BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120001-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 31, 2012

IN RE: LEVELIZED FUEL COST RECOVERY AND CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2013 THROUGH DECEMBER 2013

TESTIMONY & EXHIBITS OF:

GERARD J. YUPP
PAUL FREEMAN
TERRY J. KEITH

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 120001-EI

AUGUST 31, 2012

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in 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 2012 hedging program and its 2013 Risk Management Plan. Lastly, I present the projected fuel savings resulting from the operation of West County Energy Center Unit 3 (WCEC 3) during 2013 and the projected fuel savings resulting from the commercial operation of the Cape Canaveral Next Generation Clean Energy Center (CCEC) from June through December 2013.

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

A. Yes, I am sponsoring the following exhibits:

- GJY-2: 2013 Risk Management Plan
- GJY-3: Hedging Activity Supplemental Report for 2012 (January through July)
- GJY-4: Appendix I
- Schedules E2 through E9 of Appendix II

<u>FUEL PRICE FORECAST</u>

Q. **What forecast methodologies has FPL used for the 2013 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 3, 2012 for its 2013 projection filing.

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 2013 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 2013 compared with projected 2012 average levels primarily due to the assumed reduction in the global crude oil price. Despite some assumed strengthening in the crude oil market over the next several months, the fundamentals are not particularly supportive in 2013. Although expected demand in 2013 is forecasted to be 1.1% above projected 2012 levels and 2.2% above actual 2011 demand, non-OPEC production is projected to be 2.1% above forecasted 2012 levels and 2.7% above actual 2011 levels. With non-OPEC supply growing faster than demand, the demand for OPEC crude oil will decline and OPEC spare capacity will increase, supporting lower crude oil and petroleum prices in 2013 compared with 2012. A greater-than-expected increase in demand or a lower-than-expected increase in non-OPEC production would put upward pressure on the price of heavy oil. Conversely, a weaker-than-expected growth in demand or a greater-than-expected increase in non-OPEC production would put further downward pressure on the price of heavy oil.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2013 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 2013 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 2013 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 2013 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.

The major driver for natural gas prices during the remainder of 2012 and all of 2013 are forecasted changes in natural gas production. With the number of working natural gas rigs being down approximately 69% since the peak in August 2008, and with this trend expected to continue into 2013, domestic production is projected in 2013 to have its first year-on-year decline since 2006, which would result in average 2013 natural gas prices being higher than average 2012 levels. In addition, natural gas storage levels are now expected to end the 2012 summer injection season at the end of October 2012 at a level slightly lower level than the prior year, for the first year-on-year decline since 2008, further supporting higher prices in 2013 compared with 2012.

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

2013 period?

A. The key factors are (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 1,304,000 MMBtu/day, depending on the month. FPL has firm transportation capacity on Gulfstream of 695,000 MMBtu/day.

Additionally, FPL has 580,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline and 200,000 MMBtu/day of firm transport on the Transcontinental Pipe Line Gas Company, LLC (Transco) Zone 4A lateral. The firm transportation on the SESH and Transco pipelines does not increase transportation capacity into the state, but FPL's firm transportation rights on these pipelines provide access to 780,000 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 2013 period, 55,000 MMBtu/day to 175,000 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. **Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2013 period.**

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

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY

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

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

Q. Are you providing the outage factors projected for the period January through December 2013?

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 2013.

Q. Please describe the significant planned outages for the January through December 2013 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. Turkey Point Unit 4 is scheduled to be out of service from November 5, 2012 until March 15, 2013 or 73 days during the period to complete extended power uprate (EPU) work. St. Lucie Unit 1 is scheduled to be out of service from September 5, 2013 until October 13, 2013 or 38 days during the period. Turkey Point Unit 3 is scheduled to be out of service from October 21, 2013 until November 28, 2013 or 38 days during the period.

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

A. FPL projects to put CCEC into commercial operation on June 1, 2013. This unit will add an additional 1,210 MW of summer capacity and 1,355 MW of winter capacity.

<u>WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS</u>

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2013?

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 413,400 MWh of wholesale (off-system) power sales for the period of January through December 2013. The projected fuel cost related to these sales is $16,352,230. The projected transaction revenue from these sales is $21,800,230. The projected gain for these sales is $4,238,116.

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 2013 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 1,060,000 MWh at a cost of $42,063,927. If FPL generated this energy, FPL estimates that it would cost $72,971,010. Therefore, these purchases are projected to result in savings of $30,907,083.

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 2012 period.

A. UPS energy purchases for the period are projected to be 2,698,220 MWh at an energy cost of $96,036,724. 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 2,027,889 MWh for the period at an energy cost of $86,564,000. 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 538,023 MWh at a cost of $4,230,560. 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

3,209,622 MWh at a cost of $143,346,388.

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 563,881 MWh of energy at a cost of $4,340,025. 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 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 2013 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up filing on August 1, 2012. The 2013 Risk Management Plan is included as Exhibit GJY-2.

Q. Please provide an overview of FPL's 2013 Risk Management Plan.

A. FPL's 2013 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 2013 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2013 for its projected natural gas requirements in 2014. FPL plans to hedge the percentages of its 2014 projected natural gas requirements over the time periods in 2013 that are described in the plan. As described in the plan, FPL does not intend to execute hedges for its 2014 heavy fuel oil requirements, due primarily to extremely low consumption projections. With low consumption projections, small changes in projected heavy oil burns can cause FPL to rebalance insignificant volumes of heavy oil to remain within required hedge percentage bands. This rebalancing activity would add unnecessary costs while providing little price certainty.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2012, 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 2012 (January through July) on August 15, 2012. The Hedging Activity Supplemental Report is included as Exhibit GJY-3.

Q. Have FPL's 2012 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. Additionally, FPL's customers have been able to benefit from the decrease in natural gas prices from the unhedged portion of FPL's portfolio. At the time FPL was placing its hedges for its 2012 projected natural gas and heavy oil requirements, market prices were different than the actual settlement prices that have occurred in 2012.

For example, at the beginning of January 2011, the average monthly NYMEX forward price for natural gas for the January through July 2012 time period was approximately $5.098 per MMBtu. At the end of July 2011, the average monthly NYMEX forward price for the January through July 2012 time period was approximately $4.530 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $2.520 per MMBtu or $2.578 per MMBtu lower than the forward prices seen in January and $2.010 per MMBtu lower than the forward prices seen in July. Conversely, in January 2011, the average forward price for heavy oil for the January through July 2012 time period was approximately $83.82 per barrel. In July 2011, the average forward price for heavy oil for the January through July 2012 time period was approximately $104.09 per barrel. The actual average settlement price for heavy oil for this same time period was $107.26 per barrel or $23.44 per barrel higher than the forward prices seen in January and $3.17 per barrel higher than the forward prices seen in July. As acknowledged in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for natural gas 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 heavy oil results in savings for customers. As previously stated, however, FPL's hedging objective is to reduce fuel price volatility and deliver greater price certainty.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF WCEC 3

Q. Will the operation of WCEC 3 during 2013 result in fuel savings to FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the January through December, 2013 period, the operation of WCEC 3 is projected to save FPL's customers $133,225,000.

Q. How did FPL calculate the projected fuel savings associated with the operation of WCEC 3?

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the operation of WCEC 3. 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 WCEC 3 fuel savings. In order to calculate the WCEC 3 fuel savings, FPL ran two separate production cost simulations, one without WCEC 3 and one with WCEC 3. A comparison of the total system fuel costs from POWERSYM for the two simulations showed that the fuel costs were $133,225,000 lower in the case that included WCEC 3 than in the case without WCEC 3.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF CCEC

Q. Will the operation of CCEC during 2013 result in fuel savings to FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the June through December, 2013 period, the operation of CCEC is projected to save FPL's customers $100,908,000.

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

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the operation of CCEC. 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 CCEC fuel savings. In order to calculate the CCEC fuel savings, FPL ran two separate production cost simulations, one without CCEC and one with CCEC. A comparison of the total system fuel costs from POWERSYM for the two simulations showed that the fuel costs were $100,908,000 lower in the case that included CCEC than in the case without CCEC. Please note that, because WCEC 3 is already in service, both the “with CCEC” and “without CCEC” scenarios assumed that WCEC 3 is in service.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF PAUL FREEMAN

DOCKET NO. 120001-EI

AUGUST 31, 2012

Q. Please state your name and address.

A. My name is Paul Freeman. 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 in NextEra Energy, Inc.'s Nuclear Business Unit as Vice President of Organizational Effectiveness.

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

A. I am currently responsible for the governance and oversight of the following areas for the NextEra Nuclear Plants, including Florida Power & Light Company's (FPL) St. Lucie and Turkey Point Nuclear Plants: Training, Licensing/Nuclear Regulatory Affairs, Performance Improvement, and Nuclear Security.

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

A. I earned my Bachelor of Marine Engineering degree from Massachusetts Maritime Academy in 1984 and earned my Master of Business Administration degree from Boston College in 1990. I am a career nuclear professional with approximately 27 years of nuclear operating experience. In 1985, I joined Public Service Company of New Hampshire at the Seabrook Nuclear Power Plant (owned by NextEra Energy since 2002). I served in various roles of increasing responsibility at Seabrook until June 2012. My positions included Control Room Operator, Operations Shift Manager, Engineering Manager and Director, Plant General Manager and Site Vice President. In June 2012, I was appointed Vice President of Organizational Effectiveness. I have accountability for Training, Licensing/Nuclear Regulatory Affairs, Performance Improvement, and Nuclear Security.

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. I am also updating the status of certain litigation that affects FPL's nuclear fuel costs; plant security costs and new Nuclear Regulatory Commission (NRC) security initiatives; new NRC requirements resulting from Fukushima; and outage events. Both nuclear fuel and disposal of spent nuclear fuel costs were input values to POWERSYM used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2013 through December 2013.

<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 2013 through December 2013.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2013 through December 2013.

A. FPL projects the nuclear units will produce 285,258,283 MMBtu of energy at a cost of $0.7441 per MMBtu, excluding spent fuel disposal costs, for the period January 2013 through December 2013. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 18.

<u>Spent Nuclear Fuel Disposal Costs</u>

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2013 through December 2013 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $24.8 million are provided in Appendix II, on Schedule E-2, starting on page 14. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9363 mills per net kWh generated, including transmission and distribution line losses.

<u>Litigation Status Update</u>

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.

Nuclear Plant Security Costs

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2013 through December 2013?

A. FPL projects that it will incur $39.5 million in incremental nuclear power plant security costs in 2013.

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.

Q. Are there new impacts from the NRC's recent revisions to the security-related Orders that affect FPL's 2013 security cost projections?

A. Yes. On March 27, 2009 the NRC issued a new rule under Part 73.54 of the Code of Federal Regulations that involves the protection of station digital computer, communications systems and networks which impose significant requirements for monitoring, hardening and responding to cyber intrusions. Full regulatory implementation for this new Part 73.54 is scheduled for completion in 2014. The NRC Cyber Security rulemaking costs for 2013 are estimated to be $5.1 million for the St. Lucie and Turkey Point nuclear sites.

Also, in February 2009, the NRC updated the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). These enhancements are now being utilized during the triennial FoF inspections performed at the nuclear stations. The DBT is the measure that all nuclear stations are designed to defend against. Some examples of changes are: enhanced intrusion detection, adversary delay barriers, and additional vehicle barriers.

FoF inspections are scheduled on a repeating three year cycle. Consequently, St. Lucie and Turkey Point will receive third round FoF inspections in the 2011-2013 cycle and FPL sites may require additional modifications to ensure successful regulatory inspection conclusions. Adversary Characteristics are constantly being reviewed by the NRC due to the potential change in adversary capabilities. Consequently, future enhancements of nuclear facilities may be required. St. Lucie and Turkey Point FoF modifications are estimated to be $1.0 million for each facility for 2013.

<u>**Fukushima Costs**</u>

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

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

Q. **What changes has the NRC implemented resulting from the event in Japan?**

A. Even though the NRC has concluded that all U.S. plants are safe, incorporation of lessons learned for the Fukushima event is expected to be significant. In March 2012, the NRC issued three Orders and three Requests for Information (RFIs). The Orders address Mitigation Strategies, Hardened Vent (not applicable to FPL nuclear sites) and Spent Fuel Pool Instrumentation. The RFIs address Seismic and Flooding Walkdowns, Seismic and Flooding Re-evaluations and Emergency Planning Communications and Staffing. The response to the Orders and RFIs follow varying schedules from 60 days to several years.

Q. **What steps has FPL already implemented as a result of the new Orders and RFIs?**

A. As of June 2012, FPL has taken steps to comply with 2012 action requirements, which include acquiring additional diesel generators and water pumps, initiating seismic and flooding walkdowns and responding to all information requests.

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

A. FPL will make modifications and enhancements to current beyond design basis mitigation strategies to deal with potential events that are beyond current plant design basis. The project scope is still evolving based on NRC communications and currently expected to include modification for the following:

- Seismic Design Basis
- Flooding Design Basis
- Station Blackout Mitigation
- Spent Fuel Pool Instrumentation
- Onsite Emergency Response Capabilities
- Station Blackout/Emergency Plans

Q. **Does FPL have enough information currently to project with confidence the cost to complete the modifications and enhancements as a result of the NRC requirements?**

A. No. FPL currently has a conceptual estimate range of $17 million - $25 million per site. However, the estimate is subject to significant change as more information is gathered at FPL and other nuclear plants.

Q. **When does FPL currently expect to complete the modifications and enhancements?**

A. Based on currently available information, FPL believes that implementation of the modifications will be completed in 2016.

Q. **Has FPL included any costs to comply with the Fukushima Orders and RFIs in the 2013 Test Year Forecast that was filed in Docket No. 120015-EI?**

A. Yes. FPL included $5.1 million of capital expenditures and $144k of O&M expenses for the 2013 Test Year. However, at the time the 2013 Test Year Forecast was developed in the Fall of 2011, not enough information was available to estimate the full impact of the Fukushima event. FPL currently anticipates that actual costs in 2013 and beyond will be significantly above these levels, though we will not be able to make definitive estimates until further regulations are issued later this year and FPL has evaluated what will be required to comply with them.

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

A. FPL projects that it will incur an additional $6.1 million of capital expenditures in Fukushima power plant costs above the 2013 Test year amounts.

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

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

2012 Outage Events

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2012?

A. Yes. In April 2012, while Unit 1 was shut down to perform a scheduled refueling outage, operational issues associated with the Steam Bypass Control System (SBCS) were the primary cause that delayed the restart of the unit.

Q. Please describe the circumstances related to the operational issues with the SBCS.

A. There were four separate events that occurred during the outage related to the SBCS which was replaced in the spring 2012 Unit 1 outage.

1. On 3/31/2012, Unit 1 was at 10% reactor power conducting preoperational testing on the SBCS. One of the pressure control valves (PCV) in the SBCS experienced unstable operation and opened causing increased steam flow. The Unit was manually tripped in accordance with operating procedural requirements. Testing and inspections were performed and repairs made. Most probable cause was determined to be manufacturing quality issues.

2. On 4/7/2012, Unit 1 was at 10% power preparing to startup the turbine generator when a leak into the main condenser occurred. Unit 1 was manually shut down per station operating procedures. The cause was determined to be condenser tube damage caused by the failure of one of the discharge spargers into the condenser from SBCS. The discharge sparger failed due to high cycle fatigue. A new sparger was designed, fabricated and installed.

3. On 4/15/2012, Unit 1 was at 10% reactor power and performing capacity testing on the SBCS. While performing the testing, a decrease in steam pressure was identified due to several PCVs operating abnormally. Consequently, the operators placed alternate valves in service to safely control the plant. The Unit reduced power to 2%.

4. On 4/17/2012, Unit 1 was at 10% reactor power and the turbine was being started up per plant operating procedures. After simulated turbine trip testing was performed, one of the SBCS valves operated abnormally and was removed from service. The operators placed alternate valves in auto to safely control the plant. The unit reduced power to 2%. The direct cause of this event was a valve failure. The valve was repaired and returned to service.

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

A. Considerable effort was expended in determining the cause of these four events. A dedicated team of station and industry experts reviewed all the data from each event. However, the direct cause for the observed SBCS valve response remains indeterminate. To ensure successful operation of the unit, one of the SBCS valves has been removed from service and plant start-up procedures have been revised to operate the remaining SBCS valves at conditions which will ensure their proper operation. Future plans include replacement of these valves with upgraded design.

Q. How many days was the St. Lucie Unit 1 refueling outage delayed due to these issues?

A. The Unit 1 refueling outage was delayed approximately 21 days.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 1 in 2012?

A. Yes. In April 2012, shortly after Unit 1 returned to service from a scheduled refueling outage, switchyard breaker 8W30 faulted, causing an automatic turbine trip and subsequent shut down of the unit.

Q. What caused the switchyard breaker to fault?

A. An internal C-phase-to-ground fault occurred in the switchyard breaker. An investigation determined that the fault was caused by either failure of the Transient Recovery Voltage Capacitors or the presence of conductive particles within the C-phase, causing a short to ground.

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

A. FPL replaced the failed breaker with a new upgraded breaker. Additionally, testing was conducted on the other existing St. Lucie Unit 1 output breaker to ensure operating performance. As a long-term preventative measure, FPL replaced the one other breaker of same vintage and style during the planned LAR outage in mid-July.

Q. How many days was the St. Lucie Unit 1 outage due to this issue?

A. The Unit 1 outage due to the breaker was approximately 1 day.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 1 in 2012?

A. Yes. In June 2012, Unit 1 automatically shut down due to a malfunction of the Turbine Control System (TCS).

Q. What caused the malfunction of the TCS?

A. The TCS was replaced during the spring 2012 Unit 1 outage. The TCS is designed with redundant controllers, a primary and backup. A fiber optic cable connection in the primary controller malfunctioned, functionally affecting the interface between the primary and backup controllers. An investigation determined that this malfunction was caused by either improper installation of the fiber optic cable connector or inadvertent damage to the connector caused by other work performed in the vicinity of the connector after installation and testing.

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

A. FPL revised the procedure to include a post maintenance stress test to fiber optic equipment and has hired outside services that specialize in this work to avoid recurrence.

Q. How many days was the St. Lucie Unit 1 outage due to this issue?

A. The Unit 1 outage was approximately 4 days.

Q. Has St. Lucie Unit 2 experienced any unplanned outages in 2012?

A. Yes. In May 2012, Unit 2 initiated a manual shut down due to lowering 2A Steam Generator water levels.

Q. What caused the lower Steam Generator water level?

A. A malfunction of the Feedwater Regulating Valve controller caused the valve to operate abnormally, reducing the feedwater flow to the 2A Steam Generator.

Q. How many days was the St. Lucie Unit 2 outage due to this issue?

A. The Unit 2 outage was approximately 2 days.

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

A FPL replaced the feedwater regulating valve controller feedback devices with a different improved design. Additionally, FPL added a requirement to the risk management procedure to periodically validate input assumptions to decisions and response plans.

<u>Turkey Point</u>

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2012?

A. Yes. In August 2012, while Unit 3 was shut down to perform a scheduled refueling outage, issues associated with installation of the new Electro Hydraulic Control System (EHC) and activities required to complete major modifications to the Condensate System were the primary causes that delayed the restart of the unit.

Q. Please describe the circumstances related to the EHC and Condensate System.

A. Installation of the new EHC system and Condensate system upgrades were major Extended Power Uprate (EPU) activities During the construction phase, in-progress changes were made to the EHC design that required additional tubing to be installed. This increased the time required to complete the activity, with the delay mostly attributed to fitup, welding, and flushing of the new tubing. The Condensate System upgrade was a major construction activity that included the installation of new condensers and piping. Due to the cleanliness requirements for Condensate water, emphasis was placed on post-modification system clean-up. During the construction phase it became clear that insufficient time had been incorporated into the schedule for the Condensate flushing. Incorporating the proper time for the flushing resulted in a delay to the end of the outage, compared to the original, unrealistically short estimate for this activity.

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

A. The Unit 3 outage is still ongoing, but is expected to return to service in early September.

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

A. The Turkey Point Unit 3 part of the EPU project will be completed at the end of the current refueling outage. EPU will be completed on Unit 4 during the refueling outage scheduled to begin in November 2012. Since the Unit 3 refueling outage (including post-outage power ascension) is in progress, corrective actions to prevent similar occurrences on Unit 4 have not been specifically identified. However, FPL utilizes a rigorous outage performance review process that will be employed following the Unit 3 outage to identify and implement corrective actions that are intended to prevent schedule delays.

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. 120001-EI

August 31, 2012

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 2012 Fuel Cost Recovery (FCR) actual/estimated true-up amount, which has been updated to include July 2012 actual data and which is incorporated into the calculation of the 2013 FCR factors. Additionally, the 2012 actual/estimated true-up amount has been updated to include revised net generation fuel cost estimates for August 2012 through December 2012 reflecting a data entry correction.
- I present FCR factors for the period January 2013 through May

2013 and June 2013 through December 2013 that reflect all of the Cape Canaveral Energy Center (CCEC) fuel savings in the period after the unit goes into service (projected to be June 1, 2013). I also present for informational purposes, 2013 FCR factors based on the traditional factor calculation methodology, which spreads the fuel savings associated with CCEC over the entire calendar year.

- I present January 2013 through December 2013 FCR factors for a new Residential Time of Use Rider (RTR-1) proposed in FPL's current base rate proceeding in Docket No. 120015-EI.
- I present a revised 2012 Capacity Cost Recovery (CCR) actual/estimated true-up amount, which has been updated to include July 2012 actual data and which is incorporated into the calculation of the 2013 CCR factors.
- I present the CCR factors for the period January 2013 through December 2013. I also provide CCR factors for the period January 2013 through December 2013 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 2013 through December 2013, as proposed in the Stipulation and Settlement filed by FPL, FIPUG, the SFHHA and the FEA in Docket No. 120015-EI on August 15, 2012 (the "Proposed Settlement Agreement").
- I present FPL's Nuclear Power Plant Cost Recovery costs to be

recovered through the CCR Clause in 2013.

- I discuss cost recovery of potential incremental compliance costs resulting from the Fukushima Daiichi event.
- I discuss other issues from FPL's current base rate proceeding that may impact the 2013 FCR and CCR costs.
- Finally, I provide on pages 78-79 of Appendix II FPL's proposed COG tariff sheets, which reflect 2013 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 – Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 provide the calculation of FCR factors for January 2013 through May 2013, which exclude CCEC fuel savings. TJK-5 also includes Schedules E1-A, E1-B, E1-C, E1-D and H1, which pertain to the entire 2013 calendar year. Finally, TJK-5 includes pages 11-13 and 78-79, which provide the 2011 Actual Energy Losses by Rate Class and update COG tariff sheets. These schedules are included in Appendix II.
- TJK-6 – Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10 for the period June 2013 through December 2013, which include CCEC fuel savings. These schedules are included in

Appendix III.

- TJK-7 – Schedules E1, E1-E, E2, RS-1 Inverted Rate Calculation and E10, showing the calculation of FCR factors for the period January 2013 through December 2013 based on the traditional factor calculation methodology, which spreads the CCEC fuel savings over the entire calendar year. These schedules are included in Appendix IV.

- TJK-8 – Pages 2 through 4 providing the calculation of the 2013 CCR factors. Additionally, TJK-8 provides the calculation of the 2013 CCR factors including an adjustment to recover the projected non-fuel revenue requirements associated with WCEC-3 for the period January 2013 through December 2013. These documents are included in Appendix V.

FUEL COST RECOVERY CLAUSE

Q. Has FPL revised its 2012 FCR Actual/Estimated True-up amount that was filed on August 1, 2012 to reflect July actual data?

A. Yes. The 2012 FCR actual/estimated true-up amount has been revised to an over-recovery of $99,206,321, reflecting July 2012 actual data, plus interest. This $99,206,321 over-recovery, plus the 2011 final true-up under-recovery of $51,121,025 results in a net over-recovery of $48,085,296 (see Schedule E1-b, Page 3, Appendix II). This $48,085,296 over-recovery is to be included in the FCR factor for the January 2013 through December 2013 period. Additionally, the 2012 actual/estimated true-up amount has been updated to include revised net generation fuel cost estimates for August 2012 through December 2012 reflecting a data entry correction.

Q What adjustments are included in the calculation of the 2013 FCR factors shown on Schedules E1 included in Appendices II, III and IV?

A. The total net true-up to be included in the 2013 FCR factors is an over-recovery of $48,085,296. This amount, divided by the projected retail sales of 103,200,444 MWh for January 2013 through December 2013, results in a decrease of 0.0466¢ per kWh before applicable revenue taxes, as shown on Line 25 of Schedule E1. The Generating Performance Incentive Factor (GPIF) testimony of FPL witness J. Carine Bullock, filed on March 15, 2012, proposes a reward of $7,703,912 for the period ending December 2011. This $7,703,912 reward, divided by the projected retail sales of 103,200,444 MWh during the projected period, results in an increase of .0075¢ per kWh, as shown on line 29 of Schedule E1.

Q. Please explain how FPL has calculated its proposed FCR factors for the period January 2013 through December 2013.

A. In FPL's base rate proceeding in Docket No. 120015-EI, FPL proposes to implement new rates to recover the annualized revenue requirements associated with CCEC with the in-service date of the unit, which is scheduled for June 1, 2013. FPL proposes that the corresponding fuel savings associated with CCEC be reflected in the 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 implementation of new units that occur during the year.

Q. What are the projected jurisdictional fuel savings associated with the CCEC from June 1, 2013 through the balance of 2013?

A. As explained in the testimony of FPL witness Yupp, the projected total fuel savings for that period are $100,908,000. In order to calculate these fuel savings, FPL ran two separate production cost simulations, one without CCEC and one with CCEC. A comparison of total system fuel costs from the production model for the two simulations showed that the fuel costs were $100,908,000 lower in the case that included the CCEC than in the case without the CCEC. The jurisdictional portion of those fuel savings is $99,047,141. The calculation of this jurisdictional amount is shown on Page 2 of Appendix III.

Q. Has FPL calculated 2013 FCR factors reflecting the CCEC 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 CCEC goes into service, assumed to be January 2013 through May 2013, (Page 1 of Appendix II) and separate average "Step 2" fuel factors to be applied during the period after CCEC goes into service, assumed to be June

2013 through December 2013 (Page 1 of Appendix III).

FPL first calculates the Step 1 fuel factors assuming CCEC is not operating in 2013, 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 3.105 cents per kWh for the period January 2013 through May 2013. For FPL's Residential 1,000 kWh bill, this represents a fuel charge of $27.89 during this period.

Next, FPL adjusts the Step 2 fuel factors for the period June 2013 through December 2013 by crediting the fuel savings associated with CCEC during this period. The total jurisdictional fuel savings of $99,047,141, divided by the projected sales for June 2013 through December 2013 of 64,023,523 MWh results in a downward adjustment of 0.1547 cents per kWh, including revenue taxes (Schedule E-1, Line 30, Page 1 of Appendix III). This downward adjustment results in a lower levelized FCR factor of 2.950 cents per kWh for the period June 2013 through December 2013, which represents a reduction in the levelized fuel factor of 0.155 cents per kWh. For FPL's residential 1,000 kWh bill, this represents a fuel charge of $26.33 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. Is FPL providing any additional information related to its CCEC?

A. Yes, FPL is providing additional information to be used in the event that the Commission approves the Proposed Settlement Agreement. Appendix VI contains the affidavit and Generation Base Rate Adjustment ("GBRA") supporting schedules of Renae Deaton. Appendix VIII contains the affidavit and supporting schedules of Kim Ousdahl which present the base revenue requirement of $165.561 million for the first twelve months of operation for FPL's CCEC.

Q. Has FPL developed seasonally differentiated Time of Use multipliers used in the calculation of 2013 FCR factors for its Time of Use rates?

A. Yes. Schedule E1-D, Page 1 of 3 and Page 2 of 3 provides the calculation of FPL's seasonally differentiated Time of Use (TOU) multipliers. FPL's winter period is considered to be January through March and November through December and its summer period is considered to be April through October.

FPL's TOU multipliers for its 2013 winter period are 1.186 on-peak and 0.932 off-peak. FPL's TOU multipliers for its 2013 summer period are 1.513 on-peak and 0.737 off-peak. For the winter and summer periods the 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 3 of 3 provides the calculation of TOU multipliers of 1.721 on-peak and 0.870 off-peak for the Seasonal Demand Time of Use Rider (SDTR).

Schedule E-1E, Page 1 of 3 presents 2013 FCR factors for FPL's non TOU rates. Schedule E-1E, Page 2 of 3 presents FPL's seasonally differentiated 2013 TOU FCR factors for its TOU rates. Schedule E-1E, Page 3 of 3 presents FPL's 2013 FCR factors for its SDTR rates.

Q. Has FPL provided 2013 FCR factors based on the traditional factor calculation methodology?

A. Yes. Although FPL requests approval of its "Step 1" and "Step 2" FCR factors for 2013, 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 the twelve-month levelized fuel factor based on the traditional methodology. This twelve-month levelized fuel factor spreads the CCEC fuel savings throughout the twelve months of 2013.

Q. What is the proposed levelized FCR factor based on the traditional factor calculation methodology?

A. 3.009¢ per kWh. Schedule E1, Page 1 of Appendix IV shows the calculation of this twelve-month levelized FCR factor based on the traditional factor calculation methodology. Schedule E2, Page 5 of

Appendix IV presents the monthly fuel factors for January 2013 through December 2013 and also the twelve-month levelized FCR factor for the period.

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

A. Yes.

CAPACITY COST RECOVERY CLAUSE

Q. **Has FPL revised its 2012 CCR Actual/Estimated True-up amount that was filed on August 1, 2012 to reflect July 2012 actual data?**

A. Yes. The 2012 CCR actual/estimated true-up amount has been revised to an under-recovery of $15,878,460, reflecting July 2012 actual data, plus interest. This $15,878,460 under-recovery, plus the 2011 final true-up under-recovery of $44,704,575 results in a net under-recovery of $60,583,035 (see Page 1 of Appendix V). This $60,583,035 net under-recovery is to be included for recovery in the CCR factor for the January 2013 through December 2013 period.

Q. **Have you prepared a summary of the requested capacity payments for the projected period of January 2013 through December 2013?**

A. Yes. Page 2 of Appendix V provides this summary. Total Recoverable Capacity Payments are $529,597,847 (line 8) and include payments of $199,776,283 to non-cogenerators (line 1), payments of $270,601,412 to cogenerators (line 2), $935,844 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 3), $46,396,506 in Incremental Power Plant Security Costs (line 5) and $18,402,144 in Transmission of Electricity by Others (line 6). These amounts are partially offset by $5,304,459 of Return Requirements on SJRPP Suspension Payments (line 4) and by Transmission Revenues from Capacity Sales of $1,209,884 (line 7). The resulting amount is then increased by the net under-recovery for 2011 and 2012 of $60,583,035 (line 11 plus line 12) and the Nuclear Power Plant Cost Recovery Clause amount of $151,491,402 (line 13). The total CCR jurisdictional amount to be recovered in 2013, including taxes is $731,449,407.

Q. What is the Nuclear Power Plant Cost Recovery amount to be included in the CCR for FPL's 2013?

A. The Nuclear Power Plant Cost Recovery amount to be included in FPL's 2013 CCR factors will be approved by the Commission at its November 20, 2012, Agenda Conference. After the Commission votes on November 20, 2012, FPL will submit to the Commission, with copies to all parties, its revised schedules showing the calculation of the 2013 CCR factors. Commission staff is granted administrative authority to verify that the schedules are consistent with the Commission's vote on November 20, 2012.

FPL has included a Nuclear Power Plant Cost Recovery amount of

$151,491,402 in the calculation of its 2013 CCR factors, as reflected in Exhibit WP-5 contained in the errata sheet of Winnie Powers filed in Docket No. 120009-EI on June 11, 2012. Per Order No. PSC-07-0240-FOF-EI, issued on March 20, 2007, the Commission adopted Rule 25-6.0423 to implement Section 366.93, Florida Statutes, which was enacted by the Florida Legislature in 2006. The Rule provides the mechanism to determine recoverable costs and provides for annual recovery of those costs through the CCR.

Q. Have you revised the methodology used to allocate projected kWh sales by rate class?

A. Yes. FPL's sales forecast is developed on a revenue class basis and must be allocated to the rate schedule level in order to calculate its CCR factors by rate schedule. In the past, FPL has allocated its projected kWh sales by rate schedule based on the relationship of each rate schedule's actual kWh sales to total retail kWh sales from the prior calendar year of actual sales.

For 2013, FPL is adopting the methodology used in its base rate proceedings, which allocates kWh sales by rate schedule based on the historical relationship between sales by rate schedule and sales by revenue class. These historical percentages are then applied to the forecast of sales by revenue class. The result is an estimate of sales by retail rate schedule for the appropriate time period.

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. Have you prepared a calculation of the proposed 2013 CCR factors by rate class?

A. Yes. Exhibit TJK-8, which is Appendix V to my testimony, presents this calculation on page 4.

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 2013 (cycle day 1, which will be January 2, 2013) and that they remain effective until cycle day 21 of December 2013, 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.

COST RECOVERY FOR FUKUSHIMA DAIICHI REGULATORY COMPLIANCE

Q. FPL witness Freeman describes the Orders and Requests for

Information (RFI) issued by the Nuclear Regulatory Commission (NRC) in the wake of the earthquake and tsunami that impacted the Fukushima Daiichi nuclear plant in Japan, as well as the steps FPL is taking and anticipates taking in response to those Orders and RFIs. Do you have a recommendation as to how FPL should recover incremental Fukushima compliance costs?

A. Yes. FPL believes it would be appropriate to recover prudently incurred incremental Fukushima compliance costs through either the FCR or CCR for the following reasons:

1. The Fukushima compliance costs will be incurred in order to allow FPL's nuclear plants to continue operating and saving FPL customers substantial fossil fuel costs.
2. FPL has projected a small level of Fukushima compliance costs in its 2013 Test Year revenue requirements in Docket No. 120015-EI. However, this base rate recovery does not address either (a) the increase in the compliance costs that FPL expects in 2013 and beyond; or (b) the high degree of uncertainty that exists as to the ultimate level of compliance costs. Both of these considerations make base rate recovery problematic and clause recovery appropriate.
3. In the absence of FCR or CCR recovery, FPL will have no opportunity to recover Fukushima compliance costs that are incremental to the small level that is reflected in the 2013 test year.

