BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 100001-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 2, 2010

IN RE: LEVELIZED FUEL COST RECOVERY AND CAPACITY COST RECOVERY

ESTIMATED/ACTUAL TRUE-UP
JANUARY 2010 THROUGH DECEMBER 2010

TESTIMONY & EXHIBITS OF:

T. J. KEITH

2011 RISK MANAGEMENT PLAN

COM 5
APA 1
ECR 6
GCL 1
RAD 1
SSC
ADM
OPC
CLK Ct.RPR

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 100001-EI

August 2, 2010

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery (FCR) Clause and the Capacity Cost Recovery (CCR) Clause for the period January 2010 through December 2010.

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

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

II contains the CCR related schedules.

The FCR Schedules contained in Appendix I include Schedules E3 through E9 that provide revised estimates for the period July 2010 through December 2010. FCR Schedules A1 through A9 provide actual data for the period January 2010 through June 2010. They are filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

The CCR Schedules contained in Appendix II provide the calculation of estimated/actual variances and the estimated/actual true-up amount for the period January 2010 through December 2010.

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

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

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

A. The FCR true-up calculation compares estimated/actual data consisting of actuals for January 2010 through June 2010, and revised estimates for July 2010 through December 2010, with the original 2010 projections filed on August 20, 2009. The CCR true-up calculation compares estimated/actual data consisting of actuals for January 2010 through June 2010, and revised estimates for July 2010 through December 2010 with the original estimates for January 2010 through December 2010 filed on August 20, 2009.

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

A. The calculation of the interest provision follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount times the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the 30-day commercial paper rates as published in the Wall Street Journal on the first business day of the current and the subsequent month. The average interest rate for the projected months is the actual rate as of the first business day in July 2010.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the FCR End of Period Net True-up and Estimated/Actual True-up amounts you are requesting this Commission to approve.

A. Appendix I, Pages 2 and 3, show the calculation of the FCR End of Period Net True-up and Estimated/Actual True-up amounts. The End of Period Net True-up amount to be carried forward to the 2011 fuel factor is an under-recovery of $277,584,308 (Appendix I, Page 3, Column 13, Line C11). This $277,584,308 under-recovery includes the 2009 Final True-up under-recovery of $8,771,414 (Appendix I, Page 3, Column 13, Line C9b), filed with the Commission on March 12, 2010, and the Estimated/Actual True-up under-recovery, including interest, of $268,812,894 (Appendix I, Page 3, Column 13, Lines C7 plus C8) for the period January 2010 through December 2010.

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

A. Yes, they were.

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

A. Yes. Appendix I, Pages 2 and 3, entitled "Calculation of True-Up Amount," show the calculation of the FCR Estimated/Actual True-up by month for January 2010 through December 2010.

Q. Have you provided a schedule showing the variances between estimated/actuals and original projections for 2010?

A. Yes. Appendix I, Page 4 provides a comparison of jurisdictional revenues and costs on a dollar per MWh basis. Appendix I, Page 5 provides a variance calculation that compares the Estimated/Actual period data to the data from the original projections filing for the January 2010 through December 2010 period.

Q. Please describe the variance analysis on Page 4 of Appendix I.

A. Appendix I, Page 4 provides a comparison of Jurisdictional Total Revenues and Jurisdictional Total Fuel Costs and Net Power Transactions on a dollar per MWh basis. The $277,584,308 variance is primarily due to an increase in fuel costs per MWh of $43.80/MWh vs. $41.60/MWh that results in a cost variance of $227,646,554, and a decrease in fuel revenues per MWh of $41.32/MWh vs. $41.71/MWh that results in a cost variance of ($40,832,839), for a total variance due to cost of ($268,479,393). The impact of the variance due to consumption is mostly offset between costs per MWh and revenues per MWh, netting to a variance due to consumption of $268,679. When the interest amount of $602,180 associated with the 2010 estimated/actual true-up amount and the 2009 Final True-up under-recovery amount of $8,771,414 are added to the calculation, the total amount of the variance results in the $277,584,308.

Q. Please summarize the variance schedule on Page 5 of Appendix I.

A. FPL's original projections filed on August 20, 2009 projected Jurisdictional Total Fuel and Net Power Transactions to be $4.202 billion for 2010 (Appendix I, Page 5, Column 2, line C6). The Estimated/Actual Jurisdictional Total Fuel Costs and Net Power

Transactions are now projected to be $ 4.529 billion for that period (actual data for January 2010 through June 2010 and revised estimates for July 2010 through December 2010) (Appendix I, Page 5, Column 1, Line C6). Therefore, Jurisdictional Total Fuel Costs and Net Power Transactions are $326,206,940, or 7.8% higher than the original projections filing (Appendix I, Page 5, Column 3, Line C6). Jurisdictional Fuel Revenues for 2010 are projected to be $57,996,226, or 1.4% higher than the original projections filing (Appendix I, Page 5, Column 3, Line C3).

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

A. As shown on Appendix I, Page 5 Line C6, the variance in Jurisdictional Total Fuel Costs and Net Power Transactions of $326.2 million is a 7.8% increase from original projections. The primary reasons for this variance are higher than projected Fuel Cost of System Net Generation ($257.8 million), higher than projected Energy Cost of Economy Purchases ($58.0 million), lower than projected Fuel Cost of Power Sold ($28.3 million) and lower than projected Gains from Off-System Sales ($8.4 million), partially offset by lower than projected Incremental Hedging Costs ($0.628 million) and lower than projected Fuel Cost of Purchased Power ($22.8 million).

The $257.8 million or 6.7 % increase in the Fuel Cost of System Net

Generation is primarily due to higher than projected heavy and light oil costs partially offset by lower than projected natural gas costs. Heavy oil is currently projected to be $409.0 million (369.9%) higher than the original projection. Heavy oil burn in the estimated/actual period is projected to be 45,275,515 MMBTUs, which is 343.0% higher than the 10,221,287 MMBTUs included in the original projection. Additionally, the unit cost of heavy oil in the estimated/actual period is $11.48 per MMBTU, which is 6.09% higher than the $10.82 per MMBTU included in the original projection. Light oil costs are currently projected to be $26.2 million (234.4%) higher than the original projection. The unit cost of light oil in the estimated/actual is $14.03 per MMBTU, or 12.3% lower than the $16.01 per MMBTU included in the original projection and light oil burn in the estimated/actual period is projected to be 2,665,241 MMBTUs, which is 281.5% higher than the 698,657 MMBTUs included in the original projection. The increases in heavy oil and light oil costs are partially offset by lower than projected natural gas costs. Natural gas is currently projected to be $159.3 million, or 4.7% lower than the original projection. The unit cost of natural gas in the estimated/actual period is $6.58 per MMBTU, which is 6.6% lower than the $7.05 per MMBTU included in the original projection. Additionally, consumption of natural gas increased by 2.0% compared to the original projection. Projections for Generation by Fuel Type for the period July 2010 through December 2010 are included in Appendix I, Schedule E3.

The $58.0 million, or 149.4% increase in Energy Cost of Economy Purchases is primarily due to higher than projected economy purchases. Approximately 61% or slightly less than $35.2 million of the variance is due to higher than projected economy purchases. FPL is currently estimating that it will purchase approximately 760,000 MWh more of economy power than originally projected. Approximately 39% or slightly more than $22.8 million is due to higher than projected unit costs for economy purchases. FPL is currently estimating that the average cost of its economy purchases will be approximately $14.30/MWh higher than originally projected.

The $28.3 million, or 50.4% decrease in Fuel Cost of Power Sold is primarily due to lower than projected economy sales. Approximately 83% or slightly more than $23.6 million of the variance is due to lower than projected economy sales. FPL is currently estimating that it will sell approximately 683,000 MWh less of economy power than originally projected. Approximately 17% or slightly less than $4.7 million is due to lower than projected fuel costs for power sales. FPL is currently estimating that the average unit cost of fuel attributable to power sales will be approximately $4.60/MWh less than originally projected.

The $8.4 million or 56.0% decrease in Gains from Off-System Sales is primarily due to lower than projected economy sales. FPL is currently estimating that it will sell approximately 683,000 MWh less of economy power than originally projected. Approximately 5% or slightly less than $0.45 million is due to lower than projected gains on economy sales. FPL is currently estimating that the average gain on its economy sales will be approximately $0.74/MWh less than originally projected.

The $0.628 million, or 87.8% decrease in Incremental Hedging Costs is the result of the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI related to the recovery of incremental hedging costs. In these dockets, FPL requested to move recovery of incremental hedging costs from the FCR to base rates. In Order No. PSC-10-0153-FOF-EI, the Commission states:

> "Consistent with our prior orders, we move incremental hedging costs into base rates. The incremental hedging costs are administrative costs and properly belong in base rates, not in fuel factors."

This change became effective on March 1, 2010.

The $22.8 million, or 7.8% decrease in the Fuel Cost of Purchased

Power is primarily due to lower than projected energy purchases from UPS ($26.5 million) and SJRPP ($3.5 million), slightly offset by higher than projected energy purchases from Purchased Power Agreements ($6.3 million) and St. Lucie Unit 2 ($0.8 million).

Q. What is the appropriate estimated benchmark level for calendar year 2011 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI?

A. For the forecast year 2011, the three-year average threshold consists of actual gains for 2008, 2009 and January 2010 through June 2010, and estimates for July 2010 through December 2010. Gains on sales in 2011 are to be measured against this three-year average threshold, after it has been adjusted with the true-up filing (scheduled to be filed in March 2011) to include all actual data for the year 2010.

2008	$17,001,482
2009	$10,700,431
2010	6,581,695
Average threshold	$11,427,869

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the CCR Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Appendix II, Pages 2 and 3 show the calculation of the CCR

Estimated/Actual True-up amount. The calculation of the Estimated/Actual True-up for the period January 2010 through December 2010 is an under-recovery of $94,409,910, including interest (Appendix II, Page 3, Column 13, Lines 17 plus 18).

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

A. Yes, it is.

Q. Have you provided a schedule showing the variances between the Estimated/Actuals and the Original Projections?

A. Yes. Appendix II, Page 4 shows the Estimated/Actual capacity charges and applicable revenues (January 2010 through June 2010 reflects actual data and the data for July 2010 through December 2010 is based on updated estimates) compared to the original projections for the January 2010 through December 2010 period, filed on August 20, 2010.

Q. Please explain the variances related to capacity charges.

A. As shown in Appendix II, Page 4, Column 3, Line 13, the variance related to jurisdictional capacity charges is $115.5 million, a 22.9% increase. The primary reasons for this variance are a $74.8 million increase in total system capacity costs (Page 4, Column 3, and Line 9) and a $47.5 million increase in capacity related amounts previously included in base rates, per the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos.

080677-EI and 090130-EI (Page 4, Column 3, Line 12), partially offset by a $6.8 million decrease in costs associated with the use of a revised jurisdictional separation factor.

The $74.8 million, or 14.8% increase in total capacity charges is due to a $2.0 million increase in Capacity Payments to Non-cogenerators, a $53.5 million increase in Short Term Capacity Payments, a $2.8 million increase in Payments to Cogenerators, a $0.693 million decrease in return requirements on the SJRPP Suspension Liability, a $7.3 million increase in Incremental Plant Security Costs, an $8.1 million increase in Transmission of Electricity by Others and a $0.996 million decrease in Transmission Revenues from Capacity Sales, slightly offset by a $0.543 million decrease in the SJRPP Suspension Accrual amount.

The $2.0 million, or 1.3% increase in Payments to Non-cogenerators is primarily due to higher than projected fixed monthly O&M costs from SJRPP and UPS production adjustments issued during the first five months of 2010.

The $53.5 million, or 653.7% increase in Short Term Capacity Payments is due to the addition of the capacity payments associated with FPL's new Unit Power Sales Agreement (UPS) with Southern Company. FPL has moved these capacity payments from the

Payments to Non-cogenerators line (also from Schedule A12, Page 1 of 2) to the Short-Term Capacity Payments line to facilitate the confidential treatment of these payments in a single location (i.e., Schedule A12, Page 2 of 2). Please note that $69.7 million associated with FPL's new UPS agreement with Southern Company were inadvertently excluded from the Payments to Non-cogenerators line (Line 1) in the 2010 original projection filing dated August 20, 2010. Additionally, in the 2010 projection filing, the data reflected on the Payments to Non-cogenerators line (Line 1) and the Payments to Cogenerators line (Line 3) were inadvertently reversed. These changes have been made and are properly reflected in this filing. Because of these changes, the variances I am reporting for those line items are not representative of actual changes in FPL's 2010 capacity payments.

The $2.8 million or 0.9% increase in Payments to Cogenerators is primarily due to higher than projected capacity payments of approximately $2.8 million for the first six months of 2010. Cedar Bay's performance in the first six months of 2010 exceeded estimates by approximately $2.4 million. The remaining variance is due to ICL performing better than anticipated by approximately $0.672 million in the first half of 2010 from what was originally anticipated.

The $0.693 million, or 11.7% decrease in return requirements on the

SJRPP Suspension Liability is primarily due to the change in capital structure (debt/equity) used to calculate the return on investment resulting from the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI.

The $7.3 million, or 15.9% increase in Incremental Plant Security Costs is primarily attributable to an increase of $5.5 million from the original projection associated with activities identified by the Risk-Based Methodology annual assessment performed in March 2010. NERC CIP-002 requires FPL to maintain a documented Risk-Based Methodology, perform an annual assessment of applicable facilities and identify and address all generation resources that support the reliability of the Bulk Electric System. The March 2010 assessment identified a new critical asset (i.e., generation facility). Per NERC CIP-002, FPL is required to make modifications within a 12-month period to the physical and electronic security perimeters of the identified asset. Planned activities include the implementation of physical security boundaries and an electronic security perimeter, upgrading existing control systems and installing security appliances.

