619	0.1633	0.1628	0.1411	0.1311	0.1199	0.1211	0.1249	0.1336	0.1467	0.1491	0.1396
22	Total (¢/KWH)	2.9798	3.0470	3.6487	3.6379	3.5187	3.5010	3.4470	3.4769	3.3786	3.4458	3.0267	3.1767	3.3606
23	Revenue Tax Factor (0.00072)	0.0021	0.0022	0.0026	0.0026	0.0025	0.0025	0.0025	0.0025	0.0024	0.0025	0.0022	0.0023	0.0024
24	Recovery Factor Adjusted for Taxes (¢/KWH)	2.9819	3.0492	3.6513	3.6405	3.5212	3.5035	3.4495	3.4794	3.3810	3.4483	3.0289	3.1790	3.3630
25	GPIF (¢/KWH)	0.0195	0.0227	0.0229	0.0228	0.0197	0.0184	0.0168	0.0170	0.0175	0.0187	0.0205	0.0209	0.0195
26	Recovery Factor including GPIF (¢/KWH)	3.0014	3.0719	3.6742	3.6633	3.5409	3.5219	3.4663	3.4964	3.3985	3.4670	3.0494	3.1999	3.3825
27														
28	Recovery Factor Rounded to .001 (¢/KWH)	3.001	3.072	3.674	3.663	3.541	3.522	3.466	3.496	3.399	3.467	3.049	3.200	3.383
29														
30	Note: Totals may not add due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

	(1)	(2)	(3)	(4)	(5)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	37,388,852,427	0.030672	$1,146,776,697.45	3.067
2	All Additional KWH	18,070,887,116	0.040672	$734,972,265.24	4.067
3	Total KWH	55,459,739,543		$1,881,748,962.69	
4					
5	Avg Fuel Factor	3.383			
6	RS-1 Loss Multiplier	1.00293			
7	Average Fuel Factor	3.393			
8					
9	Target Fuel Revenues	$1,881,748,962.69			
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	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	1,183,949	230,112	965,877	3,395,847	949,606	7,736,081	9,344,546	8,068,395	5,036,187	3,523,855	0	0	40,434,454
3	Light Oil	72,089	16,248	0	405,481	0	702,542	281,798	92,183	0	0	0	0	1,570,341
4	Coal	10,094,722	7,475,072	1,689,950	4,791,987	13,244,647	14,871,995	15,387,859	13,779,124	13,478,346	14,200,718	11,664,222	11,967,065	132,645,707
5	Gas	204,229,626	189,491,935	246,044,886	237,037,191	247,564,987	255,616,206	278,990,077	282,017,622	264,328,846	260,238,344	205,137,865	212,968,470	2,883,666,055
6	Nuclear	17,528,000	15,831,000	9,218,000	13,713,000	17,494,000	16,930,000	17,494,000	17,494,000	15,967,000	13,230,000	17,176,000	17,750,000	189,825,000
7	**Total Fuel Cost of System Net Generati**	233,108,385	213,044,367	257,918,712	259,343,506	279,253,240	295,856,825	321,498,280	321,451,323	298,810,379	291,192,917	233,978,087	242,685,535	3,248,141,556
8														
9	**System Net Generation (MWH)**													
10	Heavy Oil	7,312	1,147	3,961	17,062	3,523	44,104	54,505	47,727	31,241	22,174	0	0	232,756
11	Light Oil	568	58	0	1,356	0	1,923	799	285	0	0	0	0	4,989
12	Coal	360,814	266,997	42,006	166,457	479,144	541,611	559,821	493,468	480,014	511,615	421,797	431,898	4,755,642
13	Gas	5,531,628	5,122,080	6,947,787	6,588,154	6,816,431	7,098,551	7,824,570	7,943,964	7,379,351	7,217,747	5,564,017	5,692,688	79,726,968
14	Nuclear	2,567,188	2,318,753	1,691,208	1,981,889	2,501,181	2,420,498	2,501,181	2,501,181	2,286,346	1,945,409	2,484,377	2,567,188	27,766,399
15	Solar	9,217	10,455	18,398	21,524	21,836	20,004	19,439	18,279	15,996	14,558	11,251	9,668	190,625
16	**Total System Net Generation (MWH)**	8,476,727	7,719,490	8,703,360	8,776,442	9,822,115	10,126,691	10,960,315	11,004,904	10,192,948	9,711,503	8,481,442	8,701,442	112,677,379
17														
18	**Units of Fuel Burned (Unit)** [a]													
19	Heavy Oil	12,664	2,462	10,334	36,211	10,115	82,446	99,585	85,903	54,000	37,670			431,390
20	Light Oil	719	134		3,344		5,754	2,308	755					13,014
21	Coal	211,828	157,539	22,108	98,306	282,396	318,634	329,511	289,440	280,917	302,470	249,967	255,871	2,798,987
22	Gas	38,202,064	35,717,664	49,002,821	46,704,292	48,473,113	50,657,325	55,715,799	56,296,870	52,454,740	51,014,543	38,195,941	38,921,298	561,356,468
23	Nuclear	27,109,985	24,486,449	17,963,668	21,383,576	27,094,244	26,220,236	27,094,244	27,094,244	24,718,736	20,873,643	26,235,473	27,109,985	297,384,483
24	Total Units of Fuel Burned (Unit)													
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	81,051	15,755	66,138	231,744	64,736	527,658	637,342	549,780	345,598	241,091	0	0	2,760,893
28	Light Oil	4,191	740	0	19,498	0	33,542	13,459	4,363	0	0	0	0	75,793
29	Coal	3,830,354	2,843,485	486,370	1,792,987	5,080,381	5,721,878	5,915,057	5,225,738	5,080,521	5,421,670	4,465,673	4,570,318	50,434,432
30	Gas	38,202,064	35,717,664	49,002,821	46,704,292	48,473,113	50,657,325	55,715,799	56,296,870	52,454,740	51,014,543	38,195,941	38,921,298	561,356,468
31	Nuclear	27,109,985	24,486,449	17,963,668	21,383,576	27,094,244	26,220,236	27,094,244	27,094,244	24,718,736	20,873,643	26,235,473	27,109,985	297,384,483
32	**Total BTU Burned (MMBTU)**	69,227,645	63,064,093	67,518,997	70,132,097	80,712,474	83,160,639	89,375,901	89,170,995	82,599,595	77,550,947	68,897,087	70,601,601	912,012,069
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	93.4893	93.4654	93.4659	93.7794	93.8810	93.8321	93.8349	93.9245	93.2627	93.5454	0.0000	0.0000	93.7306
36	Light Oil	100.2625	121.2562	0.0000	121.2562	0.0000	122.0963	122.0963	122.0963	0.0000	0.0000	0.0000	0.0000	120.6655
37	Coal	47.6553	47.4490	76.4406	48.7456	46.9010	46.6742	46.6991	47.6061	47.9798	46.9492	46.6630	46.7699	47.3906
38	Gas	5.3460	5.3053	5.0210	5.0753	5.1073	5.0460	5.0074	5.0095	5.0392	5.1013	5.3707	5.4718	5.1370
39	Nuclear	0.6466	0.6465	0.5131	0.6413	0.6457	0.6457	0.6457	0.6457	0.6459	0.6338	0.6547	0.6547	0.6383
40	**Total Fuel Cost per Unit ($/Unit)**													
41														
42	**Generation Mix (%)**													
43	Heavy Oil	0.09%	0.01%	0.05%	0.19%	0.04%	0.44%	0.50%	0.43%	0.31%	0.23%	0.00%	0.00%	0.21%

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Light Oil	0.01%	0.00%	0.00%	0.02%	0.00%	0.02%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Coal	4.26%	3.46%	0.48%	1.90%	4.88%	5.35%	5.11%	4.48%	4.71%	5.27%	4.97%	4.96%	4.22%
3	Gas	65.26%	66.35%	79.83%	75.07%	69.40%	70.10%	71.39%	72.19%	72.40%	74.32%	65.60%	65.42%	70.76%
4	Nuclear	30.29%	30.04%	19.43%	22.58%	25.46%	23.90%	22.82%	22.73%	22.43%	20.03%	29.29%	29.50%	24.64%
5	Solar	0.11%	0.14%	0.21%	0.25%	0.22%	0.20%	0.18%	0.17%	0.16%	0.15%	0.13%	0.11%	0.17%
6	**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%
7														
8	**Fuel Cost per MMBTU ($/MMBTU)**													
9	Heavy Oil	14.6075	14.6056	14.6040	14.6534	14.6689	14.6612	14.6617	14.6757	14.5724	14.6163	0.0000	0.0000	14.6454
10	Light Oil	17.2008	21.9572	0.0000	20.7960	0.0000	20.9451	20.9375	21.1283	0.0000	0.0000	0.0000	0.0000	20.7188
11	Coal	2.6355	2.6288	3.4746	2.6726	2.6070	2.5991	2.6015	2.6368	2.6529	2.6193	2.6120	2.6184	2.6301
12	Gas	5.3460	5.3053	5.0210	5.0753	5.1073	5.0460	5.0074	5.0095	5.0392	5.1013	5.3707	5.4718	5.1370
13	Nuclear	0.6466	0.6465	0.5131	0.6413	0.6457	0.6457	0.6457	0.6457	0.6459	0.6338	0.6547	0.6547	0.6383
14														
15	**BTU Burned per KWH (BTU/KWH)**													
16	Heavy Oil	11,085	13,736	16,697	13,582	18,375	11,964	11,693	11,519	11,062	10,873	0	0	11,862
17	Light Oil	7,379	12,759	0	14,379	0	17,443	16,845	15,309	0	0	0	0	15,192
18	Coal	10,616	10,650	11,579	10,771	10,603	10,565	10,566	10,590	10,584	10,597	10,587	10,582	10,605
19	Gas	6,906	6,973	7,053	7,089	7,111	7,136	7,121	7,087	7,108	7,068	6,865	6,837	7,041
20	Nuclear	10,560	10,560	10,622	10,789	10,833	10,833	10,833	10,833	10,811	10,730	10,560	10,560	10,710
21														
22	**Generated Fuel Cost per KWH (cents/KWH)**													
23	Heavy Oil	16.1919	20.0621	24.3847	19.9030	26.9545	17.5405	17.1444	16.9053	16.1204	15.8918	0.0000	0.0000	17.3720
24	Light Oil	12.6917	28.0144	0.0000	29.9027	0.0000	36.5337	35.2689	32.3448	0.0000	0.0000	0.0000	0.0000	31.4761
25	Coal	2.7978	2.7997	4.0231	2.8788	2.7642	2.7459	2.7487	2.7923	2.8079	2.7757	2.7654	2.7708	2.7892
26	Gas	3.6920	3.6995	3.5413	3.5979	3.6319	3.6010	3.5656	3.5501	3.5820	3.6055	3.6869	3.7411	3.6169
27	Nuclear	0.6828	0.6827	0.5451	0.6919	0.6994	0.6994	0.6994	0.6994	0.6984	0.6801	0.6914	0.6914	0.6837
28	**Total Generated Fuel Cost per KWH (ce**	2.7500	2.7598	2.9634	2.9550	2.8431	2.9216	2.9333	2.9210	2.9315	2.9984	2.7587	2.7890	2.8827
29														
30														
31	[(a)] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
32														
33														
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**Jan - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		945,260					6,154,313	1,000,000	6,154,313	32,532,832	3.44	5.29
5	Plant Unit Info	1,355	945,260	93.8%	95.8%	93.8%	6,511			6,154,313	32,532,832	3.44	
6	*Desoto Solar*												
7	Solar		3,151					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,151	16.9%		37.0%	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	443	0	0.0%	95.3%	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%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		544,169					3,965,313	1,000,000	3,965,313	21,237,565	3.90	5.36
18	Plant Unit Info	1,435	544,169	51.0%	94.9%	84.3%	7,287			3,965,313	21,237,565	3.90	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		1,201					13,014	1,000,000	13,014	70,924	5.91	5.45
22	Plant Unit Info	314	1,201	1.0%	95.5%	95.5%	10,839			13,014	70,924	5.91	
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	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		568					719	5,828,929	4,191	72,089	12.69	100.26
29	Gas		10,578					84,017	1,000,000	84,017	454,768	4.30	5.41
30	Plant Unit Info	442	11,146	3.4%	94.0%	64.7%	7,914			88,208	526,857	4.73	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		10,346					82,030	1,000,000	82,030	444,748	4.30	5.42
34	Plant Unit Info	442	10,346	3.2%	94.6%	68.9%	7,929			82,030	444,748	4.30	
35	*Manatee 1*												
36	Heavy Oil		2,419					4,354	6,400,322	27,867	410,169	16.96	94.21
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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	795	2,419	0.4%	95.3%	76.1%	11,520			27,867	410,169	16.96	
2	*Manatee 2*												
3	Heavy Oil		2,195					4,007	6,400,549	25,647	377,480	17.20	94.21
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	795	2,195	0.4%	94.0%	69.0%	11,684			25,647	377,480	17.20	
6	*Manatee 3*												
7	Gas		443,800					3,148,205	1,000,000	3,148,205	16,871,676	3.80	5.36
8	Plant Unit Info	1,116	443,800	53.5%	94.6%	89.6%	7,094			3,148,205	16,871,676	3.80	
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		2,087					3,397	6,400,353	21,742	312,770	14.99	92.07
15	Gas		1,527					20,703	1,000,000	20,703	110,824	7.26	5.35
16	Plant Unit Info	808	3,614	0.6%	82.0%	32.0%	11,744			42,445	423,595	11.72	
17	*Martin 3*												
18	Gas		16,750					127,458	1,000,000	127,458	681,507	4.07	5.35
19	Plant Unit Info	454	16,750	5.0%	94.8%	85.8%	7,609			127,458	681,507	4.07	
20	*Martin 4*												
21	Gas		14,987					114,658	1,000,000	114,658	612,997	4.09	5.35
22	Plant Unit Info	453	14,987	4.5%	94.0%	78.8%	7,651			114,658	612,997	4.09	
23	*Martin 8*												
24	Gas		697,802					4,812,747	1,000,000	4,812,747	25,795,721	3.70	5.36
25	Plant Unit Info	1,147	697,802	81.8%	94.9%	84.8%	6,897			4,812,747	25,795,721	3.70	
26	*Martin 8 Solar*												
27	Solar		4,882					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	4,882	8.8%		19.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,344	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		1,513					14,835	1,000,000	14,835	80,700	5.33	5.44
35	Plant Unit Info	251	1,513	0.8%	94.2%	75.4%	9,805			14,835	80,700	5.33	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		1,722					16,587	1,000,000	16,587	90,275	5.24	5.44
2	Plant Unit Info	255	1,722	0.9%	94.8%	84.5%	9,632			16,587	90,275	5.24	
3	*Sanford 4*												
4	Gas		78,797					584,976	1,000,000	584,976	3,130,857	3.97	5.35
5	Plant Unit Info	975	78,797	10.9%	94.7%	77.7%	7,424			584,976	3,130,857	3.97	
6	*Sanford 5*												
7	Gas		132,929					990,534	1,000,000	990,534	5,299,449	3.99	5.35
8	Plant Unit Info	994	132,929	18.0%	94.9%	78.7%	7,452			990,534	5,299,449	3.99	
9	*Scherer 4*												
10	Coal		272,271					165,972	16,999,976	2,821,520	6,574,415	2.41	39.61
11	Plant Unit Info	646	272,271	56.7%	93.1%	93.1%	10,363			2,821,520	6,574,415	2.41	
12	*St Johns 1O*												
13	Coal		42,212					22,171	22,000,361	487,770	1,702,040	4.03	76.77
14	Plant Unit Info	128	42,212	44.3%	94.0%	44.3%	11,555			487,770	1,702,040	4.03	
15	*St Johns 2O*												
16	Coal		46,331					23,685	21,999,747	521,064	1,818,267	3.92	76.77
17	Plant Unit Info	128	46,331	48.6%	93.2%	48.6%	11,247			521,064	1,818,267	3.92	
18	*St Lucie 1*												
19	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,956,000	0.68	0.66
20	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,956,000	0.68	
21	*St Lucie 2*												
22	Nuclear		623,845					6,379,606	1,000,000	6,379,606	4,026,000	0.65	0.63
23	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,226			6,379,606	4,026,000	0.65	
24	*Space Coast*												
25	Solar		1,184					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,184	15.9%		34.7%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		611					906	6,396,247	5,795	83,529	13.67	92.20
29	Gas		0					900	1,000,000	900	4,823	0.00	5.36
30	Plant Unit Info	380	611	0.2%	95.2%	80.3%	10,957			6,695	88,352	14.46	
31	*Turkey Point 3*												
32	Nuclear		604,258					6,568,489	1,000,000	6,568,489	4,284,000	0.71	0.65
33	Plant Unit Info	833	604,258	97.5%	97.5%	97.5%	10,870			6,568,489	4,284,000	0.71	
34	*Turkey Point 4*												
35	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,262,000	0.70	0.64
36	Plant Unit Info	843	611,511	97.5%	97.5%	97.5%	10,870			6,647,323	4,262,000	0.70	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		388,673					2,747,118	1,000,000	2,747,118	14,745,055	3.79	5.37
2	Plant Unit Info	1,138	388,673	45.9%	94.2%	87.1%	7,068			2,747,118	14,745,055	3.79	
3	*WCEC 01*												
4	Gas		752,253					5,145,664	1,000,000	5,145,664	27,689,962	3.68	5.38
5	Plant Unit Info	1,208	752,253	83.7%	95.5%	87.7%	6,840			5,145,664	27,689,962	3.68	
6	*WCEC 02*												
7	Gas		779,104					5,322,723	1,000,000	5,322,723	28,288,161	3.63	5.31
8	Plant Unit Info	1,202	779,104	87.1%	95.7%	87.1%	6,832			5,322,723	28,288,161	3.63	
9	*WCEC 03*												
10	Gas		710,218					4,856,270	1,000,000	4,856,270	26,086,780	3.67	5.37
11	Plant Unit Info	1,207	710,218	79.1%	95.5%	87.3%	6,838			4,856,270	26,086,780	3.67	
12	**System Totals**												
13	Plant Unit Info	25,886	8,476,727				8,167			69,227,645	233,108,385	2.75	
14													
15													
16													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**Feb - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		636,582					4,142,626	1,000,000	4,142,626	21,731,160	3.41	5.25
5	Plant Unit Info	1,355	636,582	69.9%	71.9%	93.2%	6,508			4,142,626	21,731,160	3.41	
6	*Desoto Solar*												
7	Solar		3,593					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,593	21.4%		46.7%	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	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		58					134	5,522,388	740	16,248	28.01	121.26
15	Plant Unit Info	690	58	0.0%	95.3%	8.4%	12,759			740	16,248	28.01	
16	*Fort Myers 2*												
17	Gas		638,354					4,618,451	1,000,000	4,618,451	24,550,935	3.85	5.32
18	Plant Unit Info	1,435	638,354	66.2%	94.9%	81.5%	7,235			4,618,451	24,550,935	3.85	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		4,802					52,054	1,000,000	52,054	278,370	5.80	5.35
22	Plant Unit Info	314	4,802	4.5%	95.5%	95.5%	10,839			52,054	278,370	5.80	
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	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		26,439					210,187	1,000,000	210,187	1,125,686	4.26	5.36
30	Plant Unit Info	442	26,439	8.9%	80.6%	69.6%	7,950			210,187	1,125,686	4.26	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		32,376					257,259	1,000,000	257,259	1,378,468	4.26	5.36
34	Plant Unit Info	442	32,376	10.9%	81.1%	69.8%	7,946			257,259	1,378,468	4.26	
35	*Manatee 1*												
36	Heavy Oil		633					1,608	6,398,632	10,289	151,482	23.93	94.21
37	Gas		1,477					15,409	1,000,000	15,409	83,126	5.63	5.39

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	795	2,110	0.4%	95.3%	66.3%	12,182			25,698	234,608	11.12	
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	795	0	0.0%	47.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		524,769					3,690,146	1,000,000	3,690,146	19,645,302	3.74	5.32
8	Plant Unit Info	1,116	524,769	70.0%	94.6%	84.4%	7,032			3,690,146	19,645,302	3.74	
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		514					854	6,400,468	5,466	78,630	15.30	92.07
15	Gas		3,027					37,808	1,000,000	37,808	201,898	6.67	5.34
16	Plant Unit Info	808	3,541	0.7%	82.0%	27.4%	12,219			43,274	280,528	7.92	
17	*Martin 3*												
18	Gas		62,231					477,447	1,000,000	477,447	2,533,584	4.07	5.31
19	Plant Unit Info	454	62,231	20.4%	94.8%	75.3%	7,672			477,447	2,533,584	4.07	
20	*Martin 4*												
21	Gas		59,870					459,331	1,000,000	459,331	2,437,506	4.07	5.31
22	Plant Unit Info	453	59,870	19.7%	94.0%	73.9%	7,672			459,331	2,437,506	4.07	
23	*Martin 8*												
24	Gas		610,259					4,196,400	1,000,000	4,196,400	22,363,278	3.66	5.33
25	Plant Unit Info	1,147	610,259	79.2%	89.0%	80.2%	6,876			4,196,400	22,363,278	3.66	
26	*Martin 8 Solar*												
27	Solar		5,590					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	5,590	11.1%		24.2%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,344	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		2,992					29,299	1,000,000	29,299	156,991	5.25	5.36
35	Plant Unit Info	251	2,992	1.8%	90.9%	74.5%	9,793			29,299	156,991	5.25	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	PLANT UNIT (1)	Net Capability (MW) (2)	Net Generation (MWH) (3)	Capacity Factor (%) (4)	Equivalent Availability Factor (%) (5)	Net Output Factor (%) (6)	Avg Net Heat Rate (BTU/KWH) (7)	Fuel Burned (Units) (8)	Fuel Heat Value (BTU/Unit) (9)	Fuel Burned (MMBTU) (10)	As Burned Fuel Cost ($) (11)	Fuel Cost per KWH (cents/KWH) (12)	Cost of Fuel ($/Unit) (13)
1	Gas		2,982					29,168	1,000,000	29,168	156,205	5.24	5.36
2	Plant Unit Info	255	2,982	1.7%	91.4%	73.2%	9,780			29,168	156,205	5.24	
3	*Sanford 4*												
4	Gas		185,005					1,369,391	1,000,000	1,369,391	7,280,977	3.94	5.32
5	Plant Unit Info	975	185,005	28.2%	94.7%	84.7%	7,402			1,369,391	7,280,977	3.94	
6	*Sanford 5*												
7	Gas		262,455					1,935,902	1,000,000	1,935,902	10,287,296	3.92	5.31
8	Plant Unit Info	994	262,455	39.3%	94.9%	81.3%	7,376			1,935,902	10,287,296	3.92	
9	*Scherer 4*												
10	Coal		204,188					124,475	17,000,024	2,116,078	4,935,425	2.42	39.65
11	Plant Unit Info	646	204,188	47.1%	69.8%	92.8%	10,363			2,116,078	4,935,425	2.42	
12	*St Johns 1O*												
13	Coal		24,191					13,021	22,000,230	286,465	1,000,143	4.13	76.81
14	Plant Unit Info	128	24,191	28.1%	67.1%	39.3%	11,842			286,465	1,000,143	4.13	
15	*St Johns 2O*												
16	Coal		38,618					20,043	21,999,800	440,942	1,539,503	3.99	76.81
17	Plant Unit Info	128	38,618	44.8%	93.2%	44.8%	11,418			440,942	1,539,503	3.99	
18	*St Lucie 1*												
19	Nuclear		657,165					6,787,360	1,000,000	6,787,360	4,476,000	0.68	0.66
20	Plant Unit Info	1,003	657,165	97.5%	97.5%	97.5%	10,328			6,787,360	4,476,000	0.68	
21	*St Lucie 2*												
22	Nuclear		563,473					5,762,227	1,000,000	5,762,227	3,636,000	0.65	0.63
23	Plant Unit Info	860	563,473	97.5%	97.5%	97.5%	10,226			5,762,227	3,636,000	0.65	
24	*Space Coast*												
25	Solar		1,272					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,272	18.9%		41.3%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		945					12,763	1,000,000	12,763	68,262	7.22	5.35
30	Plant Unit Info	380	945	0.4%	95.2%	41.4%	13,508			12,763	68,262	7.22	
31	*Turkey Point 3*												
32	Nuclear		545,780					5,932,829	1,000,000	5,932,829	3,869,000	0.71	0.65
33	Plant Unit Info	833	545,780	97.5%	97.5%	97.5%	10,870			5,932,829	3,869,000	0.71	
34	*Turkey Point 4*												
35	Nuclear		552,335					6,004,033	1,000,000	6,004,033	3,850,000	0.70	0.64
36	Plant Unit Info	843	552,335	97.5%	97.5%	97.5%	10,870			6,004,033	3,850,000	0.70	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		159,627					1,135,963	1,000,000	1,135,963	6,048,022	3.79	5.32
2	Plant Unit Info	1,138	159,627	20.9%	38.7%	61.0%	7,116			1,135,963	6,048,022	3.79	
3	*WCEC 01*												
4	Gas		699,667					4,782,631	1,000,000	4,782,631	25,434,756	3.64	5.32
5	Plant Unit Info	1,208	699,667	86.2%	95.5%	87.3%	6,836			4,782,631	25,434,756	3.64	
6	*WCEC 02*												
7	Gas		700,025					4,778,994	1,000,000	4,778,994	25,124,581	3.59	5.26
8	Plant Unit Info	1,202	700,025	86.6%	95.7%	86.6%	6,827			4,778,994	25,124,581	3.59	
9	*WCEC 03*												
10	Gas		508,196					3,486,435	1,000,000	3,486,435	18,605,531	3.66	5.34
11	Plant Unit Info	1,207	508,196	62.6%	79.6%	75.2%	6,860			3,486,435	18,605,531	3.66	
12	**System Totals**												
13	Plant Unit Info	25,886	7,719,490				8,169			63,064,093	213,044,367	2.76	
14													
15													
16													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**Mar - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		873,433					5,703,845	1,000,000	5,703,845	28,237,093	3.23	4.95
5	Plant Unit Info	1,355	873,433	86.6%	88.6%	87.5%	6,530			5,703,845	28,237,093	3.23	
6	*Desoto Solar*												
7	Solar		4,915					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,915	26.4%		48.8%	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	443	0	0.0%	95.3%	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%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		891,517					6,429,698	1,000,000	6,429,698	32,279,581	3.62	5.02
18	Plant Unit Info	1,435	891,517	83.5%	94.9%	83.5%	7,212			6,429,698	32,279,581	3.62	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		22,211					239,350	1,000,000	239,350	1,219,715	5.49	5.10
22	Plant Unit Info	314	22,211	19.0%	95.5%	95.5%	10,776			239,350	1,219,715	5.49	
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	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		108,853					859,804	1,000,000	859,804	4,377,487	4.02	5.09
30	Plant Unit Info	442	108,853	33.1%	94.0%	87.7%	7,899			859,804	4,377,487	4.02	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		116,308					917,110	1,000,000	917,110	4,665,282	4.01	5.09
34	Plant Unit Info	442	116,308	35.4%	94.6%	86.4%	7,885			917,110	4,665,282	4.01	
35	*Manatee 1*												
36	Heavy Oil		1,751					6,657	6,400,330	42,607	627,124	35.82	94.21
37	Gas		8,239					91,960	1,000,000	91,960	465,547	5.65	5.06

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	795	9,990	1.7%	95.3%	34.0%	13,470			134,567	1,092,670	10.94	
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	795	0	0.0%	9.1%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		656,028					4,608,176	1,000,000	4,608,176	23,198,628	3.54	5.03
8	Plant Unit Info	1,116	656,028	79.0%	94.6%	83.6%	7,024			4,608,176	23,198,628	3.54	
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		1,210					2,030	6,400,000	12,992	186,907	15.45	92.07
15	Gas		7,268					101,939	1,000,000	101,939	514,509	7.08	5.05
16	Plant Unit Info	808	8,478	1.4%	63.5%	25.0%	13,556			114,931	701,416	8.27	
17	*Martin 3*												
18	Gas		157,259					1,201,032	1,000,000	1,201,032	6,017,940	3.83	5.01
19	Plant Unit Info	454	157,259	46.5%	94.8%	91.4%	7,637			1,201,032	6,017,940	3.83	
20	*Martin 4*												
21	Gas		148,172					1,133,540	1,000,000	1,133,540	5,679,843	3.83	5.01
22	Plant Unit Info	453	148,172	44.0%	94.0%	89.4%	7,650			1,133,540	5,679,843	3.83	
23	*Martin 8*												
24	Gas		612,995					4,206,610	1,000,000	4,206,610	21,235,466	3.46	5.05
25	Plant Unit Info	1,147	612,995	71.9%	78.8%	74.7%	6,862			4,206,610	21,235,466	3.46	
26	*Martin 8 Solar*												
27	Solar		11,799					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	11,799	21.2%		29.9%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,344	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	251	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	255	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Sanford 4*												
4	Gas		400,302					2,978,262	1,000,000	2,978,262	14,968,676	3.74	5.03
5	Plant Unit Info	975	400,302	55.2%	94.7%	92.4%	7,440			2,978,262	14,968,676	3.74	
6	*Sanford 5*												
7	Gas		510,132					3,759,967	1,000,000	3,759,967	18,886,276	3.70	5.02
8	Plant Unit Info	994	510,132	69.0%	94.9%	82.5%	7,371			3,759,967	18,886,276	3.70	
9	*Scherer 4*												
10	Coal		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	646	0	0.0%	0.0%	0.0%	0			0	0	0.00	
12	*St Johns 1O*												
13	Coal		42,006					22,108	21,999,729	486,370	1,689,950	4.02	76.44
14	Plant Unit Info	128	42,006	44.0%	94.0%	44.0%	11,579			486,370	1,689,950	4.02	
15	*St Johns 2O*												
16	Coal		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	128	0	0.0%	0.0%	0.0%	0			0	0	0.00	
18	*St Lucie 1*												
19	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,956,000	0.68	0.66
20	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,956,000	0.68	
21	*St Lucie 2*												
22	Nuclear		40,248					411,590	1,000,000	411,590	0	0.00	0.00
23	Plant Unit Info	860	40,248	6.3%	6.3%	97.5%	10,226			411,590	0	0.00	
24	*Space Coast*												
25	Solar		1,684					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,684	22.7%		41.8%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		1,000					1,647	6,398,907	10,539	151,846	15.18	92.20
29	Gas		4,639					63,043	1,000,000	63,043	317,643	6.85	5.04
30	Plant Unit Info	380	5,639	2.0%	95.2%	30.3%	13,050			73,582	469,488	8.33	
31	*Turkey Point 3*												
32	Nuclear		311,875					3,390,188	1,000,000	3,390,188	0	0.00	0.00
33	Plant Unit Info	833	311,875	50.3%	50.3%	97.5%	10,870			3,390,188	0	0.00	
34	*Turkey Point 4*												
35	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,262,000	0.70	0.64
36	Plant Unit Info	843	611,511	97.5%	97.5%	97.5%	10,870			6,647,323	4,262,000	0.70	
37	*Turkey Point 5*												