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

A. Yes, in Order No. PSC-01-2516-FOF-EI, issued in Docket No. 010001-EI on December 26, 2001, the Commission approved recovery of FPL's incremental post-9/11 power plant security costs associated with the events of September 11, 2001 through the fuel clause. As with the Fukushima compliance costs, the incremental post-9/11 power plant security costs related to unanticipated, substantial new regulatory requirements that emerged following a disaster (in that instance, the 9/11 terrorist attacks). Those costs were expected to be volatile over time, and they have proven to be so.

The Fukushima compliance costs were also completely unexpected prior to the earthquake and tsunami in 2011. As stated by FPL witness Freeman, the scope of the Fukushima compliance project is still evolving based on NRC communications. Therefore, the conceptual estimate range of \$17 - \$25 million per site is subject to significant change as more information is gathered at FPL and other nuclear plants.

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

> "We find that recovery of this incremental cost through the fuel clause is appropriate in this instance because there is a nexus between protection of FPL's nuclear generation facilities and

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

Recovery through either clause mechanism would be workable, but because the costs are related to operating generating capacity, the same logic that led the Commission to move the power plant security cost recovery to the CCR in 2002 would suggest that CCR recovery would be appropriate here as well.

Q. Has FPL included in its 2013 FCR or CCR any cost projections associated with NRC or other regulatory agency compliance requirements related to the Fukushima event?

A. No. FPL has not included any cost projections related to compliance resulting from the Fukushima event in its 2013 FCR or CCR factors due to the uncertainty of the magnitude of costs and timing requirements. Because FPL expects to begin incurring substantial Fukushima compliance costs in 2013, we believe it is important to have the Commission address the availability of clause recovery in this year's clause cycle. FPL requests approval to recover prudently incurred compliance costs beginning in 2013 resulting from the Fukushima event that are incremental to the amounts included in FPL's 2013 Test Year budget (see Freeman testimony). If approved by the Commission, incremental Fukushima compliance costs incurred in 2013 will be reflected in FPL's 2013 actual/estimated and/or final true-up filings.

PENDING BASE RATE CASE ISSUES IMPACTING FCR AND CCR CLAUSES

TOU Rider (RTR-1)

Q. Is FPL proposing any adjustments in its base rate proceeding that impact the FCR calculation?

A. Yes. As explained in the direct testimony of Renae B. Deaton filed in Docket No. 120015-EI, FPL is proposing to close its existing Residential TOU rate schedule RST-1 to new customers effective January 1, 2013, and replace it with a Residential TOU Rider ("RTR-1").

Q. Has FPL calculated 2013 FCR factors for the proposed RTR-1 rider?

A. Yes. FPL has calculated on-peak and off-peak FCR factors for the proposed RTR-1 rider for the January 2013 through May 2013

(Appendix II, page 9) and June 2013 through December 2013 (Appendix III, page 4) periods as well as for the January 2013 through December 2013 period based on the traditional factor calculation methodology (Appendix IV, page 4).

Q. How were the FCR factors for the RTR-1 rider calculated?

A. The FCR factors for the RTR-1 rider represent the difference between the on-peak and off-peak RST-1 FCR factors for the RST-1 rate and the average levelized FCR factor for the RS-1 rate class.

Recovery of Incremental Power Plant Security Costs

Q. Should FPL make an adjustment to transfer incremental security costs from the CCR to base rates?

A. No. FPL believes the CCR is the most appropriate mechanism for recovery of post 9/11 security costs due to the volatile nature of these types of expenses. For example, since 2007, FPL has experienced fluctuations in incremental post 9/11 security costs of up to 40 percent. Additionally, the vast majority of these costs are related to nuclear generation facilities and there is a nexus between protecting these facilities and the fuel cost savings that result from the continued operation of these facilities.

Payroll Loadings for Incremental Power Plant Security Costs

Q. Is FPL proposing any adjustments in its base rate proceeding that impact the CCR calculation?

A. Yes. Currently, FPL has incremental security employee payroll dollars flowing through the CCR; however, payroll related costs (i.e. Federal and State Unemployment Taxes, Pension & Welfare), which vary directly with payroll dollars, are still recovered in base rates. Beginning in 2013, FPL is requesting to move $444,000 of payroll loadings associated with incremental security from base rates to the CCR.

Q. Has FPL included this proposed adjustment in the calculation of its 2013 CCR factors?

A. No, FPL has not included the $444,000 of payroll loadings associated with incremental security in the calculation of its 2013 CCR factors. Should the Commission approve this adjustment in Docket No. 120015-EI, FPL will reflect this adjustment in the 2013 true-up process.

Recovery of WCEC-3 Non-Fuel Revenue Requirements

Q. Have you provided a calculation of 2013 CCR factors by rate class including an adjustment to recover the projected non-fuel revenue requirements associated with WCEC-3 for the period

January 2013 through December 2013?

A. Yes. In FPL's rate petition filed in Docket No. 120015-E, FPL proposes to recover WCEC-3 revenue requirements through base rates. However, the Proposed Settlement Agreement would provide for FPL to recover the WCEC-3 revenue requirements through the CCR. At the time that I prepared my testimony, the Commission had not ruled on the joint motion. Accordingly, Exhibit TJK-8, which is Appendix V to my testimony, shows the calculation of 2013 CCR factors including the projected non-fuel revenue requirements associated with WCEC-3 for the period January 2013 through December 2013. The 2013 CCR factors appearing in Appendix V should be approved for application to customer bills commencing in January 2013 if the Commission approves the Proposed Settlement Agreement. In addition, in the event that the Commission approves the Proposed Settlement Agreement, FPL has included In Appendix VII the affidavit of Kim Ousdahl that presents the 2013 non-fuel revenue requirements of $166.4 million.

<u>**Proposed 2013 Residential 1,000 kWh Bill**</u>

Q. **What is FPL's proposed preliminary residential 1,000 kWh bill for the period beginning January, 2013?**

A. Based on FPL's primary requests in its cost recovery clause filings, its preliminary residential 1,000 kWh bill for January 2013 through May

2013 is $96.55. Of this amount, the base rate charges are $52.44, the FCR charge is $27.89, the CCR charge is $7.98, the Environmental charge is $2.29, the Conservation charge is $2.33, the Storm charge is $1.21 and the amount of Gross Receipts Tax is $2.41. Once CCEC becomes operational, which is expected to be on June 1, 2013, FPL's base rate charges will increase to $54.30 and its FCR charge will decrease to $26.33. FPL's preliminary Residential 1,000 kWh bill for the period June 2013 through December 2013, including an increase in the amount of Gross Receipts Tax of $0.01, will be $96.86, which is an increase of $0.31, from its January 2013 through May 2013 bill. FPL's proposed preliminary Residential 1,000 kWh bill for 2013 are provided on Schedule E-10, which is page 8 of Exhibit TJK-6, Appendix III.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

FUEL COST RECOVERY

EXHIBIT GJY-4

DOCKET NO. 120001-EI

PAGES 1-4

AUGUST 31, 2012

APPENDIX I

FUEL COST RECOVERY

TABLE OF CONTENTS

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2013

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
1.0% Sulfur Grade ($/Bbl)	103.18	103.18	103.18	102.43	102.43	102.43	101.68	101.68	101.68	100.63	100.91	101.18
1.0% Sulfur Grade ($/mmBtu)	16.12	16.12	16.12	16.00	16.00	16.00	15.89	15.89	15.89	15.72	15.77	15.81
0.7% Sulfur Grade ($/Bbl)	109.73	109.73	109.73	108.48	108.48	108.48	106.65	106.93	106.93	107.21	107.78	108.62
0.7% Sulfur Grade ($/mmBtu)	17.15	17.15	17.15	16.95	16.95	16.95	16.66	16.71	16.71	16.75	16.84	16.97
Light Oil	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
0.05% Sulfur Grade ($/Bbl)	134.67	134.45	133.78	132.87	133.81	133.31	133.31	133.41	133.54	133.66	133.79	133.87
0.05% Sulfur Grade ($/mmBtu)	23.10	23.06	22.95	22.79	22.95	22.87	22.87	22.88	22.91	22.93	22.95	22.96
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	1,304,000	1,304,000	1,304,000	1,304,000	1,304,000	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)	125,000	125,000	125,000	125,000	100,000	55,000	55,000	55,000	55,000	100,000	125,000	125,000
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)	2,020,000	2,020,000	2,020,000	2,109,000	2,149,000	2,104,000	2,054,000	2,054,000	2,054,000	2,034,000	2,020,000	2,020,000
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
**Note: The SESH and Transco 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 ($/mmBtu)	3.68	3.70	3.68	3.75	3.78	3.82	3.87	3.89	3.90	3.93	3.94	4.16
Firm Gulfstream ($/mmBtu)	3.61	3.63	3.61	3.67	3.70	3.75	3.79	3.82	3.82	3.85	3.87	4.08
Non-Firm FGT ($/mmBtu)	4.29	4.31	4.29	4.35	4.38	4.43	4.47	4.50	4.50	4.53	4.55	4.77
Non-Firm Gulfstream ($/mmBtu)	4.21	4.22	4.20	4.27	4.30	4.34	4.39	4.41	4.42	4.44	4.46	4.68
Coal	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Scherer ($/mmBtu)	2.51	2.51	2.52	2.52	2.53	2.53	2.53	2.55	2.54	2.53	2.52	2.53
SJRPP ($/mmBtu)	3.56	3.57	3.60	3.61	3.61	3.61	3.61	3.61	3.66	3.66	3.65	3.65

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2013

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral Energy Center	0.6	4.5	3.3	11/12/13 - 11/18/13			
Cutler 5	0.0	0.0	0.0	NONE			
Cutler 6	0.0	0.0	0.0	NONE			
Lauderdale 4	0.9	4.5	4.9	3/30/13 - 4/16/13			
Lauderdale 5	0.8	4.5	9.0	11/16/13 - 12/18/13			
Lauderdale GTs	1.0	7.2	0.0	NONE			
Fort Myers 2 CC	0.5	4.5	13.6	9/4/13 - 11/15/13 *	10/19/13 - 11/2/13	10/19/13 - 10/25/13 *	10/26/13 - 11/8/13 *
Ft. Myers 3	0.6	4.3	6.7	3/2/13 - 3/19/13 *	3/2/13 - 4/1/13 *		
Ft. Myers GTs	0.3	1.3	1.4	3/2/13 - 3/6/13 *			
Manatee 1	0.1	2.6	57.3	1/1/13 - 8/12/13			
Manatee 2	0.5	4.5	6.0	3/2/13 - 3/23/13			
Manatee 3	0.6	4.5	1.9	2/11/13 - 3/15/13 *			
Martin 1	0.2	2.2	53.4	6/20/13 - 12/31/13			
Martin 2	0.4	4.5	0.0	NONE			
Martin 3	0.6	4.1	16.7	10/19/13 - 12/18/13			
Martin 4	0.7	4.5	6.5	4/6/13 - 5/15/13 *	5/18/13 - 5/24/13 *		
Martin 8 CC	0.5	4.5	2.4	3/9/13 - 3/22/13 *	3/23/13 - 4/5/13 *	10/5/13 - 10/11/13 *	
Port Everglades 1	0.0	0.0	0.0	NONE			
Port Everglades 2	0.0	0.0	0.0	NONE			
Port Everglades 3	0.0	0.4	0.0	NONE			
Port Everglades 4	0.0	0.4	0.0	NONE			
Port Everglades GTs	1.9	9.7	0.0	NONE			
Putnam 1	0.5	4.5	12.6	2/19/13 - 5/5/13 *	3/16/13 - 3/26/13	11/4/14 - 11/8/13 *	
Putnam 2	0.5	4.5	14.0	3/16/13 - 3/26/13	3/16/13 - 3/30/13 *	7/8/13 - 9/20/13 *	
Sanford 3	0.0	0.0	0.0	NONE			
Sanford 4 CC	0.5	3.7	21.1	2/23/13 - 5/10/13			
Sanford 5 CC	0.6	4.5	4.6	2/9/13 - 2/15/13 *	5/6/13 - 6/4/13 *	5/27/13 - 6/2/13 *	10/1/13 - 10/30/13 *
Turkey Point 1	0.4	4.1	16.4	5/11/13 - 7/9/13			
Turkey Point 2	0.0	0.0	0.0	NONE			
Turkey Point 3	1.1	1.1	10.4	10/21/13 - 11/28/13			
Turkey Point 4	1.0	1.0	20.0	1/1/13 - 3/15/13			
Turkey Point 5	0.5	4.5	1.9	7/13/13 - 7/19/13 *	7/20/13 - 7/26/13 *	7/27/13 - 8/2/13 *	8/3/13 - 8/9/13 *
St. Lucie 1	1.1	1.1	10.4	9/5/13 - 10/13/13			
St. Lucie 2	1.2	1.2	0.0	NONE			
SJRPP 1	1.4	4.5	9.9	3/9/13 - 4/13/13			
SJRPP 2	1.5	4.5	0.0	NONE			
Scherer 4	1.7	4.5	0.0	NONE			
West County 1	0.8	4.5	4.4	3/16/13 - 3/31/13 *	3/21/13 - 4/5/13 *	3/25/13 - 3/31/13	3/25/13 - 4/9/13 *
West County 2	0.8	4.5	0.0	NONE			
West County 3	0.9	4.5	7.4	11/9/13 - 12/5/13 *	11/16/13 - 12/12/13 *	11/24/13 - 12/5/13	11/24/13 - 12/20/13 *

* Partial Planned Outage

APPENDIX II
FUEL COST RECOVERY
2013 E-SCHEDULES

FOR THE PERIOD JANUARY 2013 THROUGH MAY 2013

TJK-5
DOCKET NO. 120001-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ____________
PAGES 1-79
AUGUST 31, 2012

APPENDIX II
FUEL COST RECOVERY
2013 E SCHEDULES
TABLE OF CONTENTS

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

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH MAY 2013

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$2,836,155,287	102,655,546	2.7628
2	Cape Canaveral Energy Center (CCEC) Savings	$100,908,000	102,655,546	0.0983
3	Nuclear Fuel Disposal Costs (E2)	$24,785,825	26,472,098	0.0936
4	Fuel Cost of Sales to CKW (E2)	($3,946,028)	(112,401)	3.5107
5	TOTAL COST OF GENERATED POWER	$2,957,903,084	102,543,145	2.8845
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$186,831,284	5,264,132	3.5491
7	Energy Cost of Economy Purchases (E9)	$42,063,927	1,060,000	3.9683
8	Payments to Qualifying Facilities (E8)	$143,346,388	3,209,622	4.4661
9	TOTAL COST OF PURCHASED POWER	$372,241,599	9,533,754	3.9045
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)		112,076,899	
11	Fuel Cost of Economy Sales (E6)	($16,352,230)	(413,400)	3.9555
12	Gain from Off-System Sales (E6)	($4,238,116)	N/A	N/A
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,340,025)	(563,881)	0.7697
14	TOTAL FUEL COST AND GAINS OF POWER SALES	($24,930,371)	(977,281)	2.5510
15	Net Inadvertent Interchange	$0	0	
16	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 9 + 14)	$3,305,214,313	111,099,618	2.9750
17	Net Unbilled Sales (1)	($52,223,696)	(1,755,418)	(0.0496)
18	Company Use (1)	$9,915,643	333,299	0.0094
19	T & D Losses (1)	$214,838,930	7,221,475	0.2040
20	SYSTEM MWH SALES (Excl sales to CKW)	$3,305,214,313	105,300,262	3.1388
21	Wholesale MWH Sales (Excl sales to CKW)	$65,909,940	2,099,818	3.1388
22	Jurisdictional MWH Sales	$3,239,304,373	103,200,444	3.1388
23	Jurisdictional Loss Multiplier	$2,623,837		1.00081
24	Jurisdictional MWH Sales Adjusted for Line Losses	$3,241,928,210	103,200,444	3.1414
25	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	($48,085,296)	103,200,444	(0.0466)
26	TOTAL JURISDICTIONAL FUEL COST	$3,193,842,914	103,200,444	3.0948
27	Revenue Tax Factor	$2,299,567		1.00072
28	Fuel Factor Adjusted for Taxes	$3,196,142,481	103,200,444	3.0970
29	GPIF (2)	$7,703,912	103,200,444	0.0075
30	Fuel Factor including GPIF (Line 28 + Line 29)	$3,203,846,393	103,200,444	3.1045
31	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.105
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				

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

SCHEDULE E1-A

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.		Annual Total
1	Actual/Estimated over/(under) recovery (1)	$99,206,321
2	Final over/(under) recovery (2)	($51,121,025)
3	Total over/(under) recovery to be included in projected period (3)	$48,085,296
4		
5	Total Jurisdictional Sales (MWH)	103,200,444
6		
7	True-Up Factor (cents/kWh)	0.0466
8		
9	(1) Actual/Estimated over/(under) recovery for January 2012 - December 2012	
10	(2) Final over/(under) recovery for January 2011 - December 2011	
11	(3) Projected Period January 2013 - December 2013 (Schedule E1, Line 25)	
12		
13	Note: Totals may not add due to rounding.	
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REVISED 8.31.2012 SCHEDULE: E1-B

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF: JANUARY 2012 THROUGH DECEMBER 2012

	(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	12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3)	$237,588,651	$223,690,078	$248,031,014	$243,673,298	$279,307,523	$305,420,731	$338,696,681	$353,289,608	$299,220,675	$277,260,393	$235,211,925	$240,136,472	$3,281,527,049
3	Nuclear Fuel Disposal Costs (Per A2)	$1,533,571	$1,331,150	$1,025,644	$986,906	$1,231,819	$1,465,162	$1,379,200	$1,358,655	$1,611,874	$1,665,602	$1,272,159	$1,733,217	$16,594,958
4	Scherer Coal Cars Depreciation & Return	($47,585)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($47,585)
5	Fuel Cost of Power Sold (Per A6)	($1,280,730)	($1,239,704)	($385,357)	($330,142)	($334,747)	($907,994)	($665,514)	($2,297,828)	($1,201,397)	($1,629,131)	($2,066,955)	($2,308,784)	($14,648,284)
6	Gains from Off-System Sales (Per A6)	($661,721)	($656,059)	($169,879)	($232,884)	($82,452)	($222,303)	($134,690)	($280,100)	($119,900)	($220,200)	($513,400)	($657,300)	($3,950,890)
7	Fuel Cost of Purchased Power (Per A7)	$6,158,434	$2,629,790	$12,566,896	$23,732,423	$21,448,226	$18,503,612	$27,438,159	$25,867,051	$21,212,533	$19,774,284	$12,807,971	$12,578,477	$204,717,856
8	Energy Payments to Qualifying Facilities (Per A8)	$7,741,501	$3,950,202	$9,383,765	$6,093,903	$9,058,931	$9,876,552	$13,928,525	$18,571,111	$16,260,211	$14,844,281	$12,191,134	$11,627,271	$133,527,387
9	Energy Cost of Economy Purchases (Per A9)	($306,696)	$465,870	$1,978,339	$4,745,050	$4,951,403	$1,480,551	$3,800,890	$8,314,400	$5,129,400	$1,473,150	$376,600	$137,500	$32,546,458
10	Total Fuel Costs & Net Power Transactions	$250,725,425	$230,171,327	$272,430,422	$278,668,552	$315,580,702	$335,616,311	$384,443,252	$404,822,897	$342,113,396	$313,168,379	$259,279,434	$263,246,852	$3,650,266,950
11	**Adjustments to Fuel Cost**													
12	Sales to City of Key West (CKW)	($670,275)	($630,502)	($579,079)	($615,288)	($651,163)	($735,092)	($805,703)	($921,231)	($945,282)	($854,908)	($812,272)	($697,304)	($8,918,099)
13	Energy Imbalance Fuel Revenues	$19,819	($2,926)	($24,904)	($39,133)	($37,543)	($71,123)	$1,283,800	$0	$0	$0	$0	$0	$1,127,991
14	Inventory Adjustments	($53,798)	$11,078	$205,134	$71,452	($191,198)	($331,618)	$103,354	$0	$0	$0	$0	$0	($185,596)
15	Non Recoverable Oil/Tank Bottoms	($64,362)	($102,828)	$74,075	$0	($16,447)	$0	$549,227	$0	$0	$0	$0	$0	$439,665
16	Adjusted Total Fuel Costs & Net Power Transactions	$249,956,810	$229,446,148	$272,105,649	$278,085,583	$314,684,352	$334,478,478	$385,573,930	$403,901,666	$341,168,114	$312,313,471	$258,467,162	$262,549,548	$3,642,730,911
17	**Jurisdictional kWh Sales**													
18	Jurisdictional kWh Sales	7,840,404,689	6,965,004,441	7,465,369,459	8,057,607,586	8,207,468,174	9,555,068,717	9,956,736,569	9,896,118,254	9,513,044,327	8,905,221,052	7,980,791,176	7,822,284,715	102,165,119,159
19	Sale for Resale (excluding CKW) [1]	141,688,445	145,961,604	143,638,859	162,448,949	157,386,681	185,257,965	184,819,920	207,650,703	212,816,529	191,906,910	184,834,294	139,877,436	2,058,288,295
20	Sub-Total Sales (excluding CKW)	7,982,093,134	7,110,966,045	7,609,008,318	8,220,056,535	8,364,854,855	9,740,326,682	10,141,556,489	10,103,768,957	9,725,860,856	9,097,127,962	8,165,625,470	7,962,162,151	104,223,407,454
21														
22	**Jurisdictional % of Total Sales (Line 18/20)**	98.22492%	97.94737%	98.11225%	98.02375%	98.11848%	98.09803%	98.17760%	97.94482%	97.81185%	97.89047%	97.73643%	98.24322%	98.02512%
23	**True-up Calculation**													
24	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$284,993,002	$250,837,229	$269,729,572	$290,359,370	$297,287,803	$349,928,235	$366,419,368	$363,816,054	$349,732,912	$327,387,194	$293,401,906	$287,574,652	$3,731,467,296
25	**Fuel Adjustment Revenues Not Applicable to Period**													
26	Prior Period True-up (Collected)/Refunded This Period [2]	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($51,800,406)
27	GPIF, Net of Revenue Taxes [3]	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($6,566,718)
28	Jurisdictional Fuel Revenues Applicable to Period	$280,129,075	$245,973,302	$264,865,645	$285,495,443	$292,423,876	$345,064,308	$361,555,441	$358,952,127	$344,868,985	$322,523,267	$288,537,979	$282,710,725	$3,673,100,172
29	Adjusted Total Fuel Costs & Net Power Transactions	$249,956,810	$229,446,148	$272,105,649	$278,085,583	$314,684,352	$334,478,478	$385,573,930	$403,901,666	$341,168,114	$312,313,471	$258,467,162	$262,549,548	$3,642,730,911
30	Jurisdictional Sales % of Total kWh Sales (Line 22)	98.22492%	97.94737%	98.11225%	98.02375%	98.11848%	98.09803%	98.17760%	97.94482%	97.81185%	97.89047%	97.73643%	98.24322%	98.02512%
31	Juris. Total Fuel Costs & Net Power Trans. (Line 29xLine30x1.00085)	$245,728,568	$224,927,494	$267,195,898	$272,821,618	$309,025,952	$328,395,697	$378,868,996	$395,937,020	$333,986,491	$305,984,991	$252,831,301	$258,156,377	$3,573,860,404
32	True-up Provision for the Month - Over/(Under) Recovery (Line 28 - Line 31)	$34,400,507	$21,045,808	($2,330,253)	$12,673,825	($16,602,076)	$16,668,611	($17,313,555)	($36,984,893)	$10,882,494	$16,538,276	$35,706,678	$24,554,348	$99,239,770
33	Interest Provision for the Month	($5,223)	($4,936)	($3,154)	($2,483)	($2,712)	($2,077)	($1,843)	($5,065)	($6,157)	($3,905)	($100)	$4,206	($33,449)
34	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($51,800,406)	($13,088,421)	$12,269,151	$14,252,444	$31,240,487	$18,952,400	$39,935,635	$26,936,938	($5,736,319)	$9,456,717	$30,307,789	$70,331,067	($51,800,406)
35	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)
36	Prior Period True-up Collected/(Refunded) This Period [2]	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$51,800,406
37	End of Period Net True-up Amount Over/(Under) Recovery (Lines 32 through 36)	($64,209,447)	($38,851,874)	($36,868,581)	($19,880,538)	($32,168,625)	($11,185,391)	($24,184,087)	($56,857,345)	($41,664,307)	($20,813,236)	$19,210,042	$48,085,297	$48,085,296
38														
39	[1] Billed KWH includes all wholesale customers except CKW.													
40	[2] Prior Period 2010/2011 Net True-up.													
41	[3] Generation Performance Incentive Factor is (($6,571,449/12) x 99.9280%) - See Order No. PSC-11-0579-FOF-EI.													
42	[4] Deferred 2011 Final True-up.													
43														
44														
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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Annual Total
1. TOTAL AMOUNT OF ADJUSTMENTS	($40,381,384)
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$7,703,912
B. TRUE-UP (OVER)/UNDER RECOVERED	($48,085,296)
2. TOTAL JURISDICTIONAL SALES (MWH)	103,200,444
3. ADJUSTMENT FACTORS (cents/kWh)	(0.0391)
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0075
B. TRUE-UP FACTOR	(0 0466)

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF SEASONALLY DIFFERENTIATED TIME OF USE MULTIPLIERS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH MAY 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.		Nov - 2013	Dec - 2013	Jan - 2013	Feb - 2013	Mar - 2013	Total
1	Winter (January - March / November - December)						
2	*On-Peak Period*						
3	System MWH Requirements	2,052,131	2,244,211	2,643,396	1,988,171	2,037,467	10,965,376
4	Marginal Cost	$83,131,827	$76,056,311	$129,632,140	$67,120,653	$75,121,408	$431,062,339
5	Average Marginal Cost (¢/kWh)	4.051	3.389	4.904	3.376	3.687	3.931
6	*Off-Peak Period*						
7	System MWH Requirements	6,188,038	6,266,367	5,785,728	5,558,578	6,403,025	30,201,736
8	Marginal Cost	$202,534,484	$193,317,422	$174,439,699	$153,694,682	$208,994,736	$932,981,023
9	Average Marginal Cost (¢/kWh)	3.273	3.085	3.015	2.765	3.264	3.089
10	*Total Period*						
11	System MWH Requirements	8,240,169	8,510,578	8,429,124	7,546,749	8,440,492	41,167,112
12	Marginal Cost	$285,666,311	$269,373,733	$304,071,839	$220,815,335	$284,116,144	$1,364,043,361
13	Average Marginal Cost (¢/kWh)	3.467	3.165	3.607	2.926	3.366	3.313
14							
15	Winter Multiplier						
16	*On-Peak Period*						
17	Marginal Fuel Cost Weighting Multiplier						1.186
18	*Off-Peak Period*						
19	Marginal Fuel Cost Weighting Multiplier						0.932
20	*Average*						
21	Marginal Fuel Cost Weighting Multiplier						1.000
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23							
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25	Note: Totals may not add due to rounding.						
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FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF SEASONALLY DIFFERENTIATED TIME OF USE MULTIPLIERS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH MAY 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.		Apr - 2013	May - 2013	Jun - 2013	Jul - 2013	Aug - 2013	Sep - 2013	Oct - 2013	Total
1	Summer (April - October)								
2	*On-Peak Period*								
3	System MWH Requirements	2,951,611	3,455,266	3,170,988	3,869,007	3,839,288	3,475,006	3,414,498	24,175,664
4	Marginal Cost	$136,748,138	$202,444,035	$128,266,465	$291,761,818	$405,352,027	$452,758,532	$282,378,985	$1,899,709,998
5	Average Marginal Cost (¢/kWh)	4.633	5.859	4.045	7.541	10 558	13.029	8.270	7.858
6	*Off-Peak Period*								
7	System MWH Requirements	5,646,413	6,446,268	7,108,335	7,326,112	7,334,374	6,905,020	6,377,813	47,144,335
8	Marginal Cost	$167,416,145	$230,131,768	$231,873,888	$274,802,461	$318,971,925	$325,226,442	$256,196,748	$1,804,619,377
9	Average Marginal Cost (¢/kWh)	2.965	3.570	3.262	3.751	4.349	4.710	4.017	3.828
10	*Total Period*								
11	System MWH Requirements	8,598,024	9,901,534	10,279,323	11,195,119	11,173,662	10,380,026	9,792,311	71,319,999
12	Marginal Cost	$304,164,283	$432,575,803	$360,140,352	$566,564,279	$724,323,952	$777,984,974	$538,575,733	$3,704,329,376
13	Average Marginal Cost (¢/kWh)	3.538	4.369	3.504	5.061	6.482	7.495	5.500	5.194
14									
15	Summer Multiplier								
16	*On-Peak Period*								
17	Marginal Fuel Cost Weighting Multiplier								1.513
18	*Off-Peak Period*								
19	Marginal Fuel Cost Weighting Multiplier								0.737
20	*Average*								
21	Marginal Fuel Cost Weighting Multiplier								1.000
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23									
24									
25	Note: Totals may not add due to rounding.								
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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 2013 THROUGH MAY 2013

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.		Jun - 2013	Jul - 2013	Aug - 2013	Sep - 2013	Total
1	June - September					
2	*On-Peak Period*					
3	System MWH Requirements	1,446,361	1,760,836	1,780,523	1,593,380	6,581,100
4	Marginal Cost	$58,765,647	$129,439,054	$212,362,978	$216,189,798	$616,757,478
5	Average Marginal Cost (¢/kWh)	4.063	7.351	11.927	13.568	9.372
6	*Off-Peak Period*					
7	System MWH Requirements	8,832,962	9,434,283	9,393,139	8,786,646	36,447,030
8	Marginal Cost	$298,730,775	$416,240,566	$489,100,748	$522,102,505	$1,726,174,594
9	Average Marginal Cost (¢/kWh)	3.382	4.412	5.207	5.942	4.736
10	*Total Period*					
11	System MWH Requirements	10,279,323	11,195,119	11,173,662	10,380,026	43,028,130
12	Marginal Cost	$357,496,422	$545,679,620	$701,463,726	$738,292,304	$2,342,932,072
13	Average Marginal Cost (¢/kWh)	3.478	4.874	6.278	7.113	5.445
14						
15	June - September Multiplier					
16	*On-Peak Period*					
17	Marginal Fuel Cost Weighting Multiplier					1.721
18	*Off-Peak Period*					
19	Marginal Fuel Cost Weighting Multiplier					0.870
20	*Average*					
21	Marginal Fuel Cost Weighting Multiplier					1.000
22						
23						
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 2013 THROUGH MAY 2013

(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	3.105	1.00220	2.789
A	RS-1 all additional kWh	3.105	1.00220	3.789
A	GS-1, SL-2, GSCU-1, WIES-1	3.105	1.00220	3 112
A-1	SL-1, OL-1, PL-1 (1)	2.831	1 00220	2.837
B	GSD-1	3.105	1.00211	3.112
C	GSLD-1, CS-1	3.105	1.00109	3.108
D	GSLD-2, CS-2, OS-2, MET	3.105	0.99062	3.076
E	GSLD-3, CS-3	3.105	0.96131	2.985

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

Note: Totals may not add due to rounding.

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH MAY 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GROUPS	RATE SCHEDULE	JANUARY - MARCH / NOVEMBER - DECEMBER			APRIL - OCTOBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RST-1, GST-1 On-Peak	3.683	1.00220	3.691	4.698	1.00220	4.708
	RST-1, GST-1 Off-Peak	2.894	1.00220	2.900	2.288	1.00220	2.293
A	RTR-1 On-Peak	-	-	0.571	-	-	1.586
	RTR-1 Off-Peak	-	-	(0.218)	-	-	(0.824)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	3.683	1.00211	3.691	4.698	1.00211	4.708
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.894	1.00211	2.900	2.288	1.00211	2.293
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	3.683	1.00109	3.687	4.698	1.00109	4.703
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.894	1.00109	2.897	2.288	1.00109	2 290
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	3.683	0.99139	3.651	4.698	0.99139	4.658
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.894	0.99139	2.869	2.288	0.99139	2.268
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	3.683	0.96131	3.540	4.698	0.96131	4.516
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.894	0.96131	2.782	2.288	0.96131	2.199
F	CILC-1(D), ISST-1(D) On-Peak	3.683	0.99102	3.650	4.698	0.99102	4.656
	CILC-1(D), ISST-1(D) Off-Peak	2.894	0.99102	2.868	2.288	0.99102	2.267

Note: Totals may not add due to rounding.