Additionally, there is an increase of $1.8 million due to expenses associated with the Force on Force upgrades planned at St. Lucie, which were not included in the original projection. 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 Force on Force inspections performed at the nuclear stations. FPL could not estimate the impact of these changes for St. Lucie until a comprehensive review was completed in late 2009 after the 2010 projection was submitted. This increase was somewhat offset by a $0.6 million decrease in security payroll projections due to vacant positions.

The $8.1 million increase in Transmission of Electricity by Others is due to projected costs for "unutilized transmission" associated with FPL's new UPS agreement with Southern Company, which were inadvertently omitted from the original projections. In the previous UPS agreement, transmission costs were bundled with energy costs. The new agreement provides a separate transmission charge that is paid directly to the transmission provider, in this case Southern Company Transmission. Because this is a reservation charge, FPL pays for this transmission whether or not it is utilized. Utilized transmission dollars are recovered through the FCR on Schedule A7. The portion of transmission dollars that is unutilized is now being recovered through the CCR under the Transmission of Electricity by Others line.

The $0.996 million, or 40.0% decrease in Transmission Revenues from Capacity Sales is primarily due to lower than projected economy power sales. Through June 2010, FPL sold approximately 542,000 MWh less than projected. FPL now projects a total of approximately 683,000 MWh less economy sales by the end of 2010 versus the original projection resulting in a variance in transmission revenues of $996,111.

The $0.543 million or 25.2% decrease in the SJRPP Suspension Accrual is due to a reduction in the suspension accrual rate resulting from revised calculations reflecting current performance and an updated debt maturity schedule.

The $47.5 million or 83.3% increase in Capacity related amounts included in base rates is a result of the Commission's decision in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI related to capacity charges. In these dockets, FPL requested to transfer $56.9 million associated with St. John's River Power Park (SJRPP) from base rates to the capacity clause. In Order No. PSC-10-0153-FOF-EI, the Commission states:

> "We find that capacity charges associated with SJRPP shall be treated consistently with other capacity arrangements and shall be included in the capacity clause. This is the first general rate case in which we have had the opportunity to

transfer these charges from base rates to the capacity clause. Accordingly, the adjustments made by FPL for the St. Johns River Power Park (SJRPP) from base rates to the capacity clause are approved."

This change became effective on March 1, 2010.

Additionally, there is a $6.8 million decrease in CCR costs associated with the use of a revised jurisdictional separation factor. Order No. PSC-09-0795-FOF-EI issued in Docket No. 090001-EI on December 2, 2009 approved a jurisdictional separation factor for FPL of 99.09578%, which was used in determining the amount of CCR costs to be recovered from retail customers during the period January 2010 through December 2010. This jurisdictional separation factor was based on 2008 actual data, which was the most current 12-month period of actual data available at the time of FPL's 2010 projection filing on August 20, 2009. FPL's contract with Lee County Electric Cooperative (LCEC) became effective on January 1, 2010, which serves to reduce FPL's jurisdictional separation factor and the amount of CCR costs to be recovered from retail customers. As a result, FPL has revised the jurisdictional separation factor used in the calculation of the 2010 Estimated/Actual True-up amount to account for the additional load required to serve the LCEC contract thereby reducing the amount of CCR costs recovered from retail customers.

FPL is using the 2010 jurisdictional separation factor for demand of 98.03105% approved by the Commission in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI.

In addition to the cost variances, Appendix II, Page 4, Column 3, Line 14 shows that CCR Revenues Net of Revenue Taxes, are $21.2 million higher than originally projected. The $115.5 million higher costs (Appendix II, Page 4, Column 3, Line 13) adjusted by the $21.2 million increase in revenues (Appendix II, Page 4, Column 3, Line 14) results in an Estimated/Actual 2010 True-up under-recovery amount of $94.4 million, including interest (Appendix II, Page 4, Column 3, Lines 17 plus 18). This under-recovery of $94.4 million including interest, plus the Final 2009 True-up over-recovery of $20.9 million filed on March 12, 2010 results in a net under-recovery of $73.5 million to be carried forward to the 2011 capacity factor.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

FUEL COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

TJK- 3
DOCKET NO. 100001-EI
FPL WITNESS: T. J. KEITH
August 2, 2010

CALCULATION OF TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

LINE NO.			(1) ACTUAL JAN	(2) ACTUAL FEB	(3) ACTUAL MAR	(4) ACTUAL APR	(5) ACTUAL MAY	(6) ACTUAL JUN
A		**Fuel Costs & Net Power Transactions**						
1	a	Fuel Cost of System Net Generation	$ 378,533,784	$ 247,792,496	$ 258,792,333	$ 276,339,803	$ 372,679,512	$ 435,222,107
	b	Incremental Hedging Costs	$ 51,225	$ 36,065	$ 0	$ 0	$ 0	$ 0
	c	Nuclear Fuel Disposal Costs	$ 2,043,474	$ 1,905,348	$ 2,090,331	$ 1,460,650	$ 1,442,608	$ 1,471,860
	d	Scherer Coal Cars Depreciation & Return	$ 74,704	$ 74,034	$ 73,236	$ 72,657	$ (5,773)	$ 0
2	a	Fuel Cost of Power Sold (Per A6)	$ (2,785,805)	$ (3,439,331)	$ (2,104,182)	$ (487,993)	$ (317,396)	$ (1,043,999)
	b	Gains from Off-System Sales	$ (700,142)	$ (1,045,544)	$ (637,729)	$ (161,575)	$ (47,295)	$ (11,282)
3	a	Fuel Cost of Purchased Power (Per A7)	$ 21,519,902	$ 26,977,144	$ 17,505,531	$ 20,334,815	$ 24,960,809	$ 32,878,864
	b	Energy Payments to Qualifying Facilities (Per A8)	$ 13,569,500	$ 12,180,154	$ 10,084,009	$ 7,226,308	$ 12,712,002	$ 23,060,407
4		Energy Cost of Economy Purchases (Per A9)	$ 2,128,949	$ 372,716	$ 50,667	$ 1,094,138	$ 20,692,467	$ 35,873,446
5		Total Fuel Costs & Net Power Transactions	$ 414,435,591	$ 284,853,082	$ 285,854,194	$ 305,878,804	$ 432,116,934	$ 527,451,402
6		**Adjustments to Fuel Cost**						
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (3,530,116)	$ (4,211,769)	$ (3,076,009)	$ (3,228,478)	$ (3,164,529)	$ (4,369,021)
	b	Energy Imbalance Fuel Revenues	$ (76,823)	$ (351,680)	$ (79,847)	$ (91,728)	$ 106,367	$ (314,065)
	c	Inventory Adjustments	$ (69,559)	$ 147,744	$ (95,104)	$ (368,276)	$ 113,300	$ (49,285)
	d	Non Recoverable Oil/Tank Bottoms - Docket No. 13092	$ (402,574)	$ 0	$ (24,110)	$ 0	$ 293,850	$ 0
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 410,356,519	$ 280,437,377	$ 282,579,125	$ 302,190,323	$ 429,465,922	$ 522,719,031
B		**kWh Sales**						
1		Jurisdictional kWh Sales	$ 9,116,973,254	$ 7,491,191,418	$ 7,202,475,549	$ 6,885,209,812	$ 8,296,041,541	$ 9,976,346,291
2		Sale for Resale (excluding FKEC & CKW)	$ 5,380,147	$ 109,830,597	$ 86,226,967	$ 89,234,836	$ 87,254,389	$ 111,812,226
3		Sub-Total Sales (excluding FKEC & CKW)	$ 9,122,353,401	$ 7,601,022,015	$ 7,288,702,516	$ 6,974,444,648	$ 8,383,295,930	$ 10,088,158,517
4		**Jurisdictional % of Total Sales (B1/B3)**	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
C		**True-up Calculation**						
1		Juris Fuel Revenues (Net of Revenue Taxes)	$ (18,393,991)	$ 308,542,108	$ 297,757,817	$ 282,918,400	$ 345,371,019	$ 420,620,978
2		**Fuel Adjustment Revenues Not Applicable to Period**						
	a	Prior Period True-up (Collected)/Refunded This Period (b)	$ 364,843,209		$ 0	$ 0	$ 0	$ 0
	b	GPIF, Net of Revenue Taxes (a)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 345,494,544	$ 307,587,434	$ 296,803,143	$ 281,963,726	$ 344,416,345	$ 419,666,304
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 410,356,519	$ 280,437,377	$ 282,579,125	$ 302,190,323	$ 429,465,922	$ 522,719,031
	b	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items	$ 410,356,519	$ 280,437,377	$ 282,579,125	$ 302,190,323	$ 429,465,922	$ 522,719,031
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00040) +(Lines C4b,c,d)	$ 410,278,537	$ 276,495,751	$ 279,347,852	$ 298,443,278	$ 425,165,996	$ 517,132,245
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (64,783,993)	$ 31,091,683	$ 17,455,291	$ (16,479,552)	$ (80,749,651)	$ (97,465,941)
8		Interest Provision for the Month (Line D10)	$ 23,548	$ (9,904)	$ (5,901)	$ (6,093)	$ (19,442)	$ (49,159)
9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$ 364,843,209	$ (64,760,445)	$ (33,678,667)	$ (16,229,277)	$ (32,714,921)	$ (113,484,014)
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)
10	a	Prior Period True-up Collected/(Refunded) This Period	$ (364,843,209)	$ 0	$ 0	$ 0	$ 0	$ 0
	b	Prior Period True-up Collected/(Refunded) This Period						
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (73,531,859)	$ (42,450,081)	$ (25,000,691)	$ (41,486,335)	$ (122,255,428)	$ (219,770,528)

NOTES
(a) **Generation Performance Incentive Factor is (($11,464,340) x 99.9280%) - Per Order No. PSC-09-0795-FOF-EI.**
(b) **Refund of $364.8 million 2010 net true-up under-recovery per Order No. PSC-09-0795-FOF-EI.**

CALCULATION OF TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

LINE NO.			(7) ESTIMATED JUL	(8) ESTIMATED AUG	(9) ESTIMATED SEP	(10) ESTIMATED OCT	(11) ESTIMATED NOV	(12) ESTIMATED DEC	(13) TOTAL PERIOD
A		**Fuel Costs & Net Power Transactions**							
1	a	Fuel Cost of System Net Generation	$ 408,537,185	$ 418,623,712	$ 379,462,859	$ 387,036,394	$ 266,233,290	$ 261,768,044	$ 4,091,021,519
	b	Incremental Hedging Costs	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 87,290
	c	Nuclear Fuel Disposal Costs	$ 1,987,193	$ 1,987,193	$ 1,862,629	$ 1,518,620	$ 1,908,888	$ 2,037,156	$ 21,715,950
	d	Scherer Coal Cars Depreciation & Return	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 288,857
2	a	Fuel Cost of Power Sold (Per A6)	$ (2,313,093)	$ (2,828,993)	$ (1,451,061)	$ (2,635,253)	$ (3,214,888)	$ (5,204,689)	$ (27,826,684)
	b	Gains from Off-System Sales	$ (331,577)	$ (474,747)	$ (167,047)	$ (329,985)	$ (960,299)	$ (1,714,472)	$ (6,581,694)
3	a	Fuel Cost of Purchased Power (Per A7)	$ 24,209,944	$ 22,841,162	$ 23,007,338	$ 23,920,719	$ 14,688,751	$ 15,664,050	$ 268,509,029
	b	Energy Payments to Qualifying Facilities (Per A8)	$ 20,081,000	$ 20,058,000	$ 19,155,000	$ 16,197,000	$ 11,527,000	$ 16,006,000	$ 181,856,379
4		Energy Cost of Economy Purchases (Per A9)	$ 9,732,000	$ 9,924,000	$ 8,313,800	$ 5,933,500	$ 1,548,000	$ 1,202,400	$ 96,866,084
5		Total Fuel Costs & Net Power Transactions	$ 461,902,652	$ 470,130,327	$ 430,183,518	$ 431,640,995	$ 291,730,741	$ 289,758,489	$ 4,625,936,730
6		**Adjustments to Fuel Cost**							
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (4,579,429)	$ (4,773,166)	$ (4,836,284)	$ (4,689,155)	$ (4,331,485)	$ (3,880,453)	$ (48,669,893)
	b	Energy Imbalance Fuel Revenues	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (807,775)
	c	Inventory Adjustments	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (321,180)
	d	Non Recoverable Oil/Tank Bottoms - Docket No. 13092	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (132,835)
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 457,323,224	$ 465,357,161	$ 425,347,234	$ 426,951,841	$ 287,399,256	$ 285,878,036	$ 4,576,005,048
B		**kWh Sales**							
1		Jurisdictional kWh Sales	$ 9,810,401,877	$ 9,745,715,135	$ 10,218,618,336	$ 8,764,797,033	$ 8,105,627,877	$ 7,784,653,926	$ 103,398,052,048
2		Sale for Resale (excluding FKEC & CKW)	$ 108,435,603	$ 116,500,427	$ 121,290,071	$ 110,614,743	$ 101,498,650	$ 82,788,090	$ 1,130,866,746
3		Sub-Total Sales (excluding FKEC & CKW)	$ 9,918,837,480	$ 9,862,215,562	$ 10,339,908,406	$ 8,875,411,776	$ 8,207,126,527	$ 7,867,442,016	$ 104,528,918,794
4		**Jurisdictional % of Total Sales (B1/B3)**	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
C		**True-up Calculation**							
1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 409,191,344	$ 406,493,264	$ 426,218,031	$ 365,579,221	$ 338,085,311	$ 324,697,504	$ 3,907,081,006
2		**Fuel Adjustment Revenues Not Applicable to Period**							
	a	Prior Period True-up (Collected)/Refunded This Period (b)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 364,843,209
	b	GPIF, Net of Revenue Taxes (a)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (954,674)	$ (11,456,086)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 408,236,670	$ 405,538,590	$ 425,263,357	$ 364,624,548	$ 337,130,637	$ 323,742,830	$ 4,260,468,129
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 457,323,224	$ 465,357,161	$ 425,347,234	$ 426,951,841	$ 287,399,256	$ 285,878,036	$ 4,576,005,048
	b	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items	$ 457,323,224	$ 465,357,161	$ 425,347,234	$ 426,951,841	$ 287,399,256	$ 285,878,036	$ 4,576,005,048
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4c x C5 x 1.00040) +(Lines C4b,c,d)	$ 452,504,559	$ 460,043,934	$ 420,525,926	$ 421,799,349	$ 283,958,499	$ 282,982,918	$ 4,528,678,843
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (44,267,888)	$ (54,505,344)	$ 4,737,431	$ (57,174,802)	$ 53,172,138	$ 40,759,912	$ (268,210,714)
8		Interest Provision for the Month (Line D10)	$ (70,564)	$ (84,990)	$ (92,274)	$ (99,949)	$ (100,561)	$ (86,891)	$ (602,180)
9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$ (210,999,114)	$ (255,337,566)	$ (309,927,900)	$ (305,282,742)	$ (362,557,493)	$ (309,485,916)	$ 364,843,209
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)	$ (8,771,414)
10	a	Prior Period True-up Collected/(Refunded) This Period	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (364,843,209)
	b	Prior Period True-up Collected/(Refunded) This Period							$ 0
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (264,108,980)	$ (318,699,314)	$ (314,054,156)	$ (371,328,907)	$ (318,257,330)	$ (277,584,308)	$ (277,584,308)