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		618,559					4,294,974	1,000,000	4,294,974	21,589,547	3.49	5.03
2	Plant Unit Info	1,152	618,559	72.2%	80.5%	74.1%	6,944			4,294,974	21,589,547	3.49	
3	*WCEC 01*												
4	Gas		802,654					5,488,017	1,000,000	5,488,017	27,714,631	3.45	5.05
5	Plant Unit Info	1,208	802,654	89.3%	95.5%	89.3%	6,837			5,488,017	27,714,631	3.45	
6	*WCEC 02*												
7	Gas		785,441					5,366,832	1,000,000	5,366,832	26,803,624	3.41	4.99
8	Plant Unit Info	1,202	785,441	87.8%	95.7%	87.8%	6,833			5,366,832	26,803,624	3.41	
9	*WCEC 03*												
10	Gas		223,778					1,558,662	1,000,000	1,558,662	7,873,398	3.52	5.05
11	Plant Unit Info	1,207	223,778	24.9%	31.8%	51.8%	6,965			1,558,662	7,873,398	3.52	
12	**System Totals**												
13	Plant Unit Info	25,900	8,703,360				7,758			67,518,997	257,918,712	2.96	
14													
15													
16													
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19													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**Apr - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		811,352					5,303,570	1,000,000	5,303,570	26,428,645	3.26	4.98
5	Plant Unit Info	1,210	811,352	93.1%	95.8%	93.1%	6,537			5,303,570	26,428,645	3.26	
6	*Desoto Solar*												
7	Solar		5,489					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,489	30.5%		56.3%	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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,356					3,344	5,830,742	19,498	405,481	29.90	121.26
15	Plant Unit Info	648	1,356	0.3%	95.3%	19.0%	14,379			19,498	405,481	29.90	
16	*Fort Myers 2*												
17	Gas		711,572					5,179,092	1,000,000	5,179,092	26,160,708	3.68	5.05
18	Plant Unit Info	1,380	711,572	71.6%	94.9%	83.6%	7,278			5,179,092	26,160,708	3.68	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		17,652					192,929	1,000,000	192,929	1,010,981	5.73	5.24
22	Plant Unit Info	296	17,652	16.6%	95.5%	95.5%	10,930			192,929	1,010,981	5.73	
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	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		80,535					639,285	1,000,000	639,285	3,330,199	4.14	5.21
30	Plant Unit Info	429	80,535	26.1%	94.0%	91.2%	7,938			639,285	3,330,199	4.14	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		85,048					674,418	1,000,000	674,418	3,519,200	4.14	5.22
34	Plant Unit Info	429	85,048	27.6%	94.6%	94.0%	7,930			674,418	3,519,200	4.14	
35	*Manatee 1*												
36	Heavy Oil		7,260					17,880	6,399,888	114,430	1,684,388	23.20	94.21
37	Gas		20,586					221,609	1,000,000	221,609	1,158,857	5.63	5.23

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	789	27,846	4.9%	95.3%	49.7%	12,068			336,039	2,843,245	10.21	
2	*Manatee 2*												
3	Heavy Oil		4,812					10,661	6,399,869	68,229	1,004,321	20.87	94.21
4	Gas		11,229					118,162	1,000,000	118,162	622,380	5.54	5.27
5	Plant Unit Info	789	16,041	2.8%	94.0%	63.6%	11,620			186,391	1,626,701	10.14	
6	*Manatee 3*												
7	Gas		611,469					4,254,570	1,000,000	4,254,570	21,537,907	3.52	5.06
8	Plant Unit Info	1,058	611,469	80.3%	94.6%	89.2%	6,958			4,254,570	21,537,907	3.52	
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		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		107,236					828,479	1,000,000	828,479	4,176,635	3.89	5.04
19	Plant Unit Info	438	107,236	34.0%	94.8%	94.2%	7,726			828,479	4,176,635	3.89	
20	*Martin 4*												
21	Gas		95,675					743,649	1,000,000	743,649	3,749,016	3.92	5.04
22	Plant Unit Info	437	95,675	30.4%	94.0%	92.9%	7,773			743,649	3,749,016	3.92	
23	*Martin 8*												
24	Gas		668,423					4,620,965	1,000,000	4,620,965	23,807,061	3.56	5.15
25	Plant Unit Info	1,111	668,423	83.5%	94.9%	83.5%	6,913			4,620,965	23,807,061	3.56	
26	*Martin 8 Solar*												
27	Solar		14,206					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	14,206	26.3%		48.6%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,212	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		24,186					278,144	1,000,000	278,144	1,402,280	5.80	5.04
35	Plant Unit Info	247	24,186	13.6%	17.0%	20.0%	11,500			278,144	1,402,280	5.80	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		44,562					445,167	1,000,000	445,167	2,286,137	5.13	5.14
2	Plant Unit Info	250	44,562	24.7%	85.3%	35.6%	9,990			445,167	2,286,137	5.13	
3	*Sanford 4*												
4	Gas		229,748					1,722,873	1,000,000	1,722,873	8,708,461	3.79	5.05
5	Plant Unit Info	939	229,748	34.0%	75.0%	92.3%	7,499			1,722,873	8,708,461	3.79	
6	*Sanford 5*												
7	Gas		334,183					2,497,655	1,000,000	2,497,655	12,614,202	3.77	5.05
8	Plant Unit Info	947	334,183	49.0%	94.9%	88.4%	7,474			2,497,655	12,614,202	3.77	
9	*Scherer 4*												
10	Coal		120,347					73,952	17,000,068	1,257,189	2,936,970	2.44	39.71
11	Plant Unit Info	641	120,347	26.1%	31.0%	97.4%	10,446			1,257,189	2,936,970	2.44	
12	*St Johns 1O*												
13	Coal		41,111					21,790	22,000,459	479,390	1,659,720	4.04	76.17
14	Plant Unit Info	127	41,111	45.0%	94.0%	45.0%	11,661			479,390	1,659,720	4.04	
15	*St Johns 2O*												
16	Coal		4,999					2,564	22,000,000	56,408	195,297	3.91	76.17
17	Plant Unit Info	127	4,999	5.5%	9.3%	54.7%	11,284			56,408	195,297	3.91	
18	*St Lucie 1*												
19	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,796,000	0.70	0.66
20	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,796,000	0.70	
21	*St Lucie 2*												
22	Nuclear		491,400					5,136,800	1,000,000	5,136,800	3,054,000	0.62	0.59
23	Plant Unit Info	840	491,400	81.3%	81.2%	97.5%	10,453			5,136,800	3,054,000	0.62	
24	*Space Coast*												
25	Solar		1,829					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,829	25.4%		46.9%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		4,990					7,670	6,399,609	49,085	707,139	14.17	92.20
29	Gas		4,029					50,609	1,000,000	50,609	260,952	6.48	5.16
30	Plant Unit Info	379	9,019	3.3%	95.2%	52.8%	11,054			99,694	968,090	10.73	
31	*Turkey Point 3*												
32	Nuclear		226,886					2,539,498	1,000,000	2,539,498	1,737,000	0.77	0.68
33	Plant Unit Info	808	226,886	39.0%	39.0%	97.5%	11,193			2,539,498	1,737,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		574,937					6,435,113	1,000,000	6,435,113	4,126,000	0.72	0.64
36	Plant Unit Info	819	574,937	97.5%	97.5%	97.5%	11,193			6,435,113	4,126,000	0.72	
37	*Turkey Point 5*												

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		537,652					3,758,092	1,000,000	3,758,092	19,126,844	3.56	5.09
2	Plant Unit Info	1,138	537,652	65.6%	89.5%	83.4%	6,990			3,758,092	19,126,844	3.56	
3	*WCEC 01*												
4	Gas		734,618					5,095,693	1,000,000	5,095,693	26,053,570	3.55	5.11
5	Plant Unit Info	1,166	734,618	87.5%	95.5%	87.5%	6,937			5,095,693	26,053,570	3.55	
6	*WCEC 02*												
7	Gas		737,299					5,078,012	1,000,000	5,078,012	25,684,276	3.48	5.06
8	Plant Unit Info	1,159	737,299	88.3%	95.7%	88.3%	6,887			5,078,012	25,684,276	3.48	
9	*WCEC 03*												
10	Gas		721,102					5,001,319	1,000,000	5,001,319	25,398,879	3.52	5.08
11	Plant Unit Info	1,166	721,102	85.9%	95.5%	85.9%	6,936			5,001,319	25,398,879	3.52	
12	**System Totals**												
13	Plant Unit Info	24,933	8,776,442				7,991			70,132,097	259,343,506	2.95	
14													
15													
16													
17													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**May - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,558					5,531,199	1,000,000	5,531,199	27,751,726	3.28	5.02
5	Plant Unit Info	1,210	845,558	93.9%	95.8%	93.9%	6,541			5,531,199	27,751,726	3.28	
6	*Desoto Solar*												
7	Solar		5,860					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,860	31.5%		58.2%	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	420	0	0.0%	95.3%	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	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		747,450					5,456,209	1,000,000	5,456,209	27,873,255	3.73	5.11
18	Plant Unit Info	1,380	747,450	72.8%	94.9%	89.7%	7,300			5,456,209	27,873,255	3.73	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		16,381					180,183	1,000,000	180,183	937,051	5.72	5.20
22	Plant Unit Info	296	16,381	14.9%	94.0%	95.5%	11,000			180,183	937,051	5.72	
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	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		82,410					654,415	1,000,000	654,415	3,414,247	4.14	5.22
30	Plant Unit Info	429	82,410	25.8%	94.0%	92.4%	7,941			654,415	3,414,247	4.14	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		85,125					676,894	1,000,000	676,894	3,547,335	4.17	5.24
34	Plant Unit Info	429	85,125	26.7%	94.6%	94.5%	7,952			676,894	3,547,335	4.17	
35	*Manatee 1*												
36	Heavy Oil		2,029					7,062	6,399,745	45,195	665,277	32.79	94.21
37	Gas		6,921					75,918	1,000,000	75,918	396,839	5.73	5.23

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	789	8,950	1.5%	95.3%	40.5%	13,533			121,113	1,062,115	11.87	
2	*Manatee 2*												
3	Heavy Oil		557					1,494	6,401,606	9,564	140,742	25.27	94.21
4	Gas		1,300					13,633	1,000,000	13,633	72,056	5.54	5.29
5	Plant Unit Info	789	1,857	0.3%	94.0%	58.9%	12,492			23,197	212,799	11.46	
6	*Manatee 3*												
7	Gas		525,941					3,671,839	1,000,000	3,671,839	18,777,619	3.57	5.11
8	Plant Unit Info	1,058	525,941	66.8%	80.9%	85.9%	6,981			3,671,839	18,777,619	3.57	
9	*Martin 1*												
10	Heavy Oil		709					1,187	6,397,641	7,594	109,290	15.41	92.07
11	Gas		3,041					46,223	1,000,000	46,223	239,169	7.86	5.17
12	Plant Unit Info	799	3,750	0.6%	29.9%	33.5%	14,350			53,817	348,459	9.29	
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	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		106,285					821,893	1,000,000	821,893	4,192,910	3.94	5.10
19	Plant Unit Info	438	106,285	32.6%	94.8%	94.8%	7,733			821,893	4,192,910	3.94	
20	*Martin 4*												
21	Gas		91,966					715,953	1,000,000	715,953	3,652,390	3.97	5.10
22	Plant Unit Info	437	91,966	28.3%	94.0%	94.0%	7,785			715,953	3,652,390	3.97	
23	*Martin 8*												
24	Gas		731,924					5,071,092	1,000,000	5,071,092	26,194,105	3.58	5.17
25	Plant Unit Info	1,111	731,924	88.5%	94.9%	88.5%	6,928			5,071,092	26,194,105	3.58	
26	*Martin 8 Solar*												
27	Solar		14,070					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	14,070	25.2%		46.6%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,212	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		62,706					613,709	1,000,000	613,709	3,170,920	5.06	5.17
35	Plant Unit Info	247	62,706	34.2%	55.4%	43.7%	9,787			613,709	3,170,920	5.06	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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		101,364					927,119	1,000,000	927,119	4,818,031	4.75	5.20
2	Plant Unit Info	250	101,364	54.4%	94.8%	69.1%	9,146			927,119	4,818,031	4.75	
3	*Sanford 4*												
4	Gas		278,364					2,096,331	1,000,000	2,096,331	10,704,623	3.85	5.11
5	Plant Unit Info	939	278,364	39.9%	94.7%	95.0%	7,531			2,096,331	10,704,623	3.85	
6	*Sanford 5*												
7	Gas		340,155					2,554,056	1,000,000	2,554,056	13,040,147	3.83	5.11
8	Plant Unit Info	947	340,155	48.3%	94.9%	94.5%	7,509			2,554,056	13,040,147	3.83	
9	*Scherer 4*												
10	Coal		368,558					226,467	16,999,978	3,849,934	8,999,395	2.44	39.74
11	Plant Unit Info	641	368,558	77.3%	93.1%	97.7%	10,446			3,849,934	8,999,395	2.44	
12	*St Johns 1O*												
13	Coal		52,561					26,786	22,000,112	589,295	2,033,173	3.87	75.90
14	Plant Unit Info	127	52,561	55.7%	94.0%	55.7%	11,212			589,295	2,033,173	3.87	
15	*St Johns 2O*												
16	Coal		58,025					29,143	22,000,206	641,152	2,212,079	3.81	75.90
17	Plant Unit Info	127	58,025	61.5%	93.2%	61.5%	11,050			641,152	2,212,079	3.81	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,906					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,906	25.6%		47.3%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		228					372	6,405,914	2,383	34,297	15.04	92.20
29	Gas		3,856					53,030	1,000,000	53,030	273,635	7.10	5.16
30	Plant Unit Info	379	4,084	1.5%	95.2%	33.6%	13,568			55,413	307,932	7.54	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,264,000	0.72	0.64
36	Plant Unit Info	819	594,101	97.5%	97.5%	97.5%	11,193			6,649,613	4,264,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		414,263					2,912,087	1,000,000	2,912,087	14,925,109	3.60	5.13
2	Plant Unit Info	1,138	414,263	48.9%	75.2%	76.1%	7,030			2,912,087	14,925,109	3.60	
3	*WCEC 01*												
4	Gas		801,687					5,553,369	1,000,000	5,553,369	28,510,626	3.56	5.13
5	Plant Unit Info	1,166	801,687	92.4%	95.5%	92.4%	6,927			5,553,369	28,510,626	3.56	
6	*WCEC 02*												
7	Gas		788,246					5,428,082	1,000,000	5,428,082	27,368,758	3.47	5.04
8	Plant Unit Info	1,159	788,246	91.4%	95.7%	92.5%	6,886			5,428,082	27,368,758	3.47	
9	*WCEC 03*												
10	Gas		781,489					5,419,880	1,000,000	5,419,880	27,704,437	3.55	5.11
11	Plant Unit Info	1,166	781,489	90.1%	95.5%	91.0%	6,935			5,419,880	27,704,437	3.55	
12	**System Totals**												
13	Plant Unit Info	24,930	9,822,115				8,217			80,712,474	279,253,240	2.84	
14													
15													
16													
17													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**Jun - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		817,391					5,346,585	1,000,000	5,346,585	26,531,356	3.25	4.96
5	Plant Unit Info	1,210	817,391	93.8%	95.8%	93.8%	6,541			5,346,585	26,531,356	3.25	
6	*Desoto Solar*												
7	Solar		5,136					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,136	28.5%		52.7%	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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,923					5,754	5,829,336	33,542	702,542	36.53	122.10
15	Plant Unit Info	648	1,923	0.4%	95.3%	33.0%	17,443			33,542	702,542	36.53	
16	*Fort Myers 2*												
17	Gas		771,834					5,631,293	1,000,000	5,631,293	28,374,163	3.68	5.04
18	Plant Unit Info	1,380	771,834	77.7%	94.9%	89.5%	7,296			5,631,293	28,374,163	3.68	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		28,384					310,711	1,000,000	310,711	1,597,518	5.63	5.14
22	Plant Unit Info	296	28,384	26.7%	74.8%	95.5%	10,947			310,711	1,597,518	5.63	
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	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		88,221					699,644	1,000,000	699,644	3,632,019	4.12	5.19
30	Plant Unit Info	429	88,221	28.6%	94.0%	94.0%	7,931			699,644	3,632,019	4.12	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		101,339					802,256	1,000,000	802,256	4,169,353	4.11	5.20
34	Plant Unit Info	429	101,339	32.8%	94.6%	94.5%	7,917			802,256	4,169,353	4.11	
35	*Manatee 1*												
36	Heavy Oil		14,208					30,254	6,400,079	193,628	2,876,816	20.25	95.09
37	Gas		33,153					346,988	1,000,000	346,988	1,809,289	5.46	5.21

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	789	47,361	8.3%	95.3%	76.0%	11,415			540,616	4,686,105	9.89	
2	*Manatee 2*												
3	Heavy Oil		7,722					17,636	6,400,034	112,871	1,676,986	21.72	95.09
4	Gas		18,019					188,334	1,000,000	188,334	981,972	5.45	5.21
5	Plant Unit Info	789	25,741	4.5%	94.0%	77.7%	11,701			301,205	2,658,958	10.33	
6	*Manatee 3*												
7	Gas		189,928					1,340,849	1,000,000	1,340,849	6,766,390	3.56	5.05
8	Plant Unit Info	1,058	189,928	24.9%	30.0%	69.1%	7,060			1,340,849	6,766,390	3.56	
9	*Martin 1*												
10	Heavy Oil		18,831					29,505	6,400,000	188,832	2,716,601	14.43	92.07
11	Gas		46,058					556,949	1,000,000	556,949	2,886,723	6.27	5.18
12	Plant Unit Info	799	64,889	11.3%	92.6%	62.0%	11,493			745,781	5,603,323	8.64	
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	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		124,138					956,318	1,000,000	956,318	4,810,769	3.88	5.03
19	Plant Unit Info	438	124,138	39.4%	94.8%	94.8%	7,704			956,318	4,810,769	3.88	
20	*Martin 4*												
21	Gas		103,872					804,350	1,000,000	804,350	4,046,370	3.90	5.03
22	Plant Unit Info	437	103,872	33.1%	90.8%	94.0%	7,744			804,350	4,046,370	3.90	
23	*Martin 8*												
24	Gas		709,102					4,914,366	1,000,000	4,914,366	25,032,195	3.53	5.09
25	Plant Unit Info	1,111	709,102	88.6%	94.9%	88.6%	6,930			4,914,366	25,032,195	3.53	
26	*Martin 8 Solar*												
27	Solar		13,207					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	13,207	24.5%		45.2%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		800,926					5,233,866	1,000,000	5,233,866	25,886,458	3.23	4.95
31	Plant Unit Info	1,212	800,926	91.8%	94.8%	92.9%	6,535			5,233,866	25,886,458	3.23	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		100,020					923,523	1,000,000	923,523	4,742,618	4.74	5.14
35	Plant Unit Info	247	100,020	56.3%	94.2%	74.6%	9,233			923,523	4,742,618	4.74	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

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	(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		112,066					1,013,534	1,000,000	1,013,534	5,223,407	4.66	5.15
2	Plant Unit Info	250	112,066	62.2%	94.8%	78.6%	9,044			1,013,534	5,223,407	4.66	
3	*Sanford 4*												
4	Gas		341,330					2,553,427	1,000,000	2,553,427	12,854,231	3.77	5.03
5	Plant Unit Info	939	341,330	50.5%	94.7%	94.7%	7,481			2,553,427	12,854,231	3.77	
6	*Sanford 5*												
7	Gas		274,571					2,055,102	1,000,000	2,055,102	10,348,371	3.77	5.04
8	Plant Unit Info	947	274,571	40.3%	70.4%	92.0%	7,485			2,055,102	10,348,371	3.77	
9	*Scherer 4*												
10	Coal		419,242					257,611	17,000,016	4,379,391	10,246,871	2.44	39.78
11	Plant Unit Info	641	419,242	90.9%	93.1%	97.7%	10,446			4,379,391	10,246,871	2.44	
12	*St Johns 1O*												
13	Coal		58,803					29,494	21,999,661	648,858	2,235,442	3.80	75.79
14	Plant Unit Info	127	58,803	64.4%	94.0%	64.4%	11,034			648,858	2,235,442	3.80	
15	*St Johns 2O*												
16	Coal		63,566					31,529	21,999,715	693,629	2,389,681	3.76	75.79
17	Plant Unit Info	127	63,566	69.6%	93.2%	69.6%	10,912			693,629	2,389,681	3.76	
18	*St Lucie 1*												
19	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,796,000	0.70	0.66
20	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,796,000	0.70	
21	*St Lucie 2*												
22	Nuclear		589,677					6,164,182	1,000,000	6,164,182	3,665,000	0.62	0.59
23	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,453			6,164,182	3,665,000	0.62	
24	*Space Coast*												
25	Solar		1,661					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,661	23.1%		42.6%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		3,343					5,051	6,400,119	32,327	465,679	13.93	92.20
29	Gas		15,925					177,871	1,000,000	177,871	921,797	5.79	5.18
30	Plant Unit Info	379	19,268	7.1%	95.2%	67.7%	10,909			210,198	1,387,476	7.20	
31	*Turkey Point 3*												
32	Nuclear		567,218					6,348,776	1,000,000	6,348,776	4,343,000	0.77	0.68
33	Plant Unit Info	808	567,218	97.5%	97.5%	97.5%	11,193			6,348,776	4,343,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		574,937					6,435,113	1,000,000	6,435,113	4,126,000	0.72	0.64
36	Plant Unit Info	819	574,937	97.5%	97.5%	97.5%	11,193			6,435,113	4,126,000	0.72	
37	*Turkey Point 5*												

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		481,400					3,352,103	1,000,000	3,352,103	16,928,752	3.52	5.05
2	Plant Unit Info	1,138	481,400	58.7%	71.4%	69.8%	6,963			3,352,103	16,928,752	3.52	
3	*WCEC 01*												
4	Gas		770,855					5,341,525	1,000,000	5,341,525	27,017,217	3.50	5.06
5	Plant Unit Info	1,166	770,855	91.8%	95.5%	91.8%	6,929			5,341,525	27,017,217	3.50	
6	*WCEC 02*												
7	Gas		419,586					2,901,226	1,000,000	2,901,226	14,813,857	3.53	5.11
8	Plant Unit Info	1,159	419,586	50.3%	56.3%	78.8%	6,914			2,901,226	14,813,857	3.53	
9	*WCEC 03*												
10	Gas		750,431					5,206,507	1,000,000	5,206,507	26,241,381	3.50	5.04
11	Plant Unit Info	1,166	750,431	89.4%	95.5%	90.6%	6,938			5,206,507	26,241,381	3.50	
12	**System Totals**												
13	Plant Unit Info	24,930	10,126,691				8,212			83,160,639	295,856,825	2.92	
14													
15													
16													
17													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,462					5,530,675	1,000,000	5,530,675	27,582,632	3.26	4.99
5	Plant Unit Info	1,210	845,462	93.9%	95.8%	93.9%	6,542			5,530,675	27,582,632	3.26	
6	*Desoto Solar*												
7	Solar		5,083					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,083	27.3%		50.5%	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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		799					2,308	5,831,456	13,459	281,798	35.27	122.10
15	Plant Unit Info	648	799	0.2%	95.3%	20.6%	16,845			13,459	281,798	35.27	
16	*Fort Myers 2*												
17	Gas		724,996					5,309,295	1,000,000	5,309,295	26,491,263	3.65	4.99
18	Plant Unit Info	1,380	724,996	70.6%	94.9%	91.5%	7,323			5,309,295	26,491,263	3.65	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		34,739					379,837	1,000,000	379,837	1,955,684	5.63	5.15
22	Plant Unit Info	296	34,739	31.6%	95.5%	95.5%	10,934			379,837	1,955,684	5.63	
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	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		97,084					770,617	1,000,000	770,617	3,973,482	4.09	5.16
30	Plant Unit Info	429	97,084	30.4%	94.0%	94.0%	7,938			770,617	3,973,482	4.09	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		109,852					869,546	1,000,000	869,546	4,483,677	4.08	5.16
34	Plant Unit Info	429	109,852	34.4%	94.6%	94.5%	7,916			869,546	4,483,677	4.08	
35	*Manatee 1*												
36	Heavy Oil		14,248					32,203	6,399,994	206,099	3,081,946	21.63	95.70
37	Gas		33,663					352,504	1,000,000	352,504	1,825,926	5.42	5.18

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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	789	47,911	8.2%	95.3%	73.2%	11,659			558,603	4,907,872	10.24	
2	*Manatee 2*												
3	Heavy Oil		6,662					15,371	6,400,039	98,375	1,471,061	22.08	95.70
4	Gas		15,752					164,781	1,000,000	164,781	852,985	5.42	5.18
5	Plant Unit Info	789	22,414	3.8%	94.0%	72.9%	11,741			263,156	2,324,046	10.37	
6	*Manatee 3*												
7	Gas		442,577					3,117,479	1,000,000	3,117,479	15,583,605	3.52	5.00
8	Plant Unit Info	1,058	442,577	56.2%	73.2%	73.5%	7,044			3,117,479	15,583,605	3.52	
9	*Martin 1*												
10	Heavy Oil		18,813					29,592	6,399,905	189,386	2,724,611	14.48	92.07
11	Gas		46,008					570,308	1,000,000	570,308	2,929,167	6.37	5.14
12	Plant Unit Info	799	64,821	10.9%	92.6%	57.5%	11,720			759,694	5,653,778	8.72	
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	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		127,874					986,053	1,000,000	986,053	4,912,789	3.84	4.98
19	Plant Unit Info	438	127,874	39.2%	94.8%	94.8%	7,711			986,053	4,912,789	3.84	
20	*Martin 4*												
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	437	0	0.0%	0.0%	0.0%	0			0	0	0.00	
23	*Martin 8*												
24	Gas		728,180					5,048,090	1,000,000	5,048,090	25,441,965	3.49	5.04
25	Plant Unit Info	1,111	728,180	88.1%	94.9%	89.0%	6,932			5,048,090	25,441,965	3.49	
26	*Martin 8 Solar*												
27	Solar		12,594					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	12,594	22.6%		36.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		838,794					5,481,564	1,000,000	5,481,564	26,844,363	3.20	4.90
31	Plant Unit Info	1,212	838,794	93.0%	94.8%	93.0%	6,535			5,481,564	26,844,363	3.20	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		110,627					1,020,401	1,000,000	1,020,401	5,222,055	4.72	5.12
35	Plant Unit Info	247	110,627	60.3%	94.2%	74.4%	9,224			1,020,401	5,222,055	4.72	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

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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		121,958					1,102,537	1,000,000	1,102,537	5,654,775	4.64	5.13
2	Plant Unit Info	250	121,958	65.5%	94.8%	78.0%	9,040			1,102,537	5,654,775	4.64	
3	*Sanford 4*												
4	Gas		273,679					2,064,840	1,000,000	2,064,840	10,293,441	3.76	4.99
5	Plant Unit Info	939	273,679	39.2%	79.4%	80.1%	7,545			2,064,840	10,293,441	3.76	
6	*Sanford 5*												
7	Gas		366,541					2,748,388	1,000,000	2,748,388	13,702,323	3.74	4.99
8	Plant Unit Info	947	366,541	52.0%	94.9%	95.6%	7,498			2,748,388	13,702,323	3.74	
9	*Scherer 4*												
10	Coal		434,260					266,839	17,000,026	4,536,270	10,636,666	2.45	39.86
11	Plant Unit Info	641	434,260	91.1%	93.1%	97.7%	10,446			4,536,270	10,636,666	2.45	
12	*St Johns 1O*												
13	Coal		59,279					29,825	22,000,034	656,151	2,261,047	3.81	75.81
14	Plant Unit Info	127	59,279	62.8%	94.0%	62.8%	11,069			656,151	2,261,047	3.81	
15	*St Johns 2O*												
16	Coal		66,282					32,847	22,000,061	722,636	2,490,146	3.76	75.81
17	Plant Unit Info	127	66,282	70.2%	93.2%	70.2%	10,902			722,636	2,490,146	3.76	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,762					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,762	23.7%		43.7%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		14,782					22,419	6,400,018	143,482	2,066,928	13.98	92.20
29	Gas		7,751					99,695	1,000,000	99,695	506,715	6.54	5.08
30	Plant Unit Info	379	22,533	8.0%	95.2%	62.5%	10,792			243,177	2,573,643	11.42	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,264,000	0.72	0.64
36	Plant Unit Info	819	594,101	97.5%	97.5%	97.5%	11,193			6,649,613	4,264,000	0.72	
37	*Turkey Point 5*												

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	(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		671,494					4,676,144	1,000,000	4,676,144	23,374,227	3.48	5.00
2	Plant Unit Info	1,138	671,494	79.3%	94.2%	89.4%	6,964			4,676,144	23,374,227	3.48	
3	*WCEC 01*												
4	Gas		805,649					5,579,551	1,000,000	5,579,551	27,909,050	3.46	5.00
5	Plant Unit Info	1,166	805,649	92.9%	95.5%	92.9%	6,926			5,579,551	27,909,050	3.46	
6	*WCEC 02*												
7	Gas		656,091					4,532,701	1,000,000	4,532,701	22,934,683	3.50	5.06
8	Plant Unit Info	1,159	656,091	76.1%	80.2%	80.5%	6,909			4,532,701	22,934,683	3.50	
9	*WCEC 03*												
10	Gas		765,802					5,310,797	1,000,000	5,310,797	26,515,271	3.46	4.99
11	Plant Unit Info	1,166	765,802	88.3%	95.5%	91.3%	6,935			5,310,797	26,515,271	3.46	
12	**System Totals**												
13	Plant Unit Info	24,930	10,960,315				8,155			89,375,901	321,498,280	2.93	
14													
15													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,587					5,531,479	1,000,000	5,531,479	27,597,145	3.26	4.99
5	Plant Unit Info	1,210	845,587	93.9%	95.8%	93.9%	6,542			5,531,479	27,597,145	3.26	
6	*Desoto Solar*												
7	Solar		4,833					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,833	26.0%		48.0%	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	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		285					755	5,778,808	4,363	92,183	32.34	122.10
15	Plant Unit Info	648	285	0.1%	95.3%	22.0%	15,309			4,363	92,183	32.34	
16	*Fort Myers 2*												
17	Gas		641,553					4,721,602	1,000,000	4,721,602	23,564,230	3.67	4.99
18	Plant Unit Info	1,380	641,553	62.5%	94.9%	93.5%	7,360			4,721,602	23,564,230	3.67	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		25,418					279,105	1,000,000	279,105	1,439,909	5.66	5.16
22	Plant Unit Info	296	25,418	23.1%	95.5%	95.5%	10,980			279,105	1,439,909	5.66	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		1,271					29,365	1,000,000	29,365	151,643	11.93	5.16
26	Plant Unit Info	840	1,271	0.2%	95.3%	50.4%	23,100			29,365	151,643	11.93	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		91,041					723,271	1,000,000	723,271	3,731,154	4.10	5.16
30	Plant Unit Info	429	91,041	28.5%	87.9%	94.0%	7,944			723,271	3,731,154	4.10	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		100,934					800,146	1,000,000	800,146	4,132,261	4.09	5.16
34	Plant Unit Info	429	100,934	31.6%	94.6%	94.5%	7,927			800,146	4,132,261	4.09	
35	*Manatee 1*												
36	Heavy Oil		15,090					31,641	6,399,924	202,500	3,028,160	20.07	95.70
37	Gas		21,022					220,148	1,000,000	220,148	1,141,182	5.43	5.18