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH MAY 2013

(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	5.344	1.00211	5.355
	GSD(T)-1 Off-Peak	2.701	1.00211	2 707
C	GSLD(T)-1 On-Peak	5.344	1.00109	5.350
	GSLD(T)-1 Off-Peak	2.701	1.00109	2.704
D	GSLD(T)-2 On-Peak	5.344	0.99139	5.298
	GSLD(T)-2 Off-Peak	2.701	0.99139	2.678

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 3 and Page 2 of 3.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
2011 ACTUAL 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	54,730,610	1.062378	58,144,584	0.941285	3,413,974	
3	**Total**	54,730,610	1.062378	58,144,584	0.941285	3,413,974	1.00220
4							
5	CILC-1D						
6	Primary	1,059,945	1.029562	1,091,279	0.971287	31,334	
7	Secondary	1,873,488	1.062378	1,990,352	0.941285	116,864	
8	**Total**	2,933,433	1.050520	3,081,631	0.951909	148,198	0.99102
9							
10	CILC-1G						
11	Primary	692	1.029562	713	0.971287	20	
12	Secondary	176,662	1.062378	187,682	0.941285	11,020	
13	**Total**	177,354	1.062250	188,394	0.941398	11,040	1.00208
14							
15	CILC-1T						
16	Transmission	1,359,103	1.019027	1,384,962	0.981329	25,859	
17	**Total**	1,359,103	1.019027	1,384,962	0.981329	25,859	0.96131
18							
19	GS(T)-1						
20	Secondary	5,706,847	1.062378	6,062,828	0.941285	355,980	
21	**Total**	5,706,847	1.062378	6,062,828	0.941285	355,980	1.00220
22							
23	GSCU-1						
24	Secondary	35,379	1.062378	37,586	0.941285	2,207	
25	**Total**	35,379	1.062378	37,586	0.941285	2,207	1.00220
26							
27	GSD(T)-1						
28	Primary	74,416	1.029562	76,616	0.971287	2,200	
29	Secondary	24,352,165	1.062378	25,871,200	0.941285	1,519,034	
30	**Total**	24,426,581	1.062278	25,947,815	0.941373	1,521,234	1.00211
31							
32	GSLD(T)-1						
33	Primary	385,427	1.029562	396,821	0.971287	11,394	
34	Secondary	10,375,663	1.062378	11,022,874	0.941285	647,211	
35	**Total**	10,761,090	1.061202	11,419,694	0.942327	658,605	1.00109
36							
37	GSLD(T)-2						
38	Primary	828,564	1.029562	853,057	0.971287	24,494	
39	Secondary	1,544,458	1.062378	1,640,798	0.941285	96,340	
40	**Total**	2,373,022	1.050920	2,493,856	0.951547	120,834	0.99139
41							
42	GSLD(T)-3						
43	Transmission	213,906	1.019027	217,976	0.981329	4,070	
44	**Total**	213,906	1.019027	217,976	0.981329	4,070	0.96131
45							
46	MET						
47	Primary	82,118	1.029562	84,546	0.971287	2,428	
48	**Total**	82,118	1.029562	84,546	0.971287	2,428	0.97124
49							
50	OL-1						
51	Secondary	101,409	1.062378	107,735	0.941285	6,326	
52	**Total**	101,409	1.062378	107,735	0.941285	6,326	1.00220
53							
54	OS-2						
55	Primary	12,793	1.029562	13,171	0.971287	378	

FLORIDA POWER & LIGHT COMPANY
2011 ACTUAL 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**	12,793	1.029562	13,171	0.971287	378	0.97124
2							
3	SL-1						
4	Secondary	507,327	1.062378	538,973	0.941285	31,646	
5	**Total**	507,327	1.062378	538,973	0.941285	31,646	1.00220
6							
7	SL-2						
8	Secondary	31,219	1.062378	33,167	0 941285	1,947	
9	**Total**	31,219	1.062378	33,167	0.941285	1,947	1.00220
10							
11	SST-DST						
12	Primary	6,680	1.029562	6,877	0.971287	197	
13	**Total**	6,680	1.029562	6,877	0.971287	197	0.97124
14							
15	SST-TST						
16	Transmission	98,770	1.019027	100,649	0.981329	1,879	
17	**Total**	98,770	1.019027	100,649	0.981329	1,879	0.96131
18							
19	Total Retail						
20	**Total**	103,557,642	1.060901	109,864,444	0.942595	6,306,802	1.00081
21							
22	FKEC						
23	Transmission	474,802	1.019027	483,836	0.981329	9,034	
24	**Total**	474,802	1.019027	483,836	0.981329	9,034	0.96131
25							
26	MDCSWM						
27	Transmission	492,865	1.019027	502,243	0.981329	9,378	
28	**Total**	492,865	1.019027	502,243	0.981329	9,378	0.96131
29							
30	LCEC						
31	Transmission	1,196,267	1.019027	1,219,028	0.981329	22,761	
32	**Total**	1,196,267	1.019027	1,219,028	0.981329	22,761	0.96131
33							
34	Total Wholesale						
35	**Total**	2,163,934	1.019027	2,205,107	0 981329	41,172	0.96130
36							
37	Total Company						
38	**Total**	105,721,576	1.060044	112,069,550	0.943357	6,347,975	1.00000
39							
40	Company Use						
41	**Total**	142,951	1.062378	151,868	0.941285	8,917	1.00220
42							
43	Total FPL						
44	**Total**	105,864,527	1.060047	112,221,418	0.943354	6,356,892	1.00000
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FLORIDA POWER & LIGHT COMPANY
2011 ACTUAL 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	24,426,581	1.062278	25,947,815	0.941373	1,521,234	1.00211
2	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,761,090	1.061202	11,419,694	0 942327	658,605	1.00109
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,373,022	1.050920	2,493,856	0 951547	120,834	0.99139
4	GSLD3/GSLDT3/CS3/CST3	213,906	1.019027	217,976	0 981329	4,070	0.96131
5	CILC D/CILC G	3,110,787	1 051189	3,270,025	0.951304	159,238	0.99165
6	OL1/SL1/PL1	608,736	1.062378	646,707	0.941285	37,972	1.00220
7	SL2, GSCU1	66,598	1.062378	70,753	0.941285	4,154	1.00220
8	GSD-1/HLFT-1/SDTR-1/CILC-1G	24,603,935	1.062278	26,136,209	0 941374	1,532,274	1.00211
9	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	2,467,934	1.050098	2,591,573	0.952292	123,639	0.99062
10	GSLD-3/CS-3/CILC-1T	1,573,009	1.019027	1,602,938	0.981329	29,929	0.96131
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FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH MAY 2013

	(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	$220,073,886	$191,301,440	$208,965,847	$210,949,450	$238,217,766	$248,780,450	$275,371,825	$280,921,295	$281,678,050	$257,990,705	$211,279,250	$210,625,323	$2,836,155,287
2	Nuclear Fuel Disposal	1,828,715	1,651,746	1,922,853	2,221,055	2,350,681	2,274,853	2,350,681	2,350,681	1,714,889	1,894,975	1,824,443	2,400,253	24,785,825
3	CCEC Fuel Savings	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	100,908,000
4	Fuel Cost of Power Sold	(3,339,944)	(2,366,973)	(1,338,864)	(1,096,233)	(1,093,097)	(1,175,923)	(1,321,377)	(2,093,887)	(936,056)	(1,417,854)	(2,280,603)	(2,231,444)	(20,692,255)
5	Gain on Economy Sales	(888,156)	(641,976)	(232,510)	(192,428)	(132,846)	(207,652)	(179,359)	(276,415)	(117,119)	(215,230)	(510,215)	(644,210)	(4,238,116)
6	Fuel Cost of Purchased Power	13,244,662	10,153,704	12,860,712	13,055,056	17,778,662	16,552,796	19,498,273	19,538,400	20,254,344	19,378,907	13,329,265	11,186,503	186,831,284
7	Qualifying Facilities	11,500,528	9,984,528	11,627,530	5,533,529	13,488,533	11,817,531	14,231,534	16,060,539	16,229,540	12,395,536	9,378,531	11,098,529	143,346,388
8	Energy Cost of Economy Purchases	16,794	348,000	1,350,422	4,296,600	6,104,025	2,225,800	3,679,200	12,227,259	9,682,750	1,553,050	416,727	163,300	42,063,927
9	Fuel Cost of Sales to CKW	(598,528)	(601,104)	(605,453)	(678,375)	(700,161)	(762,407)	0	0	0	0	0	0	(3,946,028)
10	Total Fuel & Net Power Transactions	$250,246,957	$218,238,366	$242,959,536	$242,497,654	$284,422,564	$287,914,448	$322,039,777	$337,136,872	$336,915,399	$299,989,089	$241,846,398	$241,007,254	$3,305,214,313
11														
12	System MWH Sales (Excl sales to CKW)	8,684,410	7,586,674	7,497,187	7,573,999	8,601,591	9,365,603	10,232,652	10,209,655	9,837,863	9,228,977	8,324,784	8,156,867	105,300,262
13														
14	Cost per KWH (¢/KWH)	2.8816	2.8766	3.2407	3.2017	3.3066	3.0742	3.1472	3.3021	3.4247	3.2505	2.9051	2.9547	3.1388
15	Jurisdictional Loss Multiplier	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081
16	Jurisdictional Cost (¢/KWH)	2.8839	2.8789	3.2433	3.2043	3.3093	3.0767	3.1497	3.3048	3.4275	3.2531	2.9075	2.9570	3.1414
17	True-Up (¢/KWH)	(0.0469)	(0.0539)	(0.0544)	(0.0541)	(0.0475)	(0.0437)	(0.0399)	(0.0401)	(0.0416)	(0.0444)	(0.0492)	(0.0500)	(0.0466)
18	Total (¢/KWH)	2.8370	2.8250	3.1889	3.1502	3.2618	3.0330	3.1098	3.2647	3.3859	3.2087	2.8583	2.9070	3.0948
19	Revenue Tax Factor (0.00072)	0.0020	0.0020	0.0023	0.0023	0.0023	0.0022	0.0022	0.0024	0.0024	0.0023	0.0021	0.0021	0.0022
20	Recovery Factor Adjusted for Taxes (¢/KWH)	2.8390	2.8270	3.1912	3.1525	3.2641	3.0352	3.1120	3.2671	3.3883	3.2110	2.8604	2.9091	3.0970
21	GPIF (¢/KWH)	0.0075	0.0086	0.0087	0.0087	0.0076	0.0070	0.0064	0.0064	0.0067	0.0071	0.0079	0.0080	0.0075
22	Recovery Factor including GPIF (¢/KWH)	2.8465	2.8356	3.1999	3.1612	3.2717	3.0422	3.1184	3.2735	3.3950	3.2181	2.8683	2.9171	3.1045
23														
24	Recovery Factor Rounded to .001 (¢/KWH)	2.847	2.836	3.200	3.161	3.272	3.042	3.118	3.274	3.395	3.218	2.868	2.917	3.105
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26	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 2013 THROUGH MAY 2013

	(1)	(2)	(3)	(4)	(5)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	36,238,125,203	0.027892	$1,010,762,587.82	2.789
2	All Additional KWH	17,271,658,955	0.037892	$654,461,895.18	3.789
3	Total KWH	53,509,784,158		$1,665,224,483.00	
4					
5	Avg Fuel Factor	3.105			
6	RS-1 Loss Multiplier	1.00220			
7	Average Fuel Factor	3.112			
8					
9	Target Fuel Revenues	$1,665,224,483.00			
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

Line No.		Jan - 2013	Feb - 2013	Mar - 2013	Apr - 2013	May - 2013	Jun - 2013	Jul - 2013	Aug - 2013	Sep - 2013	Oct - 2013	Nov - 2013	Dec - 2013	2013
1	Fuel Cost of System Net Generation ($)													
2	Heavy Oil	4,805,400	0	883,100	2,429,200	3,627,600	245,400	2,893,400	14,657,130	24,135,000	11,299,600	1,164,200	0	66,140,030
3	Light Oil	203,700	0	0	0	0	0	0	0	407,800	0	0	0	611,500
4	Coal	11,675,200	11,684,600	12,014,600	11,436,200	13,954,600	14,773,200	15,547,900	16,286,500	15,683,500	15,337,400	14,199,600	14,454,700	167,048,000
5	Gas	188,225,086	165,919,940	180,049,747	177,885,750	200,278,166	214,061,150	236,573,125	229,620,265	226,387,750	214,850,505	180,429,950	175,821,723	2,390,103,157
6	Nuclear	15,164,500	13,696,900	16,018,400	19,198,300	20,357,400	19,700,700	20,357,400	20,357,400	15,064,000	16,503,200	15,485,500	20,348,900	212,252,600
7	Total Fuel Cost of System Net Generation ($)	220,073,886	191,301,440	208,965,847	210,949,450	238,217,766	248,780,450	275,371,825	280,921,295	281,678,050	257,990,705	211,279,250	210,625,323	2,836,155,287
8														
9	System Net Generation (MWH)													
10	Heavy Oil	26,861	0	5,066	13,204	19,016	1,104	16,976	80,275	139,777	63,627	6,101	0	372,007
11	Light Oil	423	0	0	0	0	0	0	0	915	0	0	0	1,338
12	Coal	399,451	411,226	437,494	405,762	482,637	513,864	531,048	561,442	538,789	525,793	498,610	509,328	5,815,444
13	Gas	5,431,400	4,823,112	5,203,048	5,087,969	5,852,237	6,464,421	7,126,214	6,818,404	6,726,726	6,275,614	5,138,324	4,821,357	69,768,828
14	Nuclear	1,953,129	1,764,120	2,053,672	2,372,162	2,510,607	2,429,620	2,510,607	2,510,607	1,831,559	2,023,897	1,948,567	2,563,551	26,472,098
15	Solar	16,935	17,192	22,278	22,413	21,493	18,333	19,402	19,036	17,308	18,044	16,268	17,129	225,831
16	Total System Net Generation (MWH)	7,828,199	7,015,650	7,721,558	7,901,510	8,885,990	9,427,342	10,204,247	9,989,764	9,255,074	8,906,975	7,607,870	7,911,365	102,655,546
17														
18	Units of Fuel Burned (Unit) (1)													
19	Heavy Oil	45,917	0	8,499	23,418	35,089	2,396	27,747	143,656	235,345	111,687	11,537	0	645,291
20	Light Oil	1,504	0	0	0	0	0	0	0	3,037	0	0	0	4,541
21	Coal	222,698	228,370	245,105	230,234	265,715	282,206	289,411	305,932	292,942	288,651	275,507	280,609	3,207,380
22	Gas	38,638,378	33,643,169	36,378,226	35,875,854	41,321,551	44,998,196	50,125,047	48,114,907	47,604,589	44,218,739	35,547,700	33,160,078	489,626,432
23	Nuclear	20,705,218	18,701,487	21,789,086	25,779,072	27,297,265	26,416,707	27,297,265	27,297,265	20,016,367	22,005,325	20,667,498	27,285,728	285,258,283
24	Total Units of Fuel Burned (Unit)													
25														
26	BTU Burned (MMBTU)													
27	Heavy Oil	293,869	0	54,396	149,877	224,565	15,334	177,583	919,396	1,506,212	714,796	73,837	0	4,129,865
28	Light Oil	8,765	0	0	0	0	0	0	0	17,702	0	0	0	26,467
29	Coal	4,172,614	4,251,951	4,493,453	4,232,538	4,973,355	5,275,658	5,444,996	5,739,999	5,508,199	5,402,201	5,107,152	5,211,095	59,813,211
30	Gas	38,638,378	33,643,169	36,378,226	35,875,854	41,321,551	44,998,196	50,125,047	48,114,907	47,604,589	44,218,739	35,547,700	33,160,078	489,626,432
31	Nuclear	20,705,218	18,701,487	21,789,086	25,779,072	27,297,265	26,416,707	27,297,265	27,297,265	20,016,367	22,005,325	20,667,498	27,285,728	285,258,283
32	Total BTU Burned (MMBTU)	63,818,844	56,596,607	62,715,161	66,037,341	73,816,736	76,705,895	83,044,891	82,071,567	74,653,069	72,341,061	61,396,187	65,656,901	838,854,258
33														
34	Generation Mix (%)													
35	Heavy Oil	0.34%	0.00%	0.07%	0.17%	0.21%	0.01%	0.17%	0.80%	1.51%	0.71%	0.08%	0.00%	0.36%
36	Light Oil	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
37	Coal	5.10%	5.86%	5.67%	5.14%	5.43%	5.45%	5.20%	5.62%	5.82%	5.90%	6.55%	6.44%	5.67%
38	Gas	69.38%	68.75%	67.38%	64.39%	65.86%	68.57%	69.84%	68.25%	72.68%	70.46%	67.54%	60.94%	67.96%
39	Nuclear	24.95%	25.15%	26.60%	30.02%	28.25%	25.77%	24.60%	25.13%	19.79%	22.72%	25.61%	32.40%	25.79%
40	Solar	0.22%	0.25%	0.29%	0.28%	0.24%	0.19%	0.19%	0.19%	0.19%	0.20%	0.21%	0.22%	0.22%
41	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%
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43														