NOTES
(a) **Generation Performance Incentive Factor is (($11,464,340) x 99.9280%) - Per Order No. PSC-09-0795-FOF-EI.**
(b) **Refund of $364.8 million 2010 net true-up under-recovery per Order No. PSC-09-0795-FOF-EI.**

REVENUE/ COST VARIANCE ANALYSIS - 2010 ESTIMATED/ACTUAL TRUE UP

JURISDICTIONAL FUEL REVENUES	ORIGINAL PROJECTIONS	ESTIMATED/ACTUAL		$ DIFFERENCE
REVENUES	$4,213,927,989	$4,271,924,215	*	$57,996,226
MWH	101,028,632	103,398,052		2,369,420
$ per MWH	41.71024	41.31533		(0.39491)
VARIANCE DUE TO CONSUMPTION				$ 98,829,065
VARIANCE DUE TO COST				$ (40,832,839)
				$ 57,996,226

JURISDICTIONAL TOTAL FUEL COSTS	ORIGINAL PROJECTIONS	ESTIMATED/ACTUAL		$ DIFFERENCE
COSTS	$4,202,471,903	$4,528,678,843		$326,206,940
MWH	101,028,632	103,398,052		2,369,420
$ per MWH	41.59684	43.79849		2.20165
VARIANCE DUE TO CONSUMPTION				$ 98,560,386
VARIANCE DUE TO COST				$ 227,646,554
				$ 326,206,940

TOTAL VARIANCE		$ DIFFERENCE
VARIANCE DUE TO CONSUMPTION		$ 268,679
VARIANCE DUE TO COST		$ (268,479,393)
		$ (268,210,714)
INTEREST		$ (602,180)
2009 FINAL TRUE-UP		$ (8,771,414)
		$ (277,584,308)

* Includes refund of $364.8 million 2010 net true-up under-recovery per Order No. PSC-09-0795-FOF-EI

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL vs. ORIGINAL PROJECTION
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

LINE NO.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTION	(3) DIFFERENCE AMOUNT	(4) DIFFERENCE %
A	**Fuel Costs & Net Power Transactions**				
1	a Fuel Cost of System Net Generation	$ 4,091,021,519	$ 3,833,179,991	$ 257,841,528	6.7 %
	b Incremental Hedging Costs	87,290	715,000	(627,710)	(87.8) %
	c Nuclear Fuel Disposal Costs	21,715,950	21,428,872	287,078	1.3 %
	d Scherer Coal Cars Depreciation & Return	288,857	556,595	(267,738)	(48.1) %
2	a Fuel Cost of Power Sold (Per A6)	(27,826,684)	(56,155,742)	28,329,059	(50.4) %
	b Gains from Off-System Sales	(6,581,694)	(14,959,057)	8,377,363	(56.0) %
3	a Fuel Cost of Purchased Power (Per A7)	268,509,029	291,286,480	(22,777,451)	(7.8) %
	b Energy Payments to Qualifying Facilities (Per A8)	181,856,379	182,019,000	(162,621)	(0.1) %
4	Energy Cost of Economy Purchases (Per A9)	96,866,084	38,832,738	58,033,345	149.4 %
5	Total Fuel Costs & Net Power Transactions	$ 4,625,936,730	$ 4,296,903,877	$ 329,032,853	7.7 %
6	**Adjustments to Fuel Cost**				
	a Sales to Fl. Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (48,669,893)	$ (49,762,013)	$ 1,092,120	(2.2) %
	b Reactive and Voltage Control Fuel Revenue	$ (807,775)	$ 0	$ (807,775)	N/A
	c Inventory Adjustments	$ (321,180)	$ 0	$ (321,180)	N/A
	d Non Recoverable Oil/Tank Bottoms	$ (132,835)	$ 0	$ (132,835)	N/A
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 4,576,005,048	$ 4,247,141,864	$ 328,863,184	7.7 %
B	**Jurisdictional kWh Sales**				
1	Jurisdictional kWh Sales	103,398,052,048	101,028,632,000	2,369,420,048	2.3 %
2	Sale for Resale (excluding FKEC & CKW)	1,130,866,746	1,114,923,000	15,943,746	1.4 %
3	Sub-Total Sales (excluding FKEC & CKW)	104,528,918,794	102,143,555,000	2,385,363,794	2.3 %
4	**Jurisdictional % of Total Sales (lines B1/B3)**	N/A	N/A	N/A	N/A
C	**True-up Calculation**				
1	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 3,907,081,006	4,213,927,989.00	$ (306,846,983)	(7.3) %
	Fuel Adjustment Revenues Not Applicable to Period				
2	a Prior Period True-up (Collected)/Refunded This Period (b)	$ 364,843,209	$ 0	$ 364,843,209	N/A
	b GPIF, Net of Revenue Taxes (a)	$ (11,456,086)	$ (11,456,086)	$ (0)	0.0 %
3	Jurisdictional Fuel Revenues Applicable to Period	$ 4,260,468,129	$ 4,202,471,903	$ 57,996,226	1.4 %
4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 4,576,005,048	$ 4,247,141,864	$ 328,863,184	7.7 %
	b Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items	4,576,005,048	4,247,141,864	328,863,184	7.7 %
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00040) +(Lines C4b,c,d)	$ 4,528,678,843	$ 4,202,471,903	$ 326,206,940	7.8 %
7	True-up Provision for the Period - Over/(Under) Recovery (Line C3 - Line C6)	$ (268,210,714)	$ 0	$ (268,210,714)	N/A
8	Interest Provision for the Period	(602,180)	0	$ (602,180)	N/A
9	a True-up & Interest Provision Beg of Period-Over/(Under) Recovery (b)	364,843,209	364,843,209	$ 0	N/A
	b Deferred True-up Beginning of Period - Over/(Under) Recovery	(8,771,414)	0	$ (8,771,414)	N/A
10	Prior Period True-up Collected/(Refunded) This Period	(364,843,209)	(364,843,209)	$ 0	N/A
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (277,584,308)	$ 0	$ (277,584,308)	N/A

Notes
(a) Generation Performance Incentive Factor is (($11,464,340) x 99.9280%) - Per Order No. PSC-09-0795-FOF-EI.
(b) Refund of $364.8 million 2010 net true-up under-recovery per Order No. PSC-09-0795-FOF-EI.

Generating System Comparative Data by Fuel Type

	Jan-10 ACTUALS	Feb-10 ACTUALS	Mar-10 ACTUALS	Apr-10 ACTUALS	May-10 ACTUALS	Jun-10 ACTUALS
Fuel Cost of System Net Generation ($)						
1 Heavy Oil	$70,756,596	$882,687	$18,082,910	$20,117,132	$52,262,217	$97,641,711
2 Light Oil	$22,355,479	$43,296	$1,974,293	$891,077	$1,875,063	$1,898,107
3 Coal	$11,748,266	$5,197,726	$2,390,029	$13,486,235	$15,260,270	$15,477,006
4 Gas	$261,291,953	$229,836,651	$223,687,057	$232,003,950	$293,558,193	$310,288,578
5 Nuclear	$12,381,490	$11,832,135	$12,658,044	$9,841,409	$9,723,769	$9,916,705
6 ***Total***	$378,533,784	$247,792,495	$258,792,333	$276,339,803	$372,679,512	$435,222,107
System Net Generation (MWH)						
7 Heavy Oil	602,918	4,139	143,822	171,131	440,726	826,022
8 Light Oil	139,819	286	18,336	7,741	15,812	11,351
9 Coal	388,103	146,391	95,492	533,479	592,136	595,280
10 Gas	4,793,679	4,263,681	4,728,162	4,861,517	5,791,398	6,758,761
11 Nuclear	2,194,386	2,042,780	2,241,110	1,565,243	1,544,592	1,578,149
12 Solar	3,526	3,038	4,665	6,945	7,158	7,257
12 ***Total***	8,122,431	6,460,315	7,231,587	7,146,056	8,391,822	9,776,820
Units of Fuel Burned						
13 Heavy Oil (BBLS)	959,668	12,029	242,563	275,235	714,492	1,349,498
14 Light Oil (BBLS)	294,105	530	24,535	11,048	23,070	22,802
15 Coal (TONS)	74,943	67,100	21,113	62,241	73,699	69,266
16 Gas (MCF)	35,734,698	32,742,769	33,892,958	36,555,560	47,745,866	49,166,905
17 Nuclear (MBTU)	23,474,131	21,836,278	24,020,027	17,122,179	16,928,770	18,430,406
BTU Burned (MMBTU)						
18 Heavy Oil	6,083,039	76,401	1,550,013	1,762,075	4,539,537	8,574,437
19 Light Oil	1,679,240	3,071	141,146	56,325	140,367	129,846
20 Coal	4,386,760	1,406,995	828,872	5,394,225	6,069,658	6,090,750
21 Gas	36,346,024	33,487,589	34,498,578	37,167,833	48,535,150	49,974,547
22 Nuclear	23,474,131	21,836,278	24,020,027	17,122,179	16,928,770	18,430,406
23 ***Total***	71,969,194	56,810,334	61,038,636	61,502,637	76,213,482	83,199,986

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Generating System Comparative Data by Fuel Type

	Jan-10 ACTUALS	Feb-10 ACTUALS	Mar-10 ACTUALS	Apr-10 ACTUALS	May-10 ACTUALS	Jun-10 ACTUALS
Generation Mix (%MWH)						
24 Heavy Oil	7.42%	0.06%	1.99%	2.39%	5.25%	8.45%
25 Light Oil	1.72%	0.00%	0.25%	0.11%	0.19%	0.12%
26 Coal	4.78%	2.27%	1.32%	7.47%	7.06%	6.09%
27 Gas	59.02%	66.00%	65.38%	68.03%	69.01%	69.13%
28 Nuclear	27.02%	31.62%	30.99%	21.90%	18.41%	16.14%
Solar	0.04%	0.05%	0.06%	0.10%	0.09%	0.07%
29 ***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Cost per Unit						
30 Heavy Oil ($/BBL)	73.7303	73.3799	74.5493	73.0907	73.1460	72.3541
31 Light Oil ($/BBL)	76.0119	81.6906	80.4684	80.6551	81.2771	83.2430
32 Coal ($/ton)	74.3842	75.4832	74.2802	74.2472	72.8910	74.0499
33 Gas ($/MCF)	7.3120	7.0195	6.5998	6.3466	6.1483	6.3109
34 Nuclear ($/MBTU)	0.5275	0.5419	0.5270	0.5748	0.5744	0.5381
Fuel Cost per MMBTU ($/MMBTU)						
35 Heavy Oil	11.6318	11.5533	11.6663	11.4167	11.5127	11.3875
36 Light Oil	13.3129	14.0983	13.9876	15.8203	13.3583	14.6181
37 Coal	2.6781	3.6942	2.8835	2.5001	2.5142	2.5411
38 Gas	7.1890	6.8633	6.4840	6.2421	6.0484	6.2089
39 Nuclear	0.5275	0.5419	0.5270	0.5748	0.5744	0.5381
BTU burned per KWH (BTU/KWH)						
40 Heavy Oil	10,089	18,459	10,777	10,297	10,300	10,380
41 Light Oil	12,010	10,738	7,698	7,276	8,877	11,439
42 Coal	11,303	9,611	8,680	10,111	10,250	10,232
43 Gas	7,582	7,854	7,296	7,645	8,381	7,394
44 Nuclear	10,697	10,689	10,718	10,939	10,960	11,678
Generated Fuel Cost per KWH (cents/KWH)						
45 Heavy Oil	11.7357	21.3261	12.5731	11.7554	11.8582	11.8207
46 Light Oil	15.9889	15.1385	10.7673	11.5111	11.8585	16.7219
47 Coal	3.0271	3.5506	2.5029	2.5280	2.5772	2.6000
48 Gas	5.4508	5.3906	4.7310	4.7723	5.0689	4.5909
49 Nuclear	0.5642	0.5792	0.5648	0.6287	0.6295	0.6284
50 ***Total***	4.6604	3.8356	3.5786	3.8670	4.4410	4.4516