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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	789	36,112	6.2%	95.3%	72.7%	11,704			422,648	4,169,343	11.55	
2	*Manatee 2*												
3	Heavy Oil		5,010					11,537	6,400,104	73,838	1,104,133	22.04	95.70
4	Gas		11,035					115,267	1,000,000	115,267	597,263	5.41	5.18
5	Plant Unit Info	789	16,045	2.7%	94.0%	75.4%	11,786			189,105	1,701,397	10.60	
6	*Manatee 3*												
7	Gas		637,168					4,426,441	1,000,000	4,426,441	22,099,201	3.47	4.99
8	Plant Unit Info	1,058	637,168	81.0%	90.8%	88.3%	6,947			4,426,441	22,099,201	3.47	
9	*Martin 1*												
10	Heavy Oil		15,212					23,991	6,400,108	153,545	2,208,913	14.52	92.07
11	Gas		39,073					494,115	1,000,000	494,115	2,535,978	6.49	5.13
12	Plant Unit Info	799	54,285	9.1%	92.6%	56.1%	11,931			647,660	4,744,891	8.74	
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	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		119,571					922,730	1,000,000	922,730	4,598,135	3.85	4.98
19	Plant Unit Info	438	119,571	36.7%	94.8%	94.8%	7,717			922,730	4,598,135	3.85	
20	*Martin 4*												
21	Gas		16,833					130,438	1,000,000	130,438	650,050	3.86	4.98
22	Plant Unit Info	437	16,833	5.2%	18.2%	94.0%	7,749			130,438	650,050	3.86	
23	*Martin 8*												
24	Gas		734,652					5,090,174	1,000,000	5,090,174	25,687,416	3.50	5.05
25	Plant Unit Info	1,111	734,652	88.9%	94.9%	88.8%	6,929			5,090,174	25,687,416	3.50	
26	*Martin 8 Solar*												
27	Solar		11,773					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	11,773	21.1%		39.0%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		839,004					5,483,125	1,000,000	5,483,125	26,856,591	3.20	4.90
31	Plant Unit Info	1,212	839,004	93.0%	94.8%	93.0%	6,535			5,483,125	26,856,591	3.20	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		98,737					915,112	1,000,000	915,112	4,699,008	4.76	5.13
35	Plant Unit Info	247	98,737	53.8%	94.2%	71.6%	9,268			915,112	4,699,008	4.76	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	PLANT UNIT (1)	Net Capability (MW) (2)	Net Generation (MWH) (3)	Capacity Factor (%) (4)	Equivalent Availability Factor (%) (5)	Net Output Factor (%) (6)	Avg Net Heat Rate (BTU/KWH) (7)	Fuel Burned (Units) (8)	Fuel Heat Value (BTU/Unit) (9)	Fuel Burned (MMBTU) (10)	As Burned Fuel Cost ($) (11)	Fuel Cost per KWH (cents/KWH) (12)	Cost of Fuel ($/Unit) (13)
1	Gas		111,520					1,010,849	1,000,000	1,010,849	5,201,991	4.66	5.15
2	Plant Unit Info	250	111,520	59.9%	94.8%	76.8%	9,064			1,010,849	5,201,991	4.66	
3	*Sanford 4*												
4	Gas		243,346					1,843,592	1,000,000	1,843,592	9,191,701	3.78	4.99
5	Plant Unit Info	939	243,346	34.8%	77.9%	78.3%	7,576			1,843,592	9,191,701	3.78	
6	*Sanford 5*												
7	Gas		343,916					2,582,946	1,000,000	2,582,946	12,879,302	3.74	4.99
8	Plant Unit Info	947	343,916	48.8%	94.9%	95.6%	7,510			2,582,946	12,879,302	3.74	
9	*Scherer 4*												
10	Coal		371,687					228,389	17,000,009	3,882,615	9,136,768	2.46	40.01
11	Plant Unit Info	641	371,687	78.0%	93.1%	97.7%	10,446			3,882,615	9,136,768	2.46	
12	*St Johns 1O*												
13	Coal		57,050					28,871	22,000,346	635,172	2,195,369	3.85	76.04
14	Plant Unit Info	127	57,050	60.4%	94.0%	60.4%	11,134			635,172	2,195,369	3.85	
15	*St Johns 2O*												
16	Coal		64,731					32,180	21,999,720	707,951	2,446,987	3.78	76.04
17	Plant Unit Info	127	64,731	68.6%	93.2%	68.6%	10,937			707,951	2,446,987	3.78	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,673					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,673	22.5%		41.5%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		12,415					18,734	6,399,968	119,897	1,727,188	13.91	92.20
29	Gas		5,248					71,217	1,000,000	71,217	363,046	6.92	5.10
30	Plant Unit Info	379	17,663	6.3%	95.2%	67.5%	10,820			191,114	2,090,234	11.83	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,264,000	0.72	0.64
36	Plant Unit Info	819	594,101	97.5%	97.5%	97.5%	11,193			6,649,613	4,264,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		614,881					4,295,744	1,000,000	4,295,744	21,485,477	3.49	5.00
2	Plant Unit Info	1,138	614,881	72.6%	94.2%	90.6%	6,986			4,295,744	21,485,477	3.49	
3	*WCEC 01*												
4	Gas		807,212					5,590,079	1,000,000	5,590,079	27,962,095	3.46	5.00
5	Plant Unit Info	1,166	807,212	93.1%	95.5%	93.0%	6,925			5,590,079	27,962,095	3.46	
6	*WCEC 02*												
7	Gas		800,775					5,513,705	1,000,000	5,513,705	27,953,015	3.49	5.07
8	Plant Unit Info	1,159	800,775	92.8%	95.7%	92.8%	6,885			5,513,705	27,953,015	3.49	
9	*WCEC 03*												
10	Gas		794,169					5,506,221	1,000,000	5,506,221	27,499,829	3.46	4.99
11	Plant Unit Info	1,166	794,169	91.5%	95.5%	91.5%	6,933			5,506,221	27,499,829	3.46	
12	**System Totals**												
13	Plant Unit Info	24,930	11,004,904				8,103			89,170,995	321,451,323	2.92	
14													
15													
16													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		818,924					5,357,306	1,000,000	5,357,306	26,855,820	3.28	5.01
5	Plant Unit Info	1,210	818,924	94.0%	95.8%	94.0%	6,542			5,357,306	26,855,820	3.28	
6	*Desoto Solar*												
7	Solar		4,298					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,298	23.9%		44.1%	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	420	0	0.0%	95.3%	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	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		585,315					4,306,439	1,000,000	4,306,439	21,641,394	3.70	5.03
18	Plant Unit Info	1,380	585,315	58.9%	94.9%	93.2%	7,357			4,306,439	21,641,394	3.70	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		28,102					308,900	1,000,000	308,900	1,596,744	5.68	5.17
22	Plant Unit Info	296	28,102	26.4%	95.5%	95.5%	10,992			308,900	1,596,744	5.68	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		9,161					204,824	1,000,000	204,824	1,065,458	11.63	5.20
26	Plant Unit Info	840	9,161	1.5%	95.3%	43.6%	22,359			204,824	1,065,458	11.63	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	429	0	0.0%	0.0%	0.0%	0			0	0	0.00	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		92,016					733,748	1,000,000	733,748	3,806,161	4.14	5.19
34	Plant Unit Info	429	92,016	29.8%	94.6%	94.5%	7,974			733,748	3,806,161	4.14	
35	*Manatee 1*												
36	Heavy Oil		7,337					17,119	6,399,907	109,560	1,638,351	22.33	95.70
37	Gas		17,534					184,584	1,000,000	184,584	960,485	5.48	5.20

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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	789	24,871	4.4%	95.3%	71.7%	11,827			294,144	2,598,836	10.45	
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	789	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		537,569					3,775,556	1,000,000	3,775,556	19,002,763	3.53	5.03
8	Plant Unit Info	1,078	537,569	69.2%	94.6%	92.3%	7,023			3,775,556	19,002,763	3.53	
9	*Martin 1*												
10	Heavy Oil		12,550					19,719	6,400,020	126,202	1,815,579	14.47	92.07
11	Gas		30,973					399,043	1,000,000	399,043	2,060,503	6.65	5.16
12	Plant Unit Info	799	43,523	7.6%	92.6%	61.9%	12,068			525,245	3,876,082	8.91	
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	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		114,173					882,890	1,000,000	882,890	4,431,070	3.88	5.02
19	Plant Unit Info	438	114,173	36.2%	94.8%	94.8%	7,733			882,890	4,431,070	3.88	
20	*Martin 4*												
21	Gas		105,925					823,867	1,000,000	823,867	4,134,894	3.90	5.02
22	Plant Unit Info	437	105,925	33.7%	94.0%	94.0%	7,778			823,867	4,134,894	3.90	
23	*Martin 8*												
24	Gas		690,944					4,792,520	1,000,000	4,792,520	24,320,785	3.52	5.07
25	Plant Unit Info	1,111	690,944	86.4%	94.9%	89.2%	6,936			4,792,520	24,320,785	3.52	
26	*Martin 8 Solar*												
27	Solar		10,217					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	10,217	18.9%		37.8%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		812,599					5,310,953	1,000,000	5,310,953	26,202,099	3.22	4.93
31	Plant Unit Info	1,212	812,599	93.1%	94.8%	93.1%	6,536			5,310,953	26,202,099	3.22	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		99,246					918,921	1,000,000	918,921	4,733,786	4.77	5.15
35	Plant Unit Info	247	99,246	55.9%	94.2%	71.9%	9,259			918,921	4,733,786	4.77	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		114,992					1,040,028	1,000,000	1,040,028	5,372,260	4.67	5.17
2	Plant Unit Info	250	114,992	63.8%	94.8%	78.3%	9,044			1,040,028	5,372,260	4.67	
3	*Sanford 4*												
4	Gas		269,442					2,029,057	1,000,000	2,029,057	10,193,755	3.78	5.02
5	Plant Unit Info	939	269,442	39.9%	94.7%	95.0%	7,531			2,029,057	10,193,755	3.78	
6	*Sanford 5*												
7	Gas		302,285					2,276,333	1,000,000	2,276,333	11,435,200	3.78	5.02
8	Plant Unit Info	947	302,285	44.3%	94.9%	95.6%	7,530			2,276,333	11,435,200	3.78	
9	*Scherer 4*												
10	Coal		357,920					219,930	17,000,023	3,738,815	8,831,719	2.47	40.16
11	Plant Unit Info	641	357,920	77.6%	93.1%	97.7%	10,446			3,738,815	8,831,719	2.47	
12	*St Johns 1O*												
13	Coal		57,613					29,019	22,000,034	638,419	2,210,970	3.84	76.19
14	Plant Unit Info	127	57,613	63.1%	94.0%	63.1%	11,081			638,419	2,210,970	3.84	
15	*St Johns 2O*												
16	Coal		64,481					31,968	21,999,718	703,287	2,435,656	3.78	76.19
17	Plant Unit Info	127	64,481	70.6%	93.2%	70.6%	10,907			703,287	2,435,656	3.78	
18	*St Lucie 1*												
19	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,796,000	0.70	0.66
20	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,796,000	0.70	
21	*St Lucie 2*												
22	Nuclear		589,677					6,164,182	1,000,000	6,164,182	3,665,000	0.62	0.59
23	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,453			6,164,182	3,665,000	0.62	
24	*Space Coast*												
25	Solar		1,481					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,481	20.6%		38.0%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		11,354					17,162	6,399,953	109,836	1,582,257	13.94	92.20
29	Gas		5,321					72,049	1,000,000	72,049	368,917	6.93	5.12
30	Plant Unit Info	379	16,675	6.1%	95.2%	67.6%	10,908			181,885	1,951,174	11.70	
31	*Turkey Point 3*												
32	Nuclear		567,218					6,348,776	1,000,000	6,348,776	4,343,000	0.77	0.68
33	Plant Unit Info	808	567,218	97.5%	97.5%	97.5%	11,193			6,348,776	4,343,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		440,785					4,933,613	1,000,000	4,933,613	3,163,000	0.72	0.64
36	Plant Unit Info	819	440,785	74.8%	74.8%	97.5%	11,193			4,933,613	3,163,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		506,126					3,552,099	1,000,000	3,552,099	17,883,977	3.53	5.03
2	Plant Unit Info	1,138	506,126	61.8%	94.2%	91.9%	7,018			3,552,099	17,883,977	3.53	
3	*WCEC 01*												
4	Gas		737,756					5,114,991	1,000,000	5,114,991	25,745,962	3.49	5.03
5	Plant Unit Info	1,166	737,756	87.9%	91.3%	89.4%	6,933			5,114,991	25,745,962	3.49	
6	*WCEC 02*												
7	Gas		775,469					5,340,110	1,000,000	5,340,110	27,214,552	3.51	5.10
8	Plant Unit Info	1,159	775,469	92.9%	95.7%	92.9%	6,886			5,340,110	27,214,552	3.51	
9	*WCEC 03*												
10	Gas		725,483					5,030,523	1,000,000	5,030,523	25,302,263	3.49	5.03
11	Plant Unit Info	1,166	725,483	86.4%	95.5%	91.9%	6,934			5,030,523	25,302,263	3.49	
12	**System Totals**												
13	Plant Unit Info	24,951	10,192,948				8,104			82,599,595	298,810,379	2.93	
14													
15													
16													
17													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,131					5,529,269	1,000,000	5,529,269	28,254,699	3.34	5.11
5	Plant Unit Info	1,210	845,131	93.9%	95.8%	93.9%	6,542			5,529,269	28,254,699	3.34	
6	*Desoto Solar*												
7	Solar		4,150					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,150	22.3%		41.2%	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	420	0	0.0%	95.3%	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	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		809,794					5,895,869	1,000,000	5,895,869	29,889,848	3.69	5.07
18	Plant Unit Info	1,380	809,794	78.9%	94.9%	88.4%	7,281			5,895,869	29,889,848	3.69	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		19,205					210,084	1,000,000	210,084	1,107,201	5.77	5.27
22	Plant Unit Info	296	19,205	17.5%	95.5%	95.5%	10,939			210,084	1,107,201	5.77	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		2,542					58,669	1,000,000	58,669	309,591	12.18	5.28
26	Plant Unit Info	840	2,542	0.4%	95.3%	50.4%	23,077			58,669	309,591	12.18	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		66,871					531,890	1,000,000	531,890	2,800,667	4.19	5.27
30	Plant Unit Info	429	66,871	21.0%	84.9%	94.0%	7,954			531,890	2,800,667	4.19	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		85,530					679,003	1,000,000	679,003	3,580,140	4.19	5.27
34	Plant Unit Info	429	85,530	26.8%	94.6%	94.5%	7,939			679,003	3,580,140	4.19	
35	*Manatee 1*												
36	Heavy Oil		7,645					15,029	6,400,226	96,189	1,438,331	18.81	95.70
37	Gas		5,197					54,382	1,000,000	54,382	287,369	5.53	5.28

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	789	12,842	2.2%	95.3%	74.0%	11,725			150,571	1,725,700	13.44	
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	789	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		647,728					4,520,605	1,000,000	4,520,605	22,940,058	3.54	5.07
8	Plant Unit Info	1,078	647,728	80.7%	94.6%	91.4%	6,979			4,520,605	22,940,058	3.54	
9	*Martin 1*												
10	Heavy Oil		9,724					15,237	6,399,947	97,516	1,402,909	14.43	92.07
11	Gas		18,008					221,630	1,000,000	221,630	1,163,588	6.46	5.25
12	Plant Unit Info	799	27,732	4.7%	92.6%	63.1%	11,508			319,146	2,566,498	9.25	
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	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		67,674					523,160	1,000,000	523,160	2,646,548	3.91	5.06
19	Plant Unit Info	438	67,674	20.8%	73.4%	94.8%	7,731			523,160	2,646,548	3.91	
20	*Martin 4*												
21	Gas		94,019					729,870	1,000,000	729,870	3,692,255	3.93	5.06
22	Plant Unit Info	437	94,019	29.0%	94.0%	94.0%	7,763			729,870	3,692,255	3.93	
23	*Martin 8*												
24	Gas		727,486					5,042,400	1,000,000	5,042,400	25,906,470	3.56	5.14
25	Plant Unit Info	1,111	727,486	88.0%	94.9%	89.2%	6,931			5,042,400	25,906,470	3.56	
26	*Martin 8 Solar*												
27	Solar		8,981					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	8,981	16.1%		24.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		839,419					5,486,047	1,000,000	5,486,047	27,416,683	3.27	5.00
31	Plant Unit Info	1,212	839,419	93.1%	94.8%	93.1%	6,536			5,486,047	27,416,683	3.27	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		89,122					837,061	1,000,000	837,061	4,372,322	4.91	5.22
35	Plant Unit Info	247	89,122	48.6%	94.2%	60.8%	9,392			837,061	4,372,322	4.91	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		101,684					931,573	1,000,000	931,573	4,879,329	4.80	5.24
2	Plant Unit Info	250	101,684	54.6%	87.1%	66.8%	9,161			931,573	4,879,329	4.80	
3	*Sanford 4*												
4	Gas		268,550					2,015,948	1,000,000	2,015,948	10,226,930	3.81	5.07
5	Plant Unit Info	939	268,550	38.4%	94.7%	95.0%	7,507			2,015,948	10,226,930	3.81	
6	*Sanford 5*												
7	Gas		323,497					2,424,944	1,000,000	2,424,944	12,296,667	3.80	5.07
8	Plant Unit Info	947	323,497	45.9%	94.9%	94.9%	7,496			2,424,944	12,296,667	3.80	
9	*Scherer 4*												
10	Coal		401,199					246,534	16,999,972	4,191,071	9,929,066	2.47	40.27
11	Plant Unit Info	641	401,199	84.2%	93.1%	97.4%	10,446			4,191,071	9,929,066	2.47	
12	*St Johns 1O*												
13	Coal		51,036					26,162	22,000,229	575,570	1,997,908	3.91	76.37
14	Plant Unit Info	127	51,036	54.1%	94.0%	54.1%	11,278			575,570	1,997,908	3.91	
15	*St Johns 2O*												
16	Coal		59,380					29,774	22,000,034	655,029	2,273,744	3.83	76.37
17	Plant Unit Info	127	59,380	62.9%	93.2%	62.9%	11,031			655,029	2,273,744	3.83	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,427					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,427	19.2%		38.4%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		4,805					7,404	6,400,054	47,386	682,615	14.21	92.20
29	Gas		2,088					32,420	1,000,000	32,420	165,765	7.94	5.11
30	Plant Unit Info	379	6,893	2.4%	95.2%	51.9%	11,578			79,806	848,380	12.31	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		38,329					429,012	1,000,000	429,012	0	0.00	0.00
36	Plant Unit Info	819	38,329	6.3%	6.3%	97.5%	11,193			429,012	0	0.00	
37	*Turkey Point 5*												

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		589,506					4,115,129	1,000,000	4,115,129	20,981,780	3.56	5.10
2	Plant Unit Info	1,138	589,506	69.6%	94.2%	90.8%	6,981			4,115,129	20,981,780	3.56	
3	*WCEC 01*												
4	Gas		42,760					314,071	1,000,000	314,071	1,616,066	3.78	5.15
5	Plant Unit Info	1,166	42,760	4.9%	14.4%	28.6%	7,345			314,071	1,616,066	3.78	
6	*WCEC 02*												
7	Gas		798,279					5,497,511	1,000,000	5,497,511	28,392,877	3.56	5.16
8	Plant Unit Info	1,159	798,279	92.6%	95.7%	92.5%	6,887			5,497,511	28,392,877	3.56	
9	*WCEC 03*												
10	Gas		773,656					5,363,010	1,000,000	5,363,010	27,311,492	3.53	5.09
11	Plant Unit Info	1,166	773,656	89.2%	95.5%	92.0%	6,932			5,363,010	27,311,492	3.53	
12	**System Totals**												
13	Plant Unit Info	24,951	9,711,503				7,985			77,550,947	291,192,917	3.00	
14													
15													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

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	**Nov - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		911,005					5,931,462	1,000,000	5,931,462	31,718,652	3.48	5.35
5	Plant Unit Info	1,355	911,005	93.4%	95.8%	93.4%	6,511			5,931,462	31,718,652	3.48	
6	*Desoto Solar*												
7	Solar		3,572					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,572	19.9%		43.3%	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	443	0	0.0%	95.3%	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%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		203,575					1,569,592	1,000,000	1,569,592	8,447,771	4.15	5.38
18	Plant Unit Info	1,435	203,575	19.7%	43.3%	56.3%	7,710			1,569,592	8,447,771	4.15	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		1,651					17,744	1,000,000	17,744	96,006	5.82	5.41
22	Plant Unit Info	314	1,651	1.5%	95.5%	95.5%	10,748			17,744	96,006	5.82	
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	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		14,252					113,127	1,000,000	113,127	616,178	4.32	5.45
30	Plant Unit Info	442	14,252	4.5%	94.0%	94.9%	7,938			113,127	616,178	4.32	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		13,866					110,169	1,000,000	110,169	599,910	4.33	5.45
34	Plant Unit Info	442	13,866	4.4%	94.6%	92.4%	7,946			110,169	599,910	4.33	
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: JANUARY 2014 THROUGH DECEMBER 2014

	(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	795	0	0.0%	63.5%	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	795	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		470,830					3,281,875	1,000,000	3,281,875	17,689,286	3.76	5.39
8	Plant Unit Info	1,134	470,830	57.7%	94.6%	90.2%	6,970			3,281,875	17,689,286	3.76	
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	805	0	0.0%	92.6%	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%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		60,896					468,039	1,000,000	468,039	2,518,352	4.14	5.38
19	Plant Unit Info	454	60,896	18.6%	94.8%	85.4%	7,686			468,039	2,518,352	4.14	
20	*Martin 4*												
21	Gas		42,652					327,829	1,000,000	327,829	1,763,938	4.14	5.38
22	Plant Unit Info	453	42,652	13.1%	94.0%	85.7%	7,686			327,829	1,763,938	4.14	
23	*Martin 8*												
24	Gas		625,157					4,318,806	1,000,000	4,318,806	23,261,703	3.72	5.39
25	Plant Unit Info	1,147	625,157	75.7%	94.9%	82.5%	6,908			4,318,806	23,261,703	3.72	
26	*Martin 8 Solar*												
27	Solar		6,459					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	6,459	12.0%		19.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		899,712					5,847,093	1,000,000	5,847,093	31,071,957	3.45	5.31
31	Plant Unit Info	1,344	899,712	93.0%	94.8%	93.0%	6,499			5,847,093	31,071,957	3.45	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		1,792					17,180	1,000,000	17,180	93,450	5.22	5.44
35	Plant Unit Info	251	1,792	1.0%	94.2%	89.3%	9,588			17,180	93,450	5.22	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		2,623					24,670	1,000,000	24,670	134,399	5.12	5.45
2	Plant Unit Info	255	2,623	1.4%	93.2%	85.8%	9,407			24,670	134,399	5.12	
3	*Sanford 4*												
4	Gas		197,175					1,478,444	1,000,000	1,478,444	7,958,980	4.04	5.38
5	Plant Unit Info	990	197,175	27.7%	94.7%	89.0%	7,498			1,478,444	7,958,980	4.04	
6	*Sanford 5*												
7	Gas		188,283					1,416,033	1,000,000	1,416,033	7,622,646	4.05	5.38
8	Plant Unit Info	994	188,283	26.3%	81.4%	81.0%	7,521			1,416,033	7,622,646	4.05	
9	*Scherer 4*												
10	Coal		339,077					206,720	17,000,029	3,514,246	8,353,111	2.46	40.41
11	Plant Unit Info	646	339,077	73.0%	93.1%	92.3%	10,364			3,514,246	8,353,111	2.46	
12	*St Johns 1O*												
13	Coal		40,833					21,487	22,000,047	472,715	1,645,105	4.03	76.56
14	Plant Unit Info	128	40,833	44.2%	94.0%	44.2%	11,577			472,715	1,645,105	4.03	
15	*St Johns 2O*												
16	Coal		41,887					21,760	21,999,632	478,712	1,666,006	3.98	76.56
17	Plant Unit Info	128	41,887	45.4%	93.2%	45.4%	11,429			478,712	1,666,006	3.98	
18	*St Lucie 1*												
19	Nuclear		704,105					7,272,165	1,000,000	7,272,165	4,796,000	0.68	0.66
20	Plant Unit Info	1,003	704,105	97.5%	97.5%	97.5%	10,328			7,272,165	4,796,000	0.68	
21	*St Lucie 2*												
22	Nuclear		603,721					6,173,813	1,000,000	6,173,813	3,670,000	0.61	0.59
23	Plant Unit Info	860	603,721	97.5%	97.5%	97.5%	10,226			6,173,813	3,670,000	0.61	
24	*Space Coast*												
25	Solar		1,220					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,220	17.0%		37.0%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		377					5,236	1,000,000	5,236	28,325	7.52	5.41
30	Plant Unit Info	380	377	0.1%	95.2%	24.8%	13,908			5,236	28,325	7.52	
31	*Turkey Point 3*												
32	Nuclear		584,765					6,356,602	1,000,000	6,356,602	4,348,000	0.74	0.68
33	Plant Unit Info	833	584,765	97.5%	97.5%	97.5%	10,870			6,356,602	4,348,000	0.74	
34	*Turkey Point 4*												
35	Nuclear		591,786					6,432,893	1,000,000	6,432,893	4,362,000	0.74	0.68
36	Plant Unit Info	843	591,786	97.5%	97.5%	97.5%	10,870			6,432,893	4,362,000	0.74	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		218,992					1,530,441	1,000,000	1,530,441	8,213,244	3.75	5.37
2	Plant Unit Info	1,166	218,992	26.1%	50.2%	93.9%	6,989			1,530,441	8,213,244	3.75	
3	*WCEC 01*												
4	Gas		339,915					2,343,978	1,000,000	2,343,978	12,643,140	3.72	5.39
5	Plant Unit Info	1,208	339,915	39.1%	51.0%	72.0%	6,896			2,343,978	12,643,140	3.72	
6	*WCEC 02*												
7	Gas		731,075					5,006,714	1,000,000	5,006,714	27,015,247	3.70	5.40
8	Plant Unit Info	1,202	731,075	84.5%	95.7%	84.5%	6,848			5,006,714	27,015,247	3.70	
9	*WCEC 03*												
10	Gas		640,191					4,387,510	1,000,000	4,387,510	23,644,681	3.69	5.39
11	Plant Unit Info	1,207	640,191	73.7%	95.5%	84.8%	6,853			4,387,510	23,644,681	3.69	
12	**System Totals**												
13	Plant Unit Info	25,944	8,481,442				8,123			68,897,087	233,978,087	2.76	
14													
15													
16													
17													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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 - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		940,327					6,119,294	1,000,000	6,119,294	33,265,918	3.54	5.44
5	Plant Unit Info	1,355	940,327	93.3%	95.8%	93.3%	6,508			6,119,294	33,265,918	3.54	
6	*Desoto Solar*												
7	Solar		3,244					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,244	17.4%		38.1%	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	443	0	0.0%	95.3%	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%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		330,193					2,419,712	1,000,000	2,419,712	13,275,049	4.02	5.49
18	Plant Unit Info	1,435	330,193	30.9%	94.9%	85.9%	7,328			2,419,712	13,275,049	4.02	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	0	0.0%	95.5%	0.0%	0			0	0	0.00	
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	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		26,841					211,007	1,000,000	211,007	1,164,262	4.34	5.52
30	Plant Unit Info	442	26,841	8.2%	94.0%	72.4%	7,861			211,007	1,164,262	4.34	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		17,903					141,096	1,000,000	141,096	776,648	4.34	5.50
34	Plant Unit Info	442	17,903	5.5%	94.6%	69.9%	7,881			141,096	776,648	4.34	
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: JANUARY 2014 THROUGH DECEMBER 2014