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

SCHEDULE: E3

Line No.		Jan - 2013	Feb - 2013	Mar - 2013	Apr - 2013	May - 2013	Jun - 2013	Jul - 2013	Aug - 2013	Sep - 2013	Oct - 2013	Nov - 2013	Dec - 2013	2013
1	**Fuel Cost per Unit ($/Unit)**													
2	Heavy Oil	104.6540	0.0000	103.9063	103.7322	103.3828	102.4207	104.2779	102.0294	102.5516	101.1720	100.9101	0.0000	102.4964
3	Light Oil	135.4388	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	134.2772	0.0000	0.0000	0.0000	134.6620
4	Coal	52.4262	51.1652	49.0182	49.6721	52.5172	52.3490	53.7226	53.2357	53.5379	53.1348	51.5399	51.5119	52.0824
5	Gas	4.8715	4.9318	4.9494	4.9584	4.8468	4.7571	4.7197	4.7723	4.7556	4.8588	5.0757	5.3022	4.8815
6	Nuclear	0.7324	0.7324	0.7352	0.7447	0.7458	0.7458	0.7458	0.7458	0.7526	0.7500	0.7493	0.7458	0.7441
7														
8	**Fuel Cost per MMBTU ($/MMBTU)**													
9	Heavy Oil	16.3522	0.0000	16.2346	16.2080	16.1539	16.0037	16.2932	15.9421	16.0236	15.8081	15.7672	0.0000	16.0151
10	Light Oil	23.2402	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	23.0369	0.0000	0.0000	0.0000	23.1042
11	Coal	2.7981	2.7481	2.6738	2.7020	2.8059	2.8003	2.8554	2.8374	2.8473	2.8391	2.7803	2.7738	2.7928
12	Gas	4.8715	4.9318	4.9494	4.9584	4.8468	4.7571	4.7197	4.7723	4.7556	4.8588	5.0757	5.3022	4.8815
13	Nuclear	0.7324	0.7324	0.7352	0.7447	0.7458	0.7458	0.7458	0.7458	0.7526	0.7500	0.7493	0.7458	0.7441
14														
15	**BTU Burned per KWH (BTU/KWH)**													
16	Heavy Oil	10,940	0	10,737	11,351	11,809	13,889	10,461	11,453	10,776	11,234	12,102	0	11,102
17	Light Oil	20,721	0	0	0	0	0	0	0	19,346	0	0	0	19,781
18	Coal	10,446	10,340	10,271	10,431	10,305	10,267	10,253	10,224	10,223	10,274	10,243	10,231	10,285
19	Gas	7,114	6,975	6,992	7,051	7,061	6,961	7,034	7,057	7,077	7,046	6,918	6,878	7,018
20	Nuclear	10,601	10,601	10,610	10,867	10,873	10,873	10,873	10,873	10,929	10,873	10,607	10,644	10,776
21														
22	**Generated Fuel Cost per KWH (cents/KWH)**													
23	Heavy Oil	17.8899	0.0000	17.4319	18.3975	19.0766	22.2283	17.0441	18.2586	17.2668	17.7591	19.0821	0.0000	17.7792
24	Light Oil	48.1560	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	44.5683	0.0000	0.0000	0.0000	45.7025
25	Coal	2.9228	2.8414	2.7462	2.8185	2.8913	2.8749	2.9278	2.9008	2.9109	2.9170	2.8478	2.8380	2.8725
26	Gas	3.4655	3.4401	3.4605	3.4962	3.4222	3.3114	3.3198	3.3677	3.3655	3.4236	3.5115	3.6467	3.4257
27	Nuclear	0.7764	0.7764	0.7800	0.8093	0.8109	0.8109	0.8109	0.8109	0.8225	0.8154	0.7947	0.7938	0.8018
28	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.8113	2.7268	2.7063	2.6697	2.6808	2.6389	2.6986	2.8121	3.0435	2.8965	2.7771	2.6623	2.7628
29														
30														
31	(1) Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
32														
33	Note: Totals may not add due to rounding.													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jan - 2013**												
2	*CCEC*												
3	Light 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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
6	*Desoto Solar*												
7	Solar		3,170										
8	Plant Unit Info	25	3,170										
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	383	0	0.0%	88.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		423					1,504	5,827,793	8,765	203,700	48.16	135.44
15	Plant Unit Info	627	423	0.1%	98.4%	33.7%	20,721			8,765	203,700	48.16	
16	*Fort Myers 2*												
17	Gas		512,862					3,666,762	1,000,000	3,666,762	17,973,019	3.50	4.90
18	Plant Unit Info	1,440	512,862	47.9%	94.2%	85.0%	7,150			3,666,762	17,973,019	3.50	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		14,314					197,617	1,000,000	197,617	971,612	6.79	4.92
22	Plant Unit Info	328	14,314	11.7%	94.7%	94.9%	13,805			197,617	971,612	6.79	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	766	0	0.0%	91.7%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		103,024					855,822	1,000,000	855,822	4,206,806	4.08	4.92
30	Plant Unit Info	447	103,024	31.0%	94.4%	77.9%	8,307			855,822	4,206,806	4.08	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		116,309					957,047	1,000,000	957,047	4,701,994	4.04	4.91
34	Plant Unit Info	447	116,309	35.0%	94.1%	80.1%	8,229			957,047	4,701,994	4.04	
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 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	798	0	0.0%	0.0%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		15,056					27,489	6,400,087	175,932	2,836,300	18.84	103.18
4	Gas		18,852					199,750	1,000,000	199,750	983,121	5.21	4.92
5	Plant Unit Info	798	33,908	5.7%	94.7%	48.3%	11,079			375,682	3,819,421	11.26	
6	*Manatee 3*												
7	Gas		500,200					3,450,354	1,000,000	3,450,354	16,836,263	3.37	4.88
8	Plant Unit Info	1,117	500,200	60.2%	94.8%	88.5%	6,898			3,450,354	16,836,263	3.37	
9	*Martin 1*												
10	Heavy Oil		2,161					3,332	6,399,460	21,323	365,600	16.92	109.72
11	Gas		7,846					89,309	1,000,000	89,309	439,198	5.60	4.92
12	Plant Unit Info	808	10,007	1.7%	94.8%	42.7%	11,055			110,632	804,798	8.04	
13	*Martin 2*												
14	Heavy Oil		4,880					7,411	6,399,946	47,430	813,200	16.66	109.73
15	Gas		16,818					187,643	1,000,000	187,643	923,279	5.49	4.92
16	Plant Unit Info	808	21,698	3.6%	95.1%	46.3%	10,834			235,073	1,736,479	8.00	
17	*Martin 3*												
18	Gas		130,111					970,146	1,000,000	970,146	4,750,942	3.65	4.90
19	Plant Unit Info	462	130,111	37.9%	94.3%	83.8%	7,456			970,146	4,750,942	3.65	
20	*Martin 4*												
21	Gas		147,568					1,093,145	1,000,000	1,093,145	5,353,301	3.63	4.90
22	Plant Unit Info	462	147,568	42.9%	94.4%	85.2%	7,408			1,093,145	5,353,301	3.63	
23	*Martin 8*												
24	Gas		477,429					3,319,650	1,000,000	3,319,650	16,291,858	3.41	4.91
25	Plant Unit Info	1,112	477,429	57.7%	94.8%	87.1%	6,953			3,319,650	16,291,858	3.41	
26	*Martin 8 Solar*												
27	Solar		12,565										
28	Plant Unit Info	0	12,565										
29	*Pt Everglades 1*												
30	Heavy Oil		0					0	0	0	0	0.00	0.00
31	Gas		0					0	0	0	0	0.00	0.00
32	Plant Unit Info	207	0	0.0%	100.0%	0.0%	0			0	0	0.00	
33	*Pt Everglades 2*												
34	Heavy Oil		0					0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	0.00
36	Plant Unit Info	207	0	0.0%	100.0%	0.0%	0			0	0	0.00	
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Pt Everglades 3												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	376	0	0.0%	95.5%	0.0%	0			0	0	0.00	
5	Pt Everglades 4												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	376	0	0.0%	95.5%	0.0%	0			0	0	0.00	
9	Putnam 1												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		34,138					332,062	1,000,000	332,062	1,630,843	4.78	4.91
12	Plant Unit Info	248	34,138	18.5%	94.3%	65.2%	9,727			332,062	1,630,843	4.78	
13	Putnam 2												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		23,245					231,323	1,000,000	231,323	1,136,395	4.89	4.91
16	Plant Unit Info	248	23,245	12.6%	94.2%	61.3%	9,952			231,323	1,136,395	4.89	
17	Sanford 4												
18	Gas		367,787					2,634,748	1,000,000	2,634,748	12,905,211	3.51	4.90
19	Plant Unit Info	955	367,787	51.8%	94.7%	86.9%	7,164			2,634,748	12,905,211	3.51	
20	Sanford 5												
21	Gas		336,105					2,419,695	1,000,000	2,419,695	11,855,240	3.53	4.90
22	Plant Unit Info	952	336,105	47.5%	94.7%	88.0%	7,199			2,419,695	11,855,240	3.53	
23	Scherer 4												
24	Coal		314,496					186,268	17,500,038	3,259,697	7,941,600	2.53	42.64
25	Plant Unit Info	635	314,496	66.6%	93.8%	66.6%	10,365			3,259,697	7,941,600	2.53	
26	St Johns 10												
27	Coal		40,578					17,532	25,059,320	439,340	1,796,800	4.43	102.49
28	Plant Unit Info	124	40,578	44.0%	93.5%	44.0%	10,827			439,340	1,796,800	4.43	
29	St Johns 20												
30	Coal		44,377					18,898	25,059,636	473,577	1,936,800	4.36	102.49
31	Plant Unit Info	124	44,377	48.1%	94.0%	48.1%	10,672			473,577	1,936,800	4.36	
32	St Lucie 1												
33	Nuclear		723,218					7,629,271	1,000,000	7,629,271	5,527,100	0.76	0.72
34	Plant Unit Info	997	723,218	97.5%	97.5%	97.5%	10,549			7,629,271	5,527,100	0.76	
35	St Lucie 2												
36	Nuclear		618,763					6,487,813	1,000,000	6,487,813	4,807,200	0.78	0.74
37	Plant Unit Info	853	618,763	97.5%	97.5%	97.5%	10,485			6,487,813	4,807,200	0.78	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,200										
3	Plant Unit Info	10	1,200										
4	*Turkey Point 1*												
5	Heavy Oil		4,764					7,685	6,400,000	49,184	790,300	16.59	102.84
6	Gas		9,286					106,952	1,000,000	106,952	524,529	5.65	4.90
7	Plant Unit Info	380	14,050	5.0%	94.5%	38.1%	11,113			156,136	1,314,829	9.36	
8	*Turkey Point 3*												
9	Nuclear		611,148					6,588,134	1,000,000	6,588,134	4,830,200	0.79	0.73
10	Plant Unit Info	843	611,148	97.5%	97.5%	97.5%	10,780			6,588,134	4,830,200	0.79	
11	*Turkey Point 4*												
12	Nuclear		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	720	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Turkey Point 5*												
15	Gas		420,394					2,947,908	1,000,000	2,947,908	14,501,065	3.45	4.92
16	Plant Unit Info	1,114	420,394	50.7%	94.9%	84.8%	7,012			2,947,908	14,501,065	3.45	
17	*WCEC 01*												
18	Gas		622,498					4,276,916	1,000,000	4,276,916	20,631,140	3.31	4.82
19	Plant Unit Info	1,335	622,498	62.7%	94.4%	81.4%	6,871			4,276,916	20,631,140	3.31	
20	*WCEC 02*												
21	Gas		735,157					5,049,069	1,000,000	5,049,069	24,349,674	3.31	4.82
22	Plant Unit Info	1,335	735,157	74.0%	94.7%	81.9%	6,868			5,049,069	24,349,674	3.31	
23	*WCEC 03*												
24	Gas		837,458					5,652,462	1,000,000	5,652,462	27,259,594	3.26	4.82
25	Plant Unit Info	1,335	837,458	84.3%	94.1%	85.2%	6,750			5,652,462	27,259,594	3.26	
26	**System Totals**												
27	Plant Unit Info	24,202	7,828,199				8,152			63,818,844	220,073,886	2.81	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1													
2	**Feb - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0 00	0.00
6	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
7	Desoto Solar												
8	Solar		3,619										
9	Plant Unit Info	25	3,619										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	383	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	627	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		460,479					3,273,397	1,000,000	3,273,397	16,250,001	3.53	4.96
19	Plant Unit Info	1,440	460,479	47.6%	94.2%	91.9%	7,109			3,273,397	16,250,001	3.53	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		1,245					17,184	1,000,000	17,184	85,435	6.86	4.97
23	Plant Unit Info	328	1,245	1.1%	94.7%	94.9%	13,806			17,184	85,435	6.86	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0 00
27	Plant Unit Info	766	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0 00
30	Gas		45,537					367,425	1,000,000	367,425	1,828,077	4.01	4.98
31	Plant Unit Info	447	45,537	15.2%	94.4%	86.3%	8,069			367,425	1,828,077	4.01	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		70,797					571,381	1,000,000	571,381	2,842,122	4.01	4.97
35	Plant Unit Info	447	70,797	23.6%	94.1%	85.6%	8,071			571,381	2,842,122	4.01	
36	Manatee 1												
37	Heavy Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	798	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 2*												
4	Heavy Oil		0					0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	798	0	0.0%	94.7%	0.0%	0			0	0	0.00	
7	*Manatee 3*												
8	Gas		326,137					2,326,159	1,000,000	2,326,159	11,586,503	3.55	4.98
9	Plant Unit Info	1,117	326,137	43.5%	83.8%	74.7%	7,132			2,326,159	11,586,503	3.55	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	808	0	0.0%	94.8%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	808	0	0.0%	95.1%	0.0%	0			0	0	0.00	
18	*Martin 3*												
19	Gas		84,025					619,278	1,000,000	619,278	3,070,942	3.65	4.96
20	Plant Unit Info	462	84,025	27.1%	94.3%	88.3%	7,370			619,278	3,070,942	3.65	
21	*Martin 4*												
22	Gas		110,101					804,995	1,000,000	804,995	3,991,813	3.63	4.96
23	Plant Unit Info	462	110,101	35.5%	94.4%	91.0%	7,311			804,995	3,991,813	3.63	
24	*Martin 8*												
25	Gas		538,231					3,707,507	1,000,000	3,707,507	18,419,420	3.42	4 97
26	Plant Unit Info	1,112	538,231	72.0%	94.8%	91.7%	6,888			3,707,507	18,419,420	3.42	
27	*Martin 8 Solar*												
28	Solar		12,284										
29	Plant Unit Info	0	12,284										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*Putnam 1*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		3,182					33,747	1,000,000	33,747	167,622	5.27	4.97
12	Plant Unit Info	248	3,182	1.9%	79.9%	47.5%	10,606			33,747	167,622	5.27	
13	*Putnam 2*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		6,862					60,941	1,000,000	60,941	302,508	4.41	4.96
16	Plant Unit Info	248	6,862	4.1%	94.2%	89.3%	8,881			60,941	302,508	4.41	
17	*Sanford 4*												
18	Gas		249,435					1,778,739	1,000,000	1,778,739	8,824,159	3.54	4.96
19	Plant Unit Info	955	249,435	38.9%	74.4%	92.6%	7,131			1,778,739	8,824,159	3.54	
20	*Sanford 5*												
21	Gas		222,109					1,614,899	1,000,000	1,614,899	8,010,722	3.61	4.96
22	Plant Unit Info	952	222,109	34 7%	94.7%	84.5%	7,271			1,614,899	8,010,722	3.61	
23	*Scherer 4*												
24	Coal		331,769					194,577	17,500,028	3,405,103	8,311,900	2.51	42.72
25	Plant Unit Info	635	331,769	77.8%	93.8%	77.7%	10,263			3,405,103	8,311,900	2.51	
26	*St Johns 10*												
27	Coal		37,371					16,060	25,060,274	402,468	1,602,900	4.29	99.81
28	Plant Unit Info	124	37,371	44.9%	93.5%	44.8%	10,770			402,468	1,602,900	4.29	
29	*St Johns 20*												
30	Coal		42,086					17,733	25,059,494	444,380	1,769,800	4.21	99.80
31	Plant Unit Info	124	42,086	50.5%	94.0%	50.5%	10,559			444,380	1,769,800	4.21	
32	*St Lucie 1*												
33	Nuclear		653,231					6,890,955	1,000,000	6,890,955	4,992,200	0.76	0.72
34	Plant Unit Info	997	653,231	97.5%	97.5%	97.5%	10,549			6,890,955	4,992,200	0.76	
35	*St Lucie 2*												
36	Nuclear		558,883					5,859,957	1,000,000	5,859,957	4,342,000	0.78	0.74
37	Plant Unit Info	853	558,883	97.5%	97.5%	97.5%	10,485			5,859,957	4,342,000	0.78	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,289										
3	Plant Unit Info	10	1,289										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		513					6,996	1,000,000	6,996	34,341	6.69	4.91
7	Plant Unit Info	380	513	0.2%	94.5%	22.5%	13,627			6,996	34,341	6.69	
8	*Turkey Point 3*												
9	Nuclear		552,006					5,950,575	1,000,000	5,950,575	4,362,700	0.79	0.73
10	Plant Unit Info	843	552,006	97.5%	97.5%	97.5%	10,780			5,950,575	4,362,700	0.79	
11	*Turkey Point 4*												
12	Nuclear		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	720	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Turkey Point 5*												
15	Gas		370,960					2,592,381	1,000,000	2,592,381	12,960,664	3.49	5.00
16	Plant Unit Info	1,114	370,960	49.6%	94.9%	93.3%	6,988			2,592,381	12,960,664	3.49	
17	*WCEC 01*												
18	Gas		747,725					5,115,331	1,000,000	5,115,331	25,028,843	3.35	4.89
19	Plant Unit Info	1,335	747,725	83.4%	94.4%	84.4%	6,841			5,115,331	25,028,843	3.35	
20	*WCEC 02*												
21	Gas		776,092					5,313,256	1,000,000	5,313,256	25,949,963	3.34	4.88
22	Plant Unit Info	1,335	776,092	86.5%	94.7%	86.5%	6,846			5,313,256	25,949,963	3.34	
23	*WCEC 03*												
24	Gas		809,684					5,439,556	1,000,000	5,439,556	26,566,805	3.28	4.88
25	Plant Unit Info	1,335	809,684	90.3%	94.1%	90.3%	6,718			5,439,556	26,566,805	3.28	
26	**System Totals**												
27	Plant Unit Info	23,036	7,015,650				8,067			56,596,607	191,301,440	2.73	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1													
2	**Mar - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
7	Desoto Solar												
8	Solar		4,945										
9	Plant Unit Info	25	4,945										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	383	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	627	0	0.0%	82.5%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		681,495					4,818,034	1,000,000	4,818,034	24,007,910	3.52	4.98
19	Plant Unit Info	1,440	681,495	63.6%	94.2%	92.4%	7,070			4,818,034	24,007,910	3.52	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		6,535					89,516	1,000,000	89,516	446,905	6.84	4.99
23	Plant Unit Info	328	6,535	5.4%	21.4%	94.9%	13,698			89,516	446,905	6.84	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	766	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		52,043					420,054	1,000,000	420,054	2,097,139	4.03	4.99
31	Plant Unit Info	447	52,043	15.7%	88.3%	91.0%	8,071			420,054	2,097,139	4.03	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		58,212					470,708	1,000,000	470,708	2,350,328	4.04	4.99
35	Plant Unit Info	447	58,212	17.5%	94.1%	91.1%	8,086			470,708	2,350,328	4.04	
36	Manatee 1												
37	Heavy Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	798	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 2*												
4	Heavy Oil		2,105					3,848	6,399,168	24,624	397,000	18.86	103.17
5	Gas		1,404					14,437	1,000,000	14,437	72,090	5.14	4.99
6	Plant Unit Info	798	3,509	0.6%	27.5%	55.0%	11,133			39,061	469,090	13.37	
7	*Manatee 3*												
8	Gas		503,533					3,491,857	1,000,000	3,491,857	17,302,617	3.44	4.96
9	Plant Unit Info	1,117	503,533	60.6%	83.3%	83.6%	6,935			3,491,857	17,302,617	3.44	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	808	0	0.0%	94.8%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		733					1,110	6,402,703	7,107	121,900	16.63	109.82
16	Gas		2,115					25,519	1,000,000	25,519	127,564	6.03	5.00
17	Plant Unit Info	808	2,848	0.5%	95.1%	44.1%	11,455			32,626	249,464	8.76	
18	*Martin 3*												
19	Gas		114,144					842,172	1,000,000	842,172	4,191,779	3.67	4.98
20	Plant Unit Info	462	114,144	33.2%	94.3%	91.5%	7,378			842,172	4,191,779	3.67	
21	*Martin 4*												
22	Gas		149,240					1,093,051	1,000,000	1,093,051	5,440,462	3.65	4.98
23	Plant Unit Info	462	149,240	43.4%	94.4%	92.6%	7,324			1,093,051	5,440,462	3.65	
24	*Martin 8*												
25	Gas		539,630					3,795,926	1,000,000	3,795,926	18,901,652	3.50	4.98
26	Plant Unit Info	1,112	539,630	65.2%	77.2%	76.9%	7,034			3,795,926	18,901,652	3.50	
27	*Martin 8 Solar*												
28	Solar		15,626										
29	Plant Unit Info	0	15,626										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Pt Everglades 3												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	Pt Everglades 4												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	Putnam 1												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		7,017					76,411	1,000,000	76,411	381,488	5.44	4.99
12	Plant Unit Info	248	7,017	3.8%	20.5%	44.2%	10,889			76,411	381,488	5.44	
13	Putnam 2												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		14,390					129,914	1,000,000	129,914	648,380	4.51	4.99
16	Plant Unit Info	248	14,390	7.8%	52.7%	84.1%	9,028			129,914	648,380	4.51	
17	Sanford 4												
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	955	0	0.0%	0.0%	0.0%	0			0	0	0.00	
20	Sanford 5												
21	Gas		290,748					2,090,662	1,000,000	2,090,662	10,405,992	3.58	4.98
22	Plant Unit Info	952	290,748	41.1%	94.7%	93.7%	7,191			2,090,662	10,405,992	3.58	
23	Scherer 4												
24	Coal		372,223					218,106	17,500,041	3,816,864	9,320,000	2.50	42.73
25	Plant Unit Info	635	372,223	78.8%	93.8%	78.8%	10,254			3,816,864	9,320,000	2.50	
26	St Johns 1Q												
27	Coal		12,268					5,148	25,060,800	129,013	513,800	4.19	99.81
28	Plant Unit Info	124	12,268	13.3%	24.1%	51.5%	10,516			129,013	513,800	4.19	
29	St Johns 2Q												
30	Coal		53,003					21,851	25,059,540	547,576	2,180,800	4.11	99.80
31	Plant Unit Info	124	53,003	57.5%	94.0%	57.5%	10,331			547,576	2,180,800	4.11	
32	St Lucie 1												
33	Nuclear		723,218					7,629,271	1,000,000	7,629,271	5,527,100	0.76	0.72
34	Plant Unit Info	997	723,218	97.5%	97.5%	97.5%	10,549			7,629,271	5,527,100	0.76	
35	St Lucie 2												
36	Nuclear		618,763					6,487,813	1,000,000	6,487,813	4,807,200	0.78	0.74
37	Plant Unit Info	853	618,763	97.5%	97.5%	97.5%	10,485			6,487,813	4,807,200	0.78	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,707										
3	Plant Unit Info	10	1,707										
4	*Turkey Point 1*												
5	Heavy Oil		2,228					3,541	6,400,734	22,665	364,200	16 35	102.85
6	Gas		3,368					37,781	1,000,000	37,781	187,797	5.58	4.97
7	Plant Unit Info	380	5,596	2.0%	94.5%	42.1%	10,801			60,446	551,997	9.86	
8	*Turkey Point 3*												
9	Nuclear		611,148					6,588,134	1,000,000	6,588,134	4,830,200	0.79	0.73
10	Plant Unit Info	843	611,148	97.5%	97.5%	97.5%	10,780			6,588,134	4,830,200	0.79	
11	*Turkey Point 4*												
12	Nuclear		100,543					1,083,868	1,000,000	1,083,868	853,900	0.85	0.79
13	Plant Unit Info	843	100,543	16.0%	53.5%	29.2%	10,780			1,083,868	853,900	0 85	
14	*Turkey Point 5*												
15	Gas		465,474					3,240,492	1,000,000	3,240,492	16,263,551	3.49	5.02
16	Plant Unit Info	1,114	465,474	56.2%	94.9%	93.9%	6,962			3,240,492	16,263,551	3.49	
17	*WCEC 01*												
18	Gas		543,402					3,746,053	1,000,000	3,746,053	18,409,660	3.39	4.91
19	Plant Unit Info	1,335	543,402	54.7%	59.9%	75.5%	6,894			3,746,053	18,409,660	3.39	
20	*WCEC 02*												
21	Gas		866,689					5,930,811	1,000,000	5,930,811	29,078,695	3.36	4.90
22	Plant Unit Info	1,335	866,689	87.3%	94.7%	87.3%	6,843			5,930,811	29,078,695	3.36	
23	*WCEC 03*												
24	Gas		903,609					6,064,827	1,000,000	6,064,827	29,735,739	3.29	4.90
25	Plant Unit Info	1,335	903,609	91.0%	94 1%	91.0%	6,712			6,064,827	29,735,739	3.29	
26	**System Totals**												
27	Plant Unit Info	23,159	7,721,558				8,122			62,715,161	208,965,847	2.71	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**Apr - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
7	Desoto Solar												
8	Solar		5,527										
9	Plant Unit Info	25	5,527										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	342	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	552	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		512,323					3,675,317	1,000,000	3,675,317	18,340,699	3.58	4.99
19	Plant Unit Info	1,349	512,323	52.8%	94.2%	94.2%	7,174			3,675,317	18,340,699	3.58	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		8,142					117,044	1,000,000	117,044	585,964	7.20	5.01
23	Plant Unit Info	296	8,142	7.6%	93.1%	94.9%	14,375			117,044	585,964	7.20	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	684	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		21,852					179,900	1,000,000	179,900	900,428	4.12	5.01
31	Plant Unit Info	438	21,852	6.9%	44.0%	86.0%	8,233			179,900	900,428	4.12	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		57,843					473,612	1,000,000	473,612	2,370,572	4.10	5.01
35	Plant Unit Info	438	57,843	18.3%	94.1%	92.4%	8,188			473,612	2,370,572	4.10	
36	Manatee 1												
37	Heavy Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	788	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 2*												
4	Heavy Oil		9,822					18,389	6,400,022	117,690	1,883,600	19.18	102.43
5	Gas		7,775					81,196	1,000,000	81,196	406,429	5.23	5.01
6	Plant Unit Info	788	17,597	3.1%	94.7%	55.8%	11,302			198,886	2,290,029	13.01	
7	*Manatee 3*												
8	Gas		681,591					4,689,777	1,000,000	4,689,777	23,268,005	3.41	4.96
9	Plant Unit Info	1,058	681,591	89.5%	94.8%	89.5%	6,881			4,689,777	23,268,005	3.41	
10	*Martin 1*												
11	Heavy Oil		1,098					1,646	6,401,580	10,537	178,600	16.27	108.51
12	Gas		2,561					29,816	1,000,000	29,816	149,264	5.83	5.01
13	Plant Unit Info	802	3,659	0.6%	94.8%	57.0%	11,029			40,353	327,864	8.96	
14	*Martin 2*												
15	Heavy Oil		2,284					3,383	6,399,645	21,650	367,000	16.07	108.48
16	Gas		5,330					61,043	1,000,000	61,043	305,556	5.73	5.01
17	Plant Unit Info	802	7,614	1.3%	95.1%	59.3%	10,861			82,693	672,556	8.83	
18	*Martin 3*												
19	Gas		87,174					650,499	1,000,000	650,499	3,240,368	3.72	4.98
20	Plant Unit Info	431	87,174	28.1%	94.3%	94.1%	7,462			650,499	3,240,368	3.72	
21	*Martin 4*												
22	Gas		53,304					423,773	1,000,000	423,773	2,111,023	3.96	4.98
23	Plant Unit Info	431	53,304	17.2%	54.8%	57.5%	7,950			423,773	2,111,023	3.96	
24	*Martin 8*												
25	Gas		505,825					3,592,720	1,000,000	3,592,720	17,926,957	3.54	4.99
26	Plant Unit Info	1,052	505,825	66.8%	90.9%	88.2%	7,103			3,592,720	17,926,957	3.54	
27	*Martin 8 Solar*												
28	Solar		15,045										
29	Plant Unit Info	0	15,045										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0 0%	0.0%	0.0%	0			0	0	0 00	
9	*Putnam 1*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		10,106					109,724	1,000,000	109,724	549,342	5 44	5.01
12	Plant Unit Info	239	10,106	5.9%	54.0%	47.5%	10,857			109,724	549,342	5.44	
13	*Putnam 2*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		20,147					181,292	1,000,000	181,292	907,629	4.50	5 01
16	Plant Unit Info	239	20,147	11.7%	94.2%	94.7%	8,998			181,292	907,629	4.50	
17	*Sanford 4*												
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	905	0	0.0%	0.0%	0.0%	0			0	0	0.00	
20	*Sanford 5*												
21	Gas		342,416					2,470,009	1,000,000	2,470,009	12,303,727	3.59	4.98
22	Plant Unit Info	901	342,416	52.8%	94.7%	94.5%	7,213			2,470,009	12,303,727	3.59	
23	*Scherer 4*												
24	Coal		343,864					203,326	17,500,034	3,558,212	8,691,600	2.53	42.75
25	Plant Unit Info	629	343,864	75.9%	93.8%	75.9%	10,348			3,558,212	8,691,600	2.53	
26	*St Johns 10*												
27	Coal		19,410					8,681	25,060,707	217,552	885,500	4 56	102.00
28	Plant Unit Info	124	19,410	21.7%	53.0%	38.4%	11,208			217,552	885,500	4.56	
29	*St Johns 20*												
30	Coal		42,488					18,227	25,060,295	456,774	1,859,100	4.38	102.00
31	Plant Unit Info	124	42,488	47.6%	94.0%	47.6%	10,751			456,774	1,859,100	4.38	
32	*St Lucie 1*												
33	Nuclear		690,070					7,385,019	1,000,000	7,385,019	5,350,100	0.78	0.72
34	Plant Unit Info	983	690,070	97.5%	97.5%	97.5%	10,702			7,385,019	5,350,100	0.78	
35	*St Lucie 2*												
36	Nuclear		590,380					6,279,280	1,000,000	6,279,280	4,652,700	0.79	0.74
37	Plant Unit Info	841	590,380	97.5%	97.5%	97.5%	10,636			6,279,280	4,652,700	0.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,841										
3	Plant Unit Info	10	1,841										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	378	0	0.0%	94.5%	0.0%	0			0	0	0.00	
8	*Turkey Point 3*												
9	Nuclear		574,585					6,376,204	1,000,000	6,376,204	4,674,800	0.81	0.73
10	Plant Unit Info	819	574,585	97.5%	97.5%	97.5%	11,097			6,376,204	4,674,800	0.81	
11	*Turkey Point 4*												
12	Nuclear		517,127					5,738,569	1,000,000	5,738,569	4,520,700	0.87	0.79
13	Plant Unit Info	819	517,127	87.8%	97.5%	87.7%	11,097			5,738,569	4,520,700	0.87	
14	*Turkey Point 5*												
15	Gas		656,675					4,549,561	1,000,000	4,549,561	22,874,028	3.48	5.03
16	Plant Unit Info	1,053	656,675	86.6%	94.9%	88.8%	6,928			4,549,561	22,874,028	3.48	
17	*WCEC 01*												
18	Gas		596,643					4,161,917	1,000,000	4,161,917	20,436,743	3.43	4.91
19	Plant Unit Info	1,219	596,643	68.0%	79.7%	74.4%	6,976			4,161,917	20,436,743	3.43	
20	*WCEC 02*												
21	Gas		746,195					5,167,401	1,000,000	5,167,401	25,374,045	3.40	4.91
22	Plant Unit Info	1,219	746,195	85.0%	94.7%	85.0%	6,925			5,167,401	25,374,045	3.40	
23	*WCEC 03*												
24	Gas		772,070					5,261,255	1,000,000	5,261,255	25,834,971	3.35	4.91
25	Plant Unit Info	1,219	772,070	88.0%	94.1%	88.0%	6,814			5,261,255	25,834,971	3.35	
26	**System Totals**												
27	Plant Unit Info	21,997	7,901,510				8,358			66,037,341	210,949,450	2.67	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**May - 2013**												
3	*CCEC*												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
7	*Desoto Solar*												
8	Solar		5,900										
9	Plant Unit Info	25	5,900										
10	*Everglades 1-12*												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	342	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	*Fort Myers 1-12*												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	552	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	*Fort Myers 2*												
18	Gas		516,359					3,707,019	1,000,000	3,707,019	18,054,570	3.50	4.87
19	Plant Unit Info	1,349	516,359	51.5%	94.2%	95.0%	7,179			3,707,019	18,054,570	3.50	
20	*Fort Myers 3A_B*												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		12,073					173,596	1,000,000	173,596	848,923	7.03	4.89
23	Plant Unit Info	296	12,073	11.0%	94.7%	94.9%	14,379			173,596	848,923	7.03	
24	*Lauderdale 1-24*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	684	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	*Lauderdale 4*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		70,460					577,261	1,000,000	577,261	2,826,983	4.01	4.90
31	Plant Unit Info	438	70,460	21.6%	94.4%	94.6%	8,193			577,261	2,826,983	4.01	
32	*Lauderdale 5*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		81,668					668,901	1,000,000	668,901	3,281,880	4.02	4.91
35	Plant Unit Info	438	81,668	25.1%	94.1%	94.6%	8,191			668,901	3,281,880	4.02	
36	*Manatee 1*												
37	Heavy Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	788	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 2*												
4	Heavy Oil		15,272					29,570	6,399,932	189,246	3,028,900	19.83	102.43
5	Gas		15,045					158,523	1,000,000	158,523	780,815	5.19	4.93
6	Plant Unit Info	788	30,317	5.2%	94.7%	52.7%	11,471			347,769	3,809,715	12.57	
7	*Manatee 3*												
8	Gas		726,951					4,983,524	1,000,000	4,983,524	24,350,802	3.35	4.89
9	Plant Unit Info	1,058	726,951	92.4%	94.8%	92.4%	6,855			4,983,524	24,350,802	3.35	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	802	0	0.0%	94.8%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		3,744					5,519	6,399,529	35,319	598,700	15.99	108.48
16	Gas		8,945					100,594	1,000,000	100,594	500,425	5.59	4.97
17	Plant Unit Info	802	12,689	2.1%	95.1%	63.3%	10,711			135,913	1,099,125	8.66	
18	*Martin 3*												
19	Gas		111,948					837,628	1,000,000	837,628	4,071,532	3.64	4.86
20	Plant Unit Info	431	111,948	34.9%	94.3%	94.8%	7,482			837,628	4,071,532	3.64	
21	*Martin 4*												
22	Gas		71,685					563,977	1,000,000	563,977	2,741,578	3.82	4.86
23	Plant Unit Info	431	71,685	22.4%	60.8%	62.3%	7,867			563,977	2,741,578	3.82	
24	*Martin 8*												
25	Gas		543,540					3,840,497	1,000,000	3,840,497	18,712,637	3.44	4.87
26	Plant Unit Info	1,052	543,540	69 5%	94.8%	93.9%	7,066			3,840,497	18,712,637	3.44	
27	*Martin 8 Solar*												
28	Solar		13,675										
29	Plant Unit Info	0	13,675										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*Putnam 1*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		28,162					252,598	1,000,000	252,598	1,235,347	4.39	4.89
12	Plant Unit Info	239	28,162	15.8%	87.8%	95.0%	8,970			252,598	1,235,347	4.39	
13	*Putnam 2*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		23,847					214,464	1,000,000	214,464	1,048,844	4.40	4.89
16	Plant Unit Info	239	23,847	13.4%	94.2%	95.0%	8,993			214,464	1,048,844	4.40	
17	*Sanford 4*												
18	Gas		275,832					1,971,259	1,000,000	1,971,259	9,587,099	3.48	4.86
19	Plant Unit Info	905	275,832	41.0%	64.1%	99.6%	7,147			1,971,259	9,587,099	3.48	
20	*Sanford 5*												
21	Gas		203,689					1,550,642	1,000,000	1,550,642	7,538,112	3.70	4.86
22	Plant Unit Info	901	203,689	30.4%	71.0%	72.9%	7,613			1,550,642	7,538,112	3.70	
23	*Scherer 4*												
24	Coal		378,431					222,944	17,500,000	3,901,520	9,544,300	2.52	42.81
25	Plant Unit Info	629	378,431	80.9%	93.8%	80.9%	10,310			3,901,520	9,544,300	2.52	
26	*St Johns 10*												
27	Coal		56,604					23,374	25,059,810	585,748	2,410,200	4.26	103.11
28	Plant Unit Info	124	56,604	61.4%	93.5%	61.4%	10,348			585,748	2,410,200	4.26	
29	*St Johns 20*												
30	Coal		47,602					19,397	25,059,906	486,087	2,000,100	4.20	103.11
31	Plant Unit Info	124	47,602	51.6%	94.0%	66.6%	10,211			486,087	2,000,100	4.20	
32	*St Lucie 1*												
33	Nuclear		713,072					7,631,183	1,000,000	7,631,183	5,528,500	0.78	0.72
34	Plant Unit Info	983	713,072	97.5%	97.5%	97.5%	10,702			7,631,183	5,528,500	0.78	
35	*St Lucie 2*												
36	Nuclear		610,059					6,488,588	1,000,000	6,488,588	4,807,800	0.79	0.74
37	Plant Unit Info	841	610,059	97.5%	97.5%	97.5%	10,636			6,488,588	4,807,800	0.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,918										
3	Plant Unit Info	10	1,918										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	378	0	0.0%	30.5%	0.0%	0			0	0	0.00	
8	*Turkey Point 3*												
9	Nuclear		593,738					6,588,747	1,000,000	6,588,747	4,830,600	0.81	0.73
10	Plant Unit Info	819	593,738	97.5%	97.5%	97.5%	11,097			6,588,747	4,830,600	0.81	
11	*Turkey Point 4*												
12	Nuclear		593,738					6,588,747	1,000,000	6,588,747	5,190,500	0.87	0.79
13	Plant Unit Info	819	593,738	97.5%	97.5%	97.5%	11,097			6,588,747	5,190,500	0.87	
14	*Turkey Point 5*												
15	Gas		714,489					4,930,014	1,000,000	4,930,014	24,244,902	3.39	4.92
16	Plant Unit Info	1,053	714,489	91.2%	94.9%	91.2%	6,900			4,930,014	24,244,902	3.39	
17	*WCEC 01*												
18	Gas		799,258					5,518,177	1,000,000	5,518,177	26,465,023	3.31	4.80
19	Plant Unit Info	1,219	799,258	88.1%	94.4%	88.1%	6,904			5,518,177	26,465,023	3.31	
20	*WCEC 02*												
21	Gas		812,449					5,604,059	1,000,000	5,604,059	26,839,304	3.30	4.79
22	Plant Unit Info	1,219	812,449	89.6%	94.7%	89.6%	6,898			5,604,059	26,839,304	3.30	
23	*WCEC 03*												
24	Gas		835,838					5,668,820	1,000,000	5,668,820	27,149,391	3.25	4.79
25	Plant Unit Info	1,219	835,838	92.2%	94.1%	92.2%	6,782			5,668,820	27,149,391	3.25	
26	**System Totals**												
27	Plant Unit Info	21,997	8,885,990				8,307			73,816,736	238,217,766	2.68	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**Jun - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		646,859					4,247,174	1,000,000	4,247,174	19,891,691	3.08	4.68
6	Plant Unit Info	1,210	646,859	74 3%	94.7%	99.9%	6,566			4,247,174	19,891,691	3.08	
7	Desoto Solar												
8	Solar		5,168										
9	Plant Unit Info	25	5,168										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	342	0	0.0%	88.3%	0 0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	552	0	0 0%	98.4%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		479,188					3,440,678	1,000,000	3,440,678	16,396,041	3.42	4.77
19	Plant Unit Info	1,349	479,188	49.3%	94.2%	95.0%	7,180			3,440,678	16,396,041	3.42	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		2,387					34,285	1,000,000	34,285	167,336	7.01	4.88
23	Plant Unit Info	296	2,387	2.2%	94.7%	94.9%	14,366			34,285	167,336	7.01	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	684	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		60,098					493,311	1,000,000	493,311	2,407,567	4.01	4.88
31	Plant Unit Info	438	60,098	19.1%	94.4%	94.6%	8,208			493,311	2,407,567	4.01	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		69,231					567,541	1,000,000	567,541	2,769,883	4.00	4.88
35	Plant Unit Info	438	69,231	22.0%	94.1%	94.6%	8,198			567,541	2,769,883	4.00	
36	Manatee 1												
37	Heavy Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	788	0	0.0%	26.5%	0.0%	0			0	0	0.00	
3	*Manatee 2*												
4	Heavy Oil		1,104					2,396	6,399,833	15,334	245,400	22.23	102.42
5	Gas		1,330					14,341	1,000,000	14,341	69,228	5.20	4.83
6	Plant Unit Info	788	2,434	0.4%	94.7%	38.6%	12,190			29,675	314,628	12.92	
7	*Manatee 3*												
8	Gas		719,792					4,930,048	1,000,000	4,930,048	23,579,188	3.28	4.78
9	Plant Unit Info	1,058	719,792	94.5%	94.8%	94.5%	6,849			4,930,048	23,579,188	3.28	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	802	0	0.0%	60.0%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	802	0	0.0%	95.1%	0.0%	0			0	0	0.00	
18	*Martin 3*												
19	Gas		101,325					758,098	1,000,000	758,098	3,605,545	3.56	4.76
20	Plant Unit Info	431	101,325	32.7%	94.3%	94.8%	7,482			758,098	3,605,545	3.56	
21	*Martin 4*												
22	Gas		104,566					780,118	1,000,000	780,118	3,710,316	3.55	4.76
23	Plant Unit Info	431	104,566	33.7%	94.4%	94.8%	7,461			780,118	3,710,316	3.55	
24	*Martin 8*												
25	Gas		519,288					3,669,069	1,000,000	3,669,069	17,488,580	3.37	4.77
26	Plant Unit Info	1,052	519,288	68.6%	94.8%	94.6%	7,066			3,669,069	17,488,580	3.37	
27	*Martin 8 Solar*												
28	Solar		11,493										
29	Plant Unit Info	0	11,493										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*Putnam 1*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		14,535					130,502	1,000,000	130,502	636,986	4.38	4.88
12	Plant Unit Info	239	14,535	8.5%	94.3%	95.0%	8,978			130,502	636,986	4.38	
13	*Putnam 2*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		5,451					49,035	1,000,000	49,035	239,429	4.39	4.88
16	Plant Unit Info	239	5,451	3.2%	94.2%	95.0%	8,996			49,035	239,429	4.39	
17	*Sanford 4*												
18	Gas		382,815					2,739,350	1,000,000	2,739,350	13,044,933	3.41	4.76
19	Plant Unit Info	905	382,815	58.8%	94.7%	100.0%	7,156			2,739,350	13,044,933	3.41	
20	*Sanford 5*												
21	Gas		233,397					1,708,506	1,000,000	1,708,506	8,141,048	3.49	4.77
22	Plant Unit Info	901	233,397	36.0%	89.9%	92.2%	7,320			1,708,506	8,141,048	3.49	
23	*Scherer 4*												
24	Coal		405,795					237,623	17,500,036	4,158,411	10,176,000	2.51	42.82
25	Plant Unit Info	629	405,795	89.6%	93.8%	89.6%	10,248			4,158,411	10,176,000	2.51	
26	*St Johns 10*												
27	Coal		50,501					21,055	25,060,223	527,643	2,171,100	4.30	103.12
28	Plant Unit Info	124	50,501	56.6%	93.5%	56.6%	10,448			527,643	2,171,100	4.30	
29	*St Johns 20*												
30	Coal		57,568					23,528	25,059,674	589,604	2,426,100	4.21	103.12
31	Plant Unit Info	124	57,568	64.5%	94.0%	64.5%	10,242			589,604	2,426,100	4.21	
32	*St Lucie 1*												
33	Nuclear		690,070					7,385,019	1,000,000	7,385,019	5,350,100	0.78	0.72
34	Plant Unit Info	983	690,070	97.5%	97.5%	97.5%	10,702			7,385,019	5,350,100	0.78	
35	*St Lucie 2*												
36	Nuclear		590,380					6,279,280	1,000,000	6,279,280	4,652,700	0.79	0.74
37	Plant Unit Info	841	590,380	97.5%	97.5%	97.5%	10,636			6,279,280	4,652,700	0.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,672										
3	Plant Unit Info	10	1,672										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	378	0	0.0%	0.0%	0.0%	0			0	0	0.00	
8	*Turkey Point 3*												
9	Nuclear		574,585					6,376,204	1,000,000	6,376,204	4,674,800	0.81	0.73
10	Plant Unit Info	819	574,585	97.5%	97.5%	97.5%	11,097			6,376,204	4,674,800	0.81	
11	*Turkey Point 4*												
12	Nuclear		574,585					6,376,204	1,000,000	6,376,204	5,023,100	0.87	0.79
13	Plant Unit Info	819	574,585	97.5%	97.5%	97.5%	11,097			6,376,204	5,023,100	0.87	
14	*Turkey Point 5*												
15	Gas		706,509					4,865,673	1,000,000	4,865,673	23,437,593	3.32	4.82
16	Plant Unit Info	1,053	706,509	93.2%	94.9%	94.4%	6,887			4,865,673	23,437,593	3.32	
17	*WCEC 01*												
18	Gas		793,244					5,463,567	1,000,000	5,463,567	26,295,836	3.31	4.81
19	Plant Unit Info	1,219	793,244	90.4%	94.4%	90.4%	6,888			5,463,567	26,295,836	3.31	
20	*WCEC 02*												
21	Gas		805,040					5,549,493	1,000,000	5,549,493	26,151,768	3.25	4.71
22	Plant Unit Info	1,219	805,040	91.7%	94.7%	91.7%	6,893			5,549,493	26,151,768	3.25	
23	*WCEC 03*												
24	Gas		819,367					5,557,410	1,000,000	5,557,410	26,028,182	3.18	4.68
25	Plant Unit Info	1,219	819,367	93.4%	94.1%	93.4%	6,783			5,557,410	26,028,182	3.18	
26	**System Totals**												
27	Plant Unit Info	23,207	9,427,342				8,137			76,705,895	248,780,450	2.64	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**Jul - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		669,834					4,397,934	1,000,000	4,397,934	20,358,543	3.04	4.63
6	Plant Unit Info	1,210	669,834	74.4%	94.7%	99.9%	6,566			4,397,934	20,358,543	3.04	
7	Desoto Solar												
8	Solar		5,118										
9	Plant Unit Info	25	5,118										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	342	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	552	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		556,079					3,986,928	1,000,000	3,986,928	18,785,776	3.38	4.71
19	Plant Unit Info	1,349	556,079	55.4%	94.2%	95.0%	7,170			3,986,928	18,785,776	3.38	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		19,513					280,392	1,000,000	280,392	1,353,408	6.94	4.83
23	Plant Unit Info	296	19,513	17.7%	94.7%	94.9%	14,370			280,392	1,353,408	6.94	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	684	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		96,156					786,496	1,000,000	786,496	3,803,974	3.96	4.84
31	Plant Unit Info	438	96,156	29.5%	94.4%	94.6%	8,179			786,496	3,803,974	3.96	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		104,883					857,508	1,000,000	857,508	4,169,674	3.98	4.86
35	Plant Unit Info	438	104,883	32.2%	94.1%	94.6%	8,176			857,508	4,169,674	3.98	
36	Manatee 1												
37	Heavy Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	788	0	0.0%	19.6%	0.0%	0			0	0	0.00	
3	*Manatee 2*												
4	Heavy Oil		7,436					13,285	6,400,000	85,024	1,350,900	18.17	101.69
5	Gas		4,958					51,117	1,000,000	51,117	251,052	5.06	4.91
6	Plant Unit Info	788	12,394	2.1%	94.7%	65.5%	10,985			136,141	1,601,952	12.93	
7	*Manatee 3*												
8	Gas		738,546					5,059,276	1,000,000	5,059,276	23,938,124	3.24	4.73
9	Plant Unit Info	1,058	738,546	93.8%	94.8%	93.8%	6,850			5,059,276	23,938,124	3.24	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		9,540					14,462	6,400,152	92,559	1,542,500	16.17	106.66
16	Gas		26,509					318,063	1,000,000	318,063	1,542,605	5 82	4.85
17	Plant Unit Info	802	36,049	6.0%	95.1%	45.4%	11,391			410,622	3,085,105	8.56	
18	*Martin 3*												
19	Gas		119,711					893,992	1,000,000	893,992	4,204,339	3.51	4.70
20	Plant Unit Info	431	119,711	37.3%	94 3%	94.8%	7,468			893,992	4,204,339	3.51	
21	*Martin 4*												
22	Gas		122,947					914,770	1,000,000	914,770	4,302,004	3.50	4.70
23	Plant Unit Info	431	122.947	38 3%	94 4%	94.8%	7,440			914,770	4,302,004	3.50	
24	*Martin 8*												
25	Gas		708,055					4,950,236	1,000,000	4,950,236	23,327,156	3.29	4.71
26	Plant Unit Info	1,052	708,055	90.5%	94.8%	93.5%	6,991			4,950,236	23,327,156	3.29	
27	*Martin 8 Solar*												
28	Solar		12,512										
29	Plant Unit Info	0	12,512										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0 00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Pt Everglades 3												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	Pt Everglades 4												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	Putnam 1												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		39,972					358,882	1,000,000	358,882	1,732,869	4.34	4.83
12	Plant Unit Info	239	39,972	22.5%	94.3%	95.0%	8,978			358,882	1,732,869	4.34	
13	Putnam 2												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		24,642					247,547	1,000,000	247,547	1,194,419	4.85	4.83
16	Plant Unit Info	239	24,642	13 9%	57.7%	61.0%	10,046			247,547	1,194,419	4.85	
17	Sanford 4												
18	Gas		470,059					3,343,295	1,000,000	3,343,295	15,747,275	3.35	4.71
19	Plant Unit Info	905	470,059	69.8%	94.7%	99.7%	7,112			3,343,295	15,747,275	3.35	
20	Sanford 5												
21	Gas		347,106					2,506,022	1,000,000	2,506,022	11,807,703	3.40	4.71
22	Plant Unit Info	901	347,106	51.8%	94.7%	94.9%	7,220			2,506,022	11,807,703	3.40	
23	Scherer 4												
24	Coal		407,647					239,107	17,500,027	4,184,379	10,247,500	2.51	42.86
25	Plant Unit Info	629	407,647	87.1%	93.8%	87.1%	10,265			4,184,379	10,247,500	2.51	
26	St Johns 10												
27	Coal		59,274					24,329	25,059,805	609,680	2,563,500	4.32	105.37
28	Plant Unit Info	124	59,274	64.3%	93.5%	64.2%	10,286			609,680	2,563,500	4.32	
29	St Johns 20												
30	Coal		64,127					25,975	25,060,135	650,937	2,736,900	4.27	105.37
31	Plant Unit Info	124	64,127	69.5%	94.0%	69.5%	10.151			650.937	2,736,900	4.27	
32	St Lucie 1												
33	Nuclear		713,072					7,631,183	1,000,000	7,631,183	5,528,500	0.78	0.72
34	Plant Unit Info	983	713,072	97.5%	97.5%	97.5%	10,702			7,631,183	5,528,500	0.78	
35	St Lucie 2												
36	Nuclear		610,059					6,488,588	1,000,000	6,488,588	4,807,800	0.79	0.74
37	Plant Unit Info	841	610,059	97.5%	97.5%	97.5%	10,636			6,488,588	4,807,800	0.79	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,772										
3	Plant Unit Info	10	1,772										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	378	0	0.0%	67.1%	0.0%	0			0	0	0.00	
8	*Turkey Point 3*												
9	Nuclear		593,738					6,588,747	1,000,000	6,588,747	4,830,600	0.81	0.73
10	Plant Unit Info	819	593,738	97.5%	97.5%	97.5%	11,097			6,588,747	4,830,600	0.81	
11	*Turkey Point 4*												
12	Nuclear		593,738					6,588,747	1,000,000	6,588,747	5,190,500	0.87	0.79
13	Plant Unit Info	819	593,738	97.5%	97.5%	97.5%	11,097			6,588,747	5,190,500	0.87	
14	*Turkey Point 5*												
15	Gas		582,790					4,076,124	1,000,000	4,076,124	19,441,649	3.34	4.77
16	Plant Unit Info	1,053	582,790	74.4%	80.3%	80.1%	6,994			4,076,124	19,441,649	3.34	
17	*WCEC 01*												
18	Gas		820,608					5,653,304	1,000,000	5,653,304	27,168,543	3.31	4.81
19	Plant Unit Info	1,219	820,608	90.5%	94.4%	90.5%	6,889			5,653,304	27,168,543	3.31	
20	*WCEC 02*												
21	Gas		829,473					5,717,343	1,000,000	5,717,343	26,938,506	3.25	4.71
22	Plant Unit Info	1,219	829,473	91.5%	94.7%	91.5%	6,893			5,717,343	26,938,506	3.25	
23	*WCEC 03*												
24	Gas		844,376					5,725,822	1,000,000	5,725,822	26,505,506	3.14	4.63
25	Plant Unit Info	1,219	844,376	93.1%	94.1%	93.1%	6,781			5,725,822	26,505,506	3.14	
26	**System Totals**												
27	Plant Unit Info	23,207	10,204,247				8,138			83,044,891	275,371,825	2.70	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**Aug - 2013**												
3	*CCEC*												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		696,469					4,572,838	1,000,000	4,572,838	21,435,398	3.08	4.69
6	Plant Unit Info	1,210	696,469	77.4%	94.7%	99.9%	6,566			4,572,838	21,435,398	3.08	
7	*Desoto Solar*												
8	Solar		4,866										
9	Plant Unit Info	25	4,866										
10	*Everglades 1-12*												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	342	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	*Fort Myers 1-12*												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	552	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	*Fort Myers 2*												
18	Gas		470,233					3,377,562	1,000,000	3,377,562	16,113,153	3.43	4.77
19	Plant Unit Info	1,349	470,233	46.9%	94.2%	95.0%	7,183			3,377,562	16,113,153	3.43	
20	*Fort Myers 3A_B*												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		26,392					379,309	1,000,000	379,309	1,853,044	7.02	4.89
23	Plant Unit Info	296	26,392	24.0%	94.7%	94.9%	14,372			379,309	1,853,044	7.02	
24	*Lauderdale 1-24*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	684	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	*Lauderdale 4*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		89,939					736,326	1,000,000	736,326	3,596,379	4.00	4.88
31	Plant Unit Info	438	89,939	27.6%	94.4%	94.6%	8,187			736,326	3,596,379	4.00	
32	*Lauderdale 5*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		105,254					858,595	1,000,000	858,595	4,193,824	3.98	4.88
35	Plant Unit Info	438	105,254	32.3%	94.1%	94.2%	8,157			858,595	4,193,824	3.98	
36	*Manatee 1*												
37	Heavy Oil		35,272					64,746	6,400,040	414,377	6,581,666	18.66	101.65