Generating System Comparative Data by Fuel Type

Fuel Cost of System Net Generation ($)	7/1/2010 ESTIMATES	8/1/2010 ESTIMATES	9/1/2010 ESTIMATES	10/1/2010 ESTIMATES	11/1/2010 ESTIMATES	12/1/2010 ESTIMATES	Total
1 Heavy Oil	$67,015,172	$77,764,273	$52,557,330	$57,932,624	$3,204,658	$1,366,411	$519,583,721
2 Light Oil	$1,422,200	$1,251,100	$1,031,400	$3,667,400	$782,200	$208,700	$37,400,315
3 Coal	$15,828,900	$15,577,600	$15,109,700	$15,517,400	$14,995,500	$15,501,600	$156,090,232
4 Gas	$310,883,213	$310,643,039	$298,257,129	$300,006,870	$233,982,032	$230,430,633	$3,234,869,299
5 Nuclear	$13,387,700	$13,387,700	$12,507,300	$9,912,100	$13,268,900	$14,260,700	$143,077,952
6 Total	$408,537,185	$418,623,712	$379,462,859	$387,036,394	$266,233,290	$261,768,044	$4,091,021,519
System Net Generation (MWH)							
7 Heavy Oil	602,225	692,151	468,753	509,150	27,110	10,953	4,499,100
8 Light Oil	6,058	4,104	3,129	13,292	3,282	1,634	224,844
9 Coal	639,234	639,234	618,614	633,589	614,564	642,643	6,138,759
10 Gas	6,424,147	6,510,922	6,185,150	6,121,093	4,742,436	4,489,394	65,670,341
11 Nuclear	2,131,953	2,131,953	1,998,315	1,629,246	2,047,943	2,185,555	23,291,225
12 Solar	7,026	6,680	5,934	5,726	4,895	4,417	67,267
13 *Total*	9,810,643	9,985,044	9,279,895	8,912,096	7,440,230	7,334,596	99,891,536
Units of Fuel Burned							
14 Heavy Oil (BBLS)	924,696	1,064,486	721,181	774,952	43,170	16,829	7,098,799
15 Light Oil (BBLS)	15,446	13,421	10,903	38,326	8,086	2,197	464,469
16 Coal (TONS)	340,226	340,226	329,250	337,517	325,204	339,756	2,380,541
17 Gas (MCF)	47,562,899	47,589,316	45,651,248	44,984,785	33,615,397	32,129,647	487,372,047
18 Nuclear (MBTU)	23,769,566	23,769,566	22,267,796	18,073,422	22,824,021	24,370,626	256,886,788
BTU Burned (MMBTU)							
19 Heavy Oil	5,918,067	6,812,702	4,615,551	4,959,698	276,289	107,706	45,275,515
20 Light Oil	90,048	78,246	63,566	223,437	47,140	12,809	2,665,241
21 Coal	6,490,823	6,490,823	6,281,446	6,436,811	6,195,564	6,474,803	62,547,530
22 Gas	47,562,899	47,589,316	45,651,248	44,984,785	33,615,397	32,129,647	491,543,012
23 *Nuclear*	23,769,566	23,769,566	22,267,796	18,073,422	22,824,021	24,370,626	256,886,788
24 Total	83,831,403	84,740,653	78,879,607	74,678,153	62,958,411	63,095,591	858,918,086

Generation Mix (%MWH)

Generating System Comparative Data by Fuel Type

Fuel Cost of System Net Generation ($)	7/1/2010 ESTIMATES	8/1/2010 ESTIMATES	9/1/2010 ESTIMATES	10/1/2010 ESTIMATES	11/1/2010 ESTIMATES	12/1/2010 ESTIMATES	Total
25 Heavy Oil	6.14%	6.93%	5.05%	5.71%	0.36%	0.15%	4.50%
26 Light Oil	0.06%	0.04%	0.03%	0.15%	0.04%	0.02%	0.23%
27 Coal	6.52%	6.40%	6.67%	7.11%	8.26%	8.76%	6.15%
28 Gas	65.48%	65.21%	66.65%	68.68%	63.74%	61.21%	65.74%
29 *Nuclear*	21.73%	21.35%	21.53%	18.28%	27.53%	29.80%	23.32%
30 *Solar*	0.07%	0.07%	0.06%	0.06%	0.07%	0.06%	0.07%
31 **Total**	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Cost per Unit							
32 Heavy Oil ($/BBL)	72.4727	73.0534	72.8768	74.7564	74.2334	81.1938	73.1932
33 Light Oil ($/BBL)	92.0756	93.2196	94.5978	95.6896	96.7351	94.9932	80.5227
34 Coal ($/ton)	46.5247	45.7860	45.8913	45.9752	46.1111	45.6257	65.5692
35 Gas ($/MCF)	6.5363	6.5276	6.5334	6.6691	6.9606	7.1719	6.6374
36 Nuclear ($/MBTU)	0.5632	0.5632	0.5617	0.5484	0.5814	0.5852	0.5570
Fuel Cost per MMBTU ($/MMBTU)							
37 Heavy Oil	11.3238	11.4146	11.3870	11.6807	11.5989	12.6865	11.4760
38 Light Oil	15.7938	15.9893	16.2257	16.4136	16.5931	16.2932	14.0326
39 Coal	2.4387	2.3999	2.4054	2.4107	2.4204	2.3941	2.4955
40 Gas	6.5363	6.5276	6.5334	6.6691	6.9606	7.1719	6.5811
41 Nuclear	0.5632	0.5632	0.5617	0.5484	0.5814	0.5852	0.5570
BTU burned per KWH (BTU/KWH)							
42 Heavy Oil	9,827	9,843	9,846	9,741	10,191	9,833	10,063
43 Light Oil	14,864	19,066	20,315	16,810	14,363	7,839	11,854
44 Coal	10,154	10,154	10,154	10,159	10,081	10,075	10,189
45 Gas	7,404	7,309	7,381	7,349	7,088	7,157	7,485
46 Nuclear	11,149	11,149	11,143	11,093	11,145	11,151	11,029
Generated Fuel Cost per KWH (cents/KWH)							
47 Heavy Oil	11.1279	11.2352	11.2122	11.3783	11.8209	12.4752	11.5486
48 Light Oil	23.4764	30.4849	32.9626	27.5910	23.8330	12.7723	16.6339
49 Coal	2.4762	2.4369	2.4425	2.4491	2.4400	2.4122	2.5427
50 *Gas*	4.8393	4.7711	4.8221	4.9012	4.9338	5.1328	4.9259
51 Nuclear	0.6280	0.6280	0.6259	0.6084	0.6479	0.6525	0.6143
52 **Total**	4.1642	4.1925	4.0891	4.3428	3.5783	3.5689	4.0955

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	78,818.00	33.10	93.5	85.22	9,981	Heavy Oil BBLS ->	118,326	6,400,014	757,288	8,509,740	10.80
2			14,274.70					Gas MMCF ->	171,909	1,000,000	171,909	1,143,126	8.01
3	TURKEY POINT 2	378	96,217.00	35.27	92.2	87.18	9,906	Heavy Oil BBLS ->	144,481	6,400,011	924,680	10,390,738	10.80
4			2,971.00					Gas MMCF ->	57,883	1,000,000	57,883	379,190	12.76
5	TURKEY POINT 3	693	502,707.00	97.50	97.50	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,475,600	0.69
6	TURKEY POINT 4	693	502,707.00	97.50	97.50	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,459,800	0.69
7	TURKEY POINT 5	1,053	647,195.80	82.61	93.9	85.48	6,963	Gas MMCF ->	4,506,661	1,000,000	4,506,661	29,097,569	4.50
8	LAUDERDALE 4	438	0.00	51.02	94.5	96.84	8,096	Light Oil BBLS ->	0		0	0	
9			166,276.40					Gas MMCF ->	1,346,165	1,000,000	1,346,165	8,993,538	5.41
10	LAUDERDALE 5	438	1,907.00	47.80	94.1	97.17	8,104	Light Oil BBLS ->	2,464	5,829,545	14,364	220,800	11.58
11			153,866.10					Gas MMCF ->	1,247,959	1,000,000	1,247,959	8,336,955	5.42
12	PT EVERGLADES 1	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
13			0.00					Gas MMCF ->	0		0	0	
14	PT EVERGLADES 2	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
15			0.00					Gas MMCF ->	0		0	0	
16	PT EVERGLADES 3	374	52,717.00	32.76	92.9	94.85	10,104	Heavy Oil BBLS ->	79,277	6,400,040	507,376	5,728,369	10.87
17			38,449.70					Gas MMCF ->	413,764	1,000,000	413,764	2,760,753	7.18
18	PT EVERGLADES 4	374	12,410.00	22.88	92.8	94.03	10,453	Heavy Oil BBLS ->	18,905	6,400,053	120,993	1,366,022	11.01
19			51,243.30					Gas MMCF ->	544,366	1,000,000	544,366	3,635,076	7.09
20	RIVIERA 3	273	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
21			0.00					Gas MMCF ->	0		0	0	
22	RIVIERA 4	284	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
23			0.00					Gas MMCF ->	0		0	0	
24	ST LUCIE 1	839	608,613.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,939,200	0.65
25	ST LUCIE 2	714	517,926.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,513,100	0.49
26	CAPE CANAVERAL 1	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
27			0.00					Gas MMCF ->	0		0	0	
28	CAPE CANAVERAL 2	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
29			0.00					Gas MMCF ->	0		0	0	
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0	

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	FORT MYERS 2	1,349	893,869.30	89.06	94.4	90.03	7,115	Gas MMCF ->	6,359,717	1,000,000	6,359,717	41,509,445	4.64
33	FORT MYERS 3A_B	296	0.00	47.65	93.5	195.85	14,268	Light Oil BBLS ->	0		0	0	
			52,463.30					Gas MMCF ->	748,530	1,000,000	748,530	4,998,412	9.53
34	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
35	SANFORD 4	905	612,967.50	91.04	94.4	91.04	7,053	Gas MMCF ->	4,323,396	1,000,000	4,323,396	28,530,087	4.65
36	SANFORD 5	901	408,288.20	60.91	76.9	79.08	7,366	Gas MMCF ->	3,007,614	1,000,000	3,007,614	19,778,798	4.84
37	PUTNAM 1	239	67,689.80	38.07	98.4	99.37	8,932	Gas MMCF ->	604,622	1,000,000	604,622	4,039,044	5.97
38	PUTNAM 2	239	65,025.50	36.57	98.6	99.30	8,959	Gas MMCF ->	582,577	1,000,000	582,577	3,891,420	5.98
39	MANATEE 1	788	42,257.00	11.15	95.3	73.43	10,819	Heavy Oil BBLS ->	73,385	6,400,027	469,666	5,302,610	12.55
40			23,130.60					Gas MMCF ->	237,754	1,000,000	237,754	1,589,627	6.87
41	MANATEE 2	788	71,185.00	18.60	97.7	79.97	10,699	Heavy Oil BBLS ->	121,453	6,400,007	777,300	8,775,952	12.33
42			37,840.30					Gas MMCF ->	389,201	1,000,000	389,201	2,602,213	6.88
43	MANATEE 3	1,058	702,444.40	89.24	94.4	89.24	6,895	Gas MMCF ->	4,843,532	1,000,000	4,843,532	31,272,568	4.45
44	MARTIN 1	802	83,060.00	25.02	95.1	81.63	10,438	Heavy Oil BBLS ->	124,026	6,400,005	793,767	9,058,736	10.91
45			66,203.50					Gas MMCF ->	764,314	1,000,000	764,314	5,087,805	7.69
46	MARTIN 2	802	165,561.00	36.53	97.4	84.39	10,148	Heavy Oil BBLS ->	244,843	6,400,007	1,566,997	17,883,005	10.80
47			52,383.20					Gas MMCF ->	644,587	1,000,000	644,587	4,281,952	8.17
48	MARTIN 3	431	163,129.00	50.87	83.4	88.85	7,458	Gas MMCF ->	1,216,638	1,000,000	1,216,638	7,860,872	4.82
49	MARTIN 4	431	154,306.00	48.12	72.8	95.73	7,370	Gas MMCF ->	1,137,233	1,000,000	1,137,233	7,347,912	4.76
50	MARTIN 8	1,052	704,008.20	89.95	94.2	89.95	7,032	Gas MMCF ->	4,950,346	1,000,000	4,950,346	32,638,618	4.64
51	FORT MYERS 1-12	552	4,151.00	1.01	98.4	47.00	18,233	Light Oil BBLS ->	12,982	5,829,918	75,684	1,201,400	28.94
52	LAUDERDALE 1-24	684	0.00	0.17	91.7	26.02	22,073	Light Oil BBLS ->	0		0	0	
53			890.20					Gas MMCF ->	19,646	1,000,000	19,646	129,304	14.53
54	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0	
55			0.00					Gas MMCF ->	0		0	0	
56	ST JOHNS 1O	124	90,173.00	97.16	97.2	97.74	9,892	Coal TONS ->	35,596	25,059,698	892,025	2,836,900	3.15
57	ST JOHNS 2O	124	90,425.00	96.88	96.9	98.01	9,816	Coal TONS ->	35,420	25,059,825	887,619	2,822,900	3.12
58	SCHERER 4	626	458,636.00	96.73	96.7	98.47	10,272	Coal TONS ->	269,210	17,500,015	4,711,179	10,169,100	2.22
59	WCEC_01	1,219	569,596.10	62.80	96.3	62.80	7,124	Gas MMCF ->	4,057,893	1,000,000	4,057,893	26,200,015	4.60
60	WCEC_02	1,219	775,635.10	85.52	95.3	85.52	6,945	Gas MMCF ->	5,386,594	1,000,000	5,386,594	34,778,914	4.48
61	WCEC_03	1,219	0.00	0.00				Gas MMCF ->	0		0	0	
62	DESOTO	25	5,219.00	28.06				SOLAR					
63	SPACE COAST	10	1,807.00	24.29				SOLAR					
64	MARTIN SOLAR	75	0.00					SOLAR					
65													
66	TOTAL	24,477	9,810,643.20				8,545	Gas MMCF ->	47,562,899		83,831,403	408,537,185	4.16
67		======	=======				=======	Nuclear Othr ->	23,769,566		=======	=======	======
68								Coal TONS ->	340,226				
69		PeriodHours -->		744				Heavy Oil BBLS ->	924,696				
								Light Oil BBLS ->	15,446				