	(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	795	0	0.0%	95.3%	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	795	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		437,794					3,047,161	1,000,000	3,047,161	16,738,264	3.82	5.49
8	Plant Unit Info	1,134	437,794	51.9%	94.6%	86.7%	6,960			3,047,161	16,738,264	3.82	
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	805	0	0.0%	92.6%	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%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		29,904					228,711	1,000,000	228,711	1,254,528	4.20	5.49
19	Plant Unit Info	454	29,904	8.9%	94.8%	85.5%	7,648			228,711	1,254,528	4.20	
20	*Martin 4*												
21	Gas		34,439					263,497	1,000,000	263,497	1,445,270	4.20	5.48
22	Plant Unit Info	453	34,439	10.2%	94.0%	80.9%	7,651			263,497	1,445,270	4.20	
23	*Martin 8*												
24	Gas		587,035					4,063,040	1,000,000	4,063,040	22,313,587	3.80	5.49
25	Plant Unit Info	1,147	587,035	68.8%	94.9%	83.9%	6,921			4,063,040	22,313,587	3.80	
26	*Martin 8 Solar*												
27	Solar		5,345					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	5,345	9.6%		19.2%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		705,500					4,583,073	1,000,000	4,583,073	24,814,195	3.52	5.41
31	Plant Unit Info	1,344	705,500	70.6%	73.4%	92.6%	6,496			4,583,073	24,814,195	3.52	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	251	0	0.0%	94.2%	0.0%	0			0	0	0.00	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	PLANT UNIT (1)	Net Capability (MW) (2)	Net Generation (MWH) (3)	Capacity Factor (%) (4)	Equivalent Availability Factor (%) (5)	Net Output Factor (%) (6)	Avg Net Heat Rate (BTU/KWH) (7)	Fuel Burned (Units) (8)	Fuel Heat Value (BTU/Unit) (9)	Fuel Burned (MMBTU) (10)	As Burned Fuel Cost ($) (11)	Fuel Cost per KWH (cents/KWH) (12)	Cost of Fuel ($/Unit) (13)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	255	0	0.0%	94.8%	0.0%	0			0	0	0.00	
3	*Sanford 4*												
4	Gas		88,078					662,537	1,000,000	662,537	3,634,641	4.13	5.49
5	Plant Unit Info	990	88,078	12.0%	84.0%	70.6%	7,522			662,537	3,634,641	4.13	
6	*Sanford 5*												
7	Gas		150,326					1,124,159	1,000,000	1,124,159	6,166,927	4.10	5.49
8	Plant Unit Info	994	150,326	20.3%	94.9%	84.5%	7,478			1,124,159	6,166,927	4.10	
9	*Scherer 4*												
10	Coal		347,402					211,770	16,999,972	3,600,084	8,582,953	2.47	40.53
11	Plant Unit Info	646	347,402	72.3%	93.1%	93.1%	10,363			3,600,084	8,582,953	2.47	
12	*St Johns 1O*												
13	Coal		39,261					20,911	22,000,239	460,047	1,604,616	4.09	76.74
14	Plant Unit Info	128	39,261	41.2%	94.0%	41.2%	11,718			460,047	1,604,616	4.09	
15	*St Johns 2O*												
16	Coal		45,235					23,190	22,000,302	510,187	1,779,496	3.93	76.74
17	Plant Unit Info	128	45,235	47.4%	93.2%	47.4%	11,279			510,187	1,779,496	3.93	
18	*St Lucie 1*												
19	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,956,000	0.68	0.66
20	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,956,000	0.68	
21	*St Lucie 2*												
22	Nuclear		623,845					6,379,606	1,000,000	6,379,606	3,793,000	0.61	0.59
23	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,226			6,379,606	3,793,000	0.61	
24	*Space Coast*												
25	Solar		1,079					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,079	14.5%		34.8%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	380	0	0.0%	64.5%	0.0%	0			0	0	0.00	
31	*Turkey Point 3*												
32	Nuclear		604,258					6,568,489	1,000,000	6,568,489	4,493,000	0.74	0.68
33	Plant Unit Info	833	604,258	97.5%	97.5%	97.5%	10,870			6,568,489	4,493,000	0.74	
34	*Turkey Point 4*												
35	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,508,000	0.74	0.68
36	Plant Unit Info	843	611,511	97.5%	97.5%	97.5%	10,870			6,647,323	4,508,000	0.74	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		267,184					1,866,389	1,000,000	1,866,389	10,213,096	3.82	5.47
2	Plant Unit Info	1,166	267,184	30.8%	72.9%	87.8%	6,985			1,866,389	10,213,096	3.82	
3	*WCEC 01*												
4	Gas		757,124					5,175,425	1,000,000	5,175,425	28,431,974	3.76	5.49
5	Plant Unit Info	1,208	757,124	84.3%	95.5%	89.4%	6,836			5,175,425	28,431,974	3.76	
6	*WCEC 02*												
7	Gas		763,152					5,211,691	1,000,000	5,211,691	28,585,794	3.75	5.48
8	Plant Unit Info	1,202	763,152	85.3%	95.7%	85.3%	6,829			5,211,691	28,585,794	3.75	
9	*WCEC 03*												
10	Gas		556,890					3,804,507	1,000,000	3,804,507	20,888,316	3.75	5.49
11	Plant Unit Info	1,207	556,890	62.0%	95.5%	86.5%	6,832			3,804,507	20,888,316	3.75	
12	**System Totals**												
13	Plant Unit Info	25,944	8,701,442				8,114			70,601,601	242,685,535	2.79	
14													
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Jan - 2014	Feb - 2014	Mar - 2014	Apr - 2014	May - 2014	Jun - 2014	Jul - 2014	Aug - 2014	Sep - 2014	Oct - 2014	Nov - 2014	Dec - 2014	2014
1	**#6 Heavy Oil (BBLS)**													
2	Purchases													
3	Units	0	0	0	0	0	145,000	145,000	0	0	0	0	0	290,000
4	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	101.7859	100.7759	0.0000	0.0000	0.0000	0.0000	0.0000	101.2809
5	Amount	$0	$0	$0	$0	$0	$14,758,954	$14,612,504	$0	$0	$0	$0	$0	$29,371,458
6	Burned													
7	Units	12,665	2,462	10,334	36,211	10,115	82,446	99,585	85,903	54,000	37,670	0	0	431,391
8	Unit Cost	93.4894	93.4654	93.4659	93.7794	93.8810	93.8321	93.8349	93.9245	93.2627	93.5454	0.0000	0.0000	93.7306
9	Amount	$1,184,043	$230,112	$965,877	$3,395,847	$949,606	$7,736,081	$9,344,546	$8,068,395	$5,036,187	$3,523,855	$0	$0	$40,434,548
10	Ending Inventory													
11	Units	2,754,573	2,752,111	2,741,777	2,705,566	2,690,400	2,735,586	2,803,420	2,717,517	2,663,517	2,625,847	2,625,847	2,625,847	2,625,847
12	Unit Cost	92.9749	92.9745	92.9726	92.9618	93.1329	94.1618	93.7625	93.7573	93.7674	93.7706	93.7706	93.7706	93.7706
13	Amount	$256,106,166	$255,876,055	$254,910,178	$251,514,331	$250,564,725	$257,587,598	$262,855,556	$254,787,161	$249,750,974	$246,227,119	$246,227,119	$246,227,119	$246,227,119
14	**#2 Light Oil (BBLS)**													
15	Purchases													
16	Units	0	0	0	0	0	14,346	0	0	0	0	0	0	14,346
17	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	136.8186	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	136.8186
18	Amount	$0	$0	$0	$0	$0	$1,962,799	$0	$0	$0	$0	$0	$0	$1,962,799
19	Burned													
20	Units	719	134	0	3,344	0	5,753	2,309	755	0	0	0	0	13,014
21	Unit Cost	100.2625	121.2562	0.0000	121.2562	0.0000	122.0963	122.0963	122.0963	0.0000	0.0000	0.0000	0.0000	120.6655
22	Amount	$72,089	$16,248	$0	$405,481	$0	$702,420	$281,920	$92,183	$0	$0	$0	$0	$1,570,341
23	Ending Inventory													
24	Units	1,427,249	1,427,115	1,427,115	1,423,771	1,423,771	1,432,364	1,430,055	1,429,300	1,429,300	1,429,300	1,429,300	1,429,300	1,429,300
25	Unit Cost	118.9547	118.9545	118.9545	118.9491	118.9491	119.1155	119.1106	119.1091	119.1091	119.1091	119.1091	119.1091	119.1091
26	Amount	$169,778,047	$169,761,798	$169,761,798	$169,356,318	$169,356,318	$170,616,697	$170,334,776	$170,242,594	$170,242,594	$170,242,594	$170,242,594	$170,242,594	$170,242,594
27	**Coal - SJRPP (TONS)**													
28	Purchases													
29	Units	28,540	25,850	31,230	28,540	40,940	49,010	49,010	46,320	33,920	44,680	44,680	39,300	462,020
30	Unit Cost	76.9953	77.0269	74.9200	74.8579	74.9874	75.5053	75.8511	76.5436	76.5724	76.6013	76.7741	76.9534	76.1280
31	Amount	$2,197,445	$1,991,145	$2,339,751	$2,136,444	$3,069,983	$3,700,513	$3,717,461	$3,545,498	$2,597,337	$3,422,545	$3,430,266	$3,024,270	$35,172,657
32	Burned													
33	Units	45,856	33,064	22,108	24,354	55,930	61,022	62,672	61,051	60,987	55,936	43,246	44,101	570,327
34	Unit Cost	76.7687	76.8100	76.4406	76.1689	75.9030	75.7931	75.8105	76.0406	76.1904	76.3668	76.5646	76.7372	76.2411
35	Amount	$3,520,307	$2,539,646	$1,689,950	$1,855,018	$4,245,252	$4,625,048	$4,751,193	$4,642,356	$4,646,626	$4,271,652	$3,311,111	$3,384,189	$43,482,348
36	Ending Inventory													
37	Units	135,784	128,570	137,692	141,878	126,889	114,877	101,215	86,484	59,417	48,161	49,594	44,792	44,792
38	Unit Cost	76.7687	76.8100	76.4406	76.1689	75.9043	75.7931	75.8105	76.0406	76.1904	76.3668	76.5628	75.5534	75.5534
39	Amount	$10,423,966	$9,875,464	$10,525,265	$10,806,692	$9,631,422	$8,706,887	$7,673,155	$6,576,297	$4,527,007	$3,677,900	$3,797,055	$3,384,189	$3,384,189
40														

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Jan - 2014	Feb - 2014	Mar - 2014	Apr - 2014	May - 2014	Jun - 2014	Jul - 2014	Aug - 2014	Sep - 2014	Oct - 2014	Nov - 2014	Dec - 2014	2014
1	**Coal - Scherer (MMBTU)**													
2	Purchases													
3	Units	3,361,141	3,358,193	3,406,575	3,361,439	3,406,575	3,358,193	3,406,575	3,361,439	3,406,575	3,299,389	3,468,625	3,351,400	40,546,118
4	Unit Cost	2.3260	2.3380	2.3423	2.3408	2.3438	2.3496	2.3649	2.3848	2.3937	2.3937	2.4013	2.4071	2.3655
5	Amount	$7,817,921	$7,851,328	$7,979,214	$7,868,353	$7,984,297	$7,890,524	$8,056,276	$8,016,279	$8,154,167	$7,897,599	$8,329,226	$8,067,173	$95,912,355
6	Burned													
7	Units	2,821,520	2,116,078	0	1,257,189	3,849,934	4,379,391	4,536,270	3,882,615	3,738,815	4,191,071	3,514,246	3,600,084	37,887,213
8	Unit Cost	2.3301	2.3323	0.0000	2.3361	2.3375	2.3398	2.3448	2.3532	2.3622	2.3691	2.3769	2.3841	2.3534
9	Amount	$6,574,424	$4,935,418	$0	$2,936,958	$8,999,407	$10,246,862	$10,636,649	$9,136,763	$8,831,708	$9,929,083	$8,353,097	$8,582,967	$89,163,336
10	Ending Inventory													
11	Units	493,355	566,420	766,807	890,587	864,507	804,436	737,984	707,327	687,784	635,331	632,648	618,019	618,019
12	Unit Cost	2.3301	2.3323	2.3349	2.3361	2.3375	2.3398	2.3448	2.3533	2.3622	2.3691	2.3769	2.3841	2.3841
13	Amount	$1,149,564	$1,321,088	$1,790,454	$2,080,536	$2,020,823	$1,882,215	$1,730,428	$1,664,518	$1,624,662	$1,505,163	$1,503,759	$1,473,418	$1,473,418
14	**Gas (MCF)**													
15	Burned													
16	Units	38,202,064	35,717,664	49,002,821	46,704,292	48,473,113	50,657,325	55,715,799	56,296,870	52,454,740	51,014,543	38,195,941	38,921,298	561,356,468
17	Unit Cost	5.3460	5.3053	5.0210	5.0753	5.1073	5.0460	5.0074	5.0095	5.0392	5.1013	5.3707	5.4718	5.1370
18	Amount	$204,229,626	$189,491,935	$246,044,886	$237,037,191	$247,564,987	$255,616,206	$278,990,077	$282,017,622	$264,328,846	$260,238,344	$205,137,865	$212,968,470	$2,883,666,055
19	**Nuclear (Other)**													
20	Burned													
21	Units	27,109,985	24,486,449	17,963,668	21,383,576	27,094,244	26,220,236	27,094,244	27,094,244	24,718,736	20,873,643	26,235,473	27,109,985	297,384,483
22	Unit Cost	0.6466	0.6465	0.5131	0.6413	0.6457	0.6457	0.6457	0.6457	0.6459	0.6338	0.6547	0.6547	0.6383
23	Amount	$17,528,000	$15,831,000	$9,218,000	$13,713,000	$17,494,000	$16,930,000	$17,494,000	$17,494,000	$15,967,000	$13,230,000	$17,176,000	$17,750,000	$189,825,000
24														
25	Note: Totals may not add due to rounding.													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**January Estimated**								
3	Off System	OS	160,000	160,000	3.357	4.207	$5,370,950	$6,730,950	$993,750
4	St Lucie Reliability Sales		54,189	54,189	0.681	0.681	$368,820	$368,820	$0
5	**Total January Estimated**		214,189	214,189	2.680	3.315	$5,739,770	$7,099,770	$993,750
6									
7	**February Estimated**								
8	Off System	OS	265,000	265,000	3.311	4.161	$8,772,950	$11,025,450	$1,657,500
9	St Lucie Reliability Sales		48,945	48,945	0.681	0.681	$333,129	$333,129	$0
10	**Total February Estimated**		313,945	313,945	2.901	3.618	$9,106,079	$11,358,579	$1,657,500
11									
12	**March Estimated**								
13	Off System	OS	305,000	305,000	3.451	4.337	$10,525,100	$13,227,600	$1,948,750
14	St Lucie Reliability Sales		54,189	54,189	0.681	0.681	$368,820	$368,820	$0
15	**Total March Estimated**		359,189	359,189	3.033	3.785	$10,893,920	$13,596,420	$1,948,750
16									
17	**April Estimated**								
18	Off System	OS	185,000	185,000	4.121	5.042	$7,623,500	$9,328,500	$1,193,750
19	St Lucie Reliability Sales		51,289	51,289	0.696	0.696	$356,923	$356,923	$0
20	**Total April Estimated**		236,289	236,289	3.377	4.099	$7,980,423	$9,685,423	$1,193,750
21									
22	**May Estimated**								
23	Off System	OS	135,000	135,000	3.994	4.964	$5,392,000	$6,702,000	$901,250
24	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
25	**Total May Estimated**		187,999	187,999	3.064	3.761	$5,760,820	$7,070,820	$901,250
26									
27	**June Estimated**								
28	Off System	OS	85,000	85,000	6.443	7.497	$5,476,400	$6,372,650	$650,000
29	St Lucie Reliability Sales		51,289	51,289	0.696	0.696	$356,923	$356,923	$0
30	**Total June Estimated**		136,289	136,289	4.280	4.938	$5,833,323	$6,729,573	$650,000
31									
32	**6 Month Period**								
33	Off System	OS	1,135,000	1,135,000	3.803	4.704	$43,160,900	$53,387,150	$7,345,000
34	St Lucie Reliability Sales		312,901	312,901	0.688	0.688	$2,153,437	$2,153,437	$0
35	**Total 6 Month Period**		1,447,901	1,447,901	3.130	3.836	$45,314,337	$55,540,587	$7,345,000
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
POWER SOLD

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	95,000	95,000	6.561	7.722	$6,233,200	$7,335,700	$823,750
4	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
5	**Total July Estimated**		147,999	147,999	4.461	5.206	$6,602,020	$7,704,520	$823,750
6									
7	**August Estimated**								
8	Off System	OS	70,000	70,000	5.256	6.324	$3,679,100	$4,426,600	$565,000
9	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
10	**Total August Estimated**		122,999	122,999	3.291	3.899	$4,047,920	$4,795,420	$565,000
11									
12	**September Estimated**								
13	Off System	OS	25,000	25,000	5.521	6.601	$1,380,150	$1,650,150	$203,750
14	St Lucie Reliability Sales		51,289	51,289	0.696	0.696	$356,923	$356,923	$0
15	**Total September Estimated**		76,289	76,289	2.277	2.631	$1,737,073	$2,007,073	$203,750
16									
17	**October Estimated**								
18	Off System	OS	40,000	40,000	4.005	4.967	$1,601,800	$1,986,800	$290,000
19	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
20	**Total October Estimated**		92,999	92,999	2.119	2.533	$1,970,620	$2,355,620	$290,000
21									
22	**November Estimated**								
23	Off System	OS	100,000	100,000	3.123	3.986	$3,123,000	$3,985,500	$637,500
24	St Lucie Reliability Sales		52,441	52,441	0.681	0.681	$356,923	$356,923	$0
25	**Total November Estimated**		152,441	152,441	2.283	2.849	$3,479,923	$4,342,423	$637,500
26									
27	**December Estimated**								
28	Off System	OS	190,000	190,000	3.246	4.096	$6,167,600	$7,782,600	$1,215,000
29	St Lucie Reliability Sales		54,189	54,189	0.681	0.681	$368,820	$368,820	$0
30	**Total December Estimated**		244,189	244,189	2.677	3.338	$6,536,420	$8,151,420	$1,215,000
31									
32	**12 Month Period**								
33	Off System	OS	1,655,000	1,655,000	3.948	4.867	$65,345,750	$80,554,500	$11,080,000
34	St Lucie Reliability Sales		629,817	629,817	0.689	0.689	$4,342,565	$4,342,565	$0
35	**Total 12 Month Period**		2,284,817	2,284,817	3.050	3.716	$69,688,315	$84,897,065	$11,080,000
36									
37									
38	Note: Totals may not add due to rounding.								

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**January Estimated**					
3	UPS		78,701	78,701	4.053	$3,189,917
4	SJRPP		139,422	139,422	3.974	$5,541,000
5	St Lucie Reliability		46,464	46,464	0.649	$301,580
6	**Total January Estimated**		264,587	264,587	3.414	$9,032,496
7						
8	**February Estimated**					
9	UPS		90,469	90,469	4.106	$3,714,827
10	SJRPP		114,571	114,571	4.047	$4,637,000
11	St Lucie Reliability		41,967	41,967	0.649	$272,395
12	**Total February Estimated**		247,007	247,007	3.491	$8,624,221
13						
14	**March Estimated**					
15	UPS		176,756	176,756	3.867	$6,835,040
16	SJRPP		65,075	65,075	3.939	$2,563,000
17	St Lucie Reliability		2,998	2,998	0.000	$0
18	**Total March Estimated**		244,829	244,829	3.839	$9,398,040
19						
20	**April Estimated**					
21	UPS		148,871	148,871	3.928	$5,848,164
22	SJRPP		85,847	85,847	3.966	$3,405,000
23	St Lucie Reliability		36,600	36,600	0.625	$228,626
24	**Total April Estimated**		271,318	271,318	3.495	$9,481,790
25						
26	**May Estimated**					
27	UPS		180,259	180,259	3.862	$6,961,940
28	SJRPP		165,532	165,532	3.793	$6,279,000
29	St Lucie Reliability		45,379	45,379	0.625	$283,481
30	**Total May Estimated**		391,170	391,170	3.457	$13,524,421
31						
32	**June Estimated**					
33	UPS		212,863	212,863	3.868	$8,232,812
34	SJRPP		182,976	182,976	3.766	$6,890,000
35	St Lucie Reliability		43,920	43,920	0.626	$274,814
36	**Total June Estimated**		439,759	439,759	3.501	$15,397,625
37						
38	**6 Month Period**					
39	UPS		887,919	887,919	3.917	$34,782,699
40	SJRPP		753,423	753,423	3.891	$29,315,000
41	St Lucie Reliability		217,327	217,327	0.626	$1,360,894
42	**Total 6 Month Period**		1,858,669	1,858,669	3.522	$65,458,594
43						
44						
45						
46						
47						
48						
49						
50						

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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		224,517	224,517	3.888	$8,729,299
4	SJRPP		188,550	188,550	3.784	$7,135,000
5	St Lucie Reliability		45,379	45,379	0.625	$283,481
6	**Total July Estimated**		458,446	458,446	3.522	$16,147,779
7						
8	**August Estimated**					
9	UPS		218,279	218,279	3.902	$8,518,106
10	SJRPP		182,339	182,339	3.837	$6,997,000
11	St Lucie Reliability		45,379	45,379	0.625	$283,481
12	**Total August Estimated**		445,997	445,997	3.542	$15,798,587
13						
14	**September Estimated**					
15	UPS		226,436	226,436	3.944	$8,931,460
16	SJRPP		182,651	182,651	3.824	$6,985,000
17	St Lucie Reliability		43,920	43,920	0.626	$274,814
18	**Total September Estimated**		453,007	453,007	3.574	$16,191,274
19						
20	**October Estimated**					
21	UPS		172,291	172,291	3.950	$6,804,871
22	SJRPP		165,346	165,346	3.880	$6,416,000
23	St Lucie Reliability		45,379	45,379	0.625	$283,481
24	**Total October Estimated**		383,016	383,016	3.526	$13,504,351
25						
26	**November Estimated**					
27	UPS		76,363	76,363	4.138	$3,159,621
28	SJRPP		132,578	132,578	3.988	$5,287,000
29	St Lucie Reliability		44,965	44,965	0.612	$275,201
30	**Total November Estimated**		253,906	253,906	3.435	$8,721,822
31						
32	**December Estimated**					
33	UPS		69,811	69,811	4.154	$2,899,715
34	SJRPP		132,873	132,873	4.002	$5,317,000
35	St Lucie Reliability		46,464	46,464	0.612	$284,374
36	**Total December Estimated**		249,148	249,148	3.412	$8,501,088
37						
38	**12 Month Period**					
39	UPS		1,875,616	1,875,616	3.936	$73,825,771
40	SJRPP		1,737,760	1,737,760	3.882	$67,452,000
41	St Lucie Reliability		488,814	488,814	0.623	$3,045,725
42	**Total 12 Month Period**		4,102,190	4,102,190	3.518	$144,323,495
43						
44						
45	Note: Totals may not add due to rounding.					
46						
47						
48						
49						
50						

FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**January Estimated**					
3	Qualifying Facilities		241,864	241,864	4.112	$9,945,865
4	**Total January Estimated**		241,864	241,864	4.112	$9,945,865
5						
6	**February Estimated**					
7	Qualifying Facilities		219,252	219,252	4.051	$8,880,867
8	**Total February Estimated**		219,252	219,252	4.051	$8,880,867
9						
10	**March Estimated**					
11	Qualifying Facilities		246,666	246,666	4.180	$10,309,866
12	**Total March Estimated**		246,666	246,666	4.180	$10,309,866
13						
14	**April Estimated**					
15	Qualifying Facilities		135,599	135,599	4.423	$5,997,865
16	**Total April Estimated**		135,599	135,599	4.423	$5,997,865
17						
18	**May Estimated**					
19	Qualifying Facilities		263,130	263,130	4.123	$10,849,865
20	**Total May Estimated**		263,130	263,130	4.123	$10,849,865
21						
22	**June Estimated**					
23	Qualifying Facilities		297,827	297,827	4.451	$13,256,860
24	**Total June Estimated**		297,827	297,827	4.451	$13,256,860
25						
26	**6 Month Period**					
27	Qualifying Facilities		1,404,338	1,404,338	4.218	$59,241,188
28	**Total 6 Month Period**		1,404,338	1,404,338	4.218	$59,241,188
29						
30						
31						
32						
33						
34						
35						
36						

FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	Qualifying Facilities		317,110	317,110	4.420	$14,016,861
4	**Total July Estimated**		317,110	317,110	4.420	$14,016,861
5						
6	**August Estimated**					
7	Qualifying Facilities		307,485	307,485	4.471	$13,746,860
8	**Total August Estimated**		307,485	307,485	4.471	$13,746,860
9						
10	**September Estimated**					
11	Qualifying Facilities		303,307	303,307	4.541	$13,771,859
12	**Total September Estimated**		303,307	303,307	4.541	$13,771,859
13						
14	**October Estimated**					
15	Qualifying Facilities		236,812	236,812	4.155	$9,839,862
16	**Total October Estimated**		236,812	236,812	4.155	$9,839,862
17						
18	**November Estimated**					
19	Qualifying Facilities		156,967	156,967	4.445	$6,976,866
20	**Total November Estimated**		156,967	156,967	4.445	$6,976,866
21						
22	**December Estimated**					
23	Qualifying Facilities		214,386	214,386	4.186	$8,973,866
24	**Total December Estimated**		214,386	214,386	4.186	$8,973,866
25						
26	**12 Month Period**					
27	Qualifying Facilities		2,940,405	2,940,405	4.304	$126,567,361
28	**Total 12 Month Period**		2,940,405	2,940,405	4.304	$126,567,361
29						
30						
31	Note: Totals may not add due to rounding.					
32						
33						
34						
35						
36						

FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	**January Estimated**							
3	Economy	OS	7,100	2.781	$197,461	3.578	$254,061	$56,600
4	Total January Estimated		7,100	2.781	$197,461	3.578	$254,061	$56,600
5								
6	**February Estimated**							
7	Economy	OS	3,100	2.751	$85,278	3.544	$109,878	$24,600
8	Total February Estimated		3,100	2.751	$85,278	3.544	$109,878	$24,600
9								
10	**March Estimated**							
11	Economy	OS	3,100	2.781	$86,206	3.671	$113,806	$27,600
12	Total March Estimated		3,100	2.781	$86,206	3.671	$113,806	$27,600
13								
14	**April Estimated**							
15	Economy	OS	17,100	3.038	$519,450	4.433	$758,050	$238,600
16	Total April Estimated		17,100	3.038	$519,450	4.433	$758,050	$238,600
17								
18	**May Estimated**							
19	Economy	OS	5,100	3.055	$155,794	4.145	$211,394	$55,600
20	Total May Estimated		5,100	3.055	$155,794	4.145	$211,394	$55,600
21								
22	**June Estimated**							
23	Economy	OS	55,100	5.455	$3,005,537	7.452	$4,106,137	$1,100,600
24	Total June Estimated		55,100	5.455	$3,005,537	7.452	$4,106,137	$1,100,600
25								
26	**6 Month Period**							
27	Economy	OS	90,600	4.470	$4,049,726	6.129	$5,553,326	$1,503,600
28	Total 6 Month Period		90,600	4.470	$4,049,726	6.129	$5,553,326	$1,503,600
29								
30								
31								
32								
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34								
35								
36								
37								
38								
39								

FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(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	70,200	5.448	$3,824,412	7.444	$5,225,612	$1,401,200
4	Total July Estimated		70,200	5.448	$3,824,412	7.444	$5,225,612	$1,401,200
5								
6	**August Estimated**							
7	Economy	OS	60,200	4.897	$2,947,914	6.892	$4,149,114	$1,201,200
8	Total August Estimated		60,200	4.897	$2,947,914	6.892	$4,149,114	$1,201,200
9								
10	**September Estimated**							
11	Economy	OS	35,200	5.130	$1,805,718	7.122	$2,506,918	$701,200
12	Total September Estimated		35,200	5.130	$1,805,718	7.122	$2,506,918	$701,200
13								
14	**October Estimated**							
15	Economy	OS	20,100	3.559	$715,344	5.054	$1,015,944	$300,600
16	Total October Estimated		20,100	3.559	$715,344	5.054	$1,015,944	$300,600
17								
18	**November Estimated**							
19	Economy	OS	1,100	2.691	$29,606	3.382	$37,206	$7,600
20	Total November Estimated		1,100	2.691	$29,606	3.382	$37,206	$7,600
21								
22	**December Estimated**							
23	Economy	OS	1,100	2.802	$30,818	3.493	$38,418	$7,600
24	Total December Estimated		1,100	2.802	$30,818	3.493	$38,418	$7,600
25								
26	**12 Month Period**							
27	Economy	OS	278,500	4.813	$13,403,538	6.652	$18,526,538	$5,123,000
28	Total 12 Month Period		278,500	4.813	$13,403,538	6.652	$18,526,538	$5,123,000
29								
30								
31	Note: Totals may not add due to rounding.							
32								
33								
34								
35								
36								
37								
38								
39								

	SEPT 13	PROPOSED [1], [2] JAN 14 - MAY 14	DIFFERENCE $	%
BASE	$51.33	$52.48	$1.15	2.24%
FUEL	$26.33	$30.67	$4.34	16.48%
CONSERVATION [2]	$2.33	$3.37	$1.04	44.64%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%
STORM RESTORATION SURCHARGE	$1.07	$1.07	$0.00	0.00%
SUBTOTAL	$92.73	$97.75	$5.02	5.41%
GROSS RECEIPTS TAX	$2.38	$2.51	$0.13	5.46%
TOTAL	**$95.11**	**$100.26**	$5.15	5.41%

Note: [1] Base rate changes are based on estimated EPU increase.
[2] Based on estimates of the Conservation factor to be filed on September 10, 2013.

Company: Florida Power & Light Company Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL [1]	ACTUAL [1]	ACTUAL/ESTIMATED [1]	PROJECTED			
		JAN - DEC	JAN - DEC	JAN-DEC	JAN-DEC	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)
		2011-2011	2012-2012	2013-2013	2014-2014			
		(COLUMN 1)	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)	(COLUMN 1)	(COLUMN 2)	(COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	93,949,810	61,871,530	62,546,825	40,434,454	(34.1)	1.1	(35.4)
2	LIGHT OIL	37,159,006	8,584,943	9,997,129	1,570,341	(76.9)	16.4	(84.3)
3	COAL	163,820,388	142,583,650	155,340,329	132,645,707	(13.0)	8.9	(14.6)
4	GAS	3,289,409,517	2,999,049,429	2,653,084,633	2,883,666,055	(8.8)	(11.5)	8.7
5	NUCLEAR	146,597,226	106,563,067	183,254,616	189,825,000	(27.3)	72.0	3.6
6	TOTAL ($)	3,730,935,950	3,318,652,620	3,064,223,534	3,248,141,556	(11.1)	(7.7)	6.0
	SYSTEM NET GENERATION							
7	HEAVY OIL	630,196	377,642	392,709	232,756	(40.1)	4.0	(40.7)
8	LIGHT OIL	232,917	54,367	49,192	4,989	(76.7)	(9.5)	(89.9)
9	COAL	5,634,006	4,745,211	5,640,049	4,755,642	(15.8)	18.9	(15.7)
10	GAS	74,277,900	80,593,957	75,136,502	79,726,968	8.5	(6.8)	6.1
11	NUCLEAR	21,510,395	16,915,746	25,480,181	27,766,399	(21.4)	50.6	9.0
12	SOLAR	70,687	70,534	106,585	190,625	(0.2)	51	78.8
13	TOTAL (MWH)	102,356,101	102,757,457	106,805,219	112,677,379	0.4	3.9	5.5
	UNITS OF FUEL BURNED							
14	HEAVY OIL (Bbl)	1,140,665	701,587	667,611	431,390	(38.5)	(4.8)	(35.4)
15	LIGHT OIL (Bbl)	331,653	72,767	84,377	13,014	(78.1)	16.0	(84.6)
16	COAL (TON)	637,734	578,328	592,055	2,798,987	(9.3)	2.4	372.8
17	GAS (MCF)	555,912,325	595,396,296	538,831,472	561,356,468	7.1	(9.5)	4.2
18	NUCLEAR (MMBTU)	241,129,910	188,199,021	271,163,896	297,384,483	(22.0)	44.1	9.7
	BTU'S BURNED (MMBTU)							
19	HEAVY OIL	7,268,455	4,479,894	4,269,282	2,760,893	(38.4)	(4.7)	(35.3)
20	LIGHT OIL	1,909,037	418,441	488,982	75,793	(78.1)	16.9	(84.5)
21	COAL	57,605,124	49,417,119	58,421,837	50,434,432	(14.2)	18.2	(13.7)
22	GAS	564,067,472	603,981,012	543,369,637	561,356,468	7.1	(10.0)	3.3
23	NUCLEAR	241,129,910	188,199,021	271,163,896	297,384,483	(22.0)	44.1	9.7
24	TOTAL (MMBTU)	871,979,998	846,495,487	877,713,634	912,012,069	(2.9)	3.7	3.9
	GENERATION MIX (%MWH)							
25	HEAVY OIL	0.62	0.37	0.37	0.21	-	-	-
26	LIGHT OIL	0.23	0.05	0.05	0.00	-	-	-
27	COAL	5.50	4.62	5.28	4.22			
28	GAS	72.57	78.43	70.35	70.76	-	-	-
29	NUCLEAR	21.02	16.46	23.86	24.64	-	-	-
30	SOLAR	0.07	0.07	0.10	0.17			
31	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
32	HEAVY OIL ($/Bbl)	82.3641	88.1880	93.6875	93.7306	7.1	6.2	0.0
33	LIGHT OIL ($/Bbl)	112.0418	117.9785	118.4817	120.6655	5.3	0.4	1.8
34	COAL ($/TON)	92.3945	82.6550	76.8296	47.3906	(10.5)	(7.0)	(38.3)
35	GAS ($/MCF)	5.9171	5.0371	4.9238	5.1370	(14.9)	(2.2)	4.3
36	NUCLEAR ($/MMBTU)	0.6080	0.5662	0.6758	0.6383	(6.9)	19.4	(5.5)
	FUEL COST PER MMBTU ($/MMBTU)							
37	HEAVY OIL	12.9257	13.8109	14.6504	14.6454	6.8	6.1	(0.0)
38	LIGHT OIL	19.4648	20.5165	20.4448	20.7188	5.4	(0.3)	1.3
39	COAL	2.8439	2.8853	2.6589	2.6301	1.5	(7.8)	(1.1)
40	GAS	5.8316	4.9655	4.8827	5.1370	(14.9)	(1.7)	5.2
41	NUCLEAR	0.6080	0.5662	0.6758	0.6383	(6.9)	19.4	(5.5)
42	TOTAL ($/MMBTU)	4.2787	3.9205	3.4911	3.5615	(8.4)	(11.0)	2.0
	BTU BURNED PER KWH (BTU/KWH)							
43	HEAVY OIL	11,534	11,863	10,871	11,862	2.9	(8.4)	9.1
44	LIGHT OIL	8,196	7,697	9,940	15,192	(6.1)	29.2	52.8
45	COAL	10,225	10,414	10,358	10,605	1.9	(0.5)	2.4
46	GAS	7,594	7,494	7,232	7,041	(1.3)	(3.5)	(2.6)
47	NUCLEAR	11,210	11,126	10,642	10,710	(0.8)	(4.3)	0.6
48	TOTAL (BTU/KWH)	8,519	8,238	8,218	8,094	(3.3)	(0.2)	(1.5)
	GENERATED FUEL COST PER KWH (c/KWH)							
49	HEAVY OIL	14.9080	16.3836	15.9270	17.3720	9.9	(2.8)	9.1
50	LIGHT OIL	15.9538	15.7907	20.3226	31.4761	(1.0)	28.7	54.9
51	COAL	2.9077	3.0048	2.7542	2.7892	3.3	(8.3)	1.3
52	GAS	4.4285	3.7212	3.5310	3.6169	(16.0)	(5.1)	2.4
53	NUCLEAR	0.6815	0.6300	0.7192	0.6837	(7.6)	14.2	(4.9)
54	TOTAL (c/KWH)	3.6451	3.2296	2.8690	2.8827	(11.4)	(11.2)	0.5

Note: [1] Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next two periods are as follows. In addition, As-Available Energy cost payments will include .0074¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2014 – December 31, 2014	4.27	3.87	3.98
January 1, 2015 – December 31, 2015	4.10	3.87	3.93

A MW block size ranging from 70 MW to 77 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0104
Secondary Voltage Delivery	1.0420

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)						Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Solar	Nuclear	Oil	Gas	Coal
2013	24.0	0.2	66.1	4.3	5.2	0.2	.73	41.11	3.71	2.69
2014	23.4	0.2	66.3	4.4	5.6	0.2	.75	39.71	4.23	2.71
2015	23.1	0.3	65.4	4.9	6.2	0.1	.76	38.35	4.43	2.79
2016	23.2	0.4	66.9	4.4	5.0	0.2	.78	38.58	4.68	2.87
2017	22.7	0.1	68.0	4.9	4.1	0.1	.80	38.55	5.03	2.80
2018	22.2	0.2	68.9	4.8	3.7	0.1	.82	41.31	5.85	2.97
2019	22.5	0.1	66.9	5.2	5.1	0.1	.84	42.33	6.40	3.74
2020	21.9	0.2	67.0	5.3	5.4	0.1	.86	43.42	6.94	3.88
2021	21.6	0.2	67.1	5.5	5.5	0.1	.88	45.46	7.33	3.97
2022	25.6	0.1	63.2	5.4	5.6	0.1	.90	47.80	7.65	4.06

NOTE: - Amounts may not add to 100% due to rounding.
- The Company's forecasts are for illustrative purposes, and are subject to frequent revisions.