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		26,104					272,267	1,000,000	272,267	1,333,832	5.11	4.90
2	Plant Unit Info	788	61,376	10.5%	57.3%	59.0%	11,188			686,644	7,915,497	12.90	
3	*Manatee 2*												
4	Heavy Oil		38,040					68,628	6,399,953	439,216	6,976,256	18.34	101.65
5	Gas		27,422					284,006	1,000,000	284,006	1,394,023	5.08	4.91
6	Plant Unit Info	788	65,462	11.2%	94.7%	64.9%	11,048			723,222	8,370,279	12.79	
7	*Manatee 3*												
8	Gas		746,967					5,116,131	1,000,000	5,116,131	24,494,532	3.28	4.79
9	Plant Unit Info	1,058	746,967	94.9%	94.8%	94.9%	6,849			5,116,131	24,494,532	3.28	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		6,963					10,282	6,399,825	65,803	1,099,209	15.79	106.91
16	Gas		16,248					185,218	1,000,000	185,218	903,564	5.56	4.88
17	Plant Unit Info	802	23,211	3.9%	95.1%	60.3%	10,815			251,021	2,002,773	8.63	
18	*Martin 3*												
19	Gas		105,411					789,363	1,000,000	789,363	3,758,767	3.57	4.76
20	Plant Unit Info	431	105,411	32.9%	94.3%	94.8%	7,488			789,363	3,758,767	3.57	
21	*Martin 4*												
22	Gas		110,693					826,068	1,000,000	826,068	3,933,636	3.55	4.76
23	Plant Unit Info	431	110,693	34.5%	94.4%	94.8%	7,463			826,068	3,933,636	3.55	
24	*Martin 8*												
25	Gas		546,806					3,857,087	1,000,000	3,857,087	18,400,589	3.37	4.77
26	Plant Unit Info	1,052	546,806	69.9%	94.8%	94.7%	7,054			3,857,087	18,400,589	3.37	
27	*Martin 8 Solar*												
28	Solar		12,486										
29	Plant Unit Info	0	12,486										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*Putnam 1*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		44,287					397,437	1,000,000	397,437	1,941,289	4.38	4.88
12	Plant Unit Info	239	44,287	24.9%	94.3%	95.0%	8,974			397,437	1,941,289	4.38	
13	*Putnam 2*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		22,030					239,634	1,000,000	239,634	1,170,030	5.31	4.88
16	Plant Unit Info	239	22,030	12.4%	47.1%	47.5%	10,878			239,634	1,170,030	5.31	
17	*Sanford 4*												
18	Gas		322,180					2,315,913	1,000,000	2,315,913	11,045,734	3.43	4.77
19	Plant Unit Info	905	322,180	47.9%	94.7%	100.0%	7,188			2,315,913	11,045,734	3.43	
20	*Sanford 5*												
21	Gas		298,373					2,163,771	1,000,000	2,163,771	10,319,448	3.46	4.77
22	Plant Unit Info	901	298,373	44.5%	94.7%	94.9%	7,252			2,163,771	10,319,448	3.46	
23	*Scherer 4*												
24	Coal		435,822					254,847	17,499,982	4,459,818	10,950,600	2.51	42.97
25	Plant Unit Info	629	435,822	93.1%	93.8%	93.1%	10,233			4,459,818	10,950,600	2.51	
26	*St Johns 1O*												
27	Coal		60,327					24,716	25,059,597	619,373	2,581,600	4.28	104.45
28	Plant Unit Info	124	60,327	65.4%	93.5%	65.4%	10,267			619,373	2,581,600	4.28	
29	*St Johns 2O*												
30	Coal		65,293					26,369	25,060,033	660,808	2,754,300	4.22	104.45
31	Plant Unit Info	124	65,293	70.8%	94.0%	70.8%	10,121			660,808	2,754,300	4.22	
32	*St Lucie 1*												
33	Nuclear		713,072					7,631,183	1,000,000	7,631,183	5,528,500	0.78	0.72
34	Plant Unit Info	983	713,072	97.5%	97.5%	97.5%	10,702			7,631,183	5,528,500	0.78	
35	*St Lucie 2*												
36	Nuclear		610,059					6,488,588	1,000,000	6,488,588	4,807,800	0.79	0.74
37	Plant Unit Info	841	610,059	97.5%	97.5%	97.5%	10,636			6,488,588	4,807,800	0.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,684										
3	Plant Unit Info	10	1,684										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	378	0	0.0%	94.5%	0.0%	0			0	0	0.00	
8	*Turkey Point 3*												
9	Nuclear		593,738					6,588,747	1,000,000	6,588,747	4,830,600	0.81	0.73
10	Plant Unit Info	819	593,738	97.5%	97.5%	97.5%	11,097			6,588,747	4,830,600	0.81	
11	*Turkey Point 4*												
12	Nuclear		593,738					6,588,747	1,000,000	6,588,747	5,190,500	0.87	0.79
13	Plant Unit Info	819	593,738	97.5%	97.5%	97.5%	11,097			6,588,747	5,190,500	0.87	
14	*Turkey Point 5*												
15	Gas		637,379					4,418,580	1,000,000	4,418,580	21,239,143	3.33	4.81
16	Plant Unit Info	1,053	637,379	81.4%	88.0%	89.1%	6,932			4,418,580	21,239,143	3.33	
17	*WCEC 01*												
18	Gas		830,058					5,719,894	1,000,000	5,719,894	27,556,724	3.32	4.82
19	Plant Unit Info	1,219	830,058	91.5%	94.4%	91.5%	6,891			5,719,894	27,556,724	3.32	
20	*WCEC 02*												
21	Gas		843,323					5,817,164	1,000,000	5,817,164	27,806,855	3.30	4.78
22	Plant Unit Info	1,219	843,323	93.0%	94.7%	93.0%	6,898			5,817,164	27,806,855	3.30	
23	*WCEC 03*												
24	Gas		852,838					5,787,744	1,000,000	5,787,744	27,130,300	3.18	4.69
25	Plant Unit Info	1,219	852,838	94.0%	94.1%	94.0%	6,786			5,787,744	27,130,300	3.18	
26	**System Totals**												
27	Plant Unit Info	23,207	9,989,764				8,216			82,071,567	280,921,295	2.81	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**Sep - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		653,998					4,293,957	1,000,000	4,293,957	20,043,179	3.06	4.67
6	Plant Unit Info	1,210	653,998	75.1%	94.7%	99.9%	6,566			4,293,957	20,043,179	3.06	
7	Desoto Solar												
8	Solar		4,327										
9	Plant Unit Info	25	4,327										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	342	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		915					3,037	5,828,778	17,702	407,800	44.57	134.28
16	Plant Unit Info	552	915	0.2%	98.4%	41.4%	19,346			17,702	407,800	44.57	
17	Fort Myers 2												
18	Gas		37,157					268,450	1,000,000	268,450	1,275,324	3.43	4.75
19	Plant Unit Info	1,349	37,157	3.8%	56.5%	95.0%	7,225			268,450	1,275,324	3.43	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		26,813					384,818	1,000,000	384,818	1,872,385	6.98	4.87
23	Plant Unit Info	296	26,813	25.2%	94.7%	94.9%	14,352			384,818	1,872,385	6.98	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	684	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		104,860					859,333	1,000,000	859,333	4,180,003	3.99	4.86
31	Plant Unit Info	438	104,860	33.3%	94.4%	94.6%	8,195			859,333	4,180,003	3.99	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		116,076					948,032	1,000,000	948,032	4,611,790	3.97	4.86
35	Plant Unit Info	438	116,076	36.8%	94.1%	94.6%	8,167			948,032	4,611,790	3.97	
36	Manatee 1												
37	Heavy Oil		52,240					89,638	6,399,998	573,683	9,114,600	17.45	101.68

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		35,045					361,828	1,000,000	361,828	1,768,911	5.05	4.89
2	Plant Unit Info	788	87,285	15.4%	93.5%	71.5%	10,718			935,511	10,883,511	12.47	
3	*Manatee 2*												
4	Heavy Oil		61,249					106,747	6,400,002	683,181	10,854,200	17.72	101.68
5	Gas		42,485					439,311	1,000,000	439,311	2,152,051	5.07	4.90
6	Plant Unit Info	788	103,734	18.3%	94.7%	75.7%	10,821			1,122,492	13,006,251	12.54	
7	*Manatee 3*												
8	Gas		721,209					4,939,586	1,000,000	4,939,586	23,549,089	3.27	4.77
9	Plant Unit Info	1,058	721,209	94.7%	94.8%	94.7%	6,849			4,939,586	23,549,089	3.27	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		16,474					24,245	6,400,041	155,169	2,592,600	15.74	106.93
16	Gas		38,440					432,165	1,000,000	432,165	2,101,668	5.47	4.86
17	Plant Unit Info	802	54,914	9.5%	95.1%	65.2%	10,695			587,334	4,694,268	8.55	
18	*Martin 3*												
19	Gas		135,236					1,005,919	1,000,000	1,005,919	4,770,210	3.53	4.74
20	Plant Unit Info	431	135,236	43.6%	94.3%	94.8%	7,438			1,005,919	4,770,210	3.53	
21	*Martin 4*												
22	Gas		147,455					1,091,373	1,000,000	1,091,373	5,175,397	3.51	4.74
23	Plant Unit Info	431	147,455	47.5%	94.4%	94.8%	7,401			1,091,373	5,175,397	3.51	
24	*Martin 8*												
25	Gas		689,798					4,821,125	1,000,000	4,821,125	22,867,535	3.32	4.74
26	Plant Unit Info	1,052	689,798	91.1%	94.8%	94.2%	6,989			4,821,125	22,867,535	3.32	
27	*Martin 8 Solar*												
28	Solar		11,489										
29	Plant Unit Info	0	11,489										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*Putnam 1*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		53,371					478,501	1,000,000	478,501	2,327,892	4.36	4.86
12	Plant Unit Info	239	53,371	31.0%	94.3%	95.0%	8,966			478,501	2,327,892	4.36	
13	*Putnam 2*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		29,070					286,986	1,000,000	286,986	1,395,835	4.80	4.86
16	Plant Unit Info	239	29,070	16.9%	62.8%	64.7%	9,872			286,986	1,395,835	4.80	
17	*Sanford 4*												
18	Gas		409,964					2,928,949	1,000,000	2,928,949	13,912,827	3.39	4.75
19	Plant Unit Info	905	409,964	62.9%	94.7%	100.0%	7,144			2,928,949	13,912,827	3.39	
20	*Sanford 5*												
21	Gas		346,250					2,497,817	1,000,000	2,497,817	11,866,142	3.43	4.75
22	Plant Unit Info	901	346,250	53.4%	94.7%	94.9%	7,214			2,497,817	11,866,142	3.43	
23	*Scherer 4*												
24	Coal		414,355					242,450	17,500,004	4,242,876	10,409,500	2.51	42.93
25	Plant Unit Info	629	414,355	91.5%	93.8%	91.5%	10,240			4,242,876	10,409,500	2.51	
26	*St Johns 1Q*												
27	Coal		60,287					24,608	25,059,940	616,675	2,570,400	4.26	104.45
28	Plant Unit Info	124	60,287	67.5%	93.5%	67.5%	10,229			616,675	2,570,400	4.26	
29	*St Johns 2Q*												
30	Coal		64,147					25,884	25,059,805	648,648	2,703,600	4.21	104.45
31	Plant Unit Info	124	64,147	71.9%	94.0%	71.8%	10,112			648,648	2,703,600	4.21	
32	*St Lucie 1*												
33	Nuclear		92,009					984,679	1,000,000	984,679	713,400	0.78	0.72
34	Plant Unit Info	983	92,009	13.0%	13.0%	97.5%	10,702			984,679	713,400	0.78	
35	*St Lucie 2*												
36	Nuclear		590,380					6,279,280	1,000,000	6,279,280	4,652,700	0.79	0.74
37	Plant Unit Info	841	590,380	97.5%	97.5%	97.5%	10,636			6,279,280	4,652,700	0.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,492										
3	Plant Unit Info	10	1,492										
4	*Turkey Point 1*												
5	Heavy Oil		9,814					14,715	6,400,204	94,179	1,573,600	16.03	106.94
6	Gas		6,707					72,974	1,000,000	72,974	354,619	5.29	4.86
7	Plant Unit Info	378	16,521	6.1%	94.5%	91.1%	10,118			167,153	1,928,219	11.67	
8	*Turkey Point 3*												
9	Nuclear		574,585					6,376,204	1,000,000	6,376,204	4,674,800	0.81	0.73
10	Plant Unit Info	819	574,585	97.5%	97.5%	97.5%	11,097			6,376,204	4,674,800	0.81	
11	*Turkey Point 4*												
12	Nuclear		574,585					6,376,204	1,000,000	6,376,204	5,023,100	0.87	0.79
13	Plant Unit Info	819	574,585	97.5%	97.5%	97.5%	11,097			6,376,204	5,023,100	0.87	
14	*Turkey Point 5*												
15	Gas		711,791					4,899,199	1,000,000	4,899,199	23,558,795	3.31	4.81
16	Plant Unit Info	1,053	711,791	93.9%	94.9%	93.9%	6,883			4,899,199	23,558,795	3.31	
17	*WCEC 01*												
18	Gas		796,508					5,486,567	1,000,000	5,486,567	26,284,894	3.30	4.79
19	Plant Unit Info	1,219	796,508	90.8%	94.4%	90.8%	6,888			5,486,567	26,284,894	3.30	
20	*WCEC 02*												
21	Gas		805,070					5,549,956	1,000,000	5,549,956	26,376,975	3.28	4.75
22	Plant Unit Info	1,219	805,070	91.7%	94.7%	91.7%	6,894			5,549,956	26,376,975	3.28	
23	*WCEC 03*												
24	Gas		819,422					5,557,744	1,000,000	5,557,744	25,942,230	3.17	4.67
25	Plant Unit Info	1,219	819,422	93.4%	94.1%	93.4%	6,783			5,557,744	25,942,230	3.17	
26	**System Totals**												
27	Plant Unit Info	23,207	9,255,074				8,066			74,653,069	281,678,050	3.04	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**Oct - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		673,374					4,421,201	1,000,000	4,421,201	21,164,704	3.14	4.79
6	Plant Unit Info	1,210	673,374	74.8%	94.7%	99.9%	6,566			4,421,201	21,164,704	3.14	
7	Desoto Solar												
8	Solar		4,176										
9	Plant Unit Info	25	4,176										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	342	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	552	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	1,349	0	0.0%	12.8%	0.0%	0			0	0	0.00	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		22,742					326,496	1,000,000	326,496	1,624,794	7.14	4.98
23	Plant Unit Info	296	22,742	20.7%	94.7%	94.9%	14,357			326,496	1,624,794	7.14	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	684	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		103,323					844,349	1,000,000	844,349	4,194,495	4.06	4.97
31	Plant Unit Info	438	103,323	31.7%	94.4%	94.0%	8,172			844,349	4,194,495	4.06	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		110,628					904,169	1,000,000	904,169	4,492,014	4.06	4.97
35	Plant Unit Info	438	110,628	34.0%	94.1%	93.9%	8,173			904,169	4,492,014	4.06	
36	Manatee 1												
37	Heavy Oil		35,744					64,846	6,400,009	415,015	6,525,800	18.26	100.64

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1	Gas		26,418					275,514	1,000,000	275,514	1,372,039	5.19	4.98
2	Plant Unit Info	788	62,162	10.6%	93.5%	59.8%	11,108			690,529	7,897,839	12.71	
3	*Manatee 2*												
4	Heavy Oil		21,720					37,735	6,399,973	241,503	3,797,500	17.48	100.64
5	Gas		14,687					151,588	1,000,000	151,588	759,119	5.17	5 01
6	Plant Unit Info	788	36,407	6.2%	94.7%	82.5%	10,797			393,091	4,556,619	12.52	
7	*Manatee 3*												
8	Gas		735,418					5,037,402	1,000,000	5,037,402	24,575,697	3.34	4.88
9	Plant Unit Info	1,058	735,418	93.4%	94.8%	93.4%	6,850			5,037,402	24,575,697	3.34	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		5,088					7,476	6,399,813	47,845	801,500	15.75	107.21
16	Gas		11,872					133,220	1,000,000	133,220	662,703	5.58	4.97
17	Plant Unit Info	802	16,960	2.8%	95.1%	66.1%	10,676			181,065	1,464,203	8.63	
18	*Martin 3*												
19	Gas		69,457					518,710	1,000,000	518,710	2,521,976	3.63	4.86
20	Plant Unit Info	431	69,457	21.7%	54.7%	94.8%	7,468			518,710	2,521,976	3.63	
21	*Martin 4*												
22	Gas		138,610					1,027,645	1,000,000	1,027,645	4,996,422	3.60	4.86
23	Plant Unit Info	431	138,610	43.2%	94.4%	94.6%	7,414			1,027,645	4,996,422	3.60	
24	*Martin 8*												
25	Gas		498,145					3,526,460	1,000,000	3,526,460	17,185,426	3.45	4.87
26	Plant Unit Info	1,052	498,145	63.7%	89.5%	94.7%	7,079			3,526,460	17,185,426	3.45	
27	*Martin 8 Solar*												
28	Solar		12,432										
29	Plant Unit Info	0	12,432										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0 0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*Putnam 1*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		43,833					393,484	1,000,000	393,484	1,956,576	4.46	4.97
12	Plant Unit Info	239	43,833	24.7%	94.3%	95.0%	8,977			393,484	1,956,576	4.46	
13	*Putnam 2*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		40,880					367,509	1,000,000	367,509	1,830,198	4.48	4.98
16	Plant Unit Info	239	40,880	23.0%	94.2%	95.0%	8,990			367,509	1,830,198	4.48	
17	*Sanford 4*												
18	Gas		375,574					2,690,995	1,000,000	2,690,995	13,095,647	3.49	4.87
19	Plant Unit Info	905	375,574	55.8%	94.7%	100.0%	7,165			2,690,995	13,095,647	3.49	
20	*Sanford 5*												
21	Gas		252,420					1,914,247	1,000,000	1,914,247	9,309,432	3.69	4.86
22	Plant Unit Info	901	252,420	37.7%	71.8%	73.3%	7,584			1,914,247	9,309,432	3.69	
23	*Scherer 4*												
24	Coal		413,273					242,245	17,499,994	4,239,286	10,388,800	2.51	42.89
25	Plant Unit Info	629	413,273	88.3%	93.8%	88.3%	10,258			4,239,286	10,388,800	2.51	
26	*St Johns 1O*												
27	Coal		53,393					22,211	25,059,520	556,597	2,368,500	4.44	106.64
28	Plant Unit Info	124	53,393	57.9%	93.5%	57.9%	10,425			556,597	2,368,500	4.44	
29	*St Johns 2O*												
30	Coal		59,127					24,195	25,059,640	606,318	2,580,100	4.36	106.64
31	Plant Unit Info	124	59,127	64.1%	94.0%	64.1%	10,255			606,318	2,580,100	4.36	
32	*St Lucie 1*												
33	Nuclear		437,043					4,677,215	1,000,000	4,677,215	3,388,400	0.78	0.72
34	Plant Unit Info	983	437,043	59.8%	59.8%	97.5%	10,702			4,677,215	3,388,400	0.78	
35	*St Lucie 2*												
36	Nuclear		610,059					6,488,588	1,000,000	6,488,588	4,807,800	0.79	0.74
37	Plant Unit Info	841	610,059	97.5%	97.5%	97.5%	10,636			6,488,588	4,807,800	0.79	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,436										
3	Plant Unit Info	10	1,436										
4	*Turkey Point 1*												
5	Heavy Oil		1,075					1,630	6,400,613	10,433	174,800	16.26	107.24
6	Gas		1,066					11,762	1,000,000	11,762	58,494	5.49	4.97
7	Plant Unit Info	378	2,141	0.8%	94.5%	70.8%	10,368			22,195	233,294	10.90	
8	*Turkey Point 3*												
9	Nuclear		383,057					4,250,775	1,000,000	4,250,775	3,116,500	0.81	0.73
10	Plant Unit Info	819	383,057	62.9%	62.9%	97.5%	11,097			4,250,775	3,116,500	0.81	
11	*Turkey Point 4*												
12	Nuclear		593,738					6,588,747	1,000,000	6,588,747	5,190,500	0.87	0.79
13	Plant Unit Info	819	593,738	97.5%	97.5%	97.5%	11,097			6,588,747	5,190,500	0.87	
14	*Turkey Point 5*												
15	Gas		672,769					4,645,311	1,000,000	4,645,311	22,780,607	3.39	4.90
16	Plant Unit Info	1,053	672,769	85.9%	94.9%	93.4%	6,905			4,645,311	22,780,607	3.39	
17	*WCEC 01*												
18	Gas		815,489					5,618,767	1,000,000	5,618,767	27,495,122	3.37	4.89
19	Plant Unit Info	1,219	815,489	89.9%	94.4%	89.9%	6,890			5,618,767	27,495,122	3.37	
20	*WCEC 02*												
21	Gas		825,530					5,690,477	1,000,000	5,690,477	27,395,582	3.32	4.81
22	Plant Unit Info	1,219	825,530	91.0%	94.7%	91.0%	6,893			5,690,477	27,395,582	3.32	
23	*WCEC 03*												
24	Gas		843,380					5,719,436	1,000,000	5,719,436	27,379,458	3.25	4.79
25	Plant Unit Info	1,219	843,380	93.0%	94.1%	93.0%	6,782			5,719,436	27,379,458	3.25	
26	**System Totals**												
27	Plant Unit Info	23,207	8,906,975				8,122			72,341,061	257,990,705	2.90	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1													
2	**Nov - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		528,619					3,454,143	1,000,000	3,454,143	17,364,863	3.28	5.03
6	Plant Unit Info	1,355	528,619	54.2%	72.6%	94.5%	6,534			3,454,143	17,364,863	3.28	
7	Desoto Solar												
8	Solar		3,573										
9	Plant Unit Info	25	3,573										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	383	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	627	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		272,394					1,933,356	1,000,000	1,933,356	9,882,458	3.63	5.11
19	Plant Unit Info	1,440	272,394	26.3%	60.7%	94.6%	7,098			1,933,356	9,882,458	3.63	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		2,956					40,653	1,000,000	40,653	208,333	7.05	5.12
23	Plant Unit Info	328	2,956	2.5%	94.7%	94.9%	13,755			40,653	208,333	7.05	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	766	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		37,446					304,500	1,000,000	304,500	1,559,893	4.17	5.12
31	Plant Unit Info	447	37,446	11.6%	94.4%	92.1%	8,132			304,500	1,559,893	4.17	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		32,390					261,700	1,000,000	261,700	1,340,750	4.14	5.12
35	Plant Unit Info	447	32,390	10.1%	47.1%	91.7%	8,080			261,700	1,340,750	4.14	
36	Manatee 1												
37	Heavy Oil		4,567					8,524	6,400,282	54,556	860,200	18.84	100.92

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		6,034					64,583	1,000,000	64,583	330,349	5.48	5.12
2	Plant Unit Info	798	10,601	1.9%	93.5%	39.1%	11,239			119,139	1,190,549	11.23	
3	*Manatee 2*												
4	Heavy Oil		1,534					3,013	6,399,270	19,281	304,000	19.82	100.90
5	Gas		1,429					14,941	1,000,000	14,941	76,567	5.36	5.12
6	Plant Unit Info	798	2,963	0.5%	94.7%	46.4%	11,551			34,222	380,567	12.85	
7	*Manatee 3*												
8	Gas		506,783					3,484,106	1,000,000	3,484,106	17,809,997	3.51	5.11
9	Plant Unit Info	1,117	506,783	63.0%	94.8%	94.1%	6,875			3,484,106	17,809,997	3.51	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	808	0	0.0%	95.1%	0.0%	0			0	0	0.00	
18	*Martin 3*												
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	462	0	0.0%	0.0%	0.0%	0			0	0	0.00	
21	*Martin 4*												
22	Gas		76,622					564,069	1,000,000	564,069	2,879,353	3.76	5.10
23	Plant Unit Info	462	76,622	23.0%	94.4%	94.8%	7,362			564,069	2,879,353	3.76	
24	*Martin 8*												
25	Gas		653,805					4,471,483	1,000,000	4,471,483	22,837,963	3.49	5.11
26	Plant Unit Info	1,112	653,805	81.7%	94.8%	93.9%	6,839			4,471,483	22,837,963	3.49	
27	*Martin 8 Solar*												
28	Solar		11,467										
29	Plant Unit Info	0	11,467										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Pt Everglades 3												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	Pt Everglades 4												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	Putnam 1												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		7,541					67,025	1,000,000	67,025	343,433	4.55	5.12
12	Plant Unit Info	248	7,541	4.2%	86.5%	95.0%	8,888			67,025	343,433	4.55	
13	Putnam 2												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		3,771					33,578	1,000,000	33,578	172,199	4.57	5.13
16	Plant Unit Info	248	3,771	2.1%	94.2%	95.0%	8,905			33,578	172,199	4.57	
17	Sanford 4												
18	Gas		297,786					2,136,681	1,000,000	2,136,681	10,914,197	3.67	5.11
19	Plant Unit Info	955	297,786	43.3%	94.7%	94.8%	7,175			2,136,681	10,914,197	3.67	
20	Sanford 5												
21	Gas		205,959					1,535,823	1,000,000	1,535,823	7,843,790	3.81	5.11
22	Plant Unit Info	952	205,959	30.1%	94.7%	76.4%	7,457			1,535,823	7,843,790	3.81	
23	Scherer 4												
24	Coal		408,638					237,704	17,499,979	4,159,815	10,205,300	2.50	42.93
25	Plant Unit Info	635	408,638	89.4%	93.8%	89.4%	10,180			4,159,815	10,205,300	2.50	
26	St Johns 10												
27	Coal		41,771					17,798	25,060,288	446,023	1,880,600	4.50	105.66
28	Plant Unit Info	124	41,771	46.8%	93.5%	46.8%	10,678			446,023	1,880,600	4.50	
29	St Johns 20												
30	Coal		48,201					20,005	25,059,435	501,314	2,113,700	4.39	105.66
31	Plant Unit Info	124	48,201	54.0%	94.0%	54.0%	10,400			501,314	2,113,700	4.39	
32	St Lucie 1												
33	Nuclear		699,889					7,383,166	1,000,000	7,383,166	5,348,800	0.76	0.72
34	Plant Unit Info	997	699,889	97.5%	97.5%	97.5%	10,549			7,383,166	5,348,800	0.76	
35	St Lucie 2												
36	Nuclear		598,100					6,271,150	1,000,000	6,271,150	4,646,700	0.78	0.74
37	Plant Unit Info	852	598,100	97.5%	97.5%	97.5%	10,485			6,271,150	4,646,700	0.78	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	*Space Coast*												
2	Solar		1,228										
3	Plant Unit Info	10	1,228										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	380	0	0.0%	94.5%	0.0%	0			0	0	0.00	
8	*Turkey Point 3*												
9	Nuclear		59,144					637,567	1,000,000	637,567	467,400	0.79	0.73
10	Plant Unit Info	843	59,144	9.8%	9.7%	97.5%	10,780			637,567	467,400	0.79	
11	*Turkey Point 4*												
12	Nuclear		591,434					6,375,615	1,000,000	6,375,615	5,022,600	0.85	0.79
13	Plant Unit Info	843	591,434	97.5%	97.5%	97.5%	10,780			6,375,615	5,022,600	0.85	
14	*Turkey Point 5*												
15	Gas		391,106					2,734,061	1,000,000	2,734,061	14,072,612	3.60	5.15
16	Plant Unit Info	1,114	391,106	48.8%	94.9%	94.9%	6,991			2,734,061	14,072,612	3.60	
17	*WCEC 01*												
18	Gas		842,079					5,745,400	1,000,000	5,745,400	29,047,544	3.45	5.06
19	Plant Unit Info	1,335	842,079	87.6%	94.4%	88.7%	6,823			5,745,400	29,047,544	3.45	
20	*WCEC 02*												
21	Gas		872,089					5,961,404	1,000,000	5,961,404	29,969,993	3.44	5.03
22	Plant Unit Info	1,335	872,089	90.7%	94.7%	90.7%	6,836			5,961,404	29,969,993	3.44	
23	*WCEC 03*												
24	Gas		399,518					2,740,194	1,000,000	2,740,194	13,775,656	3.45	5.03
25	Plant Unit Info	1,335	399,518	41.6%	48.1%	69.6%	6,859			2,740,194	13,775,656	3.45	
26	**System Totals**												
27	Plant Unit Info	24,513	7,607,870				8,070			61,396,187	211,279,250	2.78	
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1													
2	**Dec - 2013**												
3	CCEC												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		683,084					4,463,312	1,000,000	4,463,312	23,460,554	3.43	5.26
6	Plant Unit Info	1,355	683,084	67.8%	94.7%	94.1%	6,534			4,463,312	23,460,554	3.43	
7	Desoto Solar												
8	Solar		3,245										
9	Plant Unit Info	25	3,245										
10	Everglades 1-12												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	383	0	0.0%	88.3%	0.0%	0			0	0	0.00	
14	Fort Myers 1-12												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	627	0	0.0%	98.4%	0.0%	0			0	0	0.00	
17	Fort Myers 2												
18	Gas		377,843					2,684,115	1,000,000	2,684,115	14,343,348	3.80	5.34
19	Plant Unit Info	1,440	377,843	35.3%	94.2%	91.7%	7,104			2,684,115	14,343,348	3.80	
20	Fort Myers 3A_B												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	328	0	0.0%	94.7%	0.0%	0			0	0	0.00	
24	Lauderdale 1-24												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	766	0	0.0%	91.7%	0.0%	0			0	0	0.00	
28	Lauderdale 4												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	447	0	0.0%	94.4%	0.0%	0			0	0	0.00	
32	Lauderdale 5												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		9,180					75,847	1,000,000	75,847	406,245	4.43	5.36
35	Plant Unit Info	447	9,180	2.8%	39.5%	79.0%	8,262			75,847	406,245	4.43	
36	Manatee 1												
37	Heavy Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	798	0	0.0%	93.5%	0.0%	0			0	0	0.00	
3	*Manatee 2*												
4	Heavy Oil		0					0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	798	0	0.0%	94.7%	0.0%	0			0	0	0.00	
7	*Manatee 3*												
8	Gas		464,374					3,192,145	1,000,000	3,192,145	17,053,652	3.67	5.34
9	Plant Unit Info	1,117	464,374	55.9%	94.8%	93.2%	6,874			3,192,145	17,053,652	3.67	
10	*Martin 1*												
11	Heavy Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
14	*Martin 2*												
15	Heavy Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	808	0	0.0%	95.1%	0.0%	0			0	0	0.00	
18	*Martin 3*												
19	Gas		10,682					80,492	1,000,000	80,492	429,670	4.02	5.34
20	Plant Unit Info	462	10,682	3.1%	39.5%	85.6%	7,535			80,492	429,670	4.02	
21	*Martin 4*												
22	Gas		23,290					171,170	1,000,000	171,170	913,831	3.92	5.34
23	Plant Unit Info	462	23,290	6.8%	94.4%	91.7%	7,349			171,170	913,831	3.92	
24	*Martin 8*												
25	Gas		408,016					2,884,859	1,000,000	2,884,859	15,426,202	3.78	5.35
26	Plant Unit Info	1,112	408,016	49.3%	94.8%	79.8%	7,070			2,884,859	15,426,202	3.78	
27	*Martin 8 Solar*												
28	Solar		12,797										
29	Plant Unit Info	0	12,797										
30	*Pt Everglades 1*												
31	Heavy Oil		0					0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
34	*Pt Everglades 2*												
35	Heavy Oil		0					0	0	0	0	0.00	0.00
36	Gas		0					0	0	0	0	0.00	0.00
37	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	*Pt Everglades 3*												
2	Heavy Oil		0					0	0	0	0	0.00	0.00
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
5	*Pt Everglades 4*												
6	Heavy Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*Putnam 1*												
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	248	0	0.0%	94.3%	0.0%	0			0	0	0.00	
13	*Putnam 2*												
14	Light 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	248	0	0.0%	94.2%	0.0%	0			0	0	0.00	
17	*Sanford 4*												
18	Gas		311,559					2,221,771	1,000,000	2,221,771	11,864,919	3.81	5.34
19	Plant Unit Info	955	311,559	43.9%	94.7%	93.2%	7,131			2,221,771	11,864,919	3.81	
20	*Sanford 5*												
21	Gas		135,452					971,001	1,000,000	971,001	5,186,833	3.83	5.34
22	Plant Unit Info	952	135,452	19.1%	94.7%	93.0%	7,169			971,001	5,186,833	3.83	
23	*Scherer 4*												
24	Coal		414,026					240,868	17,500,012	4,215,193	10,352,100	2.50	42.98
25	Plant Unit Info	635	414,026	87.6%	93.8%	87.6%	10,181			4,215,193	10,352,100	2.50	
26	*St Johns 1O*												
27	Coal		42,368					18,118	25,059,830	454,034	1,870,400	4.41	103.23
28	Plant Unit Info	124	42,368	45.9%	93.5%	45.9%	10,716			454,034	1,870,400	4.41	
29	*St Johns 2O*												
30	Coal		52,934					21,623	25,059,797	541,868	2,232,200	4.22	103.23
31	Plant Unit Info	124	52,934	57.4%	94.0%	57.4%	10,237			541,868	2,232,200	4.22	
32	*St Lucie 1*												
33	Nuclear		723,218					7,629,271	1,000,000	7,629,271	5,527,100	0.76	0.72
34	Plant Unit Info	997	723,218	97.5%	97.5%	97.5%	10,549			7,629,271	5,527,100	0.76	
35	*St Lucie 2*												
36	Nuclear		618,037					6,480,189	1,000,000	6,480,189	4,801,600	0.78	0.74
37	Plant Unit Info	852	618,037	97.5%	97.5%	97.5%	10,485			6,480,189	4,801,600	0.78	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1	*Space Coast*												
2	Solar		1,087										
3	Plant Unit Info	10	1,087										
4	*Turkey Point 1*												
5	Heavy Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	380	0	0.0%	94.5%	0.0%	0			0	0	0.00	
8	*Turkey Point 3*												
9	Nuclear		611,148					6,588,134	1,000,000	6,588,134	4,830,200	0.79	0.73
10	Plant Unit Info	843	611,148	97.5%	97.5%	97.5%	10,780			6,588,134	4,830,200	0.79	
11	*Turkey Point 4*												
12	Nuclear		611,148					6,588,134	1,000,000	6,588,134	5,190,000	0.85	0.79
13	Plant Unit Info	843	611,148	97.5%	97.5%	97.5%	10,780			6,588,134	5,190,000	0.85	
14	*Turkey Point 5*												
15	Gas		390,063					2,718,073	1,000,000	2,718,073	14,608,463	3.75	5.37
16	Plant Unit Info	1,114	390,063	47.1%	94.9%	92.1%	6,968			2,718,073	14,608,463	3.75	
17	*WCEC 01*												
18	Gas		693,477					4,729,627	1,000,000	4,729,627	24,991,046	3.60	5.28
19	Plant Unit Info	1,335	693,477	69.8%	94.4%	86.0%	6,820			4,729,627	24,991,046	3.60	
20	*WCEC 02*												
21	Gas		801,543					5,473,798	1,000,000	5,473,798	28,772,052	3.59	5.26
22	Plant Unit Info	1,335	801,543	80.7%	94.7%	88.2%	6,829			5,473,798	28,772,052	3.59	
23	*WCEC 03*												
24	Gas		512,795					3,493,869	1,000,000	3,493,869	18,364,909	3.58	5.26
25	Plant Unit Info	1,335	512,795	51.6%	56.7%	77.3%	6,813			3,493,869	18,364,909	3.58	
26	**System Totals**												
27	Plant Unit Info	24,513	7,911,365				8,299			65,656,901	210,625,323	2.66	