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	86,967.00	33.86	93.5	85.10	9,949	Heavy Oil BBLS ->	130,648	6,399,991	836,146	9,461,907	10.88
2			8,252.20					Gas MMCF ->	111,208	1,000,000	111,208	736,015	8.92
3	TURKEY POINT 2	378	104,887.00	37.96	92.2	88.52	9,872	Heavy Oil BBLS ->	157,365	6,400,013	1,007,138	11,396,876	10.87
4			1,856.00					Gas MMCF ->	46,618	1,000,000	46,618	304,610	16.41
5	TURKEY POINT 3	693	502,707.00	97.50	97.50	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,475,600	0.69
6	TURKEY POINT 4	693	502,707.00	97.50	97.50	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,459,800	0.69
7	TURKEY POINT 5	1,053	677,413.20	86.47	93.9	87.41	6,933	Gas MMCF ->	4,696,635	1,000,000	4,696,635	30,371,619	4.48
8	LAUDERDALE 4	438	0.00	45.59	94.5	97.19	8,118	Light Oil BBLS ->	0		0	0	
9			148,562.90					Gas MMCF ->	1,206,020	1,000,000	1,206,020	8,048,508	5.42
10	LAUDERDALE 5	438	1,154.00	39.58	94.1	97.18	8,146	Light Oil BBLS ->	1,491	5,830,315	8,693	135,100	11.71
11			127,822.60					Gas MMCF ->	1,041,966	1,000,000	1,041,966	6,952,734	5.44
12	PT EVERGLADES 1	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
13			0.00					Gas MMCF ->	0		0	0	
14	PT EVERGLADES 2	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
15			0.00					Gas MMCF ->	0		0	0	
16	PT EVERGLADES 3	374	72,433.00	28.21	92.9	94.97	9,971	Heavy Oil BBLS ->	108,923	6,399,998	697,107	7,925,500	10.94
17			6,064.80					Gas MMCF ->	85,587	1,000,000	85,587	566,280	9.34
18	PT EVERGLADES 4	374	21,315.00	25.28	92.8	95.48	10,390	Heavy Oil BBLS ->	32,450	6,400,031	207,681	2,361,159	11.08
19			49,034.50					Gas MMCF ->	523,252	1,000,000	523,252	3,490,077	7.12
20	RIVIERA 3	273	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
21			0.00					Gas MMCF ->	0		0	0	
22	RIVIERA 4	284	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
23			0.00					Gas MMCF ->	0		0	0	
24	ST LUCIE 1	839	608,613.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,939,200	0.65
25	ST LUCIE 2	714	517,926.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,513,100	0.49
26	CAPE CANAVERAL 1	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
27			0.00					Gas MMCF ->	0		0	0	
28	CAPE CANAVERAL 2	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
29			0.00					Gas MMCF ->	0		0	0	
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0	

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	FORT MYERS 2	1,349	881,797.40	87.86	94.4	91.81	7,103	Gas	MMCF ->	6,263,818	1,000,000	6,263,818	40,865,101	4.63
33	FORT MYERS 3A_B	296	0.00	41.85	93.5	195.84	14,301	Light Oil	BBLS ->	0		0	0	
			46,086.50					Gas	MMCF ->	659,056	1,000,000	659,056	4,398,274	9.54
34	SANFORD 3	138	0.00	0.00	100.0			Gas	MMCF ->	0		0	0	
35	SANFORD 4	905	629,178.20	93.44	94.4	93.44	7,023	Gas	MMCF ->	4,418,468	1,000,000	4,418,468	29,119,544	4.63
36	SANFORD 5	901	375,094.30	55.96	94.4	80.52	7,376	Gas	MMCF ->	2,766,818	1,000,000	2,766,818	18,167,588	4.84
37	PUTNAM 1	239	63,371.20	35.64	98.4	99.31	8,949	Gas	MMCF ->	567,091	1,000,000	567,091	3,784,304	5.97
38	PUTNAM 2	239	65,262.80	36.70	98.6	99.30	8,958	Gas	MMCF ->	584,647	1,000,000	584,647	3,901,028	5.98
39	MANATEE 1	788	52,056.00	12.52	95.3	72.78	10,804	Heavy Oil	BBLS ->	89,630	6,399,967	573,629	6,521,669	12.53
40			21,355.20					Gas	MMCF ->	219,523	1,000,000	219,523	1,466,263	6.87
41	MANATEE 2	788	86,079.00	20.76	97.7	78.41	10,722	Heavy Oil	BBLS ->	146,678	6,399,992	938,738	10,672,669	12.40
42			35,649.10					Gas	MMCF ->	366,467	1,000,000	366,467	2,447,732	6.87
43	MANATEE 3	1,058	723,634.70	91.93	94.4	91.93	6,865	Gas	MMCF ->	4,967,544	1,000,000	4,967,544	32,006,984	4.42
44	MARTIN 1	802	115,060.00	28.63	95.1	83.21	10,328	Heavy Oil	BBLS ->	171,919	6,399,985	1,100,279	12,684,879	11.02
45			55,777.20					Gas	MMCF ->	664,047	1,000,000	664,047	4,412,227	7.91
46	MARTIN 2	802	153,354.00	31.18	97.4	84.05	10,196	Heavy Oil	BBLS ->	226,873	6,399,986	1,451,984	16,739,615	10.92
47			32,693.50					Gas	MMCF ->	445,025	1,000,000	445,025	2,945,772	9.01
48	MARTIN 3	431	155,971.00	48.64	94.1	96.50	7,420	Gas	MMCF ->	1,157,270	1,000,000	1,157,270	7,472,458	4.79
49	MARTIN 4	431	161,899.00	50.49	94.0	96.32	7,392	Gas	MMCF ->	1,196,732	1,000,000	1,196,732	7,727,223	4.77
50	MARTIN 8	1,052	720,156.20	92.01	94.2	92.01	7,002	Gas	MMCF ->	5,042,642	1,000,000	5,042,642	33,425,342	4.64
51	FORT MYERS 1-12	552	2,950.00	0.72	98.4	29.69	23,577	Light Oil	BBLS ->	11,930	5,830,092	69,553	1,116,000	37.83
52	LAUDERDALE 1-24	684	0.00	0.05	91.7	16.81	27,791	Light Oil	BBLS ->	0		0	0	
53			231.00					Gas	MMCF ->	6,392	1,000,000	6,392	41,312	17.88
54	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil	BBLS ->	0		0	0	
55			0.00					Gas	MMCF ->	0		0	0	
56	ST JOHNS 1O	124	90,173.00	97.16	97.2	97.74	9,892	Coal	TONS ->	35,596	25,059,698	892,025	2,693,000	2.99
57	ST JOHNS 2O	124	90,425.00	96.88	96.9	98.01	9,816	Coal	TONS ->	35,420	25,059,825	887,619	2,679,700	2.96
58	SCHERER 4	626	458,636.00	96.73	96.7	98.47	10,272	Coal	TONS ->	269,210	17,500,015	4,711,179	10,204,900	2.23
59	WCEC_01	1,219	727,746.10	80.24	96.3	80.24	6,952	Gas	MMCF ->	5,059,540	1,000,000	5,059,540	32,599,704	4.48
60	WCEC_02	1,219	796,012.40	87.8	95.3	87.77	6,901	Gas	MMCF ->	5,492,952	1,000,000	5,492,952	35,392,341	4.45
61	WCEC_03	1,219	0.00	0.00				Gas	MMCF ->	0		0	0	
62	DESOTO	25	4,962.00	26.68				SOLAR						
63	SPACE COAST	10	1,718.00	23.09				SOLAR						
64	MARTIN SOLAR	75	0.00					SOLAR						
65														
66	TOTAL	24,477	9,985,044.00				8,487	Gas	MMCF ->	47,589,316		84,740,653	418,623,712	4.19
67		=======	=======				=======	Nuclear	Othr ->	23,769,566		=======	=======	=======
68								Coal	TONS ->	340,226				
69		PeriodHours -->		744				Heavy Oil	BBLS ->	1,064,486				
								Light Oil	BBLS ->	13,421				

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-10

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	74,823.00	31.92	71.7	82.98	9,987	Heavy Oil BBLS ->	112,461	6,400,014	719,752	8,128,612	10.86
2			12,056.40					Gas MMCF ->	147,877	1,000,000	147,877	982,493	8.15
3	TURKEY POINT 2	378	82,595.00	31.49	92.2	83.37	9,957	Heavy Oil BBLS ->	124,212	6,399,986	794,955	8,977,918	10.87
4			3,118.50					Gas MMCF ->	58,515	1,000,000	58,515	383,873	12.31
5	TURKEY POINT 3	693	421,625.00	84.50	84.5	97.50	11,331	Nuclear Othr ->	4,777,394	1,000,000	4,777,394	2,915,000	0.69
6	TURKEY POINT 4	693	486,491.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,512,394	1,000,000	5,512,394	3,348,200	0.69
7	TURKEY POINT 5	1,053	647,478.40	85.40	93.9	85.40	6,957	Gas MMCF ->	4,504,657	1,000,000	4,504,657	29,073,434	4.49
8	LAUDERDALE 4	438	0.00	45.03	94.5	97.07	8,121	Light Oil BBLS ->	0		0	0	
9			142,012.10					Gas MMCF ->	1,153,216	1,000,000	1,153,216	7,704,260	5.43
10	LAUDERDALE 5	438	0.00	42.94	94.1	97.23	8,131	Light Oil BBLS ->	0		0	0	
11			135,423.00					Gas MMCF ->	1,101,072	1,000,000	1,101,072	7,355,855	5.43
12	PT EVERGLADES 1	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
13			0.00					Gas MMCF ->	0		0	0	
14	PT EVERGLADES 2	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
15			0.00					Gas MMCF ->	0		0	0	
16	PT EVERGLADES 3	374	50,179.00	33.03	92.9	90.43	10,150	Heavy Oil BBLS ->	75,629	6,400,005	484,026	5,492,104	10.95
17			38,765.60					Gas MMCF ->	418,733	1,000,000	418,733	2,793,735	7.21
18	PT EVERGLADES 4	374	23,372.00	20.29	92.8	94.84	10,339	Heavy Oil BBLS ->	35,596	6,399,933	227,812	2,584,896	11.06
19			31,252.20					Gas MMCF ->	336,950	1,000,000	336,950	2,248,992	7.20
20	RIVIERA 3	273	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
21			0.00					Gas MMCF ->	0		0	0	
22	RIVIERA 4	284	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
23			0.00					Gas MMCF ->	0		0	0	
24	ST LUCIE 1	839	588,980.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,471,126	1,000,000	6,471,126	3,812,100	0.65
25	ST LUCIE 2	714	501,219.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,506,882	1,000,000	5,506,882	2,432,000	0.49
26	CAPE CANAVERAL 1	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
27			0.00					Gas MMCF ->	0		0	0	
28	CAPE CANAVERAL 2	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
29			0.00					Gas MMCF ->	0		0	0	
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0	