(Continued on Sheet No. 10.102)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective:

(Continued from Sheet No. 10.102)

B. Interconnection Charge for Non-Variable Utility Expenses:

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. Interconnection Charge for Variable Utility Expenses:

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.137%
Distribution Equipment	0.203%
Transmission Equipment	0.133%

D. Taxes and Assessments

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III
FUEL COST RECOVERY
2014 E-SCHEDULES

INCLUDING RIVIERA BEACH MODERNIZATION PROJECT FUEL SAVINGS BEGINNING IN JUNE 1, 2014

TJK-6
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT ______________
PAGES 1-7
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APPENDIX III
FUEL COST RECOVERY
2014 E SCHEDULES
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FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,248,141,556	112,677,379	2.8827
2	Riviera Beach Energy Center (RBEC) Savings	$82,000,000	112,677,379	0.0728
3	Nuclear Fuel Disposal Costs (E2)	$26,064,319	27,766,399	0.0939
4	TOTAL COST OF GENERATED POWER	$3,356,205,875	112,677,379	2.9786
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$144,323,495	4,102,190	3.5182
6	Energy Cost of Economy Purchases (E9)	$13,403,538	278,500	4.8128
7	Payments to Qualifying Facilities (E8)	$126,567,361	2,940,405	4.3044
8	TOTAL COST OF PURCHASED POWER	$284,294,395	7,321,095	3.8832
9	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)		119,998,473	
10	Fuel Cost of Economy Sales (E6)	($65,345,750)	(1,655,000)	3.9484
11	Gain from Off-System Sales (E6)	($11,080,000)	N/A	N/A
12	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,342,565)	(629,817)	0.6895
13	TOTAL FUEL COST AND GAINS OF POWER SALES	($80,768,315)	(2,284,817)	3.5350
14	Incremental Personnel, Software, and Hardware Costs	$389,472	N/A	N/A
15	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,722,910	N/A	N/A
16	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,112,382	N/A	N/A
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 4 + 8 + 13 + 16)	$3,561,844,337	117,713,657	3.0259
18	Net Unbilled Sales [1]	($32,030,707)	(1,058,567)	(0.0289)
19	Company Use [1]	$10,685,533	353,141	0.0096
20	T & D Losses [1]	$231,519,882	7,651,388	0.2090
21	SYSTEM MWH SALES	$3,561,844,337	110,767,695	3.2156
22	Wholesale MWH Sales	$158,351,051	4,924,470	3.2156
23	Jurisdictional MWH Sales	$3,403,493,286	105,843,225	3.2156
24	Jurisdictional Loss Multiplier	$5,751,904		1.00169
25	Jurisdictional MWH Sales Adjusted for Line Losses	$3,409,245,189	105,843,225	3.2210
26	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$147,765,613	105,843,225	0.1396
27	TOTAL JURISDICTIONAL FUEL COST	$3,557,010,803	105,843,225	3.3606
28	Revenue Tax Factor	$2,561,048		1.00072
29	Fuel Factor Adjusted for Taxes	$3,559,571,851	105,843,225	3.3630
30	GPIF [2]	$20,679,970	105,843,225	0.0195
31	Jurisdictionalized RBEC Savings	($78,543,407)	65,556,788	(0.1198)
32	Fuel Factor including GPIF (Line 29 + 30 + 31)	$3,501,708,414	105,843,225	3.2627
33	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.263
34				
35	[1] For Informational Purposes Only			
36	[2] Calculation Based on Jurisdictional KWH Sales			
37				
38	Note: Totals may not add due to rounding.			

FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

Line No.	CALCULATION OF JURISDICTIONALIZED RBEC SAVINGS	Annual Total
1	RBEC Fuel Savings Total System	$82,000,000
2		
3	Jurisdictional %	95.55424%
4		
5	Jurisdictionalized RBEC Fuel Savings	$78,354,477
6		
7	Jurisdictionalized RBEC Fuel Savings Adjusted for Losses & Revenue Taxes	$78,543,407
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FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	3.263	1.00293	2.947
A	RS-1 all additional kWh	3.263	1.00293	3.947
A	GS-1, SL-2, GSCU-1, WIES-1	3.263	1.00293	3.273
A-1	SL-1, OL-1, PL-1 (1)	2.984	1.00293	2.992
B	GSD-1	3.263	1.00284	3.272
C	GSLD-1, CS-1	3.263	1.00186	3.269
D	GSLD-2, CS-2, OS-2, MET	3.263	0.99253	3.239
E	GSLD-3, CS-3	3.263	0.96479	3.148
A	GST-1 On-Peak	4.669	1.00293	4.683
	GST-1 Off-Peak	2.663	1.00293	2.671
A	RTR-1 On-Peak	-	-	1.410
	RTR-1 Off-Peak	-	-	(0.602)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.669	1.00283	4.682
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.663	1.00283	2.671
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.669	1.00186	4.678
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.663	1.00186	2.668
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.669	0.99328	4.638
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.663	0.99328	2.645
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.669	0.96479	4.505
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.663	0.96479	2.569
F	CILC-1(D), ISST-1(D) On-Peak	4.669	0.99253	4.634
	CILC-1(D), ISST-1(D) Off-Peak	2.663	0.99253	2.643

(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
		JUNE - SEPTEMBER		
GROUPS	RATE SCHEDULE	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	6.001	1.00284	6.018
	GSD(T)-1 Off-Peak	2.777	1.00284	2.785
C	GSLD(T)-1 On-Peak	6.001	1.00186	6.012
	GSLD(T)-1 Off-Peak	2.777	1.00186	2.782
D	GSLD(T)-2 On-Peak	6.001	0.99328	5.961
	GSLD(T)-2 Off-Peak	2.777	0.99328	2.758

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Fuel Cost of System Generation	$233,108,385	$213,044,367	$257,918,712	$259,343,506	$279,253,240	$295,856,825	$321,498,280	$321,451,323	$298,810,379	$291,192,917	$233,978,087	$242,685,535	$3,248,141,556
2	Nuclear Fuel Disposal	2,409,819	2,176,613	1,587,537	1,860,399	2,347,859	2,272,121	2,347,859	2,347,859	2,146,193	1,826,155	2,332,085	2,409,819	26,064,319
3	RBEC Fuel Savings	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	82,000,000
4	Fuel Cost of Power Sold	(5,739,770)	(9,106,079)	(10,893,920)	(7,980,423)	(5,760,820)	(5,833,323)	(6,602,020)	(4,047,920)	(1,737,073)	(1,970,620)	(3,479,923)	(6,536,420)	(69,688,315)
5	Gain on Economy Sales	(993,750)	(1,657,500)	(1,948,750)	(1,193,750)	(901,250)	(650,000)	(823,750)	(565,000)	(203,750)	(290,000)	(637,500)	(1,215,000)	(11,080,000)
6	Fuel Cost of Purchased Power	9,032,496	8,624,221	9,398,040	9,481,790	13,524,421	15,397,625	16,147,779	15,798,587	16,191,274	13,504,351	8,721,822	8,501,088	144,323,495
7	Qualifying Facilities	9,945,865	8,880,867	10,309,866	5,997,865	10,849,865	13,256,860	14,016,861	13,746,860	13,771,859	9,839,862	6,976,866	8,973,866	126,567,361
8	Energy Cost of Economy Purchases	197,461	85,278	86,206	519,450	155,794	3,005,537	3,824,412	2,947,914	1,805,718	715,344	29,606	30,818	13,403,538
9	Total Fuel & Net Power Transactions	$254,793,840	$228,881,101	$273,291,024	$274,862,170	$306,302,441	$330,138,979	$357,242,754	$358,512,956	$337,617,933	$321,651,343	$254,754,376	$261,683,039	$3,559,731,955
10														
11	Incremental Personnel, Software and Hardware Costs	33,432	29,280	31,536	32,961	32,961	31,536	34,387	31,536	32,961	34,387	30,110	34,387	389,472
12	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	0	326,160	279,350	203,850	128,350	143,450	105,700	37,750	60,400	151,000	286,900	1,722,910
13	Total	33,432	29,280	357,696	312,311	236,811	159,886	177,837	137,236	70,711	94,787	181,110	321,287	2,112,382
14	Adjusted Total Fuel & Net Power Transactions	254,827,272	228,910,381	273,648,719	275,174,481	306,539,252	330,298,864	357,420,590	358,650,191	337,688,644	321,746,129	254,935,486	262,004,326	3,561,844,337
15														
16	System MWH Sales	8,985,918	7,947,739	7,864,510	7,931,770	9,091,100	9,818,071	10,760,888	10,705,544	10,396,265	9,730,435	8,866,980	8,668,474	110,767,695
17														
18	Cost per KWH (¢/KWH)	2.8359	2.8802	3.4795	3.4693	3.3719	3.3642	3.3215	3.3501	3.2482	3.3066	2.8751	3.0225	3.2156
19	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
20	Jurisdictional Cost (¢/KWH)	2.8406	2.8851	3.4854	3.4751	3.3776	3.3699	3.3271	3.3558	3.2537	3.3122	2.8800	3.0276	3.2210
21	True-Up (¢/KWH)	0.1392	0.1619	0.1633	0.1628	0.1411	0.1311	0.1199	0.1211	0.1249	0.1336	0.1467	0.1491	0.1396
22	Total (¢/KWH)	2.9798	3.0470	3.6487	3.6379	3.5187	3.5010	3.4470	3.4769	3.3786	3.4458	3.0267	3.1767	3.3606
23	Revenue Tax Factor (0.00072)	0.0021	0.0022	0.0026	0.0026	0.0025	0.0025	0.0025	0.0025	0.0024	0.0025	0.0022	0.0023	0.0024
24	Recovery Factor Adjusted for Taxes (¢/KWH)	2.9819	3.0492	3.6513	3.6405	3.5212	3.5035	3.4495	3.4794	3.3810	3.4483	3.0289	3.1790	3.3630
25	GPIF (¢/KWH)	0.0195	0.0227	0.0229	0.0228	0.0197	0.0184	0.0168	0.0170	0.0175	0.0187	0.0205	0.0209	0.0195
26	Jurisdictionalized Savings - RBEC (¢/KWH)	0.0000	0.0000	0.0000	0.0000	0.0000	(0.1195)	(0.1093)	(0.1104)	(0.1138)	(0.1217)	(0.1337)	(0.1359)	(0.1198)
27	Recovery Factor including GPIF (¢/KWH)	3.0014	3.0719	3.6742	3.6633	3.5409	3.4024	3.3570	3.3860	3.2847	3.3453	2.9157	3.0640	3.2627
28														
29	Recovery Factor Rounded to .001 (¢/KWH)	3.001	3.072	3.674	3.663	3.541	3.402	3.357	3.386	3.285	3.345	2.916	3.064	3.263
30														
31	Note: Totals may not add due to rounding.													
32														
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	37,388,852,427	0.029472	$1,101,910,074.54	2.947
2	All Additional KWH	18,070,887,116	0.039472	$713,287,200.70	3.947
3	Total KWH	55,459,739,543		$1,815,197,275.24	
4					
5	Avg Fuel Factor	3.263			
6	RS-1 Loss Multiplier	1.00293			
7	Average Fuel Factor	3.273			
8					
9	Target Fuel Revenues	$1,815,197,275.24			
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	SEPT 13	PROPOSED [1], [2] JAN 14 - MAY 14	DIFFERENCE $	DIFFERENCE %	PROPOSED [1], [2] JUN 14 - DEC 14	DIFFERENCE $	DIFFERENCE %
BASE	$51.33	$52.48	$1.15	2.24%	$54.88	$2.40	4.57%
FUEL	$26.33	$30.67	$4.34	16.48%	$29.47	-$1.20	-3.91%
CONSERVATION	$2.33	$3.37	$1.04	44.64%	$3.37	$0.00	0.00%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%	$7.86	$0.00	0.00%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%	$2.30	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.07	$1.07	$0.00	0.00%	$1.07	$0.00	0.28%
SUBTOTAL	$92.73	$97.75	$5.02	5.41%	$98.95	$1.20	1.23%
GROSS RECEIPTS TAX	$2.38	$2.51	$0.13	5.46%	$2.54	$0.03	1.20%
TOTAL	**$95.11**	**$100.26**	$5.15	5.41%	**$101.49**	$1.23	1.23%

Note: [1] Base rate changes are based on estimated EPU increase.
[2] Based on estimates of the Conservation factor to be filed on September 10, 2013.

APPENDIX IV
FUEL COST RECOVERY
2014 E-SCHEDULES

TRADITIONAL FCR FACTOR CALCULATION
FOR THE PERIOD JANUARY 2014 THROUGH DECEMBER 2014

TJK-7
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT ______________
PAGES 1-6
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APPENDIX IV FUEL COST RECOVERY
E SCHEDULES
JANUARY 2014 – DECEMBER 2014
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FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,248,141,556	112,677,379	2.8827
2	Nuclear Fuel Disposal Costs (E2)	$26,064,319	27,766,399	0.0939
3	TOTAL COST OF GENERATED POWER	$3,274,205,875	112,677,379	2.9058
4	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$144,323,495	4,102,190	3.5182
5	Energy Cost of Economy Purchases (E9)	$13,403,538	278,500	4.8128
6	Payments to Qualifying Facilities (E8)	$126,567,361	2,940,405	4.3044
7	TOTAL COST OF PURCHASED POWER	$284,294,395	7,321,095	3.8832
8	TOTAL AVAILABLE MWH (LINE 3 + LINE 7)		119,998,473	
9	Fuel Cost of Economy Sales (E6)	($65,345,750)	(1,655,000)	3.9484
10	Gain from Off-System Sales (E6)	($11,080,000)	N/A	N/A
11	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,342,565)	(629,817)	0.6895
12	TOTAL FUEL COST AND GAINS OF POWER SALES	($80,768,315)	(2,284,817)	3.5350
13	Incremental Personnel, Software, and Hardware Costs	$389,472	N/A	N/A
14	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,722,910	N/A	N/A
15	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,112,382	N/A	N/A
16	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 3 + 7 + 12 + 15)	$3,479,844,337	117,713,657	2.9562
17	Net Unbilled Sales (1)	($31,293,303)	(1,058,567)	(0.0283)
18	Company Use (1)	$10,439,533	353,141	0.0094
19	T & D Losses (1)	$226,189,882	7,651,388	0.2042
20	SYSTEM MWH SALES	$3,479,844,337	110,767,695	3.1416
21	Wholesale MWH Sales	$154,705,528	4,924,470	3.1416
22	Jurisdictional MWH Sales	$3,325,138,809	105,843,225	3.1416
23	Jurisdictional Loss Multiplier	$5,619,485		1.00169
24	Jurisdictional MWH Sales Adjusted for Line Losses	$3,330,758,294	105,843,225	3.1469
25	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$147,765,613	105,843,225	0.1396
26	TOTAL JURISDICTIONAL FUEL COST	$3,478,523,907	105,843,225	3.2865
27	Revenue Tax Factor	$2,504,537		1.00072
28	Fuel Factor Adjusted for Taxes	$3,481,028,444	105,843,225	3.2889
29	GPIF (2)	$20,679,970	105,843,225	0.0195
30	Fuel Factor including GPIF (Line 28 + Line 29)	$3,501,708,414	105,843,225	3.3084
31	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.308
32				
33	(1) For Informational Purposes Only			
34	(2) Calculation Based on Jurisdictional KWH Sales			
35				
36	Note: Totals may not add due to rounding.			
37				
38				

FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	3.308	1.00293	2.992
A	RS-1 all additional kWh	3.308	1.00293	3.992
A	GS-1, SL-2, GSCU-1, WIES-1	3.308	1.00293	3.318
A-1	SL-1, OL-1, PL-1 (1)	3.025	1.00293	3.034
B	GSD-1	3.308	1.00284	3.317
C	GSLD-1, CS-1	3.308	1.00186	3.314
D	GSLD-2, CS-2, OS-2, MET	3.308	0.99253	3.283
E	GSLD-3, CS-3	3.308	0.96479	3.192
A	GST-1 On-Peak	4.734	1.00293	4.748
	GST-1 Off-Peak	2.699	1.00293	2.707
A	RTR-1 On-Peak	-	-	1.430
	RTR-1 Off-Peak	-	-	(0.611)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.734	1.00283	4.747
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.699	1.00283	2.707
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.734	1.00186	4.743
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.699	1.00186	2.704
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.734	0.99328	4.702
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.699	0.99328	2.681
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.734	0.96479	4.567
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.699	0.96479	2.604
F	CILC-1(D), ISST-1(D) On-Peak	4.734	0.99253	4.699
	CILC-1(D), ISST-1(D) Off-Peak	2.699	0.99253	2.679

(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
		JUNE - SEPTEMBER		
GROUPS	RATE SCHEDULE	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	6.083	1.00284	6.100
	GSD(T)-1 Off-Peak	2.815	1.00284	2.823
C	GSLD(T)-1 On-Peak	6.083	1.00186	6.094
	GSLD(T)-1 Off-Peak	2.815	1.00186	2.820
D	GSLD(T)-2 On-Peak	6.083	0.99328	6.042
	GSLD(T)-2 Off-Peak	2.815	0.99328	2.796

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) January Estimated	(3) February Estimated	(4) March Estimated	(5) April Estimated	(6) May Estimated	(7) June Estimated	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) 12 Month Period
1	Fuel Cost of System Generation	$233,108,385	$213,044,367	$257,918,712	$259,343,506	$279,253,240	$295,856,825	$321,498,280	$321,451,323	$298,810,379	$291,192,917	$233,978,087	$242,685,535	$3,248,141,556
2	Nuclear Fuel Disposal	2,409,819	2,176,613	1,587,537	1,860,399	2,347,859	2,272,121	2,347,859	2,347,859	2,146,193	1,826,155	2,332,085	2,409,819	26,064,319
3	Fuel Cost of Power Sold	(5,739,770)	(9,106,079)	(10,893,920)	(7,980,423)	(5,760,820)	(5,833,323)	(6,602,020)	(4,047,920)	(1,737,073)	(1,970,620)	(3,479,923)	(6,536,420)	(69,688,315)
4	Gain on Economy Sales	(993,750)	(1,657,500)	(1,948,750)	(1,193,750)	(901,250)	(650,000)	(823,750)	(565,000)	(203,750)	(290,000)	(637,500)	(1,215,000)	(11,080,000)
5	Fuel Cost of Purchased Power	9,032,496	8,624,221	9,398,040	9,481,790	13,524,421	15,397,625	16,147,779	15,798,587	16,191,274	13,504,351	8,721,822	8,501,088	144,323,495
6	Qualifying Facilities	9,945,865	8,880,867	10,309,866	5,997,865	10,849,865	13,256,860	14,016,861	13,746,860	13,771,859	9,839,862	6,976,866	8,973,866	126,567,361
7	Energy Cost of Economy Purchases	197,461	85,278	86,206	519,450	155,794	3,005,537	3,824,412	2,947,914	1,805,718	715,344	29,606	30,818	13,403,538
8	Total Fuel & Net Power Transactions	$247,960,507	$222,047,768	$266,457,690	$268,028,837	$299,469,108	$323,305,645	$350,409,420	$351,679,622	$330,784,599	$314,818,009	$247,921,043	$254,849,706	$3,477,731,955
9														
10	Incremental Personnel, Software and Hardware Costs	33,432	29,280	31,536	32,961	32,961	31,536	34,387	31,536	32,961	34,387	30,110	34,387	389,472
11	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	0	326,160	279,350	203,850	128,350	143,450	105,700	37,750	60,400	151,000	286,900	1,722,910
12	Total	33,432	29,280	357,696	312,311	236,811	159,886	177,837	137,236	70,711	94,787	181,110	321,287	2,112,382
13	Adjusted Total Fuel & Net Power Transactions	247,993,938	222,077,047	266,815,386	268,341,148	299,705,919	323,465,531	350,587,257	351,816,858	330,855,311	314,912,796	248,102,153	255,170,992	3,479,844,337
14														
15	System MWH Sales	8,985,918	7,947,739	7,864,510	7,931,770	9,091,100	9,818,071	10,760,888	10,705,544	10,396,265	9,730,435	8,866,980	8,668,474	110,767,695
16														
17	Cost per KWH (¢/KWH)	2.7598	2.7942	3.3927	3.3831	3.2967	3.2946	3.2580	3.2863	3.1824	3.2364	2.7980	2.9437	3.1416
18	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
19	Jurisdictional Cost (¢/KWH)	2.7645	2.7989	3.3984	3.3888	3.3023	3.3002	3.2635	3.2919	3.1878	3.2418	2.8028	2.9486	3.1469
20	True-Up (¢/KWH)	0.1392	0.1619	0.1633	0.1628	0.1411	0.1311	0.1199	0.1211	0.1249	0.1336	0.1467	0.1491	0.1396
21	Total (¢/KWH)	2.9037	2.9608	3.5617	3.5516	3.4434	3.4313	3.3834	3.4130	3.3127	3.3754	2.9495	3.0977	3.2865
22	Revenue Tax Factor (0.00072)	0.0021	0.0021	0.0026	0.0026	0.0025	0.0025	0.0024	0.0025	0.0024	0.0024	0.0021	0.0022	0.0024
23	Recovery Factor Adjusted for Taxes (¢/KWH)	2.9058	2.9629	3.5643	3.5542	3.4459	3.4338	3.3858	3.4155	3.3151	3.3778	2.9516	3.0999	3.2889
24	GPIF (¢/KWH)	0.0195	0.0227	0.0229	0.0228	0.0197	0.0184	0.0168	0.0170	0.0175	0.0187	0.0205	0.0209	0.0195
25	Recovery Factor including GPIF (¢/KWH)	2.9253	2.9856	3.5872	3.5770	3.4656	3.4522	3.4026	3.4325	3.3326	3.3965	2.9721	3.1208	3.3084
26														
27	Recovery Factor Rounded to .001 (¢/KWH)	2.925	2.986	3.587	3.577	3.466	3.452	3.403	3.433	3.333	3.397	2.972	3.121	3.308
28														
29	Note: Totals may not add due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	37,388,852,427	0.029922	$1,118,735,058.13	2.992
2	All Additional KWH	18,070,887,116	0.039922	$721,419,099.90	3.992
3	Total KWH	55,459,739,543		$1,840,154,158.04	
4					
5	Avg Fuel Factor	3.308			
6	RS-1 Loss Multiplier	1.00293			
7	Average Fuel Factor	3.318			
8					
9	Target Fuel Revenues	$1,840,154,158.04			
10					
11					
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COMPANY: FLORIDA POWER & LIGHT COMPANY

	SEPT 13	PROPOSED [1], [2] JAN 14 - DEC 14	DIFFERENCE $	%
BASE	$51.33	$52.48	$1.15	2.24%
FUEL	$26.33	$29.92	$3.59	13.63%
CONSERVATION	$2.33	$3.37	$1.04	44.64%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%
STORM RESTORATION SURCHARGE	$1.07	$1.07	$0.00	0.00%
SUBTOTAL	$92.73	$97.00	$4.27	4.60%
GROSS RECEIPTS TAX	$2.38	$2.49	$0.11	4.62%
TOTAL	**$95.11**	**$99.49**	$4.38	4.61%

Note: [1] Base rate changes are based on estimated EPU increase.
[2] Based on estimates of the Conservation factor to be filed on September 10, 2013.

APPENDIX V

CAPACITY COST RECOVERY

JANUARY 2014 – DECEMBER 2014 FACTORS

TJK-8
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J.KEITH
EXHIBIT __________
PAGES 1-13
AUGUST 30, 2013

APPENDIX V
CAPACITY COST RECOVERY

TABLE OF CONTENTS

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)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1	Payments to Non-cogenerators	$16,437,513	$16,618,240	$17,107,824	$16,482,672	$16,487,283	$16,076,979	$15,714,068	$16,214,757	$17,059,834	$16,492,116	$16,259,876	$16,286,036	$197,237,197
2	Payments to Co-generators	$25,038,297	$25,205,917	$20,512,305	$23,359,041	$22,728,373	$23,148,194	$23,388,910	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$278,819,477
3	SJRPP Suspension Accrual	$0	$0	($2,582,946)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return on SJRPP Suspension Liability	($445,444)	($445,444)	($435,246)	($421,647)	($414,848)	($408,049)	($405,655)	($398,786)	($391,912)	($385,038)	($378,164)	($371,291)	($4,901,525)
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	$2,485,373	$5,208,263	$5,387,066	$4,104,789	$4,317,518	$6,176,809	$46,426,048
6	Incremental Nuclear NRC Compliance Costs O&M	$25,179	$174,820	($37,256)	($3,346)	$23,650	($83,471)	$18,082	($3,127)	$46,873	($3,127)	($3,127)	($56,471)	$98,678
7	Incremental Nuclear NRC Compliance Costs Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,587	$17,587
8	Transmission of Electricity by Others	$2,270,836	$2,203,512	$2,161,119	$1,343,872	$1,441,836	($627,741)	$1,138,719	$1,541,868	$1,399,703	$1,613,647	$2,021,776	$2,069,324	$18,578,470
9	Transmission Revenues from Capacity Sales	($329,135)	($578,809)	($845,612)	($380,813)	($477,335)	($249,378)	($294,350)	($176,250)	($86,250)	($92,500)	($225,000)	($422,500)	($4,157,931)
10	Total (Lines 1 through 9)	$45,739,352	$46,248,567	$39,348,308	$42,767,130	$41,660,233	$40,480,632	$41,184,165	$44,613,432	$45,642,019	$43,956,593	$44,219,584	$45,926,201	$521,786,216
11	Jurisdictional Separation Factor [(a)]	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	N/A
12	Jurisdictional CCR	$44,810,990	$45,309,869	$38,549,663	$41,899,094	$40,814,664	$39,659,005	$40,348,258	$43,707,922	$44,715,632	$43,064,414	$43,322,068	$44,994,046	$511,195,626
13	Nuclear Cost Recovery Costs	$12,249,674	$14,229,199	$14,667,616	$13,013,524	$12,802,720	$12,659,892	$12,293,132	$12,200,448	$12,000,152	$11,888,604	$11,726,916	$11,774,862	$151,506,739
14	Jurisdictional CCR	$57,060,664	$59,539,068	$53,217,280	$54,912,618	$53,617,383	$52,318,897	$52,641,390	$55,908,370	$56,715,784	$54,953,018	$55,048,985	$56,768,908	$662,702,365
15	CCR Revenues (Net of Revenue Taxes)	$52,434,454	$49,413,054	$49,832,052	$53,331,531	$58,351,845	$61,903,701	$65,986,930	$68,299,950	$66,148,216	$61,684,870	$55,930,151	$54,654,912	697,971,665
16	Prior Period True-up Provision	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($60,583,035)
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$47,385,867	$44,364,468	$44,783,466	$48,282,945	$53,303,259	$56,855,115	$60,938,344	$63,251,364	$61,099,629	$56,636,284	$50,881,565	$49,606,325	$637,388,630
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	$8,296,954	$7,342,994	$4,383,845	$1,683,266	($4,167,420)	($7,162,583)	($25,313,735)
19	Interest Provision for Month	($4,128)	($6,193)	($6,371)	($5,832)	($5,367)	($4,266)	($3,080)	($2,268)	($1,813)	($1,476)	($1,317)	($1,343)	($43,456)
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)	($66,014,466)	($52,672,006)	($40,282,694)	($30,852,076)	($24,121,700)	($23,241,851)	($60,583,035)
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$60,583,035
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($73,126,858)	($83,259,064)	($86,650,663)	($88,237,583)	($83,508,487)	($73,927,950)	($60,585,490)	($48,196,178)	($38,765,560)	($32,035,184)	($31,155,335)	($33,270,675)	($33,270,675)

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
PROJECTED CAPACITY PAYMENTS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1	Capacity Payments To Non-Cogenerators	$16,233,478	$16,639,803	$16,494,020	$16,828,377	$16,185,974	$16,007,436	$16,028,756	$15,942,337	$16,787,414	$16,219,696	$15,987,456	$16,013,616	$195,368,363
2	Capacity Payments To Cogenerators	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$282,261,087
3	SJRPP Suspension Accrual	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return Requirements On SJRPP Suspension Liability	($364,417)	($357,543)	($350,669)	($343,795)	($336,921)	($330,047)	($323,173)	($316,299)	($309,426)	($302,552)	($295,678)	($288,804)	($3,919,323)
5	Incremental Plant Security Costs O&M	$4,294,461	$3,543,474	$4,241,372	$3,805,797	$3,733,986	$5,300,828	$5,162,205	$4,226,056	$3,950,143	$4,176,511	$4,185,604	$5,922,258	$52,542,693
6	Incremental Plant Security Costs Capital	$3,124	$8,572	$12,996	$17,559	$22,350	$31,572	$44,885	$55,194	$63,625	$77,576	$94,124	$115,123	546,699
7	Incremental Nuclear NRC Compliance Costs O&M	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$256,000
8	Incremental Nuclear NRC Compliance Costs Capital	$33,765	$48,262	$61,195	$73,863	$86,180	$98,724	$113,743	$130,977	$148,661	$166,596	$184,272	$219,333	$1,365,570
9	Transmission Of Electricity By Others	$2,083,294	$2,010,384	$1,750,171	$1,828,046	$1,738,270	$1,603,399	$1,587,912	$1,609,105	$1,555,750	$1,765,340	$2,082,589	$2,113,496	$21,727,757
10	Transmission Revenues From Capacity Sales	($366,250)	($595,000)	($753,750)	($511,250)	($408,750)	($246,250)	($278,750)	($182,500)	($66,250)	($95,000)	($225,000)	($400,000)	($4,128,750)
11	System Total	$44,599,563	$43,980,060	$44,137,444	$44,380,705	$43,703,197	$45,147,770	$45,017,686	$44,146,978	$44,812,027	$44,690,276	$44,695,476	$46,377,130	$535,688,312
12	Jurisdictional % *													95.20688%
13	Jurisdictionalized Capacity Payments													$510,012,148
14	2012 FINAL TRUE-UP -- (Over)/Under Recovery													$7,913,484
15	2013 ACT/EST TRUE-UP -- (Over)/Under Recovery													$25,357,191
16	Nuclear Cost Recovery Clause													$43,461,246
17	Total (Lines 13+14+15+16)													$586,744,069
18	Revenue Tax Multiplier													1.00072
19	Total Recoverable Capacity Payments													$587,166,525
20														
21	*Calculation of Jurisdictional %													
22	......................AVG. 12CP													
23	.....................AT GEN (MW)...........%													
24	FPSC................19,105.040.........95.206884%													
25	FERC................961.828............4.793116%													
26	TOTAL..............20,066.868.........100.00000%													
27														
28	* Based on 2014 projected Data													
29	Totals may not add up due to rounding.													
30														
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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY DEMAND ALLOCATION % BY RATE CLASS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE SCHEDULE	AVG 12CP Load Factor at Meter (%) [a]	Projected Sales at Meter (kwh) [b]	Projected AVG 12CP at Meter (kW) [c]	Demand Loss Expansion Factor [d]	Energy Loss Expansion Factor [e]	Projected Sales at Generation (kwh) [f]	Projected AVG 12CP at Generation (kW) [g]	Percentage of Sales at Generation (%) [h]	Percentage of Demand at Generation (%) [i]
RS1/RTR1	60.017%	55,459,739,543	10,548,782	1.07574702	1.05857569	58,708,332,054	11,347,821	52.46263%	59.39700%
GS1/GST1/WIES1	73.769%	6,126,227,507	948,015	1.07574702	1.05857569	6,485,075,510	1,019,824	5.79516%	5.33799%
GSD1/GSDT1/HLFT1	76.912%	25,762,255,228	3,823,703	1.07561796	1.05847562	27,268,719,075	4,112,844	24.36773%	21.52753%
OS2	86.219%	11,759,080	1,557	1.06570384	1.02863145	12,095,760	1,659	0.01081%	0.00869%
GSLD1/GSLDT1/CS1/CST1/HLFT2	77.411%	10,605,576,674	1,563,964	1.07421327	1.05744688	11,214,833,965	1,680,031	10.02174%	8.79365%
GSLD2/GSLDT2/CS2/CST2/HLFT3	91.599%	2,471,381,071	307,997	1.06229421	1.04839453	2,590,982,396	327,183	2.31534%	1.71255%
GSLD3/GSLDT3/CS3/CST3	90.819%	177,440,887	22,303	1.02281871	1.01832332	180,692,193	22,812	0.16147%	0.11940%
SST1T	80.082%	88,591,459	12,629	1.02281871	1.01832332	90,214,749	12,917	0.08062%	0.06761%
SST1D1/SST1D2/SST1D3	87.237%	9,856,390	1,290	1.03630873	1.02863145	10,138,593	1,337	0.00906%	0.00700%
CILC D/CILC G	95.745%	3,036,047,195	361,985	1.06183259	1.04827714	3,182,618,870	384,367	2.84404%	2.01186%
CILC T	98.609%	1,314,450,655	152,168	1.02281871	1.01832332	1,338,535,755	155,640	1.19614%	0.81466%
MET	74.716%	92,658,992	14,157	1.03630873	1.02863145	95,311,953	14,671	0.08517%	0.07679%
OL1/SL1/PL1	454.435%	630,606,760	15,841	1.07574702	1.05857569	667,544,986	17,041	0.59653%	0.08920%
SL2, GSCU1	100.920%	56,633,687	6,406	1.07574702	1.05857569	59,951,044	6,891	0.05357%	0.03607%
TOTAL		105,843,225,128	17,780,797			111,905,046,903	19,105,039	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2010-2012 load research data and 2014 projections.