30 Note: Totals may not add due to rounding.

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2013 thru June 2013

Line			January 2013	February 2013	March 2013	April 2013	May 2013	June 2013
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	0	0	0	0	0	136,712
3	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	104.6621
4	Amount	($)	0	0	0	0	0	14,308,571
5								
6	Burned:							
7	Units	(BBLS)	45,917	0	8,499	23,418	35,089	2,396
8	Unit Cost	($/BBLS)	104.6540	0.0000	103.9063	103.7322	103.3828	102.4207
9	Amount	($)	4,805,400	0	883,100	2,429,200	3,627,600	245,400
10								
11	Ending Inventory:							
12	Units	(BBLS)	2,882,690	2,882,690	2,874,191	2,850,773	2,815,684	2,950,000
13	Unit Cost	($/BBLS)	88.2718	88.2718	88.2757	88.2796	88.2876	89.0466
14	Amount	($)	254,460,349	254,460,349	253,721,223	251,664,973	248,590,015	262,687,329
15								
16	Light Oil							
17								
18								
19	Purchases.							
20	Units	(BBLS)	18,000	0	0	0	0	0
21	Unit Cost	($/BBLS)	133.8757	0.0000	0.0000	0.0000	0.0000	0.0000
22	Amount	($)	2,409,762	0	0	0	0	0
23								
24	Burned:							
25	Units	(BBLS)	1,504	0	0	0	0	0
26	Unit Cost	($/BBLS)	135.4388	0.0000	0.0000	0.0000	0.0000	0.0000
27	Amount	($)	203,700	0	0	0	0	0
28								
29	Ending Inventory:							
30	Units	(BBLS)	1,315,996	1,315,996	1,315,996	1,315,996	1,315,996	1,315,996
31	Unit Cost	($/BBLS)	117.4240	117.4240	117.4240	117.4240	117.4240	117.4240
32	Amount	($)	154,529,575	154,529,575	154,529,575	154,529,575	154,529,575	154,529,575
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	36,429	33,793	26,999	26,909	42,771	44,583
39	Unit Cost	($/Tons)	102.5008	99.8136	99.8185	102.0105	103.1072	103.1111
40	Amount	($)	3,734,000	3,373,000	2,695,000	2,745,000	4,410,000	4,597,000
41								
42	Burned:							
43	Units	(Tons)	36,429	33,793	26,999	26,909	42,771	44,583
44	Unit Cost	($/Tons)	102.5008	99.8136	99.8185	102.0105	103.1072	103.1111
45	Amount	($)	3,734,000	3,373,000	2,695,000	2,745,000	4,410,000	4,597,000
46								
47	Ending Inventory:							
48	Units	(Tons)	91,000	91,000	91,000	91,000	91,000	91,000
49	Unit Cost	($/Tons)	94.4835	94.4835	94.4835	94.4835	94.4835	94.4835
50	Amount	($)	8,598,000	8,598,000	8,598,000	8,598,000	8,598,000	8,598,000
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	3,259,708	3,405,098	3,816,855	3,558,205	3,901,520	4,158,420
57	Unit Cost	($/MBTU)	2.4364	2.4410	2.4418	2.4428	2.4462	2.4471
58	Amount	($)	7,942,000	8,312,000	9,320,000	8,692,000	9,544,000	10,176,000
59								
60	Burned:							
61	Units	(MBTU)	3,259,690	3,405,098	3,816,855	3,558,205	3,901,520	4,158,403
62	Unit Cost	($/MBTU)	2.4364	2.4410	2.4418	2.4428	2.4462	2.4471
63	Amount	($)	7,942,000	8,312,000	9,320,000	8,692,000	9,544,000	10,176,000
64								
65	Ending Inventory.							
66	Units	(MBTU)	5,035,414	5,035,414	5,035,414	5,035,416	5,035,418	5,035,416
67	Unit Cost	($/MBTU)	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333
68	Amount	($)	11,749,143	11,749,143	11,749,143	11,749,143	11,749,143	11,749,143
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	38,638,377	33,643,169	36,378,224	35,875,854	41,321,552	44,998,198
75	Unit Cost	($/MCF)	4.8714	4.9318	4.9494	4.9584	4.8468	4.7571
76	Amount	($)	188,224,241	165,921,880	180,049,602	177,886,770	200,276,868	214,060,445
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	20,705,218	18,701,487	21,789,086	25,779,072	27,297,265	26,416,707
83	Unit Cost	($/MBTU)	0.7324	0.7324	0.7351	0.7448	0.7458	0.7458
84	Amount	($)	15,164,000	13,697,000	16,018,000	19,199,000	20,358,000	19,701,000

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2013 thru December 2013

			July 2013	August 2013	September 2013	October 2013	November 2013	December 2013	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	27,747	143,656	235,345	110,057	0	0	653,517
3	Unit Cost	($/BBLS)	104.2728	102.0576	102.5512	101.0814	0.0000	0.0000	102.7099
4	Amount	($)	2,893,257	14,661,192	24,134,922	11,124,721	0	0	67,122,663
5									
6	Burned:								
7	Units	(BBLS)	27,747	143,656	235,345	111,687	11,537	0	645,291
8	Unit Cost	($/BBLS)	104.2779	102.0294	102.5516	101.1720	100.9101	0.0000	102.4964
9	Amount	($)	2,893,400	14,657,130	24,135,000	11,299,600	1,164,200	0	66,140,030
10									
11	Ending Inventory:								
12	Units	(BBLS)	2,950,000	2,950,000	2,950,000	2,948,370	2,936,833	2,936,833	2,936,833
13	Unit Cost	($/BBLS)	89.1851	89.7896	90.7153	91.0634	91.0603	91.0603	91.0603
14	Amount	($)	263,095,902	264,879,373	267,610,163	268,488,568	267,429,033	267,429,033	267,429,033
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	0	0	541	50,000	50,000	50,000	168,541
21	Unit Cost	($/BBLS)	0.0000	0.0000	134.3238	133.6644	133.7904	133.8744	133.7887
22	Amount	($)	0	0	72,669	6,683,219	6,689,519	6,693,719	22,548,886
23									
24	Burned								
25	Units	(BBLS)	0	0	3,037	0	0	0	4,541
26	Unit Cost	($/BBLS)	0.0000	0.0000	134.2772	0.0000	0.0000	0.0000	134.6620
27	Amount	($)	0	0	407,800	0	0	0	611,500
28									
29	Ending Inventory:								
30	Units	(BBLS)	1,315,996	1,315,996	1,313,500	1,363,500	1,413,500	1,463,500	1,463,500
31	Unit Cost	($/BBLS)	117.4240	117.4240	117.4314	118.0267	118.5843	119.1067	119.1067
32	Amount	($)	154,529,575	154,529,575	154,246,153	160,929,371	167,618,890	174,312,608	174,312,608
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	50,304	51,084	50,491	46,405	37,802	39,740	487,310
39	Unit Cost	($/Tons)	105.3594	104.4554	104.4543	106.6480	105.6558	103.2461	103.6507
40	Amount	($)	5,300,000	5,336,000	5,274,000	4,949,000	3,994,000	4,103,000	50,510,000
41									
42	Burned.								
43	Units	(Tons)	50,304	51,084	50,491	46,405	37,802	39,740	487,310
44	Unit Cost	($/Tons)	105.3594	104.4554	104.4543	106.6480	105.6558	103.2461	103.6507
45	Amount	($)	5,300,000	5,336,000	5,274,000	4,949,000	3,994,000	4,103,000	50,510,000
46									
47	Ending Inventory:								
48	Units	(Tons)	91,000	91,000	91,000	91,000	91,000	91,000	91,000
49	Unit Cost	($/Tons)	94.4835	94.4835	94.4835	94.4835	94.4835	94.4835	94.4835
50	Amount	($)	8,598,000	8,598,000	8,598,000	8,598,000	8,598,000	8,598,000	8,598,000
51									
52	Coal - SCHERER								
53									
54									
55	Purchases.								
56	Units	(MBTU)	4,184,373	4,459,823	4,242,875	4,239,288	4,159,820	4,215,190	47,601,173
57	Unit Cost	($/MBTU)	2.4491	2.4555	2.4533	2.4506	2.4532	2.4559	2.4483
58	Amount	($)	10,248,000	10,951,000	10,409,000	10,389,000	10,205,000	10,352,000	116,540,000
59									
60	Burned:								
61	Units	(MBTU)	4,184,373	4,459,823	4,242,875	4,239,288	4,159,820	4,215,190	47,601,138
62	Unit Cost	($/MBTU)	2.4491	2.4555	2.4533	2.4506	2.4532	2.4559	2.4483
63	Amount	($)	10,248,000	10,951,000	10,409,000	10,389,000	10,205,000	10,352,000	116,540,000
64									
65	Ending Inventory:								
66	Units	(MBTU)	5,035,418	5,035,414	5,035,417	5,035,417	5,035,416	5,035,416	5,035,416
67	Unit Cost	($/MBTU)	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333
68	Amount	($)	11,749,143	11,749,143	11,749,143	11,749,143	11,749,143	11,749,143	11,749,143
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	50,125,048	48,114,904	47,604,590	44,218,740	35,547,699	33,160,077	489,626,432
75	Unit Cost	($/MCF)	4.7197	4.7724	4.7556	4.8588	5.0757	5.3022	4.8815
76	Amount	($)	236,573,927	229,621,867	226,388,045	214,849,749	180,429,300	175,821,478	2,390,104,171
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	27,297,265	27,297,265	20,016,367	22,005,325	20,667,498	27,285,728	285,258,283
83	Unit Cost	($/MBTU)	0.7458	0.7458	0.7526	0.7500	0.7493	0.7458	0.7441
84	Amount	($)	20,358,000	20,358,000	15,064,000	16,503,000	15,486,000	20,349,000	212,255,000

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	SOLD TO	Type & Schedule	Total MWH Sold	MWH from Own Generation	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	85,200	85,200	3.437	4.745	$2,928,560	$4,043,160	$888,156
4	St Lucie Reliability Sales		53,864	53,864	0.764	0.764	$411,384	$411,384	$0
5	**Total January Estimated**		139,064	139,064	2.402	3.203	$3,339,944	$4,454,544	$888,156
6									
7	**February Estimated**								
8	Off System	OS	66,100	66,100	3.019	4.253	$1,995,400	$2,811,200	$641,976
9	St Lucie Reliability Sales		48,651	48,651	0.764	0.764	$371,573	$371,573	$0
10	**Total February Estimated**		114,751	114,751	2.063	2.774	$2,366,973	$3,182,773	$641,976
11									
12	**March Estimated**								
13	Off System	OS	26,400	26,400	3.513	4.709	$927,480	$1,243,080	$232,510
14	St Lucie Reliability Sales		53,864	53,864	0.764	0.764	$411,384	$411,384	$0
15	**Total March Estimated**		80,264	80,264	1.668	2.061	$1,338,864	$1,654,464	$232,510
16									
17	**April Estimated**								
18	Off System	OS	17,400	17,400	4.012	5.380	$698,020	$936,120	$192,428
19	St Lucie Reliability Sales		51,394	51,394	0.775	0.775	$398,213	$398,213	$0
20	**Total April Estimated**		68,794	68,794	1.594	1.940	$1,096,233	$1,334,333	$192,428
21									
22	**May Estimated**								
23	Off System	OS	13,100	13,100	5.203	6.478	$681,610	$848,610	$132,846
24	St Lucie Reliability Sales		53,107	53,107	0.775	0.775	$411,487	$411,487	$0
25	**Total May Estimated**		66,207	66,207	1.651	1.903	$1,093,097	$1,260,097	$132,846
26									
27	**June Estimated**								
28	Off System	OS	20,900	20,900	3.721	5.078	$777,710	$1,061,310	$207,652
29	St Lucie Reliability Sales		51,394	51,394	0.775	0.775	$398,213	$398,213	$0
30	**Total June Estimated**		72,294	72,294	1.627	2.019	$1,175,923	$1,459,523	$207,652
31									
32	**6 Month Period**								
33	Off System	OS	229,100	229,100	3.496	4.777	$8,008,780	$10,943,480	$2,295,569
34	St Lucie Reliability Sales		312,274	312,274	0.769	0.769	$2,402,254	$2,402,254	$0
35	**Total 6 Month Period**		541,374	541,374	1.923	2.465	$10,411,034	$13,345,734	$2,295,569
36									
37									
38									

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No	SOLD TO	Type & Schedule	Total MWH Sold	MWH from Own Generation	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	16,900	16,900	5.384	6.768	$909,890	$1,143,790	$179,359
4	St Lucie Reliability Sales		53,107	53,107	0.775	0.775	$411,487	$411,487	$0
5	**Total July Estimated**		70,007	70,007	1.887	2.222	$1,321,377	$1,555,277	$179,359
6									
7	**August Estimated**								
8	Off System	OS	24,000	24,000	7.010	8.518	$1,682,400	$2,044,300	$276,415
9	St Lucie Reliability Sales		53,107	53,107	0.775	0.775	$411,487	$411,487	$0
10	**Total August Estimated**		77,107	77,107	2.716	3.185	$2,093,887	$2,455,787	$276,415
11									
12	**September Estimated**								
13	Off System	OS	12,000	12,000	7.358	8.639	$882,960	$1,036,660	$117,119
14	St Lucie Reliability Sales		6,853	6,853	0.775	0.775	$53,096	$53,096	$0
15	**Total September Estimated**		18,853	18,853	4.965	5.780	$936,056	$1,089,756	$117,119
16									
17	**October Estimated**								
18	Off System	OS	23,700	23,700	4.918	6.126	$1,165,650	$1,451,950	$215,230
19	St Lucie Reliability Sales		32,550	32,550	0.775	0.775	$252,204	$252,204	$0
20	**Total October Estimated**		56,250	56,250	2.521	3.030	$1,417,854	$1,704,154	$215,230
21									
22	**November Estimated**								
23	Off System	OS	50,500	50,500	3.728	5.046	$1,882,490	$2,548,190	$510,215
24	St Lucie Reliability Sales		52,126	52,126	0.764	0.764	$398,113	$398,113	$0
25	**Total November Estimated**		102,626	102,626	2.222	2.871	$2,280,603	$2,946,303	$510,215
26									
27	**December Estimated**								
28	Off System	OS	57,200	57,200	3.182	4.601	$1,820,060	$2,631,860	$644,210
29	St Lucie Reliability Sales		53,864	53,864	0.764	0.764	$411,384	$411,384	$0
30	**Total December Estimated**		111,064	111,064	2.009	2.740	$2,231,444	$3,043,244	$644,210
31									
32	**12 Month Period**								
33	Off System	OS	413,400	413,400	3.956	5.273	$16,352,230	$21,800,230	$4,238,116
34	St Lucie Reliability Sales		563,881	563,881	0.770	0.770	$4,340,025	$4,340,025	$0
35	**Total 12 Month Period**		977,281	977,281	2.117	2.675	$20,692,255	$26,140,255	$4,238,116
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 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total MWH Purchased	MWH For Firm	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	January Estimated					
3	UPS		189,496	189,496	3.625	$6,868,321
4	SJRPP		137,788	137,788	4.367	$6,017,000
5	St Lucie Reliability		46,085	46,085	0.780	$359,341
6	**Total January Estimated**		373,369	373,369	3.547	$13,244,662
7						
8	February Estimated					
9	UPS		115,972	115,972	3.720	$4,314,139
10	SJRPP		131,137	131,137	4.206	$5,515,000
11	St Lucie Reliability		41,625	41,625	0.780	$324,566
12	**Total February Estimated**		288,734	288,734	3.517	$10,153,704
13						
14	March Estimated					
15	UPS		159,896	159,896	3.566	$5,702,371
16	SJRPP		165,127	165,127	4.117	$6,799,000
17	St Lucie Reliability		46,085	46,085	0.780	$359,341
18	**Total March Estimated**		371,108	371,108	3.465	$12,860,712
19						
20	April Estimated					
21	UPS		193,304	193,304	3.577	$6,915,245
22	SJRPP		132,361	132,361	4.376	$5,792,000
23	St Lucie Reliability		43,970	43,970	0.791	$347,811
24	**Total April Estimated**		369,635	369,635	3.532	$13,055,056
25						
26	May Estimated					
27	UPS		267,745	267,745	3.502	$9,377,257
28	SJRPP		190,997	190,997	4.211	$8,042,000
29	St Lucie Reliability		45,436	45,436	0.791	$359,405
30	**Total May Estimated**		504,178	504,178	3.526	$17,778,662
31						
32	June Estimated					
33	UPS		247,623	247,623	3.505	$8,678,985
34	SJRPP		178,130	178,130	4.225	$7,526,000
35	St Lucie Reliability		43,970	43,970	0.791	$347,811
36	**Total June Estimated**		469,723	469,723	3.524	$16,552,796
37						
38	6 Month Period					
39	UPS		1,174,036	1,174,036	3.565	$41,856,317
40	SJRPP		935,540	935,540	4.243	$39,691,000
41	St Lucie Reliability		267,170	267,170	0.785	$2,098,275
42	**Total 6 Month Period**		2,376,746	2,376,746	3.519	$83,645,592
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SCHEDULE: E7

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total MWH Purchased	MWH For Firm	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	July Estimated					
3	UPS		301,171	301,171	3.521	$10,602,868
4	SJRPP		199,520	199,520	4.278	$8,536,000
5	St Lucie Reliability		45,436	45,436	0.791	$359,405
6	**Total July Estimated**		546,127	546,127	3.570	$19,498,273
7						
8	August Estimated					
9	UPS		300,605	300,605	3.525	$10,596,995
10	SJRPP		202,877	202,877	4.230	$8,582,000
11	St Lucie Reliability		45,436	45,436	0.791	$359,405
12	**Total August Estimated**		548,918	548,918	3.559	$19,538,400
13						
14	September Estimated					
15	UPS		323,527	323,527	3.544	$11,466,533
16	SJRPP		199,712	199,712	4.226	$8,440,000
17	St Lucie Reliability		43,970	43,970	0.791	$347,811
18	**Total September Estimated**		567,209	567,209	3.571	$20,254,344
19						
20	October Estimated					
21	UPS		309,824	309,824	3.540	$10,967,502
22	SJRPP		184,154	184,154	4.372	$8,052,000
23	St Lucie Reliability		45,436	45,436	0.791	$359,405
24	**Total October Estimated**		539,414	539,414	3.593	$19,378,907
25						
26	November Estimated					
27	UPS		176,541	176,541	3.633	$6,412,925
28	SJRPP		149,398	149,398	4.397	$6,569,000
29	St Lucie Reliability		44,546	44,546	0.780	$347,340
30	**Total November Estimated**		370,485	370,485	3.598	$13,329,265
31						
32	December Estimated					
33	UPS		112,516	112,516	3.674	$4,133,585
34	SJRPP		156,688	156,688	4.272	$6,694,000
35	St Lucie Reliability		46,030	46,030	0.780	$358,918
36	**Total December Estimated**		315,234	315,234	3.549	$11,186,503
37						
38	12 Month Period					
39	UPS		2,698,220	2,698,220	3.559	$96,036,724
40	SJRPP		2,027,889	2,027,889	4.269	$86,564,000
41	St Lucie Reliability		538,023	538,023	0.786	$4,230,560
42	**Total 12 Month Period**		5,264,132	5,264,132	3.549	$186,831,284
43						
44						
45	Note: Totals may not add due to rounding					
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FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total MWH Purchased	MWH For Firm	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	January Estimated					
3	Qualifying Facilities		268,456	268,456	4.284	$11,500,528
4	**Total January Estimated**		268,456	268,456	4.284	$11,500,528
5						
6	February Estimated					
7	Qualifying Facilities		240,980	240,980	4.143	$9,984,528
8	**Total February Estimated**		240,980	240,980	4.143	$9,984,528
9						
10	March Estimated					
11	Qualifying Facilities		271,546	271,546	4.282	$11,627,530
12	**Total March Estimated**		271,546	271,546	4.282	$11,627,530
13						
14	April Estimated					
15	Qualifying Facilities		144,938	144,938	3.818	$5,533,529
16	**Total April Estimated**		144,938	144,938	3.818	$5,533,529
17						
18	May Estimated					
19	Qualifying Facilities		299,633	299,633	4.502	$13,488,533
20	**Total May Estimated**		299,633	299,633	4.502	$13,488,533
21						
22	June Estimated					
23	Qualifying Facilities		269,514	269,514	4.385	$11,817,531
24	**Total June Estimated**		269,514	269,514	4.385	$11,817,531
25						
26	6 Month Period					
27	Qualifying Facilities		1,495,070	1,495,070	4.278	$63,952,180
28	**Total 6 Month Period**		1,495,070	1,495,070	4.278	$63,952,180
29						
30						
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33						
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36						

FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)
Line No	PURCHASE FROM	Type & Schedule	Total MWH Purchased	MWH For Firm	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**July Estimated**					
3	Qualifying Facilities		311,014	311,014	4.576	$14,231,534
4	**Total July Estimated**		311,014	311,014	4.576	$14,231,534
5						
6	**August Estimated**					
7	Qualifying Facilities		333,148	333,148	4.821	$16,060,539
8	**Total August Estimated**		333,148	333,148	4.821	$16,060,539
9						
10	**September Estimated**					
11	Qualifying Facilities		333,088	333,088	4.872	$16,229,540
12	**Total September Estimated**		333,088	333,088	4.872	$16,229,540
13						
14	**October Estimated**					
15	Qualifying Facilities		259,600	259,600	4.775	$12,395,536
16	**Total October Estimated**		259,600	259,600	4.775	$12,395,536
17						
18	**November Estimated**					
19	Qualifying Facilities		220,004	220,004	4.263	$9,378,531
20	**Total November Estimated**		220,004	220,004	4.263	$9,378,531
21						
22	**December Estimated**					
23	Qualifying Facilities		257,696	257,696	4.307	$11,098,529
24	**Total December Estimated**		257,696	257,696	4.307	$11,098,529
25						
26	**12 Month Period**					
27	Qualifying Facilities		3,209,622	3,209,622	4.466	$143,346,388
28	**Total 12 Month Period**		3,209,622	3,209,622	4.466	$143,346,388
29						
30						
31	Note: Totals may not add due to rounding.					
32						
33						
34						
35						
36						

FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	PURCHASE FROM	Type & Schedule	Total MWH Purchased	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		600	2.799	$16,794	4.160	$24,960	$8,166
4	Total January Estimated		600	2.799	$16,794	4.160	$24,960	$8,166
5								
6	**February Estimated**							
7	Economy		14,500	2.400	$348,000	3.320	$481,400	$133,400
8	Total February Estimated		14,500	2.400	$348,000	3.320	$481,400	$133,400
9								
10	**March Estimated**							
11	Economy		52,000	2.597	$1,350,422	4.062	$2,112,200	$761,778
12	Total March Estimated		52,000	2.597	$1,350,422	4.062	$2,112,200	$761,778
13								
14	**April Estimated**							
15	Economy		143,300	2.998	$4,296,600	4.857	$6,959,540	$2,662,940
16	Total April Estimated		143,300	2.998	$4,296,600	4.857	$6,959,540	$2,662,940
17								
18	**May Estimated**							
19	Economy		167,600	3.642	$6,104,025	6.108	$10,237,060	$4,133,035
20	Total May Estimated		167,600	3.642	$6,104,025	6.108	$10,237,060	$4,133,035
21								
22	**June Estimated**							
23	Economy		71,800	3.100	$2,225,800	3.910	$2,807,380	$581,580
24	Total June Estimated		71,800	3.100	$2,225,800	3.910	$2,807,380	$581,580
25								
26	**6 Month Period**							
27	Economy		449,800	3.188	$14,341,641	5.029	$22,622,540	$8,280,899
28	Total 6 Month Period		449,800	3.188	$14,341,641	5.029	$22,622,540	$8,280,899
29								
30								
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	PURCHASE FROM	Type & Schedule	Total MWH Purchased	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		87,600	4.200	$3,679,200	6.720	$5,886,720	$2,207,520
4	Total July Estimated		87,600	4.200	$3,679,200	6.720	$5,886,720	$2,207,520
5								
6	**August Estimated**							
7	Economy		259,900	4.705	$12,227,259	8.495	$22,079,660	$9,852,401
8	Total August Estimated		259,900	4.705	$12,227,259	8.495	$22,079,660	$9,852,401
9								
10	**September Estimated**							
11	Economy		195,800	4.945	$9,682,750	9.571	$18,739,600	$9,056,850
12	Total September Estimated		195,800	4.945	$9,682,750	9.571	$18,739,600	$9,056,850
13								
14	**October Estimated**							
15	Economy		43,500	3.570	$1,553,050	6.277	$2,730,590	$1,177,540
16	Total October Estimated		43,500	3.570	$1,553,050	6.277	$2,730,590	$1,177,540
17								
18	**November Estimated**							
19	Economy		16,700	2.495	$416,727	4.104	$685,390	$268,663
20	Total November Estimated		16,700	2.495	$416,727	4.104	$685,390	$268,663
21								
22	**December Estimated**							
23	Economy		6,700	2.437	$163,300	3.381	$226,510	$63,210
24	Total December Estimated		6,700	2.437	$163,300	3.381	$226,510	$63,210
25								
26	**12 Month Period**							
27	Economy		1,060,000	3.968	$42,063,927	6.884	$72,971,010	$30,907,083
28	Total 12 Month Period		1,060,000	3.968	$42,063,927	6.884	$72,971,010	$30,907,083
29								
30								
31	Note: Totals may not add due to rounding.							
32								
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COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	OCT 12	PROPOSED JAN 13 - MAY 13	DIFFERENCE $	DIFFERENCE %
BASE	$43.26	$52.44	$9.18	21.22%
FUEL	$33.43	$27.89	-$5.54	-16.57%
CONSERVATION	$2.87	$2.33	-$0.54	-18.82%
CAPACITY PAYMENT	$9.69	$7.98	-$1.71	-17.65%
ENVIRONMENTAL	$1.92	$2.29	$0.37	19.27%
STORM RESTORATION SURCHARGE (1)	$1.21	$1.21	$0.00	$0.00
SUBTOTAL	$92.38	$94.14	$1.76	1.91%
GROSS RECEIPTS TAX	$2.37	$2.41	$0.04	1.69%
TOTAL	**$94.75**	**$96.55**	$1.80	1.90%

Notes (1) The Storm Surcharge is pending Commission approval.