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	FORT MYERS 2	1,349	718,899.40	74.02	83.4	82.37	7,200	Gas	MMCF ->	5,176,066	1,000,000	5,176,066	33,755,381	4.70
33	FORT MYERS 3A_B	296	0.00	38.35	49.9	195.85	14,291	Light Oil	BBLS ->	0		0	0	
			40,869.20					Gas	MMCF ->	584,050	1,000,000	584,050	3,899,590	9.54
34	SANFORD 3	138	0.00	0.00	100.0			Gas	MMCF ->	0		0	0	
35	SANFORD 4	905	595,546.20	91.40	94.4	91.40	7,048	Gas	MMCF ->	4,197,340	1,000,000	4,197,340	27,652,673	4.64
36	SANFORD 5	901	381,215.00	58.76	94.4	77.63	7,380	Gas	MMCF ->	2,813,419	1,000,000	2,813,419	18,499,324	4.85
37	PUTNAM 1	239	66,027.20	38.37	98.4	99.38	8,930	Gas	MMCF ->	589,652	1,000,000	589,652	3,937,743	5.96
38	PUTNAM 2	239	62,414.90	36.27	98.6	99.30	8,961	Gas	MMCF ->	559,312	1,000,000	559,312	3,734,395	5.98
39	MANATEE 1	788	28,053.00	7.48	63.6	74.76	10,805	Heavy Oil	BBLS ->	48,541	6,399,951	310,660	3,525,002	12.57
40			14,365.80					Gas	MMCF ->	147,685	1,000,000	147,685	987,491	6.87
41	MANATEE 2	788	66,250.00	16.10	97.7	79.42	10,672	Heavy Oil	BBLS ->	112,001	6,400,005	716,807	8,133,475	12.28
42			25,118.30					Gas	MMCF ->	258,290	1,000,000	258,290	1,727,083	6.88
43	MANATEE 3	1,058	682,113.30	89.54	94.4	89.54	6,891	Gas	MMCF ->	4,700,716	1,000,000	4,700,716	30,321,171	4.45
44	MARTIN 1	802	42,004.00	23.65	95.1	81.49	10,561	Heavy Oil	BBLS ->	62,719	6,399,990	401,401	4,633,126	11.03
45			94,582.30					Gas	MMCF ->	1,041,040	1,000,000	1,041,040	6,940,583	7.34
46	MARTIN 2	802	101,477.00	30.18	64.9	85.54	10,279	Heavy Oil	BBLS ->	150,022	6,399,981	960,138	11,082,196	10.92
47			72,775.60					Gas	MMCF ->	831,003	1,000,000	831,003	5,532,656	7.60
48	MARTIN 3	431	149,316.00	48.12	94.1	96.50	7,422	Gas	MMCF ->	1,108,151	1,000,000	1,108,151	7,163,442	4.80
49	MARTIN 4	431	161,484.00	52.04	94.0	96.32	7,387	Gas	MMCF ->	1,192,928	1,000,000	1,192,928	7,711,517	4.78
50	MARTIN 8	1,052	687,050.90	90.71	94.2	90.71	7,022	Gas	MMCF ->	4,824,136	1,000,000	4,824,136	31,951,616	4.65
51	FORT MYERS 1-12	552	3,129.00	0.79	98.4	37.78	20,321	Light Oil	BBLS ->	10,903	5,830,138	63,566	1,031,400	32.96
52	LAUDERDALE 1-24	684	0.00	0.00	91.7			Light Oil	BBLS ->	0		0	0	
53			0.00					Gas	MMCF ->	0		0	0	
54	EVERGLADES 1-12	342	0.00	0.00	88.3			Light Oil	BBLS ->	0		0	0	
55			0.00					Gas	MMCF ->	0		0	0	
56	ST JOHNS 1O	124	87,265.00	97.2	97.2	97.74	9,892	Coal	TONS ->	34,447	25,060,208	863,249	2,606,100	2.99
57	ST JOHNS 2O	124	87,508.00	96.9	96.9	98.01	9,816	Coal	TONS ->	34,277	25,060,128	858,986	2,593,200	2.96
58	SCHERER 4	626	443,841.00	96.7	96.7	98.47	10,272	Coal	TONS ->	260,526	17,500,023	4,559,211	9,910,400	2.23
59	WCEC_01	1,219	671,103.50	76.5	82.4	76.46	6,992	Gas	MMCF ->	4,692,258	1,000,000	4,692,258	30,266,604	4.51
60	WCEC_02	1,219	752,162.40	85.7	95.3	85.70	6,932	Gas	MMCF ->	5,214,183	1,000,000	5,214,183	33,633,217	4.47
61	WCEC_03	1,219	0.00	0.00				Gas	MMCF ->	0		0	0	
62	DESOTO	25	4,412.00	24.51				SOLAR						
63	SPACE COAST	10	1,522.00	21.14				SOLAR						
64	MARTIN SOLAR	75	0.00					SOLAR						
65														
66	TOTAL	24,477	9,279,895.20				8,500	Gas	MMCF ->	45,651,248		78,879,607	379,462,859	4.09
67		=======	=======				=======	Nuclear	Othr ->	22,267,796		=======	=======	=======
68								Coal	TONS ->	329,250				
69		PeriodHours -->		720				Heavy Oil	BBLS ->	721,181				
								Light Oil	BBLS ->	10,903				

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	378	74,868.00	31.16	93.5	80.78	9,987	Heavy Oil BBLS ->	112,526	6,400,023	720,169	8,327,962	11.12
2			12,770.20					Gas MMCF ->	155,080	1,000,000	155,080	1,051,500	8.23
3	TURKEY POINT 2	378	86,804.00	32.28	92.2	79.79	9,954	Heavy Oil BBLS ->	130,815	6,400,000	837,216	9,681,474	11.15
4			3,983.10					Gas MMCF ->	66,441	1,000,000	66,441	443,064	11.12
5	TURKEY POINT 3	693	0.00	0.00	0.00			Nuclear Othr ->	0		0	0	
6	TURKEY POINT 4	693	502,707.00	97.50	97.50	97.50	11,331	Nuclear Othr ->	5,696,144	1,000,000	5,696,144	3,459,800	0.69
7	TURKEY POINT 5	1,053	656,493.40	83.80	93.9	83.80	6,980	Gas MMCF ->	4,582,062	1,000,000	4,582,062	30,182,761	4.60
8	LAUDERDALE 4	438	0.00	49.14	94.5	96.46	8,097	Light Oil BBLS ->	0		0	0	
9			160,129.80					Gas MMCF ->	1,296,616	1,000,000	1,296,616	8,835,263	5.52
10	LAUDERDALE 5	438	0.00	26.79	41.1	96.77	8,104	Light Oil BBLS ->	0		0	0	
11			87,316.60					Gas MMCF ->	707,638	1,000,000	707,638	4,821,777	5.52
12	PT EVERGLADES 1	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
13			0.00					Gas MMCF ->	0		0	0	
14	PT EVERGLADES 2	203	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
15			0.00					Gas MMCF ->	0		0	0	
16	PT EVERGLADES 3	374	55,602.00	31.94	92.9	86.42	10,140	Heavy Oil BBLS ->	84,057	6,400,002	537,965	6,249,538	11.24
17			33,281.50					Gas MMCF ->	363,306	1,000,000	363,306	2,468,940	7.42
18	PT EVERGLADES 4	374	38,273.00	21.78	92.8	83.54	10,286	Heavy Oil BBLS ->	58,655	6,400,000	375,392	4,360,966	11.39
19			22,342.60					Gas MMCF ->	248,098	1,000,000	248,098	1,684,991	7.54
20	RIVIERA 3	273	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
21			0.00					Gas MMCF ->	0		0	0	
22	RIVIERA 4	284	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
23			0.00					Gas MMCF ->	0		0	0	
24	ST LUCIE 1	839	608,613.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	6,686,833	1,000,000	6,686,833	3,939,200	0.65
25	ST LUCIE 2	714	517,926.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	5,690,445	1,000,000	5,690,445	2,513,100	0.49
26	CAPE CANAVERAL 1	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
27			0.00					Gas MMCF ->	0		0	0	
28	CAPE CANAVERAL 2	378	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
29			0.00					Gas MMCF ->	0		0	0	
30	CUTLER 5	68	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
31	CUTLER 6	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0	

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	FORT MYERS 2	1,349	671,908.00	66.95	83.7	83.29	7,214	Gas MMCF ->	4,847,294	1,000,000	4,847,294	32,480,050	4.83
33	FORT MYERS 3A_B	296	0.00	56.33	93.5	195.84	14,225	Light Oil BBLS ->	0		0	0	
			62,028.40					Gas MMCF ->	882,342	1,000,000	882,342	6,014,241	9.70
34	SANFORD 3	138	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
35	SANFORD 4	905	590,439.80	87.69	94.4	90.74	7,069	Gas MMCF ->	4,173,566	1,000,000	4,173,566	28,142,381	4.77
36	SANFORD 5	901	444,022.40	66.24	94.4	78.22	7,333	Gas MMCF ->	3,255,865	1,000,000	3,255,865	21,850,964	4.92
37	PUTNAM 1	239	43,568.30	24.50	54.2	99.07	8,913	Gas MMCF ->	388,328	1,000,000	388,328	2,646,125	6.07
38	PUTNAM 2	239	43,666.70	24.56	57.2	99.30	8,927	Gas MMCF ->	389,811	1,000,000	389,811	2,656,249	6.08
39	MANATEE 1	788	66,375.00	12.44	95.3	79.78	10,621	Heavy Oil BBLS ->	110,477	6,400,029	707,056	8,213,931	12.38
40			6,552.70					Gas MMCF ->	67,488	1,000,000	67,488	460,175	7.02
41	MANATEE 2	788	5,810.00	1.03	3.2	84.94	10,487	Heavy Oil BBLS ->	9,527	6,399,916	60,972	708,276	12.19
42			214.10					Gas MMCF ->	2,205	1,000,000	2,205	15,002	7.01
43	MANATEE 3	1,058	688,974.50	87.53	94.4	87.53	6,919	Gas MMCF ->	4,766,793	1,000,000	4,766,793	31,385,611	4.56
44	MARTIN 1	802	53,508.00	15.48	67.5	81.66	10,462	Heavy Oil BBLS ->	79,993	6,400,035	511,958	6,065,946	11.34
45			38,834.40					Gas MMCF ->	454,141	1,000,000	454,141	3,082,664	7.94
46	MARTIN 2	802	127,910.00	27.57	97.4	81.72	10,165	Heavy Oil BBLS ->	188,902	6,399,985	1,208,970	14,324,531	11.20
47			36,604.10					Gas MMCF ->	463,272	1,000,000	463,272	3,136,983	8.57
48	MARTIN 3	431	180,942.00	56.43	94.1	96.07	7,398	Gas MMCF ->	1,338,690	1,000,000	1,338,690	8,831,311	4.88
49	MARTIN 4	431	187,077.60	58.34	94.0	95.40	7,373	Gas MMCF ->	1,379,390	1,000,000	1,379,390	9,107,315	4.87
50	MARTIN 8	1,052	628,896.30	80.35	83.5	80.35	7,147	Gas MMCF ->	4,494,509	1,000,000	4,494,509	30,486,900	4.85
51	FORT MYERS 1-12	552	13,292.00	3.24	98.4	56.00	16,811	Light Oil BBLS ->	38,326	5,829,907	223,437	3,667,400	27.59
52	LAUDERDALE 1-24	684	0.00	0.90	91.7	39.55	18,656	Light Oil BBLS ->	0		0	0	
53			4,600.10					Gas MMCF ->	85,799	1,000,000	85,799	582,295	12.66
54	EVERGLADES 1-12	342	0.00	0.50	88.3	93.35	17,480	Light Oil BBLS ->	0		0	0	
55			1,277.90					Gas MMCF ->	22,323	1,000,000	22,323	152,175	11.91
56	ST JOHNS 1O	124	88,804.00	96.26	97.2	96.26	9,904	Coal TONS ->	35,095	25,059,809	879,474	2,657,300	2.99
57	ST JOHNS 2O	124	89,401.00	96.90	96.9	96.90	9,824	Coal TONS ->	35,045	25,060,237	878,236	2,653,600	2.97
58	SCHERER 4	626	455,384.00	96.73	96.7	97.78	10,275	Coal TONS ->	267,377	17,500,013	4,679,101	10,206,500	2.24
59	WCEC_01	1,219	760,702.60	83.88	94.2	83.88	6,963	Gas MMCF ->	5,296,457	1,000,000	5,296,457	34,873,078	4.58
60	WCEC_02	1,219	754,465.50	83.19	95.3	83.19	6,968	Gas MMCF ->	5,257,273	1,000,000	5,257,273	34,615,053	4.59
61	WCEC_03	1,219	0.00	0.00				Gas MMCF ->	0		0	0	
62	DESOTO	25	4,260.00	22.90				SOLAR					
63	SPACE COAST	10	1,466.00	19.70				SOLAR					
64	MARTIN SOLAR	75	0.00					SOLAR					
65													
66	TOTAL	24,477	8,912,095.60				8,379	Gas MMCF ->	44,984,785		74,678,153	387,036,394	4.34
67		=======	=======				=======	Nuclear Othr ->	18,073,422		=======	=======	=======
68								Coal TONS ->	337,517				
69		PeriodHours -->		744				Heavy Oil BBLS ->	774,952				
								Light Oil BBLS ->	38,326				

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	6,441.00	4.81	93.5	45.60	10,613	Heavy Oil BBLS ->	10,146	6,400,256	64,937	749,254	11.63
2			6,729.30					Gas MMCF ->	74,836	1,000,000	74,836	523,683	7.78
3	TURKEY POINT 2	380	9,498.00	5.11	92.2	44.86	10,609	Heavy Oil BBLS ->	15,026	6,399,774	96,163	1,109,479	11.68
4			4,481.60					Gas MMCF ->	52,143	1,000,000	52,143	361,263	8.06
5	TURKEY POINT 3	717	436,222.00	84.50	84.5	97.50	11,331	Nuclear Othr ->	4,942,844	1,000,000	4,942,844	3,456,500	0.79
6	TURKEY POINT 4	717	503,332.00	97.50	97.5	97.50	11,331	Nuclear Othr ->	5,703,297	1,000,000	5,703,297	3,464,100	0.69
7	TURKEY POINT 5	1,114	538,122.00	67.09	87.7	87.67	6,966	Gas MMCF ->	3,748,633	1,000,000	3,748,633	26,170,892	4.86
8	LAUDERDALE 4	447	0.00	22.35	94.5	83.38	8,256	Light Oil BBLS ->	0		0	0	
9			71,930.90					Gas MMCF ->	593,831	1,000,000	593,831	4,170,126	5.80
10	LAUDERDALE 5	447	0.00	3.07	34.4	92.00	8,197	Light Oil BBLS ->	0		0	0	
11			9,870.00					Gas MMCF ->	80,905	1,000,000	80,905	569,952	5.77
12	PT EVERGLADES 1	204	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
13			0.00					Gas MMCF ->	0		0	0	
14	PT EVERGLADES 2	204	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
15			0.00					Gas MMCF ->	0		0	0	
16	PT EVERGLADES 3	376	0.00	3.64	92.9	58.30	10,740	Heavy Oil BBLS ->	0		0	0	
17			9,864.60					Gas MMCF ->	105,945	1,000,000	105,945	747,903	7.58
18	PT EVERGLADES 4	376	0.00	2.20	92.8	88.00	10,544	Heavy Oil BBLS ->	0		0	0	
19			5,956.80					Gas MMCF ->	62,800	1,000,000	62,800	445,217	7.47
20	RIVIERA 3	275	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
21			0.00					Gas MMCF ->	0		0	0	
22	RIVIERA 4	286	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
23			0.00					Gas MMCF ->	0		0	0	
24	ST LUCIE 1	853	598,803.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	6,579,119	1,000,000	6,579,119	3,875,700	0.65
25	ST LUCIE 2	726	509,586.00	97.50	97.5	97.50	10,987	Nuclear Othr ->	5,598,761	1,000,000	5,598,761	2,472,600	0.49
26	CAPE CANAVERAL 1	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
27			0.00					Gas MMCF ->	0		0	0	
28	CAPE CANAVERAL 2	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
29			0.00					Gas MMCF ->	0		0	0	
30	CUTLER 5	69	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
31	CUTLER 6	139	0.00	0.00	100.0			Gas MMCF ->	0		0	0	