[b] Projected kwh sales for the period January 2014 through December 2014.

[c] Calculated: Col(3)/(8760 hours * Col(2))

[d] Based on projected 2014 demand losses.

[e] Based on projected 2014 energy losses.

[f] Col(3) * Col(6)

[g] Col(4) * Col(5)

[h] Col(7) / Total for Col(7)

[i] Col(8) / Total for Col(8)

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Percentage of Sales at Generation (%) [a]	Percentage of Demand at Generation (%) [b]	Energy Related Cost ($) [c]	Demand Related Cost ($) [d]	Total Capacity Costs ($) [e]	Projected Sales at Meter (kwh) [f]	Billing KW Load Factor (%) [g]	Projected Billed KW at Meter (KW) [h]	Capacity Recovery Factor ($/KW) [i]	Capacity Recovery Factor ($/kwh) [j]	RDC ($/KW) [k]	SDD ($/KW) [l]
RS1/RTR1	52.46263%	59.39700%	$23,695,616	$321,931,681	$345,627,297	55,459,739,543	-	-	-	0.00623	-	-
GS1/GST1/WIES1	5.79516%	5.33799%	$2,617,480	$28,931,877	$31,549,356	6,126,227,507	-	-	-	0.00515	-	-
GSD1/GSDT1/HLFT1	24.36773%	21.52753%	$11,006,088	$116,679,201	$127,685,289	25,762,255,228	50.43267%	69,975,985	1.82	-	-	-
OS2	0.01081%	0.00869%	$4,882	$47,073	$51,956	11,759,080	-	-	-	0.00442	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	10.02174%	8.79365%	$4,526,485	$47,661,589	$52,188,074	10,605,576,674	55.65176%	26,105,529	2.00	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.31534%	1.71255%	$1,045,762	$9,282,021	$10,327,783	2,471,381,071	65.76804%	5,147,567	2.01	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.16147%	0.11940%	$72,930	$647,162	$720,093	177,440,887	75.40900%	322,335	2.23	-	-	-
SST1T	0.08062%	0.06761%	$36,412	$366,454	$402,866	88,591,459	14.06729%	862,697	-	-	$0.26	$0.12
SST1D1/SST1D2/SST1D3	0.00906%	0.00700%	$4,092	$37,925	$42,017	9,856,390	13.75824%	98,137	-	-	$0.27	$0.13
CILC D/CILC G	2.84404%	2.01186%	$1,284,556	$10,904,302	$12,188,858	3,036,047,195	73.97652%	5,622,012	2.17	-	-	-
CILC T	1.19614%	0.81466%	$540,254	$4,415,432	$4,955,687	1,314,450,655	76.69387%	2,347,798	2.11	-	-	-
MET	0.08517%	0.07679%	$38,469	$416,209	$454,679	92,658,992	63.58056%	199,637	2.28	-	-	-
OL1/SL1/PL1	0.59653%	0.08920%	$269,432	$483,442	$752,873	630,606,760	-	-	-	0.00119	-	-
SL2, GSCU1	0.05357%	0.03607%	$24,197	$195,501	$219,698	56,633,687	-	-	-	0.00388	-	-
TOTAL			$45,166,656	$541,999,869	$587,166,525	105,843,225,128		110,681,696				

[a] Obtained from Page 3, Col(9)

[b] Obtained from Page 3, Col(10)

[c] (Total Capacity Costs/13) * Col(2)

[d] (Total Capacity Costs/13 * 12) * Col(3)

[e] Col(4) + Col(5)

[f] Projected kwh sales for the period January 2014 through December 2014.

[g] (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))

[h] Col(7) / (Col(8) *730)

[i] Col(6) / Col(9)

[j] Col(6) / Col(7)

[k] RDC = Reservation Demand Charge - (Total Col 6)/(Page 2 Total Col 8)(.10)(Page 2 Col 5)/12 Months

[l] SDD = Sum of Daily Demand Charge - (Total Col 6)/(Page 2 Total Col 8)/(21 onpeak days)(Page 2 Col 5)/12 Months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2014

Return on Capital Investments, Depreciation and Taxes
Incremental Security 2014
(in Dollars)

Line			Beginning of Period Amount	January Estimate	February Estimate	March Estimate	April Estimate	May Estimate	June Estimate	Six Month Amount
1.	Investments									
	a.	Expenditures/Additions		$782,475	$582,446	$525,739	$617,424	$582,851	$1,727,326	$4,818,261
	b.	Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c.	Retirements		$0	$0	$0	$0	$0	$0	$0
	d.	Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (A)		$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation		$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing		$0	782,475	1,364,921	1,890,660	2,508,084	3,090,935	4,818,261	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$0	$782,475	$1,364,921	$1,890,660	$2,508,084	$3,090,935	$4,818,261	n/a
6.	Average Net Investment			391,238	1,073,698	1,627,791	2,199,372	2,799,510	3,954,598	n/a
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		2,613	7,171	10,872	14,689	18,698	26,412	$80,455
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		510	1,401	2,124	2,870	3,653	5,160	$15,718
8.	Investment Expenses									
	a.	Depreciation		0	0	0	0	0	0	$0
	b.	Amortization		0	0	0	0	0	0	$0
	c.	Dismantlement								
	d.	Property Expenses								
	e.	Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)			$3,124	$8,572	$12,996	$17,559	$22,350	$31,572	$96,173

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).

(B) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the 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.

(C) The Debt Component for Jan. - Dec 2014 is 1.5658% based on the May 2013 ROR Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2014

Return on Capital Investments, Depreciation and Taxes
Incremental Security 2014
(in Dollars)

Line		Beginning of Period Amount	July Estimate	August Estimate	September Estimate	October Estimate	November Estimate	December Estimate	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,607,720	$974,719	$1,137,382	$1,440,448	$1,572,675	$2,149,673	$13,700,878
	b. Clearings to Plant		$0	$0	$0	$4,900,460	$1,196,547	$5,274,032	$11,371,039
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	4,900,460	6,097,007	11,371,039	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	3,675	11,918	26,391	n/a
4.	CWIP - Non Interest Bearing	$4,818,261	6,425,981	7,400,700	8,538,082	5,078,070	5,454,198	2,329,839	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,818,261	$6,425,981	$7,400,700	$8,538,082	$9,974,855	$11,539,287	$13,674,487	n/a
6.	Average Net Investment		5,622,121	6,913,341	7,969,391	9,256,468	10,757,071	12,606,887	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		37,549	46,173	53,227	61,823	71,845	84,200	435,272
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		7,336	9,021	10,398	12,078	14,036	16,449	85,036
8.	Investment Expenses								
	a. Depreciation		0	0	0	3,675	8,243	14,473	26,391
	b. Amortization		0	0	0	0	0	0	0
	c. Dismantlement								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$44,885	$55,194	$63,625	$77,576	$94,124	$115,123	546,699

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).

(B) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the 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.

(C) The Debt Component for Jan. - Dec 2014 is 1.5658% based on the May 2013 ROR Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	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		$2,020,790	$1,610,944	$1,628,955	$1,544,348	$1,541,164	$1,601,266	$2,161,125	$2,156,267	$2,273,797	$2,219,094	$2,208,885	$6,574,213	$27,540,850
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	($1,063,826)	($139,702)	($136,245)	($138,737)	($1,779,343)	($3,257,853)
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	$13,218,806	$15,239,595	$16,850,540	$18,479,494	$20,023,843	$21,565,007	$23,166,273	$25,327,398	$26,419,839	$28,553,934	$30,636,783	$32,706,932	$37,501,802	N/A
5. Net Investment (Lines 2 - 3 + 4)	$13,218,806	$15,239,595	$16,850,540	$18,479,494	$20,023,843	$21,565,007	$23,166,273	$25,327,398	$26,419,839	$28,553,934	$30,636,783	$32,706,932	$37,501,802	N/A
6. Total Estimated Capital Expenditures Included in Base Rates [b]	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$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	$1,063,826	$1,203,528	$1,339,773	$1,478,510	$3,257,853	N/A
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$8,936,174	$8,796,472	$8,660,227	$8,521,490	$6,742,147	N/A
9. Adjusted Net Investment (Lines 5 - 8)	$3,218,806	$5,239,595	$6,850,540	$8,479,494	$10,023,843	$11,565,007	$13,166,273	$15,327,398	$17,483,666	$19,757,462	$21,976,557	$24,185,442	$30,759,655	N/A
10. Average Net Investment		$4,229,200	$6,045,067	$7,665,017	$9,251,668	$10,794,425	$12,365,640	$14,246,836	$16,405,532	$18,620,564	$20,867,010	$23,080,999	$27,472,549	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [d]		$28,246	$40,374	$51,194	$61,791	$72,095	$82,589	$95,153	$109,571	$124,364	$139,368	$154,155	$183,486	$1,142,385
b. Debt Component (Line 10 x debt rate x 1/12) [e]		$5,518	$7,888	$10,002	$12,072	$14,085	$16,135	$18,590	$21,406	$24,297	$27,228	$30,117	$35,847	$223,185
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)		$33,765	$48,262	$61,195	$73,863	$86,180	$98,724	$113,743	$130,977	$148,661	$166,596	$184,272	$219,333	$1,365,570

[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 is 4.9230%, which is based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

Florida Power & Light Company
Schedule E12 - Capacity Costs

2014 Projection

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

QF = Qualifying Facility

2014 Projection Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	125,613,000
ICL	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	138,633,627
BN-NEG '91	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	3,892,680
BS-NEG '91	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	1,238,580
SWAPBC	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	12,883,200
Total	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	282,261,087

Florida Power & Light Company

Schedule E12 - Capacity Costs **CONFIDENTIAL**

2014 Projection

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

2014 Capacity in MW

Contract	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
1	163	163	163	163	163	163	163	163	163	163	163	163
2	600	600	600	600	600	600	600	600	600	600	600	600
3	190	190	190	190	190	190	190	190	190	190	190	190
4	375	375	375	375	375	375	375	375	375	375	375	375
Total	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328

2014 Capacity in Dollars

Contract	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
1	[redacted]											
2												
3												
4												
Total	16,233,478	16,639,803	16,494,020	16,828,377	16,185,974	16,007,436	16,028,756	15,942,337	16,787,414	16,219,696	15,987,456	16,013,616

Total Capacity Payments to Non-Cogenerators for 2014	195,368,363

FLORIDA POWER & LIGHT COMPANY
RATE CASE ALLOCATION OF GAS TURBINE PRODUCTION REVENUE REQUIREMENT
JANUARY 2014 THROUGH DECEMBER 2014

	Rate (a)	Demand & Energy Component[1] $000s (b)	Allocation[2] (c)	Allocation of WC3 Revenue Requirement @ 10.5% ROE [3] (d)
1	CILC-1D	22,378	2.083%	$3,316,762
2	CILC-1G	1,442	0.134%	$213,693
3	CILC-1T	9,888	0.921%	$1,465,532
4	GS1	61,812	5.754%	$9,161,544
5	GSCU-1	288	0.027%	$42,698
6	GSD1	237,906	22.148%	$35,261,321
7	GSLD1	105,089	9.783%	$15,575,765
8	GSLD2	20,042	1.866%	$2,970,566
9	GSLD3	1,575	0.147%	$233,409
10	MET	936	0.087%	$138,795
11	OL-1	274	0.025%	$40,578
12	OS-2	101	0.009%	$14,949
13	RS1	609,861	56.774%	$90,390,743
14	SL-1	1,438	0.134%	$213,103
15	SL-2	256	0.024%	$37,943
16	SST-DST	49	0.005%	$7,212
17	SST-TST	849	0.079%	$125,778
18				
19	Total	1,074,183	100.0%	$159,210,391

Notes:
[1] Other Production revenue requirements as approved in Docket 120015-EI 2013
[2] Calculated: Col (c) / TotalCol (c)
[3] Calculated: Col (b) * Col (c)

Calculation differences are due to rounding

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF REVENUE IMPACT FOR WEST COUNTY 3

	(a)	Total Revenue[1] (b)	Total WC3 Costs[2] (c)		% Increase[3] (d)
1	RS1/RTR-1	$5,545,061,516	$90,390,743		1.63%
2	GS1/GST1	$603,514,952	$9,161,544		1.52%
3	GSD1/GSDT1/HLFT1 (21-499 kW)	$2,114,775,715	$35,261,321		1.67%
4	OS2	$1,489,330	$14,949		1.00%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	$785,102,939	$15,575,765		1.98%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	$168,982,932	$2,970,566		1.76%
7	GSLD3/GSLDT3/CS3/CST3	$11,167,080	$233,409		2.09%
8	SST1T	$7,437,796	$125,778		1.69%
9	SST1D1/SST1D2/SST1D3	$1,144,222	$7,212		0.63%
10	CILC D/CILC G	$186,089,149	$3,530,454		1.90%
11	CILC T	$69,377,081	$1,465,532		2.11%
12	MET	$7,670,568	$138,795		1.81%
13	OL1/SL1/PL1	$119,675,788	$253,681		0.21%
14	SL2, GSCU1	$4,876,565	$80,641		1.65%
15					
16	TOTAL	$9,626,365,633	$159,210,391		1.65%
				1.5x	2.48%
				Max	2.11%

Notes

[1] Based on Projections of 2014 base and clause revenues.

[2] 2014 WC3 Revenue Requirements by rate class

[3] Calculated: Col (c) * Col (d)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR WEST COUNTY 3
JANUARY 2014 THROUGH DECEMBER 2014

	Rate Schedule	(1) Projected Billed Sales at Meter (kWh)	(2) Billing kW Load Factor (%)	(3) Projected Billed kW at Meter (KW)	(4) Total Capacity Costs ($)	(5) Capacity Recovery Factor ($/KW)	(6) Capacity Recovery Factor ($/kWh)
1	RS1/RTR-1	55,459,739,543	-	-	$90,390,743		0.00163
2	GS1/GST1	6,126,227,507	-	-	$9,161,544		0.00150
3	GSD1/GSDT1/HLFT1 (21-499 kW)	25,762,255,228	50.43267%	69,975,985	$35,261,321	0.50	
4	OS2	11,759,080	-	-	$14,949		0.00127
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	10,605,576,674	55.65176%	26,105,529	$15,575,765	0.60	
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	2,471,381,071	65.76804%	5,147,567	$2,970,566	0.58	
7	GSLD3/GSLDT3/CS3/CST3	177,440,887	75.40900%	322,335	$233,409	0.72	
8	SST1T/ISST1T	88,591,459	14.06729%	862,697	$125,778		
9	SST1D1/SST1D2/SST1D3/ISST1D	9,856,390	13.75824%	98,137	$7,212		
10	CILC D/CILC G	3,036,047,195	73.97652%	5,622,012	$3,530,454	0.63	
11	CILC T	1,314,450,655	76.69387%	2,347,798	$1,465,532	0.62	
12	MET	92,658,992	63.58056%	199,637	$138,795	0.70	
13	OL1/SL1/PL1	630,606,760	-	-	$253,681		0.00040
14	SL2, GSCU1	56,633,687	-	-	$80,641		0.00142
15							
16	TOTAL	105,843,225,128		110,681,696	$159,210,391		
17							
18							
19							

(1) Projected kwh sales for the period January 2014 through December 2014
(2) Billing kW Load Factor based on load research data
(3) Calculated: Col(1)/(730 hours * Col(2))
(4) Per Rate Case Allocation Worksheet
(5) Calculated: Col (4) / Col (3)
(6) Calculated: Col (4) / Col (1)

Calculation differences are due to rounding

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 4)/(Total Proj Ave 12CP at Generation)(.10) (Demand Loss Factor/12) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 4)/(Total Proj Ave 12CP at Generation)/(21 onpeak days) (Demand Loss Factor/12) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
SST1T/ISST1T	$0.07	$0.03
SST1D1/SST1D2/SST1D3/ISST1D	$0.07	$0.03

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
INCLUDING WEST COUNTY ENERGY CENTER UNIT 3

ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2014 - Dec 2014 Capacity Recovery Factor				2014 WCEC-3 Capacity Recovery Factor				Total Jan 2014 - Dec 2014 Capacity Recovery Factor			
	($KW)	($/kwh)	RDC ($/KW) (1)	SDD ($/KW) (2)	($KW)	($/kwh)	RDC ($/KW)	SDD ($/KW)	($KW)	($/kwh)	RDC ($/KW) (1)	SDD ($/KW) (2)
RS1/RTR1	-	0.00623	-	-	-	0.00163	-	-	-	0.00786	-	-
GS1/GST1/WIES1	-	0.00515	-	-	-	0.00150	-	-	-	0.00665	-	-
GSD1/GSDT1/HLFT1	1.82	-	-	-	0.50	-	-	-	2.32	-	-	-
OS2	-	0.00442	-	-	-	0.00127	-	-	-	0.00569	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	2.00	-	-	-	0.60	-	-	-	2.60	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.01	-	-	-	0.58	-	-	-	2.59	-	-	-
GSLD3/GSLDT3/CS3/CST3	2.23	-	-	-	0.72	-	-	-	2.95	-	-	-
SST1T	-	-	$0.26	$0.12	-	-	$0.07	$0.03	-	-	$0.33	$0.15
SST1D1/SST1D2/SST1D3	-	-	$0.27	$0.13	-	-	$0.07	$0.03	-	-	$0.34	$0.16
CILC D/CILC G	2.17	-	-	-	0.63	-	-	-	2.80	-	-	-
CILC T	2.11	-	-	-	0.62	-	-	-	2.73	-	-	-
MET	2.28	-	-	-	0.70	-	-	-	2.98	-	-	-
OL1/SL1/PL1	-	0.00119	-	-	-	0.00040	-	-	-	0.00159	-	-
SL2, GSCU1	-	0.00388	-	-	-	0.00142	-	-	-	0.00530	-	-

(1) RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor))/12 months

(2) SDD=((Total Capacity Costs)/(Projected Avg 12 CP @gen)/(21 onpeak days)(demand loss expansion factor))/12 months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

APPENDIX VI

2014 REVENUE REQUIREMENT CALCULATION FOR WEST COUNTY ENERGY CENTER UNIT 3

TJK-9
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J.KEITH
EXHIBIT _____________
PAGES 1-2
AUGUST 30, 2013

WCEC UNIT 3
2014 REVENUE REQUIREMENTS

Line No.	WCEC3 Revenue Requirement Calculation	2014
1	Jurisdictional Adjusted Rate Base	$727,516,144
2	Rate of Return on Rate Base	8.701%
3	Required Jurisdictional Net Operating Income	63,301,616
4	Required Net Operating Income	63,301,616
5	Jurisdictional Adjusted Net Operating Income (Loss)	(34,127,805)
6	Net Operating Income Deficiency (Excess)	97,429,421
7	Net Operating Income Multiplier	1.63411
8	2013 Revenue Requirement	$159,210,391

Note:

The Rate of Return was calculated using the Settlement Agreement ROE of 10.5%, as approved in Order No. PSC-13-0023-S-EI.

Line No.	Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	After Tax COC
1	Long Term Debt	44.200%	6.430%	2.84206%	2.84206%	1.84450%
2	Common Equity	55.800%	10.500%	5.85900%	9.53846%	5.85900%
3	Total	100.000%		8.70106%	12.38052%	7.70350%
4						
6						
7	**Assumptions**					
8	Income Tax Rate	38.575%				
9	Production Depreciation Rate	4.000%				
10	Transmission Depreciation Rate	2.500%				
11	Rate of Return	8.70106%				
12						
13						

Line No.	Net Plant	6/01/2011	12/31/2011	5/31/2012	12/31/2012	12/31/2013	12/31/2014
15	Production Plant	819,157,500	819,157,500	819,157,500	819,157,500	819,157,500	819,157,500
16	Transmission Plant	45,570,260	45,570,260	45,570,260	45,570,260	45,570,260	45,570,260
17	Production Reserve	0	(19,113,675)	(32,766,300)	(51,879,975)	(84,646,275)	(117,412,575)
18	Transmission Reserve	0	(664,566)	(1,139,257)	(1,803,823)	(2,943,079)	(4,082,336)
19	Deferred Taxes	9,376,790	4,664,390	(450,838)	(5,746,400)	(14,504,962)	(23,263,524)
20	Net Plant	874,104,550	849,613,909	830,371,366	805,297,562	762,633,444	719,969,325
21							
22							

Line No.		6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013	12/31/2013-12/31/2014
23							
24	**Average Rate Base**	861,859,229	852,237,958	827,455,735	819,157,500	783,965,503	741,301,384
25	Juris Factor	0.981404	0.981404	0.981404	0.981404	0.981404	0.981404
26	**Juris Rate Base**	845,832,095	836,389,741	812,068,369	803,924,447	769,386,880	727,516,144
27							
28	**Juris Interest Expense**	14,022,782	23,770,698	23,079,470	9,520,006	21,866,437	20,676,445
29	**Income Tax - Interest Expense**	(5,409,288)	(9,169,547)	(8,902,906)	(3,672,342)	(8,434,978)	(7,975,939)
30							
31							

Line No.	Operating Expenses	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013	12/31/2013-12/31/2014
32							
33	Other O&M - FOM, CAP, VOM, Prop Ins	11,041,700	19,123,583	19,396,520	8,081,883	19,774,240	19,759,190
34	Depreciation	19,778,241	33,905,557	33,905,557	14,127,315	33,905,557	33,905,557
35	Taxes Other Than Income Taxes - Prop Tax	9,079,640	15,416,761	15,209,090	6,337,121	14,598,800	13,988,490
36	Total Operating Expenses	39,899,581	68,445,901	68,511,167	28,546,319	68,278,597	67,653,237
37							
38	**Juris Operating Expenses**	39,149,725	67,159,426	67,223,284	28,009,702	66,994,769	66,381,049
39	**Income Tax - Operating Expenses**	(15,102,006)	(25,906,749)	(25,931,382)	(10,804,742)	(25,843,232)	(25,606,490)
40							
41	**Other Income Taxes - Def Taxes**	790,050	1,354,370	1,354,370	564,320	1,354,370	1,354,370
42	**Juris Other Income Taxes**	775,358	1,329,184	1,329,184	553,826	1,329,184	1,329,184
43							
44							

Line No.	Juris Net Operating Income	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013	12/31/2013-12/31/2014
45							
46	Operating Expenses	(39,149,725)	(67,159,426)	(67,223,284)	(28,009,702)	(66,994,769)	(66,381,049)
47	Income Tax - Operating Expenses	15,102,006	25,906,749	25,931,382	10,804,742	25,843,232	25,606,490
48	Income Tax - Interest Expense	5,409,288	9,169,547	8,902,906	3,672,342	8,434,978	7,975,939
49	Other Income Taxes	(775,358)	(1,329,184)	(1,329,184)	(553,826)	(1,329,184)	(1,329,184)
50	**Juris Net Operating Income**	(19,413,788)	(33,412,315)	(33,718,181)	(14,086,443)	(34,045,743)	(34,127,805)

APPENDIX VII

AFFIDAVIT OF KIM OUSDAHL

2014 REVENUE REQUIREMENT CALCULATION FOR RIVIERA BEACH ENERGY CENTER (“RBEC”)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	)))	DOCKET NO. 130001-EI FILED: August 30, 2013

AFFIDAVIT

STATE OF FLORIDA COUNTY
OF PALM BEACH

BEFORE ME, the undersigned authority, personally appeared Kim Ousdahl, who being first duly sworn deposes and says:

1. My name is Kim Ousdahl, and my business address is Florida Power & Light Company ("FPL" or the “Company”), 700 Universe Boulevard, Juno Beach, Florida, 33408.
2. I graduated from Kansas State University in 1979 with a Bachelor of Science Degree in Business Administration, majoring in Accounting. I am a Certified Public Accountant (“CPA”) licensed in the State of Texas and a member of the American Institute of CPA’s, the Texas Society of CPAs, and the Florida Institute of CPAs.
3. I am employed by FPL as Vice President, Controller and Chief Accounting Officer.
4. The purpose of my affidavit and supporting documentation is to provide the Generation Base Rate Adjustment ("GBRA") revenue requirement calculation

for the Riviera Beach Energy Center ("RBEC"). On December 13, 2012, the Commission approved a revised Stipulation and Settlement Agreement ("Settlement Agreement"), which is addressed in and attached to Order No. PSC-13-0023-S-EI. This affidavit calculates the GBRA RBEC revenue requirements consistent with the Settlement Agreement as approved.

5. Paragraph 8 of the Settlement Agreement provides that FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation for each of the modernization projects that achieve commercial in-service operation during the term of the Settlement Agreement. Specifically, it provides that the initial GBRA factor resulting from the commercial operation of RBEC would be applied to meter readings made on and after the commercial operations date, currently expected to be June 1, 2014. In addition, the Settlement Agreement requires that the RBEC annualized base revenue requirement shall reflect the costs upon which the cumulative present value of revenue requirement was predicated, and pursuant to which a need determination was granted by the Commission. The RBEC GBRA factor must also be calculated using an ROE of 10.5% and the same capital structure utilized for the Cape Canaveral Energy Center ("CCEC") GBRA revenue requirement calculation.

6. Appendix VII of this filing shows the calculation of RBEC's jurisdictional annualized base revenue requirement for the first 12 months of operations as reflected in FPL's Determination of Need, Docket No. 080245-EI, Order No. PSC-08-0591-FOF-EI, except for the Settlement Agreement ROE of 10.5% and the capital structure utilized for the CCEC GBRA. The resulting

jurisdictionalized annualized base revenue requirement for the first 12 months of operations for Riviera is $233.6 million.

FURTHER AFFIANT SAYETH NOT.

Kim Ousdahl

I hereby certify that on this 29th day of August, 2013 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Kim Ousdahl who is personally known to me, and she acknowledged before me that she executed this certification of signature as her free act and deed who did not take an oath.

I witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as this 29th day of August, 2013.

NICOLE ANDREA GREGORY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# EE173212
Expires 2/26/2016

Notary Public

State of Florida

My Commission Expires:

RIVIERA BEACH ENERGY CENTER
ESTIMATED FIRST YEAR REVENUE REQUIREMENTS

Line No.	Revenue Requirement Calculation	FIRST YEAR OPERATIONS
1	Jurisdictional Adjusted Rate Base	$1,220,926,444
2	Rate of Return on Rate Base	8.428%
3	Required Jurisdictional Net Operating Income	102,903,172
4	Required Net Operating Income	102,903,172
5	Jurisdictional Adjusted Net Operating Income (Loss)	(40,252,673)
6	Net Operating Income Deficiency (Excess)	143,155,845
7	Net Operating Income Multiplier	1.63188
8	Revenue Requirement	$233,613,160

RIVIERA BEACH ENERGY CENTER
ESTIMATED FIRST YEAR REVENUE REQUIREMENTS BACKUP DATA

Line No.	Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC
1	Long Term Debt	39.031%	5.192%	2.027%	2.027%
2	Common Equity	60.969%	10.500%	6.402%	10.422%
3	Total	100.000%		8.428%	12.449%
4					
5					
6	**Assumptions**				
7	Income Tax Rate	38.575%			
8	Production Depreciation Rate	4.000%			
9	Transmission Depreciation Rate	2.500%			
10	Rate of Return	8.42829%			
11	Juris Factor - Generation	98.14000%			
12	Juris Factor - Transmission	89.47240%			
13	Juris Factor - Property Insurance	97.92240%			
14					
15					
16	**Net Plant**	**6/01/2014**	**12/31/2014**	**5/31/2015**	
17	Other Production Plant	1,116,295,066	1,116,295,066	1,116,295,066	
18	Transmission Plant	159,287,859	159,287,859	159,287,859	
19	Other Production Reserve	0	(26,046,885)	(44,651,803)	
20	Transmission Reserve	0	(2,322,948)	(3,982,196)	
21	Deferred Taxes	15,643,694	6,196,447	(2,109,956)	
22	Net Plant	1,291,226,619	1,253,409,539	1,224,838,970	
23					
24					
25	**Juris Net Plant**	**6/01/2014**	**12/31/2014**	**5/31/2015**	
26	Other Production Plant	1,095,531,978	1,095,531,978	1,095,531,978	
27	Transmission Plant	142,518,670	142,518,670	142,518,670	
28	Other Production Reserve	0	(25,562,413)	(43,821,279)	
29	Transmission Reserve	0	(2,078,397)	(3,562,967)	
30	Deferred Taxes	15,183,400	6,013,600	(2,047,562)	
31	Juris Net Plant	1,253,234,048	1,216,423,438	1,188,618,840	
32					
33					
34				**6/01/2014-5/31/2015**	
35	**Average Rate Base**			1,258,032,794	
36	Juris Factor			0.970504	
37	**Juris Rate Base**			1,220,926,444	Capital
38					
39	**Juris Interest Expense**			24,742,446	
40	**Income Tax - Interest Expense**			(9,544,398)	
41					
42	**Operating Expenses**			**6/01/2014-5/31/2015**	
43	Fixed O&M			7,237,474	
44	Variable O&M			1,078,479	
46	Property Insurance			787,023	
47	Depreciation - Other Production			44,651,803	
48	Depreciation - Transmission			3,982,196	
49	Taxes Other Than Income Taxes - Prop Tax			23,576,735	
50	Total Operating Expenses			81,313,710	
51					
52	**Juris Operating Expenses**			**6/01/2014-5/31/2015**	
53	Fixed O&M			7,102,857	Fixed O&M
54	Variable O&M			1,058,419	Variable O&M
56	Property Insurance			770,672	Capital
57	Depreciation - Other Production			43,821,279	Capital
58	Depreciation - Transmission			3,562,967	Capital
59	Taxes Other Than Income Taxes - Prop Tax			22,881,327	Capital
60	Total Juris Operating Expenses			79,197,521	
61					
62	**Juris Operating Expenses**			79,197,521	
63	**Income Tax - Operating Expenses**			(30,550,444)	
64					
65	**Other Income Taxes**			(1,184,945)	
66	**Juris Other Income Taxes**			(1,149,994)	
67					
68					
69	**Juris Net Operating Income**			**6/01/2014-5/31/2015**	
70	Operating Expenses			(79,197,521)	
71	Income Tax - Operating Expenses			30,550,444	
72	Income Tax - Interest Expense			9,544,398	
73	Other Income Taxes			(1,149,994)	
74	**Juris Net Operating Income**			(40,252,673)	

APPENDIX VIII

2014 GENERATION BASE RATE ADJUSTMENT (“GBRA”) FACTOR CALCULATIONS
FOR
RIVIERA BEACH ENERGY CENTER (“RBEC”)

AFFIDAVIT AND EXHIBITS OF TIFFANY COHEN

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power)	DOCKET NO. 130001-EI
Cost Recovery Clause and Generating)	
Performance Incentive Factor)	FILED: August 30, 2013

AFFIDAVIT

STATE OF FLORIDA COUNTY
OF PALM BEACH

BEFORE ME, the undersigned authority, personally appeared Tiffany Cohen, who being first duly sworn deposes and says:

1. My name is Tiffany Cohen, and my business address is Florida Power & Light Company ("FPL"' or the " Company"), 700 Universe Boulevard, Juno Beach, Florida, 33408.