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL JAN - DEC 2010 - 2010 (COLUMN 1)	ACTUAL JAN - DEC 2011-2011 (COLUMN 2)	ESTIMATED/ ACTUAL JAN-DEC 2012-2012 (COLUMN 3)	PROJECTED JAN-DEC 2013-2013 (COLUMN 4)	(COLUMN 2) (COLUMN 1)	(COLUMN 3) (COLUMN 2)	(COLUMN 4) (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	492,904,740	93,949,810	113,421,749	66,140,030	(80 9)	20.7	(41.7)
2	LIGHT OIL	41,380,850	37,159,006	8,471,454	611,500	(10.2)	(77.2)	(92.8)
3	COAL	152,699,819	163,820,388	134,601,163	167,048,000	7.3	(17.8)	24.1
4	GAS	3,265,159,503	3,289,409,517	2,903,692,274	2,390,103,671	0.7	(11.7)	(17.7)
5	NUCLEAR	137,029,789	146,597,226	121,345,737	212,252,600	7.0	(17.2)	74.9
6	TOTAL ($)	4,089,174,705	3,730,935,950	3,281,532,378	2,836,155,801	(8.8)	(12 0)	(13.6)
	SYSTEM NET GENERATION							
7	HEAVY OIL	4,081,077	630,196	727,708	372,007	(84.6)	15.5	(48 9)
8	LIGHT OIL	278,376	232,917	22,112	1,338	(16.3)	(90.5)	(93.9)
9	COAL	5,721,481	5,634,006	4,561,943	5,815,444	(1.5)	(19.0)	27.5
10	GAS	66,765,163	74,277,900	79,026,370	69,768,828	11.3	6.4	(11.7)
11	NUCLEAR	22,849,609	21,510,395	17,741,089	26,472,098	(5.9)	(17.5)	49.2
12	SOLAR	68,613	70,687	132,411	225,831	3.0	87	70.6
13	TOTAL (MWH)	99,764,318	102,356,101	102,211,633	102,655,546	2.6	(0.1)	0.4
	UNITS OF FUEL BURNED							
14	HEAVY OIL (Bbl)	6,753,471	1,140,665	1,217,119	645,291	(83.1)	6.7	(47.0)
15	LIGHT OIL (Bbl)	522,326	331,653	69,939	4,541	(36.5)	(78.9)	(93.5)
16	COAL (TON)	801,948	637,734	1,580,471	3,207,380	(20.5)	147.8	102.9
17	GAS (MCF)	504,996,090	555,912,325	574,506,826	489,626,432	10.1	3.3	(14 8)
18	NUCLEAR (MMBTU)	249,750,347	241,129,910	200,110,913	285,258,283	(3.5)	(17.0)	42.6
	BTU'S BURNED (MMBTU)							
19	HEAVY OIL	42,914,556	7,268,455	7,780,871	4,129,865	(83.1)	7.0	(46.9)
20	LIGHT OIL	2,989,828	1,909,037	402,518	26,467	(36 1)	(78.9)	(93.4)
21	COAL	59,019,792	57,605,124	47,374,271	59,813,211	(2.4)	(17.8)	26.3
22	GAS	513,742,638	564,067,472	579,754,604	489,626,432	9.8	2.8	(15.5)
23	NUCLEAR	249,750,348	241,129,910	200,110,913	285,258,283	(3.5)	(17.0)	42.6
24	TOTAL (MMBTU)	868,417,162	871,979,998	835,423,177	838,854,258	0.4	(4.2)	0.4
	GENERATION MIX (%MWH)							
25	HEAVY OIL	4.09	0.62	0.71	0.36	-	-	-
26	LIGHT OIL	0.28	0.23	0 02	0.00	-	-	-
27	COAL	5.73	5.50	4.46	5.67			
28	GAS	66 92	72.57	77.32	67.96	-	-	-
29	NUCLEAR	22.90	21.02	17.36	25.79	-	-	-
30	SOLAR	0.07	0.07	0 13	0.22			
31	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
32	HEAVY OIL ($/Bbl)	72.9854	82.3641	93.1887	102.4964	12 9	13.1	10.0
33	LIGHT OIL ($/Bbl)	79.2242	112.0418	121.1263	134.6620	41.4	8.1	11 2
34	COAL ($/TON)	87.6467	92.3945	85.1652	52.0824	5.4	(7.8)	(38.8)
35	GAS ($/MCF)	6.4657	5.9171	5.0542	4 8815	(8.5)	(14.6)	(3.4)
36	NUCLEAR ($/MMBTU)	0.5487	0 0608	0.6064	0.7441	(88.9)	897.4	22.7
	FUEL COST PER MMBTU ($/MMBTU)							
37	HEAVY OIL	11.4857	12 9257	14.5770	16.0151	12 5	12.8	9.9
38	LIGHT OIL	13.8405	19.4648	21.0462	23.1042	40.6	8 1	9.8
39	COAL	2 5873	2.8439	2.8412	2 7928	9.9	(0.1)	(1.7)
40	GAS	6.3556	5.8316	5.0085	4.8815	(8.2)	(14.1)	(2.5)
41	NUCLEAR	0.5487	0.6080	0.6064	0 7441	10.8	(0.3)	22.7
42	TOTAL ($/MMBTU)	4 7088	4.2787	3.9280	3.3810	(9.1)	(8.2)	(13.9)
	BTU BURNED PER KWH (BTU/KWH)							
43	HEAVY OIL	10,515	11,534	10,692	11,102	9.7	(7.3)	3.8
44	LIGHT OIL	10,740	8,196	18,203	19,781	(23.7)	122.1	8.7
45	COAL	10,315	10,225	10,385	10,285	(0.9)	1.6	(1.0)
46	GAS	7,695	7,594	7,336	7,018	(1.3)	(3.4)	(4.3)
47	NUCLEAR	10,930	11,210	11,280	10,776	2.6	0.6	(4.5)
48	TOTAL (BTU/KWH)	8,705	8,519	8,173	8,172	(2.1)	(4.1)	(0.0)
	GENERATED FUEL COST PER KWH (c/KWH)							
49	HEAVY OIL	12.0778	14.9080	15 5862	17.7792	23.4	4.5	14.1
50	LIGHT OIL	14.8651	15.9538	38.3108	45.7025	7.3	140.1	19.3
51	COAL	2.6689	2.9077	2.9505	2.8725	8 9	1.5	(2.6)
52	GAS	4.8905	4.4285	3.6743	3 4257	(9.4)	(17.0)	(6.8)
53	NUCLEAR	0.5997	0.6815	0.6840	0.8018	13.6	0.4	17 2
54	TOTAL (c/KWH)	4.0988	3 6451	3.2105	2 7628	(11.1)	(11 9)	(13.9)

Note: 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 .0044¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2013 – December 31, 2013	4.58	3.86	4.06
January 1, 2014 – December 31, 2014	4.43	3.93	4.10

A MW block size ranging from 93 MW to 104 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	1.0103
Secondary Voltage Delivery	1.0425

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
2012	17.24	0.87	70.97	4.56	6.19	0.18	.70	16.24	3.90	2.73
2013	23.55	0.37	64.99	5.36	5.52	0.19	.75	15.78	4.49	2.69
2014	23.80	0.27	65.45	4.82	5.49	0.18	.79	16.81	4.94	2.79
2015	21.80	0.35	64.93	5.62	7.15	0.15	.79	17.10	5.25	2.91
2016	23.08	0.40	64.56	5.47	6.32	0.17	.82	21.02	5.85	3.04
2017	22.81	0.37	66.05	5.93	4.69	0.15	.83	21.53	6.37	2.91
2018	21.61	0.32	68.32	5.38	4.21	0.16	.86	22.16	6.90	2.91
2019	22.18	0.34	67.14	5.78	4.38	0.16	.88	22.89	7.33	3.42
2020	21.85	0.38	67.45	5.27	4.88	0.15	.90	23.47	7.91	3.50
2021	20.42	0.50	68.07	5.55	5.28	0.15	.92	23.85	8.50	3.56

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	0.148%
Distribution Equipment	0.211%
Transmission Equipment	0.117%

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
2013 E-SCHEDULES

INCLUDING CAPE CANAVERAL MODERNIZATION PROJECT FUEL SAVINGS BEGINNING IN JUNE 1, 2013

TJK-6
DOCKET NO. 120001-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ____________
PAGES 1-8
AUGUST 31, 2012

APPENDIX III
FUEL COST RECOVERY
2013 E SCHEDULES
TABLE OF CONTENTS

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

ESTIMATED FOR THE PERIOD OF: JUNE 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$2,836,155,287	102,655,546	2.7628
2	Cape Canaveral Energy Center (CCEC) Savings	$100,908,000	102,655,546	0.0983
3	Nuclear Fuel Disposal Costs (E2)	$24,785,825	26,472,098	0.0936
4	Fuel Cost of Sales to CKW (E2)	($3,946,028)	(112,401)	3.5107
5	TOTAL COST OF GENERATED POWER	$2,957,903,084	102,543,145	2.8845
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$186,831,284	5,264,132	3.5491
7	Energy Cost of Economy Purchases (E9)	$42,063,927	1,060,000	3.9683
8	Payments to Qualifying Facilities (E8)	$143,346,388	3,209,622	4.4661
9	TOTAL COST OF PURCHASED POWER	$372,241,599	9,533,754	3 9045
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)		112,076,899	
11	Fuel Cost of Economy Sales (E6)	($16,352,230)	(413,400)	3.9555
12	Gain from Off-System Sales (E6)	($4,238,116)	N/A	N/A
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,340,025)	(563,881)	0.7697
14	TOTAL FUEL COST AND GAINS OF POWER SALES	($24,930,371)	(977,281)	2.5510
15	Net Inadvertent Interchange	$0	0	
16	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 9 + 14)	$3,305,214,313	111,099,618	2.9750
17	Net Unbilled Sales [1]	($52,223,696)	(1,755,418)	(0.0496)
18	Company Use [1]	$9,915,643	333,299	0.0094
19	T & D Losses [1]	$214,838,930	7,221,475	0.2040
20	SYSTEM MWH SALES (Excl sales to CKW)	$3,305,214,313	105,300,262	3.1388
21	Wholesale MWH Sales (Excl sales to CKW)	$65,909,940	2,099,818	3.1388
22	Jurisdictional MWH Sales	$3,239,304,373	103,200,444	3.1388
23	Jurisdictional Loss Multiplier	$2,623,837		1.00081
24	Jurisdictional MWH Sales Adjusted for Line Losses	$3,241,928,210	103,200,444	3.1414
25	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	($48,085,296)	103,200,444	(0.0466)
26	TOTAL JURISDICTIONAL FUEL COST	$3,193,842,914	103,200,444	3.0948
27	Revenue Tax Factor	$2,299,567		1.00072
28	Fuel Factor Adjusted for Taxes	$3,196,142,481	103,200,444	3.0970
29	GPIF [2]	$7,703,912	103,200,444	0.0075
30	Jurisdictionalized CCEC Savings	($99,047,141)	64,023,523	(0.1547)
31	Fuel Factor including GPIF (Line 28 + Line 29 + Line 30)	$3,104,799,252	103,200,444	2.9498
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.950
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.			

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

ESTIMATED FOR THE PERIOD OF: JUNE 2013 THROUGH DECEMBER 2013

Line No.	CALCULATION OF JURISDICTIONALIZED CCEC SAVINGS	Annual Total
1	CCEC Fuel Savings Total System	$100,908,000
2		
3	Jurisdictional %	98.00588%
4		
5	Jurisdictionalized CCEC Fuel Savings	$98,895,773
6		
7	Jurisdictionalized CCEC Fuel Savings Adjusted for Losses & Revenue Taxes	$99,047,141

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

ESTIMATED FOR THE PERIOD OF: JUNE 2013 THROUGH DECEMBER 2013

(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	2.950	1.00220	2.633
A	RS-1 all additional kWh	2.950	1.00220	3 633
A	GS-1, SL-2, GSCU-1, WIES-1	2 950	1.00220	2.956
A-1	SL-1, OL-1, PL-1 [1]	2.690	1.00220	2.696
B	GSD-1	2.950	1 00211	2.956
C	GSLD-1, CS-1	2.950	1.00109	2.953
D	GSLD-2, CS-2, OS-2, MET	2.950	0 99062	2.922
E	GSLD-3, CS-3	2.950	0.96131	2.836

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

Note: Totals may not add due to rounding.

ESTIMATED FOR THE PERIOD OF: JUNE 2013 THROUGH DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GROUPS	RATE SCHEDULE	JANUARY - MARCH / NOVEMBER - DECEMBER			APRIL - OCTOBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RST-1, GST-1 On-Peak	3.499	1.00220	3.507	4.463	1.00220	4.473
	RST-1, GST-1 Off-Peak	2.749	1.00220	2.755	2.174	1.00220	2.179
A	RTR-1 On-Peak	-	-	0.543	-	-	1.507
	RTR-1 Off-Peak	-	-	(0.207)	-	-	(0.782)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	3.499	1.00211	3.506	4.463	1.00211	4.472
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.749	1.00211	2 755	2 174	1.00211	2.179
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	3.499	1.00109	3.503	4.463	1.00109	4.468
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.749	1.00109	2.752	2.174	1.00109	2.176
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	3.499	0.99139	3 469	4 463	0.99139	4.425
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.749	0.99139	2.725	2.174	0.99139	2.155
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	3.499	0.96131	3.364	4.463	0.96131	4.290
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.749	0.96131	2.643	2.174	0 96131	2.090
F	CILC-1(D), ISST-1(D) On-Peak	3.499	0.99102	3.468	4.463	0.99102	4.423
	CILC-1(D), ISST-1(D) Off-Peak	2.749	0.99102	2.724	2.174	0.99102	2.154

Note: Totals may not add due to rounding.

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

ESTIMATED FOR THE PERIOD OF: JUNE 2013 THROUGH DECEMBER 2013

(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	5.077	1.00211	5.088
	GSD(T)-1 Off-Peak	2.567	1.00211	2.572
C	GSLD(T)-1 On-Peak	5.077	1.00109	5.083
	GSLD(T)-1 Off-Peak	2.567	1.00109	2.570
D	GSLD(T)-2 On-Peak	5.077	0.99139	5.033
	GSLD(T)-2 Off-Peak	2.567	0.99139	2.545

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 3 and Page 2 of 3

Note: Totals may not add due to rounding.

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

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JUNE 2013 THROUGH DECEMBER 2013

	(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	$220,073,886	$191,301,440	$208,965,847	$210,949,450	$238,217,766	$248,780,450	$275,371,825	$280,921,295	$281,678,050	$257,990,705	$211,279,250	$210,625,323	$2,836,155,287
2	Nuclear Fuel Disposal	1,828,715	1,651,746	1,922,853	2,221,055	2,350,681	2,274,853	2,350,681	2,350,681	1,714,889	1,894,975	1,824,443	2,400,253	24,785,825
3	CCEC Fuel Savings	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	8,409,000	100,908,000
4	Fuel Cost of Power Sold	(3,339,944)	(2,366,973)	(1,338,864)	(1,096,233)	(1,093,097)	(1,175,923)	(1,321,377)	(2,093,887)	(936,056)	(1,417,854)	(2,280,603)	(2,231,444)	(20,692,255)
5	Gain on Economy Sales	(888,156)	(641,976)	(232,510)	(192,428)	(132,846)	(207,652)	(179,359)	(276,415)	(117,119)	(215,230)	(510,215)	(644,210)	(4,238,116)
6	Fuel Cost of Purchased Power	13,244,662	10,153,704	12,860,712	13,055,056	17,778,662	16,552,796	19,498,273	19,538,400	20,254,344	19,378,907	13,329,265	11,186,503	186,831,284
7	Qualifying Facilities	11,500,528	9,984,528	11,627,530	5,533,529	13,488,533	11,817,531	14,231,534	16,060,539	16,229,540	12,395,536	9,378,531	11,098,529	143,346,388
8	Energy Cost of Economy Purchases	16,794	348,000	1,350,422	4,296,600	6,104,025	2,225,800	3,679,200	12,227,259	9,682,750	1,553,050	416,727	163,300	42,063,927
9	Fuel Cost of Sales to CKW	(598,528)	(601,104)	(605,453)	(678,375)	(700,161)	(762,407)	0	0	0	0	0	0	(3,946,028)
10	Total Fuel & Net Power Transactions	$250,246,957	$218,238,366	$242,959,536	$242,497,654	$284,422,564	$287,914,448	$322,039,777	$337,136,872	$336,915,399	$299,989,089	$241,846,398	$241,007,254	$3,305,214,313
11														
12	System MWH Sales (Excl sales to CKW)	8,684,410	7,586,674	7,497,187	7,573,999	8,601,591	9,365,603	10,232,652	10,209,655	9,837,863	9,228,977	8,324,784	8,156,867	105,300,262
13														
14	Cost per KWH (¢/KWH)	2.8816	2.8766	3.2407	3.2017	3.3066	3.0742	3.1472	3.3021	3.4247	3.2505	2.9051	2.9547	3.1388
15	Jurisdictional Loss Multiplier	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081
16	Jurisdictional Cost (¢/KWH)	2.8839	2.8789	3.2433	3.2043	3.3093	3.0767	3.1497	3.3048	3.4275	3.2531	2.9075	2.9570	3.1414
17	True-Up (¢/KWH)	(0.0469)	(0.0539)	(0.0544)	(0.0541)	(0.0475)	(0.0437)	(0.0399)	(0.0401)	(0.0416)	(0.0444)	(0.0492)	(0.0500)	(0.0466)
18	Total (¢/KWH)	2.8370	2.8250	3.1889	3.1502	3.2618	3.0330	3.1098	3.2647	3.3859	3.2087	2.8583	2.9070	3.0948
19	Revenue Tax Factor (0.00072)	0.0020	0.0020	0.0023	0.0023	0.0023	0.0022	0.0022	0.0024	0.0024	0.0023	0.0021	0.0021	0.0022
20	Recovery Factor Adjusted for Taxes (¢/KWH)	2.8390	2.8270	3.1912	3.1525	3.2641	3.0352	3.1120	3.2671	3.3883	3.2110	2.8604	2.9091	3.0970
21	GPIF (¢/KWH)	0.0075	0.0086	0.0087	0.0087	0.0076	0.0070	0.0064	0.0064	0.0067	0.0071	0.0079	0.0080	0.0075
22	Jurisdictionalized Savings - CCEC (¢/KWH)	0.0000	0.0000	0.0000	0.0000	0.0000	(0.1542)	(0.1410)	(0.1415)	(0.1470)	(0.1566)	(0.1739)	(0.1765)	(0.1547)
23	Recovery Factor including GPIF (¢/KWH)	2.8465	2.8356	3.1999	3.1612	3.2717	2.8880	2.9774	3.1320	3.2480	3.0615	2.6944	2.7406	2.9498
24														
25	Recovery Factor Rounded to .001 (¢/KWH)	2.847	2.836	3.200	3.161	3.272	2.888	2.977	3.132	3.248	3.062	2.694	2.741	2.950
26														
27	Note: Totals may not add due to rounding.													
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29														
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JUNE 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	36,238,125,203	0.026332	$954,231,112.50	2.633
2	All Additional KWH	17,271,658,955	0.036332	$627,518,107.21	3.633
3	Total KWH	53,509,784,158		$1,581,749,219.71	
4					
5	Avg Fuel Factor	2.950			
6	RS-1 Loss Multiplier	1.00220			
7	Average Fuel Factor	2.956			
8					
9	Target Fuel Revenues	$1,581,749,219.71			
10					
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COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	OCT 12	PROPOSED JAN 13 - MAY 13	DIFFERENCE $	DIFFERENCE %	PROPOSED JUN 13 - DEC 13	DIFFERENCE $	DIFFERENCE %
BASE	$43.26	$52.44	$9.18	21.22%	$54.30	$1.86	3.55%
FUEL	$33.43	$27.89	-$5.54	-16.57%	$26.33	-$1.56	-5.59%
CONSERVATION	$2.87	$2.33	-$0.54	-18.82%	$2.33	$0.00	0.00%
CAPACITY PAYMENT	$9.69	$7.98	-$1.71	-17.65%	$7.98	$0.00	0.00%
ENVIRONMENTAL	$1.92	$2.29	$0.37	19.27%	$2.29	$0.00	0.00%
STORM RESTORATION SURCHARGE (1)	$1.21	$1.21	$0.00	0.00%	$1.21	$0.00	0.00%
SUBTOTAL	$92.38	$94.14	$1.76	1.91%	$94.44	$0.30	0.32%
GROSS RECEIPTS TAX	$2.37	$2.41	$0.04	1.69%	$2.42	$0.01	0.41%
TOTAL	**$94.75**	**$96.55**	$1.80	1.90%	**$96.86**	$0.31	0.32%

Notes (1) The Storm Surcharge is pending Commission approval.

APPENDIX IV
FUEL COST RECOVERY
2013 E-SCHEDULES

TRADITIONAL FCR FACTOR CALCULATION
FOR THE PERIOD JANUARY 2013 THROUGH DECEMBER 2013

TJK-7
DOCKET NO. 120001-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ____________
PAGES 1-7
AUGUST 31, 2012

APPENDIX IV FUEL COST RECOVERY
E SCHEDULES
JANUARY 2013 – DECEMBER 2013
TABLE OF CONTENTS

SCHEDULE: E1

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$2,836,155,287	102,655,546	2.7628
2	Nuclear Fuel Disposal Costs (E2)	$24,785,825	26,472,098	0.0936
3	Fuel Cost of Sales to CKW (E2)	($3,946,028)	(112,401)	3.5107
4	TOTAL COST OF GENERATED POWER	$2,856,995,084	102,543,145	2.7861
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$186,831,284	5,264,132	3.5491
6	Energy Cost of Economy Purchases (E9)	$42,063,927	1,060,000	3.9683
7	Payments to Qualifying Facilities (E8)	$143,346,388	3,209,622	4.4661
8	TOTAL COST OF PURCHASED POWER	$372,241,599	9,533,754	3.9045
9	TOTAL AVAILABLE MWH (LINE 4 + LINE 8)		112,076,899	
10	Fuel Cost of Economy Sales (E6)	($16,352,230)	(413,400)	3.9555
11	Gain from Off-System Sales (E6)	($4,238,116)	N/A	N/A
12	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,340,025)	(563,881)	0.7697
13	TOTAL FUEL COST AND GAINS OF POWER SALES	($24,930,371)	(977,281)	2.5510
14	Net Inadvertent Interchange	$0	0	
15	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 4 + 8 + 13)	$3,204,306,313	111,099,618	2.8842
16	Net Unbilled Sales (1)	($50,629,310)	(1,755,418)	(0.0481)
17	Company Use (1)	$9,612,919	333,299	0.0091
18	T & D Losses (1)	$208,279,910	7,221,475	0.1978
19	SYSTEM MWH SALES (Excl sales to CKW)	$3,204,306,313	105,300,262	3.0430
20	Wholesale MWH Sales (Excl sales to CKW)	$63,897,713	2,099,818	3.0430
21	Jurisdictional MWH Sales	$3,140,408,600	103,200,444	3.0430
22	Jurisdictional Loss Multiplier	$2,543,731		1.00081
23	Jurisdictional MWH Sales Adjusted for Line Losses	$3,142,952,331	103,200,444	3.0455
24	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	($48,085,296)	103,200,444	(0.0466)
25	TOTAL JURISDICTIONAL FUEL COST	$3,094,867,035	103,200,444	2.9989
26	Revenue Tax Factor	$2,228,304		1.00072
27	Fuel Factor Adjusted for Taxes	$3,097,095,339	103,200,444	3.0011
28	GPIF (2)	$7,703,912	103,200,444	0.0075
29	Fuel Factor including GPIF (Line 27 + Line 28)	$3,104,799,251	103,200,444	3.0086
30	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.009
31				
32	(1) For Informational Purposes Only			
33	(2) Calculation Based on Jurisdictional KWH Sales			
34				
35	Note: Totals may not add due to rounding.			
36				
37				

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

(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	3.009	1.00220	2.693
A	RS-1 all additional kWh	3.009	1.00220	3.693
A	GS-1, SL-2, GSCU-1, WIES-1	3.009	1.00220	3.016
A-1	SL-1, OL-1, PL-1 [(1)]	2.744	1.00220	2.750
B	GSD-1	3.009	1.00211	3.015
C	GSLD-1, CS-1	3.009	1.00109	3.012
D	GSLD-2, CS-2, OS-2, MET	3.009	0.99062	2.981
E	GSLD-3, CS-3	3.009	0.96131	2.893

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

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
SEASONALLY DIFFERENTIATED TIME OF USE FUEL RECOVERY FACTORS - BY RATE GROUP

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		JANUARY - MARCH / NOVEMBER - DECEMBER			APRIL - OCTOBER		
GROUPS	RATE SCHEDULE	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RST-1, GST-1 On-Peak	3.569	1.00220	3.577	4.553	1.00220	4.563
	RST-1, GST-1 Off-Peak	2.804	1.00220	2.810	2.218	1.00220	2.223
A	RTR-1 On-Peak	-	-	0.553	-	-	1.537
	RTR-1 Off-Peak	-	-	(0.212)	-	-	(0.798)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	3.569	1.00211	3.577	4.553	1.00211	4.563
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.804	1.00211	2.810	2.218	1.00211	2.223
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	3.569	1.00109	3.573	4.553	1.00109	4.558
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.804	1.00109	2.807	2.218	1.00109	2.220
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	3.569	0.99139	3.538	4.553	0.99139	4.514
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.804	0.99139	2.780	2.218	0.99139	2.199
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	3.569	0.96131	3.431	4.553	0.96131	4.377
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.804	0.96131	2.696	2.218	0.96131	2.132
F	CILC-1(D), ISST-1(D) On-Peak	3.569	0.99102	3.537	4.553	0.99102	4.512
	CILC-1(D), ISST-1(D) Off-Peak	2.804	0.99102	2.779	2.218	0.99102	2.198

Note: Totals may not add due to rounding.

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

(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	5.178	1.00211	5.189
	GSD(T)-1 Off-Peak	2.618	1.00211	2.624
C	GSLD(T)-1 On-Peak	5.178	1.00109	5.184
	GSLD(T)-1 Off-Peak	2.618	1.00109	2.621
D	GSLD(T)-2 On-Peak	5.178	0.99139	5 133
	GSLD(T)-2 Off-Peak	2.618	0.99139	2 595

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 3 and Page 2 of 3

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 2013 THROUGH DECEMBER 2013

	(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	$220,073,886	$191,301,440	$208,965,847	$210,949,450	$238,217,766	$248,780,450	$275,371,825	$280,921,295	$281,678,050	$257,990,705	$211,279,250	$210,625,323	$2,836,155,287
2	Nuclear Fuel Disposal	1,828,715	1,651,746	1,922,853	2,221,055	2,350,681	2,274,853	2,350,681	2,350,681	1,714,889	1,894,975	1,824,443	2,400,253	24,785,825
3	Fuel Cost of Power Sold	(3,339,944)	(2,366,973)	(1,338,864)	(1,096,233)	(1,093,097)	(1,175,923)	(1,321,377)	(2,093,887)	(936,056)	(1,417,854)	(2,280,603)	(2,231,444)	(20,692,255)
4	Gain on Economy Sales	(888,156)	(641,976)	(232,510)	(192,428)	(132,846)	(207,652)	(179,359)	(276,415)	(117,119)	(215,230)	(510,215)	(644,210)	(4,238,116)
5	Fuel Cost of Purchased Power	13,244,662	10,153,704	12,860,712	13,055,056	17,778,662	16,552,796	19,498,273	19,538,400	20,254,344	19,378,907	13,329,265	11,186,503	186,831,284
6	Qualifying Facilities	11,500,528	9,984,528	11,627,530	5,533,529	13,488,533	11,817,531	14,231,534	16,060,539	16,229,540	12,395,536	9,378,531	11,098,529	143,346,388
7	Energy Cost of Economy Purchases	16,794	348,000	1,350,422	4,296,600	6,104,025	2,225,800	3,679,200	12,227,259	9,682,750	1,553,050	416,727	163,300	42,063,927
8	Fuel Cost of Sales to CKW	(598,528)	(601,104)	(605,453)	(678,375)	(700,161)	(762,407)	0	0	0	0	0	0	(3,946,028)
9	Total Fuel & Net Power Transactions	$241,837,957	$209,829,366	$234,550,536	$234,088,654	$276,013,564	$279,505,448	$313,630,777	$328,727,872	$328,506,399	$291,580,089	$233,437,398	$232,598,254	$3,204,306,313
10														
11	System MWH Sales (Excl sales to CKW)	8,684,410	7,586,674	7,497,187	7,573,999	8,601,591	9,365,603	10,232,652	10,209,655	9,837,863	9,228,977	8,324,784	8,156,867	105,300,262
12														
13	Cost per KWH (¢/KWH)	2.7847	2.7658	3.1285	3.0907	3.2089	2.9844	3.0650	3.2198	3.3392	3.1594	2.8041	2.8516	3.0430
14	Jurisdictional Loss Multiplier	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081	1.00081
15	Jurisdictional Cost (¢/KWH)	2.7870	2.7680	3.1310	3.0932	3.2115	2.9868	3.0675	3.2224	3.3419	3.1620	2.8064	2.8539	3.0455
16	True-Up (¢/KWH)	(0.0469)	(0.0539)	(0.0544)	(0.0541)	(0.0475)	(0.0437)	(0.0399)	(0.0401)	(0.0416)	(0.0444)	(0.0492)	(0.0500)	(0.0466)
17	Total (¢/KWH)	2.7401	2.7141	3.0766	3.0391	3.1640	2.9431	3.0276	3.1823	3.3003	3.1176	2.7572	2.8039	2.9989
18	Revenue Tax Factor (0.00072)	0.0020	0.0020	0.0022	0.0022	0.0023	0.0021	0.0022	0.0023	0.0024	0.0022	0.0020	0.0020	0.0022
19	Recovery Factor Adjusted for Taxes (¢/KWH)	2.7421	2.7161	3.0788	3.0413	3.1663	2.9452	3.0298	3.1846	3.3027	3.1198	2.7592	2.8059	3.0011
20	GPIF (¢/KWH)	0.0075	0.0086	0.0087	0.0087	0.0076	0.0070	0.0064	0.0064	0.0067	0.0071	0.0079	0.0080	0.0075
21	Recovery Factor including GPIF (¢/KWH)	2.7496	2.7247	3.0875	3.0500	3.1739	2.9522	3.0362	3.1910	3.3094	3.1269	2.7671	2.8139	3.0086
22														
23	Recovery Factor Rounded to .001 (¢/KWH)	2.750	2.725	3.088	3.050	3.174	2.952	3.036	3.191	3.309	3.127	2.767	2.814	3.009
24														
25	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 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	36,238,125,203	0.026932	$975,973,987.62	2.693
2	All Additional KWH	17,271,658,955	0.036932	$637,881,102.58	3.693
3	Total KWH	53,509,784,158		$1,613,855,090.21	
4					
5	Avg Fuel Factor	3.009			
6	RS-1 Loss Multiplier	1.00220			
7	Average Fuel Factor	3.016			
8					
9	Target Fuel Revenues	$1,613,855,090.21			
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COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	OCT 12	PROPOSED JAN 13 - MAY 13	DIFFERENCE $	DIFFERENCE %	PROPOSED JUN 13 - DEC 13	DIFFERENCE $	DIFFERENCE %
BASE	$43.26	$52.44	$9.18	21.22%	$54.30	$1.86	3.55%
FUEL	$33.43	$26.93	-$6.50	-19.44%	$26.93	$0.00	0.00%
CONSERVATION	$2.87	$2.33	-$0.54	-18.82%	$2.33	$0.00	0.00%
CAPACITY PAYMENT	$9.69	$7.98	-$1.71	-17.65%	$7.98	$0.00	0.00%
ENVIRONMENTAL	$1.92	$2.29	$0.37	19.27%	$2.29	$0.00	0.00%
STORM RESTORATION SURCHARGE (1)	$1.21	$1.21	$0.00	0.00%	$1.21	$0.00	0.00%
SUBTOTAL	$92.38	$93.18	$0.80	0.87%	$95.04	$1.86	2.00%
GROSS RECEIPTS TAX	$2.37	$2.39	$0.02	0.84%	$2.44	$0.05	2.09%
TOTAL	**$94.75**	**$95.57**	$0.82	0.87%	**$97.48**	$1.91	2.00%

Notes (1) The Storm Surcharge is pending Commission approval.

APPENDIX V

CAPACITY COST RECOVERY

JANUARY 2013 – DECEMBER 2013 FACTORS

TJK-8
DOCKET NO. 120001-EI
FPL WITNESS: T.J.KEITH
EXHIBIT __________
PAGES 1-12
AUGUST 31, 2012

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 2012 THROUGH DECEMBER 2012

REVISED 8 31 2012

	(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	$16,212,289	$18,735,487	$17,260,731	$19,897,479	$17,649,852	$18,338,941	$18,371,831	$18,923,549	$17,546,969	$17,134,201	$17,067,581	$17,331,101	$214,470,011
2	Payments to Co-generators	$25,047,746	$24,589,854	$24,964,259	$25,107,774	$24,536,250	$25,841,540	$25,154,871	$24,510,356	$24,510,356	$24,510,356	$24,510,356	$24,510,356	$297,794,075
3	SJRPP Suspension Accrual	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$935,844
4	Return on SJRPP Suspension Liability	($444,180)	($444,804)	($445,428)	($446,053)	($446,677)	($447,301)	($447,925)	($448,549)	($449,173)	($449,797)	($450,421)	($451,045)	($5,371,351)
5	Incremental Plant Security	$3,155,284	$2,826,276	$2,979,759	$3,069,584	$3,232,072	$3,030,391	$3,018,723	$3,410,172	$4,330,973	$3,021,666	$3,099,627	$4,687,947	$39,862,475
6	Transmission of Electricity by Others	$2,202,085	$2,539,767	$2,793,846	$213,714	$1,382,621	($694,480)	$804,439	$1,219,356	$1,321,189	$1,374,603	$1,831,292	$1,835,989	$16,824,422
7	Transmission Revenues from Capacity Sales	($183,416)	($189,248)	$25,792	($65,281)	($24,007)	($83,793)	($43,542)	($81,800)	($33,800)	($66,100)	($152,300)	($154,500)	($1,051,995)
8	Total (Lines 1 through 7)	$46,067,795	$48,135,319	$47,656,946	$47,855,204	$46,408,099	$46,063,285	$46,936,384	$47,611,072	$47,304,501	$45,602,917	$45,984,122	$47,837,835	$563,463,481
9	Jurisdictional Separation Factor [(a)]	98.01395%	98.01395%	98.01395%	98 01395%	98 01395%	98.01395%	98.01395%	98.01395%	98.01395%	98 01395%	98.01395%	98.01395%	N/A
10	Jurisdictional CCR	$45,152,866	$47,179,328	$46,710,455	$46,904,776	$45,486,411	$45,148,446	$46,004,204	$46,665,492	$46,365,010	$44,697,220	$45,070,854	$46,887,752	$552,272,814
11	Nuclear Cost Recovery Costs	$12,722,828	$12,890,348	$16,437,588	$15,015,050	$15,273,871	$19,744,593	$16,537,502	$16,639,273	$17,111,442	$17,427,238	$17,634,384	$18,655,619	$196,089,735
12	Jurisdictional CCR	$57,875,694	$60,069,676	$63,148,043	$61,919,826	$60,760,282	$64,893,039	$62,541,706	$63,304,766	$63,476,452	$62,124,458	$62,705,238	$65,543,371	$748,362,549
13	CCR Revenues (Net of Revenue Taxes)	$53,321,438	$48,321,333	$51,351,805	$54,944,454	$56,137,491	$64,510,352	$67,627,868	$69,025,170	$66,353,238	$62,113,689	$55,665,813	$54,560,238	$703,932,889
14	Prior Period True-up Provision	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$28,608,272
15	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$55,705,461	$50,705,356	$53,735,828	$57,328,477	$58,521,514	$66,894,375	$70,011,891	$71,409,192	$68,737,261	$64,497,711	$58,049,836	$56,944,260	$732,541,161
16	True-up Provision for Month - Over/(Under) Recovery (Line 15 - Line 12)	($2,170,233)	($9,364,320)	($9,412,215)	($4,591,349)	($2,238,768)	$2,001,336	$7,470,185	$8,104,427	$5,260,809	$2,373,253	($4,655,402)	($8,599,110)	($15,821,388)
17	Interest Provision for Month	($1,148)	($2,541)	($3,190)	($4,173)	($5,574)	($5,365)	($5,591)	($6,032)	($5,496)	($5,317)	($5,758)	($6,886)	($57,071)
18	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$28,608,272	$24,052,868	$12,301,984	$502,556	($6,476,989)	($11,105,353)	($11,493,405)	($6,412,834)	($698,462)	$2,172,829	$2,156,742	($4,888,441)	$28,608,272
19	Deferred True-up - Over/(Under) Recovery	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)
20	Prior Period True-up Provision - Collected/(Refunded) this Month	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($28,608,272)
21	End of Period True-up - Over/(Under) Recovery (Sum of Lines 16 through 20)	($20,651,707)	($32,402,591)	($44,202,019)	($51,181,564)	($55,809,928)	($56,197,980)	($51,117,409)	($45,403,037)	($42,531,746)	($42,547,833)	($49,593,016)	($60,583,035)	($60,583,035)

[(a)] As approved on Order No PSC-11-0579-FOF-EI

Totals may not add up due to rounding.