Company: Florida Power & Light | Schedule E4

Estimated For The Period of : Nov-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	FORT MYERS 2	1,440	323,703.90	31.22	88.1	92.89	7,118	Gas MMCF ->	2,304,019	1,000,000	2,304,019	16,119,136	4.98
33	FORT MYERS 3A_B	328	34.00	13.96	87.2	189.59	13,912	Light Oil BBLS ->	77	5,818,182	448	7,400	21.76
			16,445.80					Gas MMCF ->	228,801	1,000,000	228,801	1,606,840	9.77
34	SANFORD 3	140	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
35	SANFORD 4	955	406,064.80	59.06	94.4	95.12	7,131	Gas MMCF ->	2,895,558	1,000,000	2,895,558	20,268,821	4.99
36	SANFORD 5	952	270,129.20	39.41	94.4	80.61	7,407	Gas MMCF ->	2,000,865	1,000,000	2,000,865	13,939,121	5.16
37	PUTNAM 1	248	0.00	0.00	0.0			Gas MMCF ->	0		0	0	
38	PUTNAM 2	248	0.00	0.00	0.0			Gas MMCF ->	0		0	0	
39	MANATEE 1	798	6,856.00	1.99	95.3	79.55	10,611	Heavy Oil BBLS ->	11,658	6,400,069	74,612	864,738	12.61
40			4,570.60					Gas MMCF ->	46,629	1,000,000	46,629	330,723	7.24
41	MANATEE 2	798	0.00	0.00	6.5			Heavy Oil BBLS ->	0		0	0	
42			0.00					Gas MMCF ->	0		0	0	
43	MANATEE 3	1,117	667,694.00	83.02	94.4	86.88	6,881	Gas MMCF ->	4,594,192	1,000,000	4,594,192	31,940,272	4.78
44	MARTIN 1	808	0.00	0.00	28.5			Heavy Oil BBLS ->	0		0	0	
45			0.00					Gas MMCF ->	0		0	0	
46	MARTIN 2	808	4,315.00	2.41	97.4	82.65	10,301	Heavy Oil BBLS ->	6,340	6,400,158	40,577	481,186	11.15
47			9,710.10					Gas MMCF ->	103,880	1,000,000	103,880	735,544	7.58
48	MARTIN 3	462	117,568.00	35.34	94.1	92.54	7,408	Gas MMCF ->	870,924	1,000,000	870,924	6,032,877	5.13
49	MARTIN 4	462	139,015.50	41.79	94.0	94.03	7,359	Gas MMCF ->	1,023,043	1,000,000	1,023,043	7,088,243	5.10
50	MARTIN 8	1,112	607,068.10	75.82	94.2	80.05	7,006	Gas MMCF ->	4,252,976	1,000,000	4,252,976	29,772,787	4.90
51	FORT MYERS 1-12	627	3,248.00	0.72	98.4	73.98	14,392	Light Oil BBLS ->	8,009	5,829,941	46,692	774,800	23.85
52	LAUDERDALE 1-24	766	0.00	0.18	91.7	25.40	21,127	Light Oil BBLS ->	0		0	0	
53			974.20					Gas MMCF ->	20,558	1,000,000	20,558	143,344	14.71
54	EVERGLADES 1-12	383	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0	
55			0.00					Gas MMCF ->	0		0	0	
56	ST JOHNS 1O	124	85,334.00	95.58	97.2	95.58	9,806	Coal TONS ->	33,392	25,059,625	836,791	2,549,200	2.99
57	ST JOHNS 2O	124	85,915.00	96.23	96.9	96.23	9,725	Coal TONS ->	33,341	25,060,076	835,528	2,545,400	2.96
58	SCHERER 4	632	443,315.00	96.73	96.7	97.42	10,203	Coal TONS ->	258,471	17,500,010	4,523,245	9,900,900	2.23
59	WCEC_01	1,335	775,970.30	80.73	96.3	80.73	6,890	Gas MMCF ->	5,346,776	1,000,000	5,346,776	36,987,378	4.77
60	WCEC_02	1,335	756,566.70	78.71	95.3	78.71	6,884	Gas MMCF ->	5,208,084	1,000,000	5,208,084	36,027,909	4.76
61	WCEC_03	1,335	0.00	0.00				Gas MMCF ->	0		0	0	
62	DESOTO	25	3,643.00	20.24				SOLAR					
63	SPACE COAST	10	1,252.00	17.39				SOLAR					
64	MARTIN SOLAR	75	0.00					SOLAR					
65													
66	TOTAL	25,643	7,440,230.40				8,462	Gas MMCF ->	33,615,397		62,958,411	266,233,290	3.58
67		=======	=======				=======	Nuclear Othr ->	22,824,021		=======	=======	=======
68								Coal TONS ->	325,204				
69		PeriodHours -->		720				Heavy Oil BBLS ->	43,170				
								Light Oil BBLS ->	8,086				

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TURKEY POINT 1	380	1,105.00	4.81	93.5	42.64	10,907	Heavy Oil BBLS ->	1,736	6,398,618	11,108	138,064	12.49
2			12,506.50					Gas MMCF ->	137,344	1,000,000	137,344	988,740	7.91
3	TURKEY POINT 2	380	1,958.00	8.17	92.2	35.97	11,192	Heavy Oil BBLS ->	3,171	6,399,874	20,294	252,228	12.88
4			21,146.30					Gas MMCF ->	238,265	1,000,000	238,265	1,710,565	8.09
5	TURKEY POINT 3	717	520,110.00	97.50	97.50	97.50	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	4,121,200	0.79
6	TURKEY POINT 4	717	520,110.00	97.50	97.50	97.50	11,331	Nuclear Othr ->	5,893,410	1,000,000	5,893,410	3,579,600	0.69
7	TURKEY POINT 5	1,114	333,250.40	40.21	57.6	83.56	6,995	Gas MMCF ->	2,331,048	1,000,000	2,331,048	16,799,279	5.04
8	LAUDERDALE 4	447	1,565.00	28.45	94.5	86.40	8,154	Light Oil BBLS ->	2,043	5,830,641	11,912	193,700	12.38
9			93,053.70					Gas MMCF ->	759,611	1,000,000	759,611	5,495,913	5.91
10	LAUDERDALE 5	447	0.00	23.12	94.1	85.14	8,185	Light Oil BBLS ->	0		0	0	
11			76,879.50					Gas MMCF ->	629,234	1,000,000	629,234	4,547,412	5.91
12	PT EVERGLADES 1	204	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
13			0.00					Gas MMCF ->	0		0	0	
14	PT EVERGLADES 2	204	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
15			0.00					Gas MMCF ->	0		0	0	
16	PT EVERGLADES 3	376	0.00	5.51	92.9	54.66	10,798	Heavy Oil BBLS ->	0		0	0	
17			15,414.50					Gas MMCF ->	166,435	1,000,000	166,435	1,200,339	7.79
18	PT EVERGLADES 4	376	0.00	2.04	92.8	29.78	11,940	Heavy Oil BBLS ->	0		0	0	
19			5,710.60					Gas MMCF ->	68,181	1,000,000	68,181	489,542	8.57
20	RIVIERA 3	275	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
21			0.00					Gas MMCF ->	0		0	0	
22	RIVIERA 4	286	0.00	0.00	100.0			Heavy Oil BBLS ->	0		0	0	
23			0.00					Gas MMCF ->	0		0	0	
24	ST LUCIE 1	853	618,763.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	6,798,424	1,000,000	6,798,424	4,004,900	0.65
25	ST LUCIE 2	726	526,572.00	97.50	97.50	97.50	10,987	Nuclear Othr ->	5,785,382	1,000,000	5,785,382	2,555,000	0.49
26	CAPE CANAVERAL 1	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
27			0.00					Gas MMCF ->	0		0	0	
28	CAPE CANAVERAL 2	380	0.00	0.00	0.0			Heavy Oil BBLS ->	0		0	0	
29			0.00					Gas MMCF ->	0		0	0	
30	CUTLER 5	69	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
31	CUTLER 6	139	0.00	0.00	100.0			Gas MMCF ->	0		0	0	

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-10

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	FORT MYERS 2	1,440	342,085.30	31.93	94.4	86.39	7,153	Gas MMCF ->	2,446,924	1,000,000	2,446,924	17,612,602	5.15
33	FORT MYERS 3A_B	328	69.00	15.79	93.5	192.55	13,813	Light Oil BBLS ->	154	5,824,675	897	15,000	21.74
			19,194.40					Gas MMCF ->	265,176	1,000,000	265,176	1,915,109	9.98
34	SANFORD 3	140	0.00	0.00	100.0			Gas MMCF ->	0		0	0	
35	SANFORD 4	955	477,521.40	67.21	94.4	89.45	7,108	Gas MMCF ->	3,394,396	1,000,000	3,394,396	24,471,607	5.12
36	SANFORD 5	952	283,209.50	39.99	94.4	79.54	7,384	Gas MMCF ->	2,091,354	1,000,000	2,091,354	15,048,351	5.31
37	PUTNAM 1	248	3,778.80	2.05	44.5	58.59	10,240	Gas MMCF ->	38,686	1,000,000	38,686	280,703	7.43
38	PUTNAM 2	248	3,822.90	2.07	44.5	59.27	10,222	Gas MMCF ->	39,069	1,000,000	39,069	283,411	7.41
39	MANATEE 1	798	0.00	0.00	95.3			Heavy Oil BBLS ->	0		0	0	
40			0.00					Gas MMCF ->	0		0	0	
41	MANATEE 2	798	0.00	0.00	97.7			Heavy Oil BBLS ->	0		0	0	
42			0.00					Gas MMCF ->	0		0	0	
43	MANATEE 3	1,117	676,986.60	81.46	94.4	87.58	6,860	Gas MMCF ->	4,643,961	1,000,000	4,643,961	33,174,222	4.90
44	MARTIN 1	808	0.00	0.00	95.1			Heavy Oil BBLS ->	0		0	0	
45			0.00					Gas MMCF ->	0		0	0	
46	MARTIN 2	808	7,890.00	5.39	97.4	46.09	10,530	Heavy Oil BBLS ->	11,922	6,400,268	76,304	976,119	12.37
47			24,511.80					Gas MMCF ->	264,897	1,000,000	264,897	1,906,367	7.78
48	MARTIN 3	462	102,976.00	29.96	94.1	90.24	7,404	Gas MMCF ->	762,459	1,000,000	762,459	5,447,026	5.29
49	MARTIN 4	462	126,343.40	36.76	94.0	90.85	7,386	Gas MMCF ->	933,107	1,000,000	933,107	6,668,542	5.28
50	MARTIN 8	1,112	603,302.80	72.92	94.2	80.73	7,002	Gas MMCF ->	4,224,532	1,000,000	4,224,532	30,375,077	5.03
51	FORT MYERS 1-12	627	0.00	0.00	98.4			Light Oil BBLS ->	0		0	0	
52	LAUDERDALE 1-24	766	0.00	0.00	91.7			Light Oil BBLS ->	0		0	0	
53			0.00					Gas MMCF ->	0		0	0	
54	EVERGLADES 1-12	383	0.00	0.00	88.3			Light Oil BBLS ->	0		0	0	
55			0.00					Gas MMCF ->	0		0	0	
56	ST JOHNS 1O	124	89,616.00	97.14	97.2	97.14	9,795	Coal TONS ->	35,028	25,060,038	877,803	2,568,600	2.87
57	ST JOHNS 2O	124	90,162.00	96.88	96.9	97.73	9,715	Coal TONS ->	34,953	25,060,310	875,933	2,563,200	2.84
58	SCHERER 4	632	462,865.00	96.73	96.7	98.44	10,200	Coal TONS ->	269,775	17,500,017	4,721,067	10,369,800	2.24
59	WCEC_01	1,335	794,296.60	79.97	96.3	79.97	6,859	Gas MMCF ->	5,448,135	1,000,000	5,448,135	38,858,151	4.89
60	WCEC_02	1,335	473,403.10	47.66	58.4	75.13	6,858	Gas MMCF ->	3,246,835	1,000,000	3,246,835	23,157,675	4.89
61	WCEC_03	1,335	0.00	0.00				Gas MMCF ->	0		0	0	
62	DESOTO	25	3,309.00	17.79				SOLAR					
63	SPACE COAST	10	1,108.00	14.89				SOLAR					
64	MARTIN SOLAR	75	0.00					SOLAR					
65													
66	TOTAL	25,643	7,334,596.10				8,602	Gas MMCF ->	32,129,647		63,095,591	261,768,044	3.57
67		=======	=======				=======	Nuclear Othr ->	24,370,626		=======	=======	=======
68								Coal TONS ->	339,756				
69		PeriodHours -->		744				Heavy Oil BBLS ->	16,829				
								Light Oil BBLS ->	2,197				