2. I hold a Bachelor of Science Degree in Commerce and Business Administration, with a major in Accounting from the University of Alabama. I obtained a Masters of Business Administration from the University of New Orleans. I joined FPL in 2008 as the Manager of the Nuclear Cost Recovery Clause. I began my current position in June 2013. Prior to joining FPL, I was employed at Duke Energy for five years, where I held a variety of positions in the Rates & Regulatory, Corporate Risk Management and Internal Audit departments. Prior to joining Duke Energy I was employed at KPMG, LLP.

3. I am employed by FPL as Senior Manager, Rate Development with

responsibilities for retail rate development and tariff administration.

4. The purpose of my affidavit is to provide the Generation Base Rate Adjustment ("GBRA") Factor calculations for the Riviera Beach Energy Center ("RBEC"). I have calculated the GBRA factor based on the ratio of the RBEC jurisdictional revenue requirements and the forecasted retail base revenues from the sales of electricity during the first twelve months of operation, consistent with the Stipulation and Settlement ("Settlement Agreement") approved by the Commission in Order No. PSC-13-0023-S-EI.

5. As presented in Ms. Ousdahl's affidavit, the RBEC's jurisdictional annualized base revenue requirement is $233.613 million.

6. The GBRA Factor requires computation of the retail base revenues from the sales of electricity during the first twelve months of RBEC's commercial operation. This computation does not include the base revenues associated with West County Unit 3, which are recovered through the Capacity Clause charge. Document No. TC-1, page 1 of 1, reflects the forecasted retail base revenues from the sales of electricity for the period June 2014 through May 2015 for all customer classes. Forecasted retail base revenues from the sales of electricity include customer, demand and energy charge revenues, base revenues recovered through the Conservation clause for the Commercial/Industrial Load Control Program ("CILC") and Commercial/Industrial Demand Reduction Rider ("CDR") credits, and non-clause recoverable credits. Forecasted retail base revenues also include the current estimate of the base revenue increase associated with the Nuclear Extended Power Uprate ("EPU"), to be effective January 1, 2014. Thus, all

the charges subject to the GBRA Factor are included in this revenue figure. In addition, unbilled retail base revenues are included in total retail base revenues from the sales of electricity in order to account for the collection lag resulting from the billing cycle. As shown in Document No. TC-1, page 1 of 1, the total retail base revenues from the sales of electricity over the first twelve months of RBEC's commercial operation are projected to be $5,117.881 million.

7. The computation and resulting GBRA Factor of 4.565% is provided in Document No. TC-2, page 1 of 1. New charges reflecting the increase for the GBRA factor will be applied to meter readings made on and after the commercial in-service date of RBEC, currently projected to occur by June 1, 2014. The Summary of Tariff Changes is provided in Document No. TC-3. The actual amount of the EPU increase will be determined by the Commission later this year. Once the EPU base rate increase is approved and known, FPL will determine if the GBRA factor including the approved EPU rate would be different from the currently projected GBRA factor. If there is a difference, FPL will submit for administrative approval by Staff an updated GBRA factor and an updated Summary of Tariff Changes reflecting the application of the updated GBRA factor to base rates to be effective June 1, 2014. FPL will also submit for administrative approval by Staff revised tariff sheets reflecting these new charges prior to the actual commercial in service date.

9. Once RBEC's actual capital costs are known, if the unit's actual capital costs

are less than the projected costs used to develop this initial GBRA Factor, a one-time credit will be made through the capacity clause. In order to determine the amount of this credit, a revised GBRA Factor would be computed using the same data and methodology incorporated into the initial GBRA Factor, with the exception that RBEC's actual capital costs will be used in lieu of the capital cost upon which the initial GBRA factor was based. On a going forward basis, base rates will be adjusted to reflect this revised GBRA Factor for RBEC. In addition, the difference between the cumulative base revenues since the implementation of the initial GBRA Factor and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented during the same time period will be credited to customers through the capacity clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109.

Tiffany Cohen

I hereby certify that on this this 29th day of August 2013 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Tiffany Cohen who is personally known to me, and she acknowledged before me that she executed this certification of signature as her free act and deed who did not take an oath.

I witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as this 29 day of August, 2013.

Notary Public
State of Florida
My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA
ANNETTE L. GIVENS
Notary Public - State of Florida
My Comm. Expires Mar 15, 2017
Commission # EE 854124

GBRA FACTOR RBEC

	($million)	Source
(A) Jurisdictional Annualized Revenue Requirement	233.613	Doc. No. KO-1 as filed
(B) Total Retail Base Revenues From the Sales of Electricity	5,117.881	Doc. No. TC-2
(C) GBRA FACTOR [(A) / (B)]	4.565%	

Docket No. 130001-EI
T. Cohen, Exhibit No. _____
Document No. TC-2, Page 1 of 1
Retail Base Revenues For The
First 12 Months Of The Riviera Beach Energy
Center's Commercial Operation

	2014						
Customer Class	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Residential	$ 274,961,463	$ 305,420,892	$ 304,583,071	$ 292,553,530	$ 264,711,495	$ 227,359,015	$ 219,498,928
Commercial	$ 147,339,767	$ 157,423,141	$ 155,322,069	$ 151,879,595	$ 150,851,560	$ 149,991,074	$ 150,223,929
Industrial	$ 5,072,462	$ 5,230,932	$ 5,167,312	$ 5,194,780	$ 5,221,151	$ 5,150,835	$ 5,187,857
Street & Highway	$ 4,528,271	$ 4,473,072	$ 4,561,273	$ 4,472,359	$ 4,532,663	$ 4,572,279	$ 4,549,993
Other	$ 98,580	$ 93,624	$ 101,081	$ 110,111	$ 110,288	$ 107,909	$ 106,809
Railroads & Railways	$ 294,025	$ 311,701	$ 324,880	$ 308,043	$ 321,231	$ 303,452	$ 303,704
Total Jurisdictional Billed Revenue	432,294,569	472,953,362	470,059,687	454,518,417	425,748,388	387,484,564	379,871,221
CILC/CDR Incentive	7,594,286	4,867,820	5,517,583	4,763,984	4,751,534	4,417,410	6,961,286
Unbilled Revenue	458,721	501,865	498,795	482,303	451,775	411,172	403,093
EPU 2014	9,993,130	10,933,019	10,866,127	10,506,868	9,841,806	8,957,281	8,781,287
Total Retail Base Revenues From the Sales of Electricity	$ 450,340,707	$ 489,256,067	$ 486,942,192	$ 470,271,572	$ 440,793,503	$ 401,270,426	$ 396,016,887

	2015					
Customer Class	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**12 Months Ending**
Residential	$ 249,099,194	$ 213,582,040	$ 209,434,970	$ 211,738,824	$ 251,278,119	$ 3,024,221,538
Commercial	$ 154,538,739	$ 141,796,574	$ 142,333,210	$ 138,046,288	$ 150,678,128	1,790,424,074
Industrial	$ 5,128,878	$ 5,173,088	$ 5,195,696	$ 5,152,551	$ 5,181,487	62,057,029
Street & Highway	$ 4,629,571	$ 4,464,396	$ 4,597,150	$ 4,547,154	$ 4,557,937	54,486,119
Other	$ 98,841	$ 103,694	$ 114,063	$ 104,305	$ 95,495	1,244,799
Railroads & Railways	$ 291,842	$ 302,455	$ 295,785	$ 285,816	$ 297,306	3,640,239
Total Jurisdictional Billed Revenue	413,787,065	365,422,247	361,970,873	359,874,936	412,088,471	4,936,073,798
CILC/CDR Incentive Credit	4,329,305	3,918,021	4,007,722	4,651,569	5,456,972	61,237,493
Unbilled Revenue	439,082	387,761	384,098	381,874	437,280	5,237,819
EPU 2014	9,565,302	8,447,278	8,367,494	8,319,043	9,526,037	114,104,671
EPU Increase - with Sales Growth Adj for 2015	171,994	294,798	275,061	241,424	244,354	1,227,631
Total Retail Base Revenues From the Sales of Electricity	$ 428,292,747	$ 378,470,104	$ 375,005,248	$ 373,468,846	$ 427,753,114	$ 5,117,881,412

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	RS-1	Residential Service						
2		Customer Charge/Minimum	$7.24		$7.24	$7.57	$0.33	4.6%
3								
4		Base Energy Charge (¢ per kWh)						
5		First 1,000 kWh	4.409	0.115	4.524	4.731	0.207	4.6%
6		All additional kWh	5.444	0.115	5.559	5.813	0.254	4.6%
7								
8	RTR-1	Residential Time of Use Rider						
9		Customer Charge/Minimum	$11.38		$11.38	$11.90	$0.52	4.6%
10		with $248.34 Lump-sum metering payment						
11								
12		Customer Charge/Minimum						
13		with $259.68 Lump-sum metering payment	$7.24		$7.24	$7.57	$0.33	4.6%
14								
15		Energy Charges/Credits (¢ per kWh)*						
16		On-Peak	8.425		8.425	8.810	0.385	4.6%
17		Off-Peak	(3.748)		(3.748)	(3.919)	(0.171)	4.6%
18		*RS/RTR rate differential w/ EPU remains unchanged since both are increasing by the same amount						
19								
20	GS-1	General Service - Non Demand (0-20 kW)						
21		Customer Charge/Minimum						
22		Metered	$7.13		$7.13	$7.46	$0.33	4.6%
23		Unmetered	$0.92		$0.92	$0.96	$0.04	4.3%
24								
25		Base Energy Charge (¢ per kWh)	4.851	0.107	4.958	5.184	0.226	4.6%
26								
27								
28	GST-1	General Service - Non Demand - Time of Use (0-20 kW)						
29		Customer Charge/Minimum	$14.00		$14.00	$14.64	$0.64	4.6%
30		with $412.24 Lump-sum metering payment						
31		made prior to Proposed Rate Effective Date						
32								
33		with $431.06 Lump-sum metering payment	$7.13		$7.13	$7.46	$0.33	4.6%
34		effective with Proposed Rate Effective Date						
35								
36		Base Energy Charge (¢ per kWh)						
37		On-Peak	9.017	0.107	9.124	9.541	0.417	4.6%
38		Off-Peak	2.986	0.107	3.093	3.234	0.141	4.6%

SUPPORTING SCHEDULES: RECAP SCHEDULES:

[1]The actual amount of the EPU increase will be determined by the Commission later this year.
[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	GSD-1	General Service Demand (21-499 kW)						
2		Customer Charge	$18.63		$18.63	$19.48	$0.85	4.6%
3								
4		Demand Charge ($/kW)	$7.24	$0.37	$7.61	$7.96	$0.35	4.6%
5								
6		Base Energy Charge (¢ per kWh)	1.781		1.781	1.862	0.081	4.5%
7								
8								
9	GSDT-1	General Service Demand - Time of Use (21-499 kW)						
10		Customer Charge	$24.83		$24.83	$25.96	$1.13	4.6%
11		with $372.51 Lump-sum metering payment						
12		made prior to Proposed Rate Effective Date						
13								
14		with $389.52 Lump-sum metering payment	$18.63		$18.63	$19.48	$0.85	4.6%
15		effective with Proposed Rate Effective Date						
16								
17		Demand Charge - On-Peak ($/kW)	$7.24	$0.37	$7.61	$7.96	$0.35	4.6%
18								
19		Base Energy Charge (¢ per kWh)						
20		On-Peak	3.788		3.788	3.961	0.173	4.6%
21		Off-Peak	0.963		0.963	1.007	0.044	4.6%
22								
23								
24	GSLD-1	General Service Large Demand (500-1999 kW)						
25		Customer Charge	$56.91		$56.91	$59.51	$2.60	4.6%
26								
27		Demand Charge ($/kW)	$8.28	$0.44	$8.72	$9.12	$0.40	4.6%
28								
29		Base Energy Charge (¢ per kWh)	1.317		1.317	1.377	0.060	4.6%
30								
31								
32	GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)						
33		Customer Charge	$56.91		$56.91	$59.51	$2.60	4.6%
34								
35		Demand Charge - On-Peak ($/kW)	$8.28	$0.44	$8.72	$9.12	$0.40	4.6%
36								
37		Base Energy Charge (¢ per kWh)						
38		On-Peak	2.192		2.192	2.292	0.100	4.6%
39		Off-Peak	0.953		0.953	0.997	0.044	4.6%
40								
41								
42								

SUPPORTING SCHEDULES: RECAP SCHEDULES:

[1] The actual amount of the EPU increase will be determined by the Commission later this year.
[2] The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	CURRENT RATE SCHEDULE	TYPE OF CHARGE	DEC-2013 CURRENT RATE	EPU INCREASE[1]	JAN-2014 PROPOSED RATE	JUN-2014 PROPOSED RATE[2]	CHANGE IN RATE Jan to Jun	% CHANGE IN RATE Jan to Jun
1	CS-1	Curtailable Service (500-1999 kW)						
2		Customer Charge	$82.78		$82.78	$86.56	$3.78	4.6%
3								
4		Demand Charge ($/kW)	$8.28	$0.44	$8.72	$9.12	$0.40	4.6%
5								
6		Base Energy Charge (¢ per kWh)	1.317		1.317	1.377	0.060	4.6%
7								
8		Monthly Credit ($ per kW)	($1.78)		($1.78)	($1.86)	($0.08)	4.5%
9								
10		Charges for Non-Compliance of Curtailment Demand						
11		Rebilling for last 36 months (per kW)	$1.78		$1.78	$1.86	$0.08	4.5%
12		Penalty Charge-current month (per kW)	$3.83		$3.83	$4.00	$0.17	4.4%
13		Early Termination Penalty charge (per kW)	$1.13		$1.13	$1.18	$0.05	4.4%
14								
15	CST-1	Curtailable Service -Time of Use (500-1999 kW)						
16		Customer Charge	$82.78		$82.78	$86.56	$3.78	4.6%
17								
18		Demand Charge - On-Peak ($/kW)	$8.28	$0.44	$8.72	$9.12	$0.40	4.6%
19								
20		Base Energy Charge (¢ per kWh)						
21		On-Peak	2.192		2.192	2.292	0.100	4.6%
22		Off-Peak	0.953		0.953	0.997	0.044	4.6%
23								
24		Monthly Credit (per kW)	($1.78)		($1.78)	($1.86)	($0.08)	4.5%
25								
26		Charges for Non-Compliance of Curtailment Demand						
27		Rebilling for last 36 months (per kW)	$1.78		$1.78	$1.86	$0.08	4.5%
28		Penalty Charge-current month (per kW)	$3.83		$3.83	$4.00	$0.17	4.4%
29		Early Termination Penalty charge (per kW)	$1.13		$1.13	$1.18	$0.05	4.4%
30								
31	GSLD-2	General Service Large Demand (2000 kW +)						
32		Customer Charge	$201.78		$201.78	$210.99	$9.21	4.6%
33								
34		Demand Charge ($/kW)	$8.59	$0.43	$9.02	$9.43	$0.41	4.5%
35								
36		Base Energy Charge (¢ per kWh)	1.186		1.186	1.240	0.054	4.6%
37								
38								
39								
40								
41								
42								

SUPPORTING SCHEDULES: RECAP SCHEDULES:

[1]The actual amount of the EPU increase will be determined by the Commission later this year.
[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	CURRENT RATE SCHEDULE	TYPE OF CHARGE	DEC-2013 CURRENT RATE	EPU INCREASE[1]	JAN-2014 PROPOSED RATE	JUN-2014 PROPOSED RATE[2]	CHANGE IN RATE Jan to Jun	% CHANGE IN RATE Jan to Jun
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)						
2		Customer Charge	$201.78		$201.78	$210.99	$9.21	4.6%
3								
4		Demand Charge - On-Peak ($/kW)	$8.59	$0.43	$9.02	$9.43	$0.41	4.5%
5								
6		Base Energy Charge (¢ per kWh)						
7		On-Peak	1.879		1.879	1.965	0.086	4.6%
8		Off-Peak	0.924		0.924	0.966	0.042	4.5%
9								
10								
11	CS-2	Curtailable Service (2000 kW +)						
12		Customer Charge	$227.65		$227.65	$238.04	$10.39	4.6%
13								
14		Demand Charge ($/kW)	$8.59	$0.43	$9.02	$9.43	$0.41	4.5%
15								
16		Base Energy Charge (¢ per kWh)	1.186		1.186	1.240	0.054	4.6%
17								
18		Monthly Credit (per kW)	($1.78)		($1.78)	($1.86)	($0.08)	4.5%
19								
20		Charges for Non-Compliance of Curtailment Demand						
21		Rebilling for last 36 months (per kW)	$1.78		$1.78	$1.86	$0.08	4.5%
22		Penalty Charge-current month (per kW)	$3.83		$3.83	$4.00	$0.17	4.4%
23		Early Termination Penalty charge (per kW)	$1.13		$1.13	$1.18	$0.05	4.4%
24								
25	CST-2	Curtailable Service -Time of Use (2000 kW +)						
26		Customer Charge	$227.65		$227.65	$238.04	$10.39	4.6%
27								
28		Demand Charge - On-Peak ($/kW)	$8.59	$0.43	$9.02	$9.43	$0.41	4.5%
29								
30		Base Energy Charge (¢ per kWh)						
31		On-Peak	1.879		1.879	1.965	0.0860	4.6%
32		Off-Peak	0.924		0.924	0.966	0.0420	4.5%
33								
34		Monthly Credit (per kW)	($1.78)		($1.78)	($1.86)	($0.08)	4.5%
35								
36		Charges for Non-Compliance of Curtailment Demand						
37		Rebilling for last 36 months (per kW)	$1.78		$1.78	$1.86	$0.08	4.5%
38		Penalty Charge-current month (per kW)	$3.83		$3.83	$4.00	$0.17	4.4%
39		Early Termination Penalty charge (per kW)	$1.13		$1.13	$1.18	$0.05	4.4%
40								
41								
42								

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

[1] The actual amount of the EPU increase will be determined by the Commission later this year.

[2] The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	GSLD-3	General Service Large Demand (2000 kW +)						
2		Customer Charge	$1,491.99		$1,491.99	$1,560.10	$68.11	4.6%
3								
4		Demand Charge ($/kW)	$6.54	$0.55	$7.09	$7.41	$0.32	4.5%
5								
6		Base Energy Charge (¢ per kWh)	0.859		0.859	0.898	0.039	4.5%
7								
8								
9	GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)						
10		Customer Charge	$1,491.99		$1,491.99	$1,560.10	$68.11	4.6%
11								
12		Demand Charge - On-Peak ($/kW)	$6.54	$0.55	$7.09	$7.41	$0.32	4.5%
13								
14		Base Energy Charge (¢ per kWh)						
15		On-Peak	0.961		0.961	1.005	0.044	4.6%
16		Off-Peak	0.822		0.822	0.860	0.038	4.6%
17								
18								
19	CS-3	Curtailable Service (2000 kW +)						
20		Customer Charge	$1,517.85		$1,517.85	$1,587.14	$69.29	4.6%
21								
22		Demand Charge ($/kW)	$6.54	$0.55	$7.09	$7.41	$0.32	4.5%
23								
24		Base Energy Charge (¢ per kWh)	0.859		0.859	0.898	0.039	4.5%
25								
26		Monthly Credit (per kW)	($1.78)		($1.78)	($1.86)	($0.08)	4.5%
27								
28		Charges for Non-Compliance of Curtailment Demand						
29		Rebilling for last 36 months (per kW)	$1.78		$1.78	$1.86	$0.08	4.5%
30		Penalty Charge-current month (per kW)	$3.83		$3.83	$4.00	$0.17	4.4%
31		Early Termination Penalty charge (per kW)	$1.13		$1.13	$1.18	$0.05	4.4%
32								
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SUPPORTING SCHEDULES: RECAP SCHEDULES:

[1]The actual amount of the EPU increase will be determined by the Commission later this year.
[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	CST-3	Curtailable Service -Time of Use (2000 kW +)						
2		Customer Charge	$1,517.85		$1,517.85	$1,587.14	$69.29	4.6%
3								
4		Demand Charge - On-Peak ($/kW)	$6.54	$0.55	$7.09	$7.41	$0.32	4.5%
5								
6		Base Energy Charge (¢ per kWh)						
7		On-Peak	0.961		0.961	1.005	0.044	4.6%
8		Off-Peak	0.822		0.822	0.860	0.038	4.6%
9								
10		Monthly Credit (per kW)	($1.78)		($1.78)	($1.86)	($0.08)	4.5%
11								
12		Charges for Non-Compliance of Curtailment Demand						
13		Rebilling for last 12 months (per kW)	$1.78		$1.78	$1.86	$0.08	4.5%
14		Penalty Charge-current month (per kW)	$3.83		$3.83	$4.00	$0.17	4.4%
15		Early Termination Penalty charge (per kW)	$1.13		$1.13	$1.18	$0.05	4.4%
16								
17	OS-2	Sports Field Service [Schedule closed to new customers]						
18		Customer Charge	$106.58		$106.58	$111.45	$4.87	4.6%
19								
20		Base Energy Charge (¢ per kWh)	6.150	0.096	6.246	6.531	0.285	4.6%
21								
22								
23	MET	Metropolitan Transit Service						
24		Customer Charge	$413.90		$413.90	$432.79	$18.89	4.6%
25								
26		Base Demand Charge ($/kW)	$10.42	$0.50	$10.92	$11.42	$0.50	4.6%
27								
28		Base Energy Charge (¢ per kWh)	1.530		1.530	1.600	0.070	4.6%
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								
42								

SUPPORTING SCHEDULES: RECAP SCHEDULES:

[1]The actual amount of the EPU increase will be determined by the Commission later this year.
[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	CILC-1	Commercial/Industrial Load Control Program [Schedule closed to new customers]						
2		Customer Charge						
3		(G) 200-499kW	$103.48		$103.48	$108.20	$4.72	4.6%
4		(D) above 500kW	$155.21		$155.21	$162.30	$7.09	4.6%
5		(T) transmission	$2,043.63		$2,043.63	$2,136.92	$93.29	4.6%
6								
7		Base Demand Charge ($/kW)						
8		per kW of Max Demand All kW:						
9		(G) 200-499kW	$3.52		$3.52	$3.68	$0.16	4.5%
10		(D) above 500kW	$3.21		$3.21	$3.36	$0.15	4.7%
11		(T) transmission	None		None	None		
12								
13								
14		per kW of Load Control On-Peak:						
15		(G) 200-499kW	$1.35	$0.48	$1.83	$1.91	$0.08	4.4%
16		per kW of Load Control On-Peak:						
17		(D) above 500kW	$1.35	$0.48	$1.83	$1.91	$0.08	4.4%
18		(T) transmission	$1.35	$0.48	$1.83	$1.91	$0.08	4.4%
19								
20								
21								
22		Per kW of Firm On-Peak Demand						
23		(G) 200-499kW	$7.56	$0.48	$8.04	$8.41	$0.37	4.6%
24		(D) above 500kW	$7.36	$0.48	$7.84	$8.20	$0.36	4.6%
25		(T) transmission	$7.50	$0.48	$7.98	$8.34	$0.36	4.5%
26								
27		Base Energy Charge (¢ per kWh)						
28		On-Peak						
29		(G) 200-499kW	1.313		1.313	1.373	0.060	4.6%
30		(D) above 500kW	0.757		0.757	0.792	0.035	4.6%
31		(T) transmission	0.674		0.674	0.705	0.031	4.6%
32		Off-Peak						
33		(G) 200-499kW	1.313		1.313	1.373	0.060	4.6%
34		(D) above 500kW	0.757		0.757	0.792	0.035	4.6%
35		(T) transmission	0.674		0.674	0.705	0.031	4.6%
36								
37		Excess "Firm Demand"						
38		¤ Up to prior 60 months of service			Difference between Firm and			
39					Load-Control On-Peak Demand Charge			
40								
41		¤ Penalty Charge per kW for	$0.99		$0.99	$1.04	$0.05	5.1%
42		each month of rebilling						

SUPPORTING SCHEDULES: RECAP SCHEDULES:

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	CURRENT RATE SCHEDULE	TYPE OF CHARGE	DEC-2013 CURRENT RATE	EPU INCREASE[1]	JAN-2014 PROPOSED RATE	JUN-2014 PROPOSED RATE[2]	CHANGE IN RATE Jan to Jun	% CHANGE IN RATE Jan to Jun
1	CDR	Commercial/Industrial Demand Reduction Rider						
2		Monthly Rate						
3		Customer Charge			Otherwise Applicable Rate			
4		Demand Charge			Otherwise Applicable Rate			
5		Energy Charge			Otherwise Applicable Rate			
6								
7		Monthly Administrative Adder						
8		GSD-1	$77.61		$77.61	$81.15	$3.54	4.6%
9		GSDT-1, HLFT-1	$77.61		$77.61	$81.15	$3.54	4.6%
10		GSLD-1, GSLDT-1, HLFT2	$129.34		$129.34	$135.24	$5.90	4.6%
11		GSLD-2, GSLDT-2, HLFT3	$51.74		$51.74	$54.10	$2.36	4.6%
12		GSLD-3, GSLDT-3	$491.51		$491.51	$513.95	$22.44	4.6%
13								
14								
15								
16		Utility Controlled Demand Credit $/kW	($7.55)		($7.55)	($7.89)	-$0.34	4.5%
17								
18		Excess "Firm Demand"	$7.55		$7.55	$7.89	$0.34	4.5%
19		¤ Up to prior 60 months of service						
20								
21		¤ Penalty Charge per kW for	$0.99		$0.99	$1.04	$0.05	5.1%
22		each month of rebilling*						
23		*The CDR penalty has been revised to equal the CILC penalty.						
24	SL-1	Street Lighting						
25		Charges for FPL-Owned Units						
26		Fixture						
27		Sodium Vapor 6,300 lu 70 watts	$3.58		$3.58	$3.74	$0.16	4.5%
28		Sodium Vapor 9,500 lu 100 watts	$3.64		$3.64	$3.81	$0.17	4.7%
29		Sodium Vapor 16,000 lu 150 watts	$3.76		$3.76	$3.93	$0.17	4.5%
30		Sodium Vapor 22,000 lu 200 watts	$5.69		$5.69	$5.95	$0.26	4.6%
31		Sodium Vapor 50,000 lu 400 watts	$5.75		$5.75	$6.01	$0.26	4.5%
32		* Sodium Vapor 12,800 lu 150 watts	$3.91		$3.91	$4.09	$0.18	4.6%
33		* Sodium Vapor 27,500 lu 250 watts	$6.05		$6.05	$6.33	$0.28	4.6%
34		* Sodium Vapor 140,000 lu 1,000 watts	$9.11		$9.11	$9.53	$0.42	4.6%
35		* Mercury Vapor 6,000 lu 140 watts	$2.82		$2.82	$2.95	$0.13	4.6%
36		* Mercury Vapor 8,600 lu 175 watts	$2.87		$2.87	$3.00	$0.13	4.5%
37		* Mercury Vapor 11,500 lu 250 watts	$4.79		$4.79	$5.01	$0.22	4.6%
38		* Mercury Vapor 21,500 lu 400 watts	$4.77		$4.77	$4.99	$0.22	4.6%
39		* Mercury Vapor 39,500 lu 700 watts	$6.75		$6.75	$7.06	$0.31	4.6%
40		* Mercury Vapor 60,000 lu 1,000 watts	$6.90		$6.90	$7.21	$0.31	4.5%
41								
42								

SUPPORTING SCHEDULES: RECAP SCHEDULES:

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	CURRENT RATE SCHEDULE	TYPE OF CHARGE		DEC-2013 CURRENT RATE	EPU INCREASE[1]	JAN-2014 PROPOSED RATE	JUN-2014 PROPOSED RATE[2]	CHANGE IN RATE Jan to Jun	% CHANGE IN RATE Jan to Jun
1	SL-1	Street Lighting (continued))							
2		Maintenance							
3		Sodium Vapor 6,300 lu 70 watts		$1.68		$1.68	$1.76	$0.08	4.8%
4		Sodium Vapor 9,500 lu 100 watts		$1.69		$1.69	$1.77	$0.08	4.7%
5		Sodium Vapor 16,000 lu 150 watts		$1.72		$1.72	$1.80	$0.08	4.7%
6		Sodium Vapor 22,000 lu 200 watts		$2.19		$2.19	$2.29	$0.10	4.6%
7		Sodium Vapor 50,000 lu 400 watts		$2.20		$2.20	$2.30	$0.10	4.5%
8	*	Sodium Vapor 12,800 lu 150 watts		$1.92		$1.92	$2.01	$0.09	4.7%
9	*	Sodium Vapor 27,500 lu 250 watts		$2.39		$2.39	$2.50	$0.11	4.6%
10	*	Sodium Vapor 140,000 lu 1,000 watts		$4.28		$4.28	$4.48	$0.20	4.7%
11	*	Mercury Vapor 6,000 lu 140 watts		$1.51		$1.51	$1.58	$0.07	4.6%
12	*	Mercury Vapor 8,600 lu 175 watts		$1.51		$1.51	$1.58	$0.07	4.6%
13	*	Mercury Vapor 11,500 lu 250 watts		$2.18		$2.18	$2.28	$0.10	4.6%
14	*	Mercury Vapor 21,500 lu 400 watts		$2.14		$2.14	$2.24	$0.10	4.7%
15	*	Mercury Vapor 39,500 lu 700 watts		$3.64		$3.64	$3.81	$0.17	4.7%
16	*	Mercury Vapor 60,000 lu 1,000 watts		$3.56		$3.56	$3.72	$0.16	4.5%
17									
18		Energy Non-Fuel**	kWh						
19		Sodium Vapor 6,300 lu 70 watts	29	$0.72		$0.74	$0.77	$0.03	4.1%
20		Sodium Vapor 9,500 lu 100 watts	41	$1.02		$1.04	$1.09	$0.05	4.8%
21		Sodium Vapor 16,000 lu 150 watts	60	$1.50		$1.52	$1.59	$0.07	4.6%
22		Sodium Vapor 22,000 lu 200 watts	88	$2.19		$2.23	$2.33	$0.10	4.5%
23		Sodium Vapor 50,000 lu 400 watts	168	$4.19		$4.26	$4.46	$0.20	4.7%
24	*	Sodium Vapor 12,800 lu 150 watts	60	$1.50		$1.52	$1.59	$0.07	4.6%
25	*	Sodium Vapor 27,500 lu 250 watts	116	$2.89		$2.94	$3.08	$0.14	4.8%
26	*	Sodium Vapor 140,000 lu 1,000 watts	411	$10.24		$10.42	$10.90	$0.48	4.6%
27	*	Mercury Vapor 6,000 lu 140 watts	62	$1.55		$1.57	$1.64	$0.07	4.5%
28	*	Mercury Vapor 8,600 lu 175 watts	77	$1.92		$1.95	$2.04	$0.09	4.6%
29	*	Mercury Vapor 11,500 lu 250 watts	104	$2.59		$2.64	$2.76	$0.12	4.5%
30	*	Mercury Vapor 21,500 lu 400 watts	160	$3.99		$4.06	$4.24	$0.18	4.4%
31	*	Mercury Vapor 39,500 lu 700 watts	272	$6.78		$6.90	$7.21	$0.31	4.5%
32	*	Mercury Vapor 60,000 lu 1,000 watts	385	$9.59		$9.76	$10.21	$0.45	4.6%
33									
34		Total Charge-Fixtures, Maintenance & Energy							
35	*	Incandescent 1,000 lu 103 watts	36	$7.15	$0.02	$7.17	$7.50	$0.33	4.6%
36	*	Incandescent 2,500 lu 202 watts	71	$7.57	$0.03	$7.60	$7.95	$0.35	4.6%
37	*	Incandescent 4,000 lu 327 watts	116	$9.06	$0.05	$9.11	$9.53	$0.42	4.6%
38									
39		** Note: The proposed monthly Non-Fuel Energy charge is calculated by multiplying the kWh rating for each fixture by the proposed Non-Fuel Energy Rate.							
40		This avoids rounding issues caused by separating the increases into the various components							
41									
42									

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

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[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE		(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	SL-1	Street Lighting (continued))							
2		<u>Charge for Customer-Owned Units</u>							
3		Relamping and Energy**							
4		Sodium Vapor 6,300 lu 70 watts		$2.43		$2.45	$2.56	$0.11	4.5%
5		Sodium Vapor 9,500 lu 100 watts		$2.74		$2.76	$2.89	$0.13	4.7%
6		Sodium Vapor 16,000 lu 150 watts		$3.25		$3.27	$3.42	$0.15	4.6%
7		Sodium Vapor 22,000 lu 200 watts		$4.39		$4.43	$4.63	$0.20	4.5%
8		Sodium Vapor 50,000 lu 400 watts		$6.40		$6.47	$6.77	$0.30	4.6%
9	*	Sodium Vapor 12,800 lu 150 watts		$3.42		$3.44	$3.60	$0.16	4.7%
10	*	Sodium Vapor 27,500 lu 250 watts		$5.28		$5.33	$5.58	$0.25	4.7%
11	*	Sodium Vapor 140,000 lu 1,000 watts		$14.61		$14.79	$15.47	$0.68	4.6%
12	*	Mercury Vapor 6,000 lu 140 watts		$3.09		$3.11	$3.25	$0.14	4.5%
13	*	Mercury Vapor 8,600 lu 175 watts		$3.46		$3.49	$3.65	$0.16	4.6%
14	*	Mercury Vapor 11,500 lu 250 watts		$4.81		$4.86	$5.08	$0.22	4.5%
15	*	Mercury Vapor 21,500 lu 400 watts		$6.17		$6.24	$6.52	$0.28	4.5%
16	*	Mercury Vapor 39,500 lu 700 watts		$10.42		$10.54	$11.02	$0.48	4.6%
17	*	Mercury Vapor 60,000 lu 1,000 watts		$13.21		$13.38	$14.00	$0.62	4.6%
18	*	Incandescent 1,000 lu 103 watts		$4.31		$4.32	$4.52	$0.20	4.6%
19	*	Incandescent 2,500 lu 202 watts		$5.21		$5.24	$5.48	$0.24	4.6%
20	*	Incandescent 4,000 lu 327 watts		$6.43		$6.48	$6.78	$0.30	4.6%
21	*	Fluorescent 19,800 lu 300 watts		$4.86		$4.91	$5.14	$0.23	4.7%
22									
23		Energy Only***	kWh						
24		Sodium Vapor 6,300 lu 70 watts	29	$0.72		$0.74	$0.77	$0.03	4.1%
25		Sodium Vapor 9,500 lu 100 watts	41	$1.02		$1.04	$1.09	$0.05	4.8%
26		Sodium Vapor 16,000 lu 150 watts	60	$1.50		$1.52	$1.59	$0.07	4.6%
27		Sodium Vapor 22,000 lu 200 watts	88	$2.19		$2.23	$2.33	$0.10	4.5%
28		Sodium Vapor 50,000 lu 400 watts	168	$4.19		$4.26	$4.46	$0.20	4.7%
29	*	Sodium Vapor 12,800 lu 150 watts	60	$1.50		$1.52	$1.59	$0.07	4.6%
30	*	Sodium Vapor 27,500 lu 250 watts	116	$2.89		$2.94	$3.08	$0.14	4.8%
31	*	Sodium Vapor 140,000 lu 1,000 watts	411	$10.24		$10.42	$10.90	$0.48	4.6%
32	*	Mercury Vapor 6,000 lu 140 watts	62	$1.55		$1.57	$1.64	$0.07	4.5%
33	*	Mercury Vapor 8,600 lu 175 watts	77	$1.92		$1.95	$2.04	$0.09	4.6%
34	*	Mercury Vapor 11,500 lu 250 watts	104	$2.59		$2.64	$2.76	$0.12	4.5%
35	*	Mercury Vapor 21,500 lu 400 watts	160	$3.99		$4.06	$4.24	$0.18	4.4%
36	*	Mercury Vapor 39,500 lu 700 watts	272	$6.78		$6.90	$7.21	$0.31	4.5%
37	*	Mercury Vapor 60,000 lu 1,000 watts	385	$9.59		$9.76	$10.21	$0.45	4.6%
38	*	Incandescent 1,000 lu 103 watts	36	$0.90		$0.91	$0.95	$0.04	4.4%
39	*	Incandescent 2,500 lu 202 watts	71	$1.77		$1.80	$1.88	$0.08	4.4%

**Note: The monthly Relamp and Energy charge for Jun-2014 is calculated by adding the Relamp increase to the Energy-only increase. This avoids rounding issues.
***Note: See note for FPL-Owned Non-Fuel Energy rates.

SUPPORTING SCHEDULES: RECAP SCHEDULES:

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE		(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	SL-1	Street Lighting (continued))							
2		* Incandescent 4,000 lu 327 watts	116	$2.89		$2.94	$3.08	$0.14	4.8%
3		* Fluorescent 19,800 lu 300 watts	122	$3.04		$3.09	$3.24	$0.15	4.9%
4									
5		Non-Fuel Energy (¢ per kWh)		2.492	0.044	2.536	2.652	0.116	4.6%
6									
7		<u>Other Charges</u>							
8		Wood Pole		$4.34		$4.34	$4.54	$0.20	4.6%
9		Concrete Pole		$5.96		$5.96	$6.23	$0.27	4.5%
10		Fiberglass Pole		$7.05		$7.05	$7.37	$0.32	4.5%
11		Underground conductors not under paving (¢ per foc		3.40		3.40	3.56	0.16	4.7%
12		Underground conductors under paving (¢ per foot)		8.33		8.33	8.71	0.38	4.6%
13									
14		<u>Willful Damage</u>							
15		Cost for Shield upon second occurrence		$280.00		$280.00	$280.00	$0.00	0.0%
16		* These units are closed to new FPL owned installations.							
17									
18									
19									
20	PL-1	Premium Lighting (Note: Also includes Recreational Lighting RL-1)							
21		Present Value Revenue Requirement							
22		Multiplier		1.1941		1.1941	1.1941	0.0000	0.0%
23									
24		Monthly Rate							
25		Facilities (Percentage of total work order cost)							
26		10 Year Payment Option		1.362%		1.362%	1.362%	0.000%	0.0%
27		20 Year Payment Option		0.925%		0.925%	0.925%	0.000%	0.0%
28									
29		Maintenance				FPL's estimated cost of			
30						maintaining facilities			
31									
32		Termination Factors							
33		10 Year Payment Option							
34			1	1.1941		1.1941	1.1941	0.0000	0.0%
35			2	1.0306		1.0306	1.0306	0.0000	0.0%
36			3	0.9473		0.9473	0.9473	0.0000	0.0%
37			4	0.8575		0.8575	0.8575	0.0000	0.0%
38			5	0.7608		0.7608	0.7608	0.0000	0.0%
39			6	0.6565		0.6565	0.6565	0.0000	0.0%

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	PL-1	Premium Lighting (continued)						
2		7	0.5441		0.5441	0.5441	0.0000	0.0%
3		8	0.4230		0.4230	0.4230	0.0000	0.0%
4		9	0.2924		0.2924	0.2924	0.0000	0.0%
5		10	0.1517		0.1517	0.1517	0.0000	0.0%
6		>10	0.0000		0.0000	0.0000	0.0000	
7								
8		20 Year Payment Option						
9		1	1.1941		1.1941	1.1941	0.0000	0.0%
10		2	1.0831		1.0831	1.0831	0.0000	0.0%
11		3	1.0563		1.0563	1.0563	0.0000	0.0%
12		4	1.0275		1.0275	1.0275	0.0000	0.0%
13		5	0.9965		0.9965	0.9965	0.0000	0.0%
14		6	0.9630		0.9630	0.9630	0.0000	0.0%
15		7	0.9269		0.9269	0.9269	0.0000	0.0%
16		8	0.8880		0.8880	0.8880	0.0000	0.0%
17		9	0.8461		0.8461	0.8461	0.0000	0.0%
18		10	0.8009		0.8009	0.8009	0.0000	0.0%
19		11	0.7523		0.7523	0.7523	0.0000	0.0%
20		12	0.6998		0.6998	0.6998	0.0000	0.0%
21		13	0.6432		0.6432	0.6432	0.0000	0.0%
22		14	0.5823		0.5823	0.5823	0.0000	0.0%
23		15	0.5166		0.5166	0.5166	0.0000	0.0%
24		16	0.4458		0.4458	0.4458	0.0000	0.0%
25		17	0.3695		0.3695	0.3695	0.0000	0.0%
26		18	0.2872		0.2872	0.2872	0.0000	0.0%
27		19	0.1985		0.1985	0.1985	0.0000	0.0%
28		20	0.1030		0.1030	0.1030	0.0000	0.0%
29		>20	0.0000		0.0000	0.0000	0.0000	
30								
31		Non-Fuel Energy (¢ per kWh)	2.492	0.044	2.536	2.652	0.116	4.6%
32								
33		<u>Willful Damage</u>						
34		All occurrences after initial repair			Cost for repair or replacement			
35	* 10 and 20 year payment options closed to new facilities							
36								
37	RL-1	Recreational Lighting [Schedule closed to new customers]						
38								
39		Non-Fuel Energy (¢ per kWh)			Otherwise applicable General			
40					Service Rate			
41								
42		Maintenance			FPL's estimated cost of			
					maintaining facilities			

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

[1]The actual amount of the EPU increase will be determined by the Commission later this year.
[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE		(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	OL-1	Outdoor Lighting							
2		Charges for FPL-Owned Units							
3		Fixture							
4		Sodium Vapor 6,300 lu 70 watts		$4.65		$4.65	$4.86	$0.21	4.5%
5		Sodium Vapor 9,500 lu 100 watts		$4.75		$4.75	$4.97	$0.22	4.6%
6		Sodium Vapor 16,000 lu 150 watts		$4.92		$4.92	$5.14	$0.22	4.5%
7		Sodium Vapor 22,000 lu 200 watts		$7.15		$7.15	$7.48	$0.33	4.6%
8		Sodium Vapor 50,000 lu 400 watts		$7.61		$7.61	$7.96	$0.35	4.6%
9	*	Sodium Vapor 12,000 lu 150 watts		$5.28		$5.28	$5.52	$0.24	4.5%
10	*	Mercury Vapor 6,000 lu 140 watts		$3.57		$3.57	$3.73	$0.16	4.5%
11	*	Mercury Vapor 8,600 lu 175 watts		$3.59		$3.59	$3.75	$0.16	4.5%
12	*	Mercury Vapor 21,500 lu 400 watts		$5.88		$5.88	$6.15	$0.27	4.6%
13									
14		Maintenance							
15		Sodium Vapor 6,300 lu 70 watts		$1.70		$1.70	$1.78	$0.08	4.7%
16		Sodium Vapor 9,500 lu 100 watts		$1.70		$1.70	$1.78	$0.08	4.7%
17		Sodium Vapor 16,000 lu 150 watts		$1.73		$1.73	$1.81	$0.08	4.6%
18		Sodium Vapor 22,000 lu 200 watts		$2.24		$2.24	$2.34	$0.10	4.5%
19		Sodium Vapor 50,000 lu 400 watts		$2.20		$2.20	$2.30	$0.10	4.5%
20	*	Sodium Vapor 12,000 lu 150 watts		$1.98		$1.98	$2.07	$0.09	4.5%
21	*	Mercury Vapor 6,000 lu 140 watts		$1.53		$1.53	$1.60	$0.07	4.6%
22	*	Mercury Vapor 8,600 lu 175 watts		$1.53		$1.53	$1.60	$0.07	4.6%
23	*	Mercury Vapor 21,500 lu 400 watts		$2.15		$2.15	$2.25	$0.10	4.7%
24									
25		Energy Non-Fuel**	kWh						
26		Sodium Vapor 6,300 lu 70 watts	29	$0.73		$0.74	$0.78	$0.04	5.4%
27		Sodium Vapor 9,500 lu 100 watts	41	$1.03		$1.05	$1.10	$0.05	4.8%
28		Sodium Vapor 16,000 lu 150 watts	60	$1.51		$1.54	$1.61	$0.07	4.5%
29		Sodium Vapor 22,000 lu 200 watts	88	$2.21		$2.25	$2.35	$0.10	4.4%
30		Sodium Vapor 50,000 lu 400 watts	168	$4.23		$4.30	$4.50	$0.20	4.7%
31	*	Sodium Vapor 12,000 lu 150 watts	60	$1.51		$1.54	$1.61	$0.07	4.5%
32	*	Mercury Vapor 6,000 lu 140 watts	62	$1.56		$1.59	$1.66	$0.07	4.4%
33	*	Mercury Vapor 8,600 lu 175 watts	77	$1.94		$1.97	$2.06	$0.09	4.6%
34	*	Mercury Vapor 21,500 lu 400 watts	160	$4.02		$4.09	$4.28	$0.19	4.6%
35									
36		**Note: The proposed monthly Non-Fuel Energy charge is calculated by multiplying the kWh rating for each fixture by the proposed Non-Fuel Energy Rate.							
37		This avoids rounding issues caused by separating the increases into the various components.							
38									
39									
40									
41									
42									

SUPPORTING SCHEDULES: RECAP SCHEDULES:

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE		(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	OL-1	Outdoor Lighting (continued)							
2		Charges for Customer Owned Units							
3		Total Charge-Relamping & Energy**							
4		Sodium Vapor 6,300 lu 70 watts		$2.43		$2.44	$2.56	$0.12	4.9%
5		Sodium Vapor 9,500 lu 100 watts		$2.73		$2.75	$2.88	$0.13	4.7%
6		Sodium Vapor 16,000 lu 150 watts		$3.24		$3.27	$3.42	$0.15	4.6%
7		Sodium Vapor 22,000 lu 200 watts		$4.45		$4.49	$4.69	$0.20	4.5%
8		Sodium Vapor 50,000 lu 400 watts		$6.43		$6.50	$6.80	$0.30	4.6%
9		* Sodium Vapor 12,000 lu 150 watts		$3.49		$3.52	$3.68	$0.16	4.5%
10		* Mercury Vapor 6,000 lu 140 watts		$3.09		$3.12	$3.26	$0.14	4.5%
11		* Mercury Vapor 8,600 lu 175 watts		$3.47		$3.50	$3.66	$0.16	4.6%
12		* Mercury Vapor 21,500 lu 400 watts		$6.17		$6.24	$6.53	$0.29	4.6%
13									
14		Energy Only***	kWh						
15		Sodium Vapor 6,300 lu 70 watts	29	$0.73		$0.74	$0.78	$0.04	5.4%
16		Sodium Vapor 9,500 lu 100 watts	41	$1.03		$1.05	$1.10	$0.05	4.8%
17		Sodium Vapor 16,000 lu 150 watts	60	$1.51		$1.54	$1.61	$0.07	4.5%
18		Sodium Vapor 22,000 lu 200 watts	88	$2.21		$2.25	$2.35	$0.10	4.4%
19		Sodium Vapor 50,000 lu 400 watts	168	$4.23		$4.30	$4.50	$0.20	4.7%
20		* Sodium Vapor 12,000 lu 150 watts	60	$1.51		$1.54	$1.61	$0.07	4.5%
21		* Mercury Vapor 6,000 lu 140 watts	62	$1.56		$1.59	$1.66	$0.07	4.4%
22		* Mercury Vapor 8,600 lu 175 watts	77	$1.94		$1.97	$2.06	$0.09	4.6%
23		* Mercury Vapor 21,500 lu 400 watts	160	$4.02		$4.09	$4.28	$0.19	4.6%
24									
25		Non-Fuel Energy (¢ per kWh)		2.515	0.044	2.559	2.676	0.117	4.6%
26									
27		Other Charges							
28		Wood Pole		$8.92		$8.92	$9.33	$0.41	4.6%
29		Concrete Pole		$12.04		$12.04	$12.59	$0.55	4.6%
30		Fiberglass Pole		$14.15		$14.15	$14.80	$0.65	4.6%
31		Underground conductors excluding							
32		Trenching per foot		$0.072		$0.072	$0.075	$0.003	4.2%
33		Down-guy, Anchor and Protector		$8.60		$8.60	$8.99	$0.39	4.5%
34		* These units are closed to new FPL owned installations.							
35									
36	SL-2	Traffic Signal Service							
37		Base Energy Charge (¢ per kWh)		4.042	0.109	4.151	4.340	0.189	4.6%
38		Minimum Charge at each point		$2.98		$2.98	$3.12	$0.14	4.7%
39									
40		**Note: The monthly Relamp and Energy charge for Jun-2014 is calculated by adding the Relamp increase to the Energy-only increase. This avoids rounding issues.							
41		***Note: See note for FPL-Owned Non-Fuel Energy rates.							
42									

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

							GBRA FACTOR	4.565%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	CURRENT RATE SCHEDULE	TYPE OF CHARGE	DEC-2013 CURRENT RATE	EPU INCREASE[1]	JAN-2014 PROPOSED RATE	JUN-2014 PROPOSED RATE[2]	CHANGE IN RATE Jan to Jun	% CHANGE IN RATE Jan to Jun
1	SST-1	Standby and Supplemental Service						
2		Customer Charge						
3		SST-1(D1)	$103.48		$103.48	$108.20	$4.72	4.6%
4		SST-1(D2)	$103.48		$103.48	$108.20	$4.72	4.6%
5		SST-1(D3)	$388.03		$388.03	$405.74	$17.71	4.6%
6		SST-1(T)	$1,502.16		$1,502.16	$1,570.73	$68.57	4.6%
7								
8		Distribution Demand $/kW Contract Standby Demand						
9		SST-1(D1)	$2.79		$2.79	$2.92	$0.13	4.7%
10		SST-1(D2)	$2.79		$2.79	$2.92	$0.13	4.7%
11		SST-1(D3)	$2.79		$2.79	$2.92	$0.13	4.7%
12		SST-1(T)	N/A		N/A	N/A		
13								
14		Reservation Demand $/kW						
15		SST-1(D1)	$1.03	$0.05	$1.08	$1.13	$0.05	4.6%
16		SST-1(D2)	$1.03	$0.05	$1.08	$1.13	$0.05	4.6%
17		SST-1(D3)	$1.03	$0.05	$1.08	$1.13	$0.05	4.6%
18		SST-1(T)	$1.07	$0.05	$1.12	$1.17	$0.05	4.5%
19								
20		Daily Demand (On-Peak) $/kW						
21		SST-1(D1)	$0.51	$0.02	$0.53	$0.55	$0.02	3.8%
22		SST-1(D2)	$0.51	$0.02	$0.53	$0.55	$0.02	3.8%
23		SST-1(D3)	$0.51	$0.02	$0.53	$0.55	$0.02	3.8%
24		SST-1(T)	$0.30	$0.02	$0.32	$0.33	$0.01	3.1%
25								
26		Supplemental Service						
27		Demand			Otherwise Applicable Rate			
28		Energy			Otherwise Applicable Rate			
29								
30		Non-Fuel Energy - On-Peak (¢ per kWh)						
31		SST-1(D1)	0.906		0.906	0.947	0.041	4.5%
32		SST-1(D2)	0.906		0.906	0.947	0.041	4.5%
33		SST-1(D3)	0.906		0.906	0.947	0.041	4.5%
34		SST-1(T)	0.882		0.882	0.922	0.040	4.5%
35		Non-Fuel Energy - Off-Peak (¢ per kWh)						
36		SST-1(D1)	0.906		0.906	0.947	0.041	4.5%
37		SST-1(D2)	0.906		0.906	0.947	0.041	4.5%
38		SST-1(D3)	0.906		0.906	0.947	0.041	4.5%
39		SST-1(T)	0.882		0.882	0.922	0.040	4.5%
40								
41								
42								

SUPPORTING SCHEDULES: RECAP SCHEDULES:

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	ISST-1	Interruptible Standby and Supplemental Service						
2		Customer Charge						
3		Distribution	$388.03		$388.03	$405.74	$17.71	4.6%
4		Transmission	$1,956.71		$1,956.71	$2,046.03	$89.32	4.6%
5								
6		Distribution Demand						
7		Distribution	$2.79		$2.79	$2.92	$0.13	4.7%
8		Transmission	N/A		N/A	N/A		
9								
10		Reservation Demand-Interruptible						
11		Distribution	$0.09	$0.05	$0.14	$0.15	$0.01	7.1%
12		Transmission	$0.17	$0.05	$0.22	$0.23	$0.01	4.5%
13								
14		Reservation Demand-Firm						
15		Distribution	$1.03	$0.05	$1.08	$1.13	$0.05	4.6%
16		Transmission	$0.84	$0.05	$0.89	$0.93	$0.04	4.5%
17								
18		Supplemental Service						
19		Demand			Otherwise Applicable Rate			
20		Energy			Otherwise Applicable Rate			
21								
22		Daily Demand (On-Peak) Firm Standby						
23		Distribution	$0.51	$0.02	$0.53	$0.55	$0.02	3.8%
24		Transmission	$0.39	$0.02	$0.41	$0.43	$0.02	4.9%
25								
26		Daily Demand (On-Peak) Interruptible Standby						
27		Distribution	$0.05	$0.02	$0.07	$0.07	$0.00	0.0%
28		Transmission	$0.07	$0.02	$0.09	$0.09	$0.00	0.0%
29								
30		Non-Fuel Energy - On-Peak (¢ per kWh)						
31		Distribution	0.906		0.906	0.947	0.041	4.5%
32		Transmission	0.829		0.829	0.867	0.038	4.6%
33		Non-Fuel Energy - Off-Peak (¢ per kWh)						
34		Distribution	0.906		0.906	0.947	0.041	4.5%
35		Transmission	0.829		0.829	0.867	0.038	4.6%
36								
37		Excess "Firm Standby Demand"						
38		¤ Up to prior 60 months of service			Difference between reservation charge for			
39					firm and interruptible standby demand			
40					times excess demand			
41								
42		¤ Penalty Charge per kW for each month of rebilling	$1.02		$1.02	$1.07	$0.05	4.9%

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
6	TR	Transformation Rider						
7		Transformer Credit						
8		(per kW of Billing Demand)	($0.28)		($0.28)	($0.29)	($0.01)	3.6%
9								
10								
11	GSCU-1	General Service constant Usage						
12		Customer Charge:	$12.42		$12.42	$12.99	$0.57	4.6%
13								
14		Non-Fuel Energy Charges:						
15		Base Energy Charge*	2.977	0.109	3.086	3.227	0.141	4.6%
16		* The fuel and non-fuel energy charges will be assessed on the Constant Usage kWh						
17								
18								
19	HLFT	High Load Factor - Time of Use						
20		Customer Charge:						
21		21 - 499 kW:	$24.83		$24.83	$25.96	$1.13	4.6%
22		500 - 1,999 kW	$56.91		$56.91	$59.51	$2.60	4.6%
23		2,000 kW or greater	$201.78		$201.78	$210.99	$9.21	4.6%
24								
25		Demand Charges:						
26		On-peak Demand Charge:						
27		21 - 499 kW:	$8.69	$0.37	$9.06	$9.47	$0.41	4.5%
28		500 - 1,999 kW	$8.80	$0.44	$9.24	$9.66	$0.42	4.5%
29		2,000 kW or greater	$8.80	$0.43	$9.23	$9.65	$0.42	4.6%
30								
31		Maximum Demand Charge:						
32		21 - 499 kW:	$1.97		$1.97	$2.06	$0.09	4.6%
33		500 - 1,999 kW	$2.07		$2.07	$2.16	$0.09	4.3%
34		2,000 kW or greater	$2.07		$2.07	$2.16	$0.09	4.3%
35								
36		Non-Fuel Energy Charges: (¢ per kWh)						
37		On-Peak Period						
38		21 - 499 kW:	1.489		1.489	1.557	0.068	4.6%
39		500 - 1,999 kW	0.816		0.816	0.853	0.037	4.5%
40		2,000 kW or greater	0.747		0.747	0.781	0.034	4.6%
41								
42								

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FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1								
2		Off-Peak Period						
3		21 - 499 kW:	0.963		0.963	1.007	0.044	4.6%
4		500 - 1,999 kW	0.816		0.816	0.853	0.037	4.5%
5		2,000 kW or greater	0.747		0.747	0.781	0.034	4.6%
6								
7								
8	SDTR	Seasonal Demand – Time of Use Rider						
9		Option A						
10		Customer Charge:						
11		21 - 499 kW:	$24.83		$24.83	$25.96	$1.13	4.6%
12		500 - 1,999 kW	$56.91		$56.91	$59.51	$2.60	4.6%
13		2,000 kW or greater	$201.78		$201.78	$210.99	$9.21	4.6%
14								
15		Demand Charges:						
16		Seasonal On-peak Demand:						
17		21 - 499 kW:	$8.48	$0.37	$8.85	$9.25	$0.40	4.5%
18		500 - 1,999 kW	$9.21	$0.44	$9.65	$10.09	$0.44	4.6%
19		2,000 kW or greater	$9.52	$0.43	$9.95	$10.40	$0.45	4.5%
20								
21		Non-seasonal Demand Max Demand:						
22		21 - 499 kW:	$6.93	$0.37	$7.30	$7.63	$0.33	4.5%
23		500 - 1,999 kW	$7.97	$0.44	$8.41	$8.79	$0.38	4.5%
24		2,000 kW or greater	$8.38	$0.43	$8.81	$9.21	$0.40	4.5%
25								
26		Energy Charges (¢ per kWh):						
27		Seasonal On-peak Energy:						
28		21 - 499 kW:	6.700		6.700	7.006	0.306	4.6%
29		500 - 1,999 kW	4.640		4.640	4.852	0.212	4.6%
30		2,000 kW or greater	3.961		3.961	4.142	0.181	4.6%
31								
32		Seasonal Off-peak Energy:						
33		21 - 499 kW:	1.263		1.263	1.321	0.058	4.6%
34		500 - 1,999 kW	0.953		0.953	0.997	0.044	4.6%
35		2,000 kW or greater	0.858		0.858	0.897	0.039	4.5%
36								
37		Non-seasonal Energy						
38		21 - 499 kW:	1.781		1.781	1.862	0.081	4.5%
39		500 - 1,999 kW	1.317		1.317	1.377	0.060	4.6%
40		2,000 kW or greater	1.186		1.186	1.240	0.054	4.6%
41								
42								

SUPPORTING SCHEDULES: RECAP SCHEDULES:

[1]The actual amount of the EPU increase will be determined by the Commission later this year.
[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JUNE 2014 GBRA RATES

GBRA FACTOR 4.565%

LINE NO.	(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) DEC-2013 CURRENT RATE	(4) EPU INCREASE[1]	(5) JAN-2014 PROPOSED RATE	(6) JUN-2014 PROPOSED RATE[2]	(7) CHANGE IN RATE Jan to Jun	(8) % CHANGE IN RATE Jan to Jun
1	SDTR	Seasonal Demand – Time of Use Rider (continued)						
2		Option B						
3		Customer Charge:						
4		21 - 499 kW:	$24.83		$24.83	$25.96	$1.13	4.6%
5		500 - 1,999 kW	$56.91		$56.91	$59.51	$2.60	4.6%
6		2,000 kW or greater	$201.78		$201.78	$210.99	$9.21	4.6%
7								
8		Demand Charges:						
9		Seasonal On-peak Demand:						
10		21 - 499 kW:	$8.48	$0.37	$8.85	$9.25	$0.40	4.5%
11		500 - 1,999 kW	$9.21	$0.44	$9.65	$10.09	$0.44	4.6%
12		2,000 kW or greater	$9.52	$0.43	$9.95	$10.40	$0.45	4.5%
13								
14		Non-seasonal On-peak Demand:						
15		21 - 499 kW:	$6.93	$0.37	$7.30	$7.63	$0.33	4.5%
16		500 - 1,999 kW	$7.97	$0.44	$8.41	$8.79	$0.38	4.5%
17		2,000 kW or greater	$8.38	$0.43	$8.81	$9.21	$0.40	4.5%
18								
19		Energy Charges (¢ per kWh):						
20		Seasonal On-peak Energy:						
21		21 - 499 kW:	6.700		6.700	7.006	0.306	4.6%
22		500 - 1,999 kW	4.640		4.640	4.852	0.212	4.6%
23		2,000 kW or greater	3.961		3.961	4.142	0.181	4.6%
24								
25		Seasonal Off-peak Energy:						
26		21 - 499 kW:	1.263		1.263	1.321	0.058	4.6%
27		500 - 1,999 kW	0.953		0.953	0.997	0.044	4.6%
28		2,000 kW or greater	0.858		0.858	0.897	0.039	4.5%
29								
30		Non-seasonal On-peak Energy:						
31		21 - 499 kW:	3.573		3.573	3.736	0.163	4.6%
32		500 - 1,999 kW	2.495		2.495	2.609	0.114	4.6%
33		2,000 kW or greater	2.283		2.283	2.387	0.104	4.6%
34								
35		Non-seasonal Off-peak Energy:						
36		21 - 499 kW:	1.263		1.263	1.321	0.058	4.6%
37		500 - 1,999 kW	0.953		0.953	0.997	0.044	4.6%
38		2,000 kW or greater	0.858		0.858	0.897	0.039	4.5%
39								
40								
41								
42								

SUPPORTING SCHEDULES: RECAP SCHEDULES:

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[2]The Jun-2014 proposed rate is based on the Jan-2014 proposed rate increased by the GBRA factor.