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Estimated	February Estimated	March Estimated	Apnl Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1	Capacity Payments To Non-Cogenerators	$16,669,791	$16,669,791	$16,669,791	$16,669,791	$16,617,549	$16,617,549	$16,617,549	$16,617,549	$16,617,549	$16,669,791	$16,669,791	$16,669,791	$199,776,283
2	Capacity Payments To Cogenerators	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$22,550,118	$270,601,412
3	SJRPP Suspension Accrual	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$935,844
4	Retum Requirements On SJRPP Suspension Liability	($438,705)	($439,311)	($439,917)	($440,523)	($441,129)	($441,735)	($442,341)	($442,947)	($443,554)	($444,160)	($444,766)	($445,372)	($5,304,459)
5	Incremental Plant Security Costs	$3,079,631	$2,796,760	$5,199,606	$2,965,673	$3,229,748	$5,515,948	$3,339,977	$2,936,239	$5,275,502	$2,971,129	$3,012,781	$6,073,511	$46,396,506
6	Transmission Of Electricity By Others	$1,662,584	$1,864,767	$1,760,535	$1,628,661	$1,403,649	$1,442,921	$1,293,038	$1,294,911	$1,183,373	$1,264,404	$1,685,981	$1,917,321	$18,402,144
7	Transmission Revenues From Capacity Sales	($226,444)	($173,824)	($83,090)	($45,672)	($34,154)	($75,948)	($54,541)	($85,485)	($36,581)	($71,070)	($155,485)	($167,590)	($1,209,884)
8	System Total	$43,374,963	$43,346,288	$45,735,030	$43,406,035	$43,403,767	$45,686,840	$43,381,786	$42,948,372	$45,224,394	$43,018,199	$43,396,407	$46,675,766	$529,597,847
9	Junsdictional % *													97 97032%
10	Jurisdictionalized Capacity Payments													$518,848,705
11	2011 FINAL TRUE-UP – (Over)/Under Recovery													$44,704,575
12	2012 ACT/EST TRUE-UP – (Over)/Under Recovery													$15,878,460
13	Nuclear Cost Recovery Clause													$151,491,402
14	Total (Lines 10+11+12+13)													$730,923,142
15	Revenue Tax Multiplier													1.00072
16	Total Recoverable Capacity Payments													$731,449,407
17														
18	*Calculation of Junsdictional %													
19	... .AVG. 12CP													
20	....AT GEN (MW)..........%													
21	FPSC.. . ...18,298.317........97.97032%													
22	FERC...... ... .379.092........ 2.02968%													
23	TOTAL..............18,677.409.......100.00000%													
24														
25	* Based on 2011 Actual Data													
26	Totals may not add up due to rounding.													

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY DEMAND ALLOCATION % BY RATE CLASS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

(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/RST1	61.443%	53,023,166,899	9,851,224	1.07934640	1.06237778	56,330,634,339	10,632,883	51.45044%	58.40675%
GS1/GST1/WIES1	76.122%	5,844,824,242	876,512	1.07934640	1.06237778	6,209,411,403	946,060	5.67146%	5.19674%
GSD1/GSDT1/HLFT1	78.359%	25,078,522,608	3,653,482	1.07921924	1.06227781	26,640,358,074	3,942,908	24.33238%	21.65851%
OS2	72.864%	12,578,957	1,971	1.06664274	1.02956173	12,950,813	2,102	0.01183%	0.01155%
GSLD1/GSLDT1/CS1/CST1/HLFT2	81.031%	11,310,651,252	1,593,418	1.07776257	1.06120242	12,002,890,480	1,717,326	10.96302%	9.43333%
GSLD2/GSLDT2/CS2/CST2/HLFT3	93.875%	2,450,692,797	298,011	1.06537601	1.05091974	2,575,481,437	317,494	2.35236%	1.74400%
GSLD3/GSLDT3/CS3/CST3	103.341%	199,482,765	22,036	1.02320090	1.01902664	203,278,252	22,547	0.18567%	0.12385%
SST1T	80.153%	97,610,914	13,902	1.02320090	1.01902664	99,468,122	14,225	0.09085%	0.07814%
SST1D1/SST1D2/SST1D3	67.698%	7,613,528	1,284	1.03677940	1.02956173	7,838,597	1,331	0.00716%	0.00731%
CILC D/CILC G	93.225%	3,039,558,994	372,200	1.06418212	1.05118900	3,195,150,979	396,089	2.91834%	2.17573%
CILC T	95.590%	1,341,477,742	160,202	1.02320090	1.01902664	1,367,001,556	163,919	1.24857%	0.90041%
MET	79.014%	92,698,007	13,393	1.03677940	1.02956173	95,438,320	13,886	0.08717%	0.07627%
OL1/SL1/PL1	305.172%	630,970,753	23,603	1.07934640	1.06237778	670,329,308	25,476	0.61226%	0.13994%
SL2, GSCU1	100.650%	70,594,840	8,007	1.07934640	1.06237778	74,998,389	8,642	0.06850%	0.04747%
TOTAL		103,200,444,298	16,889,245			109,485,230,069	18,204,888	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2011 load research data.
[b] Projected kwh sales for the period January 2013 through December 2013.
[c] Calculated: Col(3)/(8760 hours * Col(2))
[d] Based on 2011 demand losses.
[e] Based on 2011 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 2013 THROUGH DECEMBER 2013

(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/RST1	51.45044%	58.40675%	$28,948,765	$394,353,064	$423,301,829	53,023,166,899	-	-	-	0.00798	-	-
GS1/GST1/WIES1	5.67146%	5.19674%	$3,191,066	$35,087,538	$38,278,604	5,844,824,242	-	-	-	0.00655	-	-
GSD1/GSDT1/HLFT1	24.33238%	21.65851%	$13,690,694	$146,234,831	$159,925,525	25,078,522,608	52.41924%	65,537,273	2.44	-	-	-
OS2	0.01183%	0.01155%	$6,656	$77,972	$84,628	12,578,957	-	-	-	0.00673	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	10.96302%	9.43333%	$6,168,382	$63,692,309	$69,860,691	11,310,651,252	56.10673%	27,615,301	2.53	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.35236%	1.74400%	$1,323,561	$11,775,230	$13,098,790	2,450,692,797	67.14099%	5,000,096	2.62	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.18567%	0.12385%	$104,466	$836,234	$940,700	199,482,765	77.92278%	350,686	2.68	-	-	-
SST1T	0.09085%	0.07814%	$51,117	$527,561	$578,678	97,610,914	15.11426%	884,685	-	-	$0.34	$0.16
SST1D1/SST1D2/SST1D3	0.00716%	0.00731%	$4,028	$49,373	$53,401	7,613,528	34.08000%	30,603	-	-	$0.35	$0.17
CILC D/CILC G	2.91834%	2.17573%	$1,642,014	$14,690,159	$16,332,173	3,039,558,994	74.46729%	5,591,420	2.92	-	-	-
CILC T	1.24857%	0.90041%	$702,513	$6,079,432	$6,781,945	1,341,477,742	75.73600%	2,426,377	2.80	-	-	-
MET	0.08717%	0.07627%	$49,047	$514,990	$564,036	92,698,007	65.19800%	194,766	2.90	-	-	-
OL1/SL1/PL1	0.61226%	0.13994%	$344,488	$944,849	$1,289,336	630,970,753	-	-	-	0.00204	-	-
SL2, GSCU1	0.06850%	0.04747%	$38,542	$320,527	$359,069	70,594,840	-	-	-	0.00509	-	-
TOTAL			$56,265,339	$675,184,068	$731,449,407	103,200,444,298		107,631,206				

[a] Obtained from Page 2, Col(9)

[b] Obtained from Page 2, 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 2013 through December 2013.

[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
Schedule E12 - Capacity Costs

2013 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	4/1/2012	3/31/2032	QF

QF = Qualifying Facility

2013 Projection Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	9,806,529	117,678,346
ICL	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	11,287,264	135,447,167
BN-NEG '91	317,350	317,350	317,350	317,350	317,350	317,350	317,350	317,350	317,350	317,350	317,350	317,350	3,808,200
BS-NEG '91	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	100,975	1,211,700
SWAPBC	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	1,038,000	12,456,000
Total	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	22,550,118	270,601,412

Florida Power & Light Company
Schedule E12 - Capacity Costs
Page 2 of 2

CONFIDENTIAL

2013 Projection

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

2013 Capacity in MW

Contract	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
1	163	163	163	163	163	163	163	163	163	163	163	163
2	600	600	600	600	600	600	600	600	600	600	600	600
3	190	190	190	190	190	190	190	190	190	190	190	190
4	375	375	375	375	375	375	375	375	375	375	375	375
Total	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328

2013 Capacity in Dollars

Contract	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
1	[redacted]											
2												
3												
4												
Total	16,669,791	16,669,791	16,669,791	16,669,791	16,617,549	16,617,549	16,617,549	16,617,549	16,617,549	16,669,791	16,669,791	16,669,791

Total Capacity Payments to Non-Cogenerators for 2013	199,776,283	(1)

(1) August 31, 2012 Projection Filing, Appendix V, page 2, line 1

FLORIDA POWER & LIGHT COMPANY
2012 RATE CASE ALLOCATION OF GAS TURBINE PRODUCTION REVENUE REQUIREMENT
JANUARY 2013 THROUGH DECEMBER 2013

	Rate (a)	Total Allocation [1] (b)	Allocation (c)	WC3 Revenue Requirement Allocation (d)	WC3 Revenue Requirement Adjusted Allocation[2] (e)	Capacity Class Allocation (f)	Rate code % of Capacity Class (g)
1	CILC-1D	$22,378,000	2.1%	$3,467,223	$ 3,824,617	$ 3,690,609	94%
2	CILC-1G	$1,441,772	0.1%	$223,387	$ 246,413	$ 3,690,609	6%
3	CILC-1T	$9,887,858	0.9%	$1,532,014	$ 1,827,468	$ 1,532,014	100%
4	GS1	$61,812,409	5.8%	$9,577,147	$ 9,577,147	$ 9,577,147	100%
5	GSCU-1	$288,082	0.0%	$44,635	$ 44,635	$ 84,299	53%
6	GSD1	$237,906,097	22.1%	$36,860,910	$ 31,208,404	$ 36,860,910	100%
7	GSLD1	$105,088,787	9.8%	$16,282,342	$ 19,887,927	$ 16,282,342	100%
8	GSLD2	$20,042,237	1.9%	$3,105,322	$ 4,277,249	$ 3,105,322	100%
9	GSLD3	$1,574,798	0.1%	$243,997	$ 481,877	$ 243,997	100%
10	MET	$936,444	0.1%	$145,092	$ 113,872	$ 145,092	100%
11	OL-1	$273,779	0.0%	$42,419	$ 42,419	$ 265,189	16%
12	OS-2	$100,858	0.0%	$15,627	$ 19,580	$ 15,627	100%
13	RS1	$609,861,121	56.8%	$94,491,214	$ 94,491,214	$ 94,491,214	100%
14	SL-1	$1,437,792	0.1%	$222,770	$ 222,770	$ 265,189	84%
15	SL-2	$255,999	0.0%	$39,664	$ 39,664	$ 84,299	47%
16	SST-DST	$48,659	0.0%	$7,539	$ 7,539	$ 7,539	100%
17	SST-TST	$848,619	0.1%	$131,484	$ 119,990	$ 131,484	100%
18		$0					
19	Total	$1,074,183,308	100.0%	$166,432,784	$ 166,432,784		

Notes:
1) Combined Cycle cost allocation per E6b (Cape Canaveral - Corrected)
2) Revenue requirement allocation adjusted to ensure no class recieves more than 1.5 x system average rate increase

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

						Reallocation					
		Total Revenue[1]	Total WC3 Costs	% Increase	% Increase Capped at 1.5x	Allocation capped at 3.0%	Increase % of Deficiency	Revenue of Classes to reallocate	Reallocation of shortfall	Total Allocation	% Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	RS1/RST1	$4,769,535,475	$94,491,214	2.0%	2.0%	$94,491,214	1.02	-	$ -	$94,491,214	2.0%
2	GS1/GST1	$561,361,971	$9,577,147	1.7%	1.7%	$9,577,147	-	-	$ -	$9,577,147	1.7%
3	GSD1/GSDT1/HLFT1 (21-499 kW)	$1,040,280,126	$36,860,910	3.5%	3.0%	$31,208,404	1.13	-	$ -	$31,208,404	3.0%
4	OS2	$1,402,695	$15,627	1.1%	1.1%	$15,627	0.55	1,402,695	$ 3,954	$19,580	1.4%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	$1,279,250,088	$16,282,342	1.3%	1.3%	$16,282,342	0.30	1,279,250,088	$ 3,605,586	$19,887,927	1.6%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	$415,795,983	$3,105,322	0.7%	0.7%	$3,105,322	0.30	415,795,983	$ 1,171,927	$4,277,249	1.0%
7	GSLD3/GSLDT3/CS3/CST3	$84,398,940	$243,997	0.3%	0.3%	$243,997	0.00	84,398,940	$ 237,880	$481,877	0.6%
8	ISST1D	$0	$0	0.0%	0.0%	$0		-	$ -	$0	
9	ISST1T	$0	$0	0.0%	0.0%	$0		-	$ -	$0	
10	SST1T	$3,999,650	$131,484	3.3%	3.0%	$119,990	0.00	-	$ -	$119,990	3.0%
11	SST1D1/SST1D2/SST1D3	$731,090	$7,539	1.0%	1.0%	$7,539	5.32	-	$ -	$7,539	1.0%
12	CILC D/CILC G	$134,971,958	$3,690,609	2.7%	2.7%	$3,690,609	0.61	134,971,958	$ 380,420	$4,071,030	3.0%
13	CILC T	$104,826,204	$1,532,014	1.5%	1.5%	$1,532,014	0.62	104,826,204	$ 295,454	$1,827,468	1.7%
14	MET	$3,795,719	$145,092	3.8%	3.0%	$113,872	0.98	-	$ -	$113,872	3.0%
15	OL1/SL1/PL1	$39,492,251	$265,189	0.7%	0.7%	$265,189	1.04	-	$ -	$265,189	0.7%
16	SL2, GSCU1	$23,083,478	$84,299	0.4%	0.4%	$84,299	(0.10)	-	$ -	$84,299	0.4%
17											
18	TOTAL	$8,462,925,627	$166,432,784	2.0%		$160,737,564		2,020,645,867	$5,695,221	$166,432,784	
					re-allocation	$5,695,221					
			1.5x	3.0%							
			Max	3.8%						Max	3.0%

Notes
1) Based on 2013 Projections of base and clause revenues.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR WEST COUNTY ENERGY CENTER UNIT 3
JANUARY 2013 THROUGH DECEMBER 2013

	Rate Schedule	(1) Projected 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/RST1	53,023,166,898	0.00000%	0	$94,491,214	-	0.00178
2	GS1/GST1	5,844,824,242	0.00000%	0	$9,577,147	-	0.00164
3	GSD1/GSDT1/HLFT1 (21-499 kW)	25,078,522,608	52.41924%	65,537,273	$31,208,404	0.48	-
4	OS2	12,578,957	0.00000%	0%	$19,580	-	0.00156
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	11,310,651,252	56.10673%	27,615,301	$19,887,927	0.72	-
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	2,450,692,797	67.14099%	5,000,096	$4,277,249	0.86	-
7	GSLD3/GSLDT3/CS3/CST3	199,482,765	77.92278%	350,686	$481,877	1.37	-
8	ISST1D	0	34.08000%	0	$0	**	-
9	ISST1T	0	15.11426%	0	$0	**	-
10	SST1T	97,610,914	15.11426%	884,685	$119,990	**	-
11	SST1D1/SST1D2/SST1D3	7,613,528	34.08000%	30,603	$7,539	**	-
12	CILC D/CILC G	3,039,558,994	74.46729%	5,591,420	$4,071,030	0.73	-
13	CILC T	1,341,477,742	75.73600%	2,426,377	$1,827,468	0.75	-
14	MET	92,698,007	65.19800%	194,766	$113,872	0.58	-
15	OL1/SL1/PL1	630,970,753	0.00000%	0	$265,189	-	0.00042
16	SL2, GSCU1	70,594,840	0.00000%	0	$84,299	-	0.00119
17							
18	TOTAL	103,200,444,297			$166,432,784		0.00161

(1) Projected kwh sales for the period January 2013 through December 2013
(2) Billing kW Load Factor based on 2011 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)

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 4)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 4)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.08	$0.04
ISST1T	$0.08	$0.04
SST1T	$0.08	$0.04
SST1D1/SST1D2/SST1I	$0.08	$0.04

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

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2013 - Dec 2013 Capacity Recovery Factor				2013 WCEC-3 Capacity Recovery Factor				Total Jan 2013 - Dec 2013 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/RST1	-	0.00798	-	-	-	0.00178	-	-	-	0.00976	-	-
GS1/GST1/WIES1	-	0.00655	-	-	-	0.00164	-	-	-	0.00819	-	-
GSD1/GSDT1/HLFT1	2.44	-	-	-	0.48	-	-	-	2.92	-	-	-
OS2	-	0.00673	-	-	-	0.00156	-	-	-	0.00829	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	2.53	-	-	-	0.72	-	-	-	3.25	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.62	-	-	-	0.86	-	-	-	3.48	-	-	-
GSLD3/GSLDT3/CS3/CST3	2.68	-	-	-	1.37	-	-	-	4.05	-	-	-
SST1T	-	-	$0.34	$0.16	-	-	$0.08	$0.04	-	-	$0.42	$0.20
SST1D1/SST1D2/SST1D3	-	-	$0.35	$0.17	-	-	$0.08	$0.04	-	-	$0.43	$0.21
CILC D/CILC G	2.92	-	-	-	0.73	-	-	-	3.65	-	-	-
CILC T	2.80	-	-	-	0.75	-	-	-	3.55	-	-	-
MET	2.90	-	-	-	0.58	-	-	-	3.48	-	-	-
OL1/SL1/PL1	-	0.00204	-	-	-	0.00042	-	-	-	0.00246	-	-
SL2, GSCU1	-	0.00509	-	-	-	0.00119	-	-	-	0.00628	-	-

(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

2013 GENERATION BASE RATE ADJUSTMENT ("GBRA") FACTOR CALCULATIONS
FOR
CAPE CANAVERAL ENERGY CENTER ("CCEC")

AFFIDAVIT AND EXHIBITS OF RENAE B. DEATON

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	)))	DOCKET NO. 120001-EI FILED: August 31, 2012

AFFIDAVIT

STATE OF FLORIDA COUNTY
OF LEON

BEFORE ME, the undersigned authority, personally appeared Renae B. Deaton, who being first duly sworn deposes and says:

1. My name is Renae B. Deaton. I am employed by Florida Power & Light Company ("FPL"). My business address is 700 Universe Bld. Juno Beach FL 33408.

2. I hold a Bachelor of Science in Business Administration and a Masters of Business Administration from Charleston Southern University. Since joining FPL in 1998 I have held positions in the rates and regulatory areas. Prior to joining FPL, I was employed at the South Carolina Public Service Authority (d/b/a Santee Cooper) for fourteen years where I held a variety of positions in the Corporate Forecasting, Rates, and Marketing Departments and in generation plant operations.

3. I currently hold the position of Rate Development Manager with responsibilities for rate development and tariff administration.

4. The purpose of my affidavit is to submit for informational purposes the Generation Base Rate Adjustment ("GBRA") Factor calculations for the Cape Canaveral Energy Center ("CCEC") should the Commission approve the Settlement Agreement filed in FPL's base rate case in Docket No. 120015-EI. 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. The Settlement Agreement provides that the initial GBRA factor resulting from the commercial operation of CCEC would be applied to meter readings made on and after the commercial operations date, currently expected to be June 1 2013.

5. As presented in Ms. Ousdahl's affidavit, the CCEC's jurisdictional annualized base revenue requirement as reflected in the 2012 rate petition and accompanying MFRs filed in Docket No. 120015-EI, adjusted for 10.7% ROE is $165.561 million.

6. The GBRA Factor also requires computation of the retail base revenues from the sales of electricity during the first twelve months of CCEC's commercial operation, excluding the base revenues associated with West County Unit 3 recovered through the capacity charge. Billed retail base revenues from the sales of electricity have been projected using the same load forecast incorporated in the Company's current capacity c lause filing. Document No. RBD-1 shows the billed retail base revenues from the sales of electricity for the period June 2013 through May 2014 for all customer classes. Billed retail base revenues from the sales of electricity include

customer, demand and energy charge revenues, base revenues recovered through the Conservation clause for the CILC and CDR credits, and non-clause recoverable credits. The sales revenues also include the increase in sales revenues of $313.122 million as provided in the Settlement Agreement and the current estimate of the base revenue increase associated with the Nuclear Extended Power Uprate, EPU, to be effective January 1, 2013. Thus, all the charges subject to the GBRA Factor are included in this revenue figure. Since the actual amount of the EPU increase will be decided later this year, FPL will update the GBRA factor for the actual base revenue increase once approved. 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. RBD-2, the total retail base revenues from the sales of electricity over the first twelve months of CCEC's commercial operation are projected be $4,694.464 million.

7. The GBRA Factor is calculated based on the ratio of CCEC's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of CCEC's commercial operation. The computation and resulting estimate of the GBRA Factor of 3.527% is provided in Document No. RBD-2. Pursuant to the Settlement Agreement, 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 CCEC, currently projected to occur in June 2013. Once the EPU base rate increase is approved and known, FPL will submit an updated GBRA Factor and a

Summary of Tariff Changes reflecting the application of the GBRA factor to base rates to be effective January 1, 2013. FPL will submit for the FPSC staff's administrative approval revised tariff sheets reflecting these new charges prior to the actual commercial in service date.

8. Once CCEC's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the 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 will be computed using the same data and methodology incorporated into the initial GBRA Factor, with the exception that CCEC's actual capital costs will be used in lieu of the capital cost the initial GBRA factor was based on. On a going forward basis, base rates will be adjusted to reflect the revised GBRA Factor for CCEC. 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.

Renae B. Deaton

I hereby certify that on this this 30th day of August, 2012 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Renae B. Deaton 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 30th day of August, 2012.

Traci D. Goldwire

Notary Public

State of Florida

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

Docket No 120001-EI
R. Deaton, Exhibit No. _______
Document No. RBD-1, Page 1 of 1
Retail Base Revenues For The First 12 Months Of Cape Canaveral Energy Center's Commercial Operation

Line No.	Customer Class	2013 Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Residential	$ 224,444,472	$ 249,577,316	$ 252,155,574	$ 241,978,798	$ 216,950,795	$ 185,547,914	$ 179,233,924
2	Commercial	126,849,063	135,828,988	134,025,222	127,149,519	131,175,118	126,870,870	129,180,894
3	Industrial	4,983,244	4,972,773	5,072,927	4,743,607	4,857,370	4,872,786	4,845,730
4	Street & Highway	4,173,024	4,224,439	4,224,361	4,192,341	4,185,341	4,204,674	4,131,329
5	Other	87,193	89,019	83,695	90,022	96,204	97,753	96,141
6	Railroads & Railways	219,168	225,029	242,432	217,158	250,757	248,239	246,926
7	Total Jurisdictional Billed Revenue	360,756,164	394,917,565	395,804,211	378,371,444	357,515,585	321,842,236	317,734,945
8	CILC/CDR Incentive	3,039,848	3,057,190	3,072,371	3,072,916	3,073,829	2,844,698	2,845,893
9	2013 Base Rate Increase	27,411,060	30,006,720	30,074,089	28,749,509	27,164,834	24,454,293	24,142,212
10	Unbilled Revenue	514,723	563,464	564,729	539,856	510,099	459,201	453,341
11	EPU 2013	18,655,019	20,421,535	20,467,385	19,565,921	18,487,446	16,642,746	16,430,354
12	Total Retail Base Revenues From the Sales of Electricity	$ 410,376,814	$ 448,966,473	$ 449,982,785	$ 430,299,645	$ 406,751,793	$ 366,243,173	$ 361,606,744

Line No.	Customer Class	2014 Jan	Feb	Mar	Apr	May	12 Month Ending
13	Residential	$ 207,484,284	$ 173,380,779	$ 169,241,872	$ 172,572,239	$ 200,030,869	$ 2,472,598,838
14	Commercial	135,069,968	121,801,904	119,653,917	117,489,034	130,685,101	1,535,779,599
15	Industrial	4,906,139	4,730,308	4,855,123	4,721,265	4,856,529	58,417,801
16	Street & Highway	4,041,521	4,202,236	4,238,984	4,234,268	4,245,124	50,297,641
17	Other	90,835	98,011	99,265	92,691	90,364	1,111,194
18	Railroads & Railways	232,426	248,565	212,892	214,732	226,113	2,784,437
19	Total Jurisdictional Billed Revenue	351,825,174	304,461,803	298,302,054	299,324,228	340,134,101	4,120,989,511
20	CILC/CDR Incentive	2,848,326	2,851,322	2,854,862	3,094,862	3,099,507	35,755,623
21	2013 Base Rate Increase	26,732,464	23,133,689	22,665,657	22,743,324	25,844,150	313,122,000
22	Unbilled Revenue	501,980	434,403	425,614	427,072	485,299	5,879,780
23	EPU 2013	18,193,190	15,743,988	15,425,462	15,478,320	17,588,634	213,100,000
24	2013 Base Rate & EPU Increase - with Sales Growth Adj for 2014	1,822,285	945,206	1,043,596	906,492	899,665	5,617,245
25	Total Retail Base Revenues From the Sales of Electricity	$ 401,923,418	$ 347,570,411	$ 340,717,245	$ 341,974,299	$ 388,051,357	$ 4,694,464,159

Totals may not add due to rounding

Docket No. 120001-EI
R. Deaton, Exhibit No. _______
Document No. RBD-2, Page 1 of 1
GBRA FACTOR CAPE CANAVERAL

	($million)	source
(A) Jurisdictional Annualized Revenue Requirement	165.561	Doc. No. KO-1 as filed
(B) Total Retail Base Revenues From the Sales of Electricity	4,694.464	Doc. No. RBD-1
(C) GBRA FACTOR [(A) / (B)]	3.527%	

APPENDIX VII

AFFIDAVIT OF KIM OUSDHAL

2013 REVENUE REQUIREMENT CALCULATION FOR WEST COUNTY ENERGY CENTER UNIT 3

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	)))	DOCKET NO. 120001-EI FILED: August 31, 2012

AFFIDAVIT

STATE OF FLORIDA COUNTY
OF MIAMI-DADE

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, 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. That same year, I was employed by Houston Lighting & Power Company in Houston, Texas. During my tenure there, I held various accounting and regulatory management positions. Prior to joining FPL in June 2004, I was the Vice President and Controller of Reliant Energy. 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 Florida Power & Light Company ("FPL" or the "Company") as Vice President, Controller and Chief Accounting Officer.

4. The purpose of my affidavit and supporting documentation is to provide the 2013 revenue requirement for West County Energy Center Unit 3 ("WCEC3") and the Generation Base Rate Adjustment ("GBRA") revenue requirement calculation for the Cape Canaveral Energy Center ("CCEC"). Both of these calculations are being submitted in order to provide information that would be used in the event that the Commission approves the Stipulation and Settlement Agreement jointly filed by FPL, FIPUG, the SFHHA and the FEA on August 15, 2012 in FPL's base rate case in Docket No. 120015-EI (the "Proposed Settlement Agreement"). Paragraph 7 of the Proposed Settlement Agreement provides that the annual revenue requirements for WCEC3 would continue to be recovered through FPL's capacity clause, based upon the settlement ROE of 10.7% (see Paragraph 2 of the Proposed Settlement Agreement). Paragraph 8 of the Proposed Settlement Agreement provides, among other things, that FPL's base rates would be increased by a GBRA for the annualized base revenue requirement of the first 12 months of CCEC's operation as reflected in FPL's 2012 rate petition and accompanying MFRs. Thus, the GBRA for CCEC would provide the same base rate increase as the Canaveral Step Increase requested in the 2012 rate petition.

5. Appendix VII of this filing shows the calculation of WCEC3's 2013 jurisdictional annualized base revenue requirements based on the costs included in FPL's Petition for a Determination of Need for WCEC3, except for the settlement ROE of 10.7%. The resulting jurisdictional annualized base revenue requirement for WCEC3 for 2013 is $166.4 million.

6. Appendix VIII of this filing shows the calculation of CCEC's jurisdictional

annualized base revenue requirement for the first 12 months of operations based on the forecasted amounts reflected on Schedule A-1 for the Canaveral Step Increase included in FPL's 2012 rate petition (I have reduced that revenue requirement to reflect the adjustment shown in Item 18 of my Exhibit KO-16 and the settlement ROE of 10.7%). The resulting jurisdictional annualized base revenue requirement for the first 12 months of operations for CCEC is $165.6 million.

7. In conclusion, the revenue requirement for WCEC3 for 2013 is $166.4 million, and the annual base revenue requirement for the first 12 months of operation for CCEC is $165.6 million.

Ki Ousdahl

Kim Ousdahl

I hereby certify that on this 30th day of August, 2012 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 he acknowledged before me that he executed this certification of signature as his 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 30th day of August 2012.

Traci D. Goldwire

NOTARY PUBLIC STATE OF FLORIDA

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

Notary Public

State of Florida

My Commission Expires: July 31, 2015

WCEC UNIT 3
2013 REVENUE REQUIREMENTS

WCEC3 Revenue Requirement Calculation	2013 ($000)
Jurisdictional Adjusted Rate Base	$769,387
Rate of Return on Rate Base	8.813%
Required Jurisdictional Net Operating Income	67,803
Required Net Operating Income	67,803
Jurisdictional Adjusted Net Operating Income (Loss)	(34,046)
Net Operating Income Deficiency (Excess)	101,849
Net Operating Income Multiplier	1.63411
2013 Revenue Requirement	$166,433

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	After Tax COC
Long Term Debt	44.200%	6.430%	2.84206%	2.84206%	1.74574%
Common Equity	55.800%	10.700%	5.97060%	9.72015%	5.97060%
Total	100.000%		8.81266%	12.56221%	7.71634%

Assumptions	
Income Tax Rate	38.575%
Production Depreciation Rate	4.000%
Transmission Depreciation Rate	2.500%
Rate of Return	8.81266%

Net Plant	6/01/2011	12/31/2011	5/31/2012	12/31/2012	12/31/2013
Production Plant	819,157,500	819,157,500	819,157,500	819,157,500	819,157,500
Transmission Plant	45,570,260	45,570,260	45,570,260	45,570,260	45,570,260
Production Reserve	0	(19,113,675)	(32,766,300)	(51,879,975)	(84,646,275)
Transmission Reserve	0	(664,566)	(1,139,257)	(1,803,823)	(2,943,079)
Deferred Taxes	9,376,790	4,664,390	(450,838)	(5,746,400)	(14,504,962)
Net Plant	874,104,550	849,613,909	830,371,366	805,297,562	762,633,444

	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
Average Rate Base	861,859,229	852,237,958	827,455,735	819,157,500	783,965,503
Juris Factor	0.981404	0.981404	0.981404	0.981404	0.981404
Juris Rate Base	845,832,095	836,389,741	812,068,369	803,924,447	769,386,880
Juris Interest Expense	14,022,782	23,770,698	23,079,470	9,520,006	21,866,437
Income Tax - Interest Expense	(5,409,288)	(9,169,547)	(8,902,906)	(3,672,342)	(8,434,978)

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
Other O&M - FOM, CAP, VOM, Prop Ins	11,041,700	19,123,583	19,396,520	8,081,883	19,774,240
Depreciation	19,778,241	33,905,557	33,905,557	14,127,315	33,905,557
Taxes Other Than Income Taxes - Prop Tax	9,079,640	15,416,761	15,209,090	6,337,121	14,598,800
Total Operating Expenses	39,899,581	68,445,901	68,511,167	28,546,319	68,278,597
Juris Operating Expenses	39,149,725	67,159,426	67,223,284	28,009,702	66,994,769
Income Tax - Operating Expenses	(15,102,006)	(25,906,749)	(25,931,382)	(10,804,742)	(25,843,232)
Other Income Taxes - Def Taxes	790,050	1,354,370	1,354,370	564,320	1,354,370
Juris Other Income Taxes	775,358	1,329,184	1,329,184	553,826	1,329,184

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
Operating Expenses	(39,149,725)	(67,159,426)	(67,223,284)	(28,009,702)	(66,994,769)
Income Tax - Operating Expenses	15,102,006	25,906,749	25,931,382	10,804,742	25,843,232
Income Tax - Interest Expense	5,409,288	9,169,547	8,902,906	3,672,342	8,434,978
Other Income Taxes	(775,358)	(1,329,184)	(1,329,184)	(553,826)	(1,329,184)
Juris Net Operating Income	(19,413,788)	(33,412,315)	(33,718,181)	(14,086,443)	(34,045,743)

APPENDIX VIII

2013 REVENUE REQUIREMENT CALCULATION FOR CAPE CANAVERAL ENERGY CENTER ("CCEC")

CAPE CANAVERAL FIRST YEAR REVENUE REQUIREMENTS
($000)

Cape Canaveral Revenue Requirement Calculation	FIRST YEAR OPERATIONS ($000)
Jurisdictional Adjusted Rate Base	$811,809
Rate of Return on Rate Base	8.576%
Required Jurisdictional Net Operating Income	69,621
Required Net Operating Income	69,621
Jurisdictional Adjusted Net Operating Income (Loss)	(31,833)
Net Operating Income Deficiency (Excess)	101,454
Net Operating Income Multiplier	1.63188
Revenue Requirement	$165,561

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC
Long Term Debt	39.031%	5.258%	2.052%	2.052%
Common Equity	60.969%	10.700%	6.524%	10.621%
Total	100.000%		8.576%	12.673%

Jurisdictional Rate Base - MFR B-1	811,809
Jurisdictional NOI	(31,833)

Juris Rate Base - MFR B-1	($000)	KO -16 Adj	Revised	
Plant In Service	956,492	(10,069)	946,423	
Accum Provision Depreciation	(15,557)	166	(15,391)	
Working Capital	0	0	0	
Other - Deferred Taxes	(119,610)	387	(119,223)	
Total	821,325	(9,516)	811,809	Capital

Juris NOI - MFR C-1	($000)	KO -16 Adj	Revised	
Fixed O&M	6,394		6,394	Fixed O&M
Variable O&M	4,484		4,484	Variable O&M
Property Insurance	1,249		1,249	Capital
Depreciation	31,502	(331)	31,171	Capital
Property Taxes	17,670	(212)	17,458	Capital
Payroll Taxes	286		286	
Income Taxes	(29,494)	285	(29,209)	
Total NOI	(32,092)	(258)	(31,833)	