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2010 thru December 2010

			July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	482,114	1,059,335	721,180	474,952	43,170	16,829	2,797,580
3	Unit Cost	($/BBLS)	74.0738	74.5052	74.9702	75.5655	75.7702	77.4853	74.7682
4	Amount	($)	35,712,000	78,926,000	54,067,000	35,890,000	3,271,000	1,304,000	209,170,000
5									
6	Burned:								
7	Units	(BBLS)	924,697	1,064,484	721,180	774,952	43,170	16,829	3,545,312
8	Unit Cost	($/BBLS)	72.4726	73.0541	72.8771	74.7582	74.2381	81.1522	73.2918
9	Amount	($)	67,015,172	77,764,873	52,557,530	57,934,024	3,204,858	1,365,711	259,842,168
10									
11	Ending Inventory:								
12	Units	(BBLS)	2,683,149	2,678,000	2,677,999	2,378,001	2,378,000	2,378,000	2,378,000
13	Unit Cost	($/BBLS)	76.2052	76.2087	76.2088	76.2720	76.2721	76.2721	76.2721
14	Amount	($)	204,470,000	204,087,000	204,087,000	181,375,000	181,375,000	181,375,000	181,375,000
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	0	0	0	0	0	0	0
21	Unit Cost	($/BBLS)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	#DIV/0!
22	Amount	($)	0	0	0	0	0	0	0
23									
24	Burned:								
25	Units	(BBLS)	15,446	13,421	10,903	38,325	8,093	2,197	88,385
26	Unit Cost	($/BBLS)	92.0627	93.2121	94.5611	95.6817	96.7503	95.1297	94.6201
27	Amount	($)	1,422,000	1,251,000	1,031,000	3,667,000	783,000	209,000	8,363,000
28									
29	Ending Inventory:								
30	Units	(BBLS)	1,203,511	1,190,090	1,179,187	1,140,862	1,132,769	1,130,572	1,130,572
31	Unit Cost	($/BBLS)	90.8816	90.8553	90.8202	90.6569	90.6134	90.6046	90.6046
32	Amount	($)	109,377,000	108,126,000	107,094,000	103,427,000	102,644,000	102,435,000	102,435,000
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	71,014	71,014	68,724	70,139	66,732	69,981	417,604
39	Unit Cost	($/Tons)	79.7026	75.6611	75.6504	75.7211	76.3502	73.3342	76.0769
40	Amount	($)	5,660,000	5,373,000	5,199,000	5,311,000	5,095,000	5,132,000	31,770,000
41									
42	Burned:								
43	Units	(Tons)	71,014	71,014	68,724	70,139	66,732	69,981	417,604
44	Unit Cost	($/Tons)	79.7026	75.6611	75.6504	75.7211	76.3502	73.3342	76.0769
45	Amount	($)	5,660,000	5,373,000	5,199,000	5,311,000	5,095,000	5,132,000	31,770,000
46									
47	Ending Inventory:								
48	Units	(Tons)	90,999	90,999	91,000	91,000	90,999	90,999	90,999
49	Unit Cost	($/Tons)	77.5943	77.5943	77.5934	77.5934	77.5943	77.5943	77.5943
50	Amount	($)	7,061,000	7,061,000	7,061,000	7,061,000	7,061,000	7,061,000	7,061,000
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	4,711,175	4,711,175	4,559,205	4,679,098	4,523,243	4,721,063	27,904,958
57	Unit Cost	($/MBTU)	2.1585	2.1661	2.1736	2.1814	2.1889	2.1965	2.1775
58	Amount	($)	10,169,000	10,205,000	9,910,000	10,207,000	9,901,000	10,370,000	60,762,000
59									
60	Burned:								
61	Units	(MBTU)	4,711,175	4,711,175	4,559,205	4,679,098	4,523,243	4,721,063	27,904,958
62	Unit Cost	($/MBTU)	2.1585	2.1661	2.1736	2.1814	2.1889	2.1965	2.1775
63	Amount	($)	10,169,000	10,205,000	9,910,000	10,207,000	9,901,000	10,370,000	60,762,000
64									
65	Ending Inventory:								
66	Units	(MBTU)	5,035,433	5,035,433	5,035,433	5,035,433	5,035,380	5,035,380	5,035,380
67	Unit Cost	($/MBTU)	2.1128	2.1128	2.1128	2.1128	2.1128	2.1128	2.1128
68	Amount	($)	10,639,000	10,639,000	10,639,000	10,639,000	10,639,000	10,639,000	10,639,000
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	47,562,898	47,589,317	45,651,251	44,984,787	33,615,396	32,129,648	251,533,297
75	Unit Cost	($/MCF)	6.5363	6.5276	6.5333	6.6691	6.9605	7.1719	6.6957
76	Amount	($)	310,883,513	310,644,139	298,255,529	300,006,570	233,981,532	230,431,033	1,684,202,317
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	23,769,566	23,769,566	22,267,796	18,073,422	22,824,021	24,370,626	135,074,997
83	Unit Cost	($/MBTU)	0.5632	0.5632	0.5617	0.5484	0.5814	0.5852	0.5680
84	Amount	($)	13,388,000	13,388,000	12,507,000	9,912,000	13,270,000	14,261,000	76,726,000

Company: Florida Power & Light

Schedule: E6

POWER SOLD

Estimated for the Period of : July 2010 thru December 2010

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost (Cents / KWH)	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	36,000		36,000	5.610	6.786	2,019,760	2,443,000	331,577
2010	St.Lucie Rel.		45,332		45,332	0.647	0.647	293,333	293,333	0
Total			81,332	0	81,332	2.844	3.364	2,313,093	2,736,333	331,577
August		OS	42,000		42,000	6.037	7.483	2,535,660	3,143,000	474,747
2010	St.Lucie Rel.		45,332		45,332	0.647	0.647	293,333	293,333	0
Total			87,332	0	87,332	3.239	3.935	2,828,993	3,436,333	474,747
September		OS	20,000		20,000	5.836	6.886	1,167,190	1,377,250	167,047
2010	St.Lucie Rel.		43,866		43,866	0.647	0.647	283,871	283,871	0
Total			63,866	0	63,866	2.272	2.601	1,451,061	1,661,121	167,047
October		OS	36,000		36,000	6.505	7.667	2,341,920	2,760,000	329,985
2010	St.Lucie Rel.		45,332		45,332	0.647	0.647	293,333	293,333	0
Total			81,332	0	81,332	3.240	3.754	2,635,253	3,053,333	329,985
November		OS	82,001		82,001	3.569	4.965	2,926,280	4,071,250	960,299
2010	St.Lucie Rel.		44,598		44,598	0.647	0.647	288,608	288,608	0
Total			126,599	0	126,599	2.539	3.444	3,214,888	4,359,858	960,299
December		OS	138,000		138,000	3.555	5.080	4,906,460	7,011,000	1,714,472
2010	St.Lucie Rel.		46,084		46,084	0.647	0.647	298,229	298,229	0
Total			184,084	0	184,084	2.827	3.971	5,204,689	7,309,229	1,714,472
Period		OS	354,001	0	354,001	4.491	5.877	15,897,270	20,805,500	3,978,127
	St.Lucie Rel.		270,545	0	270,545	0.647	0.647	1,750,708	1,750,708	0
Total			624,546	0	624,546	2.826	3.612	17,647,978	22,556,208	3,978,127

Schedule: E7

Company: Florida Power & Light

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : July 2010 thru December 2010

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2010	UPS		381,279			381,279	4.020		15,326,959
July	St. Lucie Rel.		38,577			38,577	0.486		187,324
	SJRPP		270,898			270,898	3.134		8,489,000
	PPAs		2,671			2,671	7.737		206,661
Total			693,425			693,425	3.491		24,209,944
2010	UPS		357,247			357,247	4.021		14,366,549
August	St. Lucie Rel.		38,577			38,577	0.486		187,324
	SJRPP		270,898			270,898	2.975		8,058,000
	PPAs		2,881			2,881	7.959		229,288
Total			669,603			669,603	3.411		22,841,162
2010	UPS		363,789			363,789	4.068		14,797,459
September	St. Lucie Rel.		37,333			37,333	0.486		181,291
	SJRPP		262,159			262,159	2.975		7,798,000
	PPAs		2,881			2,881	8.004		230,588
Total			666,162			666,162	3.454		23,007,338
2010	UPS		373,253			373,253	4.092		15,273,772
October	St. Lucie Rel.		38,577			38,577	0.486		187,324
	SJRPP		267,195			267,195	2.980		7,962,000
	PPAs		6,748			6,748	7.374		497,623
Total			685,773			685,773	3.488		23,920,719
	UPS		175,755			175,755	3.889		6,834,508
2010	St. Lucie Rel.		37,956			37,956	0.486		184,316
November	SJRPP		255,606			255,606	2.975		7,605,000
	PPAs		940			940	6.907		64,927
Total			470,257			470,257	3.124		14,688,751
	UPS		195,431			195,431	3.986		7,789,590
2010	St. Lucie Rel.		39,221			39,221	0.486		190,460
December	SJRPP		269,175			269,175	2.855		7,684,000
	PPAs								
Total			503,827			503,827	3.109		15,664,050
	UPS		1,846,754			1,846,754	4.028		74,388,837
Period	St. Lucie Rel.		230,241			230,241	0.486		1,118,039
Total	SJRPP		1,595,931			1,595,931	2.982		47,596,000
	PPAs		16,121			16,121	7.624		1,229,087
Total			3,689,047			3,689,047	3.370		124,331,964

Schedule: E8

Company: Florida Power & Light

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2010 thru December 2010

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2010 July	Qual. Facilities		431,153			431,153	4.658	4.658	20,081,000
Total			431,153			431,153	4.658	4.658	20,081,000
2010 August	Qual. Facilities		429,628			429,628	4.669	4.669	20,058,000
Total			429,628			429,628	4.669	4.669	20,058,000
2010 September	Qual. Facilities		417,540			417,540	4.588	4.588	19,155,000
Total			417,540			417,540	4.588	4.588	19,155,000
2010 October	Qual. Facilities		351,024			351,024	4.614	4.614	16,197,000
Total			351,024			351,024	4.614	4.614	16,197,000
2010 November	Qual. Facilities		304,043			304,043	3.791	3.791	11,527,000
Total			304,043			304,043	3.791	3.791	11,527,000
2010 December	Qual. Facilities		425,996			425,996	3.757	3.757	16,006,000
Total			425,996			425,996	3.757	3.757	16,006,000
Period Total	Qual. Facilities		2,359,384			2,359,384	4.367	4.367	103,024,000
Total			2,359,384			2,359,384	4.367	4.367	103,024,000

Company: Florida Power & Light

Economy Energy Purchases

Estimated For the Period of : July 2010 Thru December 2010

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
July	Florida	C	90,000	6.178	5,560,000	8.200	7,380,400	1,820,400
2010	Non-Florida	C	68,000	6.135	4,172,000	8.395	5,708,680	1,536,680
Total			158,000	6.159	9,732,000	8.284	13,089,080	3,357,080
August	Florida	C	120,000	5.467	6,560,000	7.059	8,470,800	1,910,800
2010	Non-Florida	C	55,000	6.116	3,364,000	8.164	4,490,370	1,126,370
Total			175,000	5.671	9,924,000	7.406	12,961,170	3,037,170
September	Florida	C	94,000	6.039	5,677,000	8.361	7,859,810	2,182,810
2010	Non-Florida	C	48,100	5.482	2,636,800	8.194	3,941,256	1,304,456
Total			142,100	5.851	8,313,800	8.305	11,801,066	3,487,266
October	Florida	C	48,000	5.542	2,660,000	8.431	4,047,120	1,387,120
2010	Non-Florida	C	61,500	5.323	3,273,500	8.399	5,165,370	1,891,870
Total			109,500	5.419	5,933,500	8.413	9,212,490	3,278,990
November	Florida	C	18,500	3.081	570,000	4.022	744,015	174,015
2010	Non-Florida	C	32,750	2.986	978,000	4.026	1,318,473	340,473
Total			51,250	3.020	1,548,000	4.024	2,062,488	514,488
December	Florida	C	12,900	2.972	383,400	3.868	498,973	115,573
2010	Non-Florida	C	26,500	3.091	819,000	3.876	1,027,200	208,200
Total			39,400	3.052	1,202,400	3.874	1,526,173	323,773
Period	Florida	C	383,400	5.584	21,410,400	7.564	29,001,118	7,590,718
Total	Non-Florida	C	291,850	5.223	15,243,300	7.419	21,651,349	6,408,049
Total			675,250	5.428	36,653,700	7.501	50,652,467	13,998,767

APPENDIX II

CAPACITY COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

TJK- 4
DOCKET NO. 100001-EI
FPL WITNESS: T. J. KEITH
August 2, 2010

CAPACITY COST RECOVERY CLAUSE CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT FOR THE PERIOD JANUARY THROUGH DECEMBER 2010							
LINE NO.		(1) ACTUAL JAN 2010	(2) ACTUAL FEB 2010	(3) ACTUAL MAR 2010	(4) ACTUAL APR 2010	(5) ACTUAL MAY 2010	(6) ACTUAL JUN 2010
1.	Payments to Non-cogenerators (UPS & SJRPP)	$22,025,054	$21,859,869	$21,638,970	$21,873,834	$22,635,491	$6,797,830
2.	Short-Term Capacity Purchases CCR	613,800	613,800	286,440	286,440	286,440	8,561,020
3.	QF Capacity Charges	26,440,047	27,333,692	27,247,711	24,947,038	25,051,318	25,097,317
4.	SJRPP Suspension Accrual	134,495	134,495	134,495	134,495	134,495	134,495
5.	Return on SJRPP Suspension Liability	(483,556)	(484,800)	(420,545)	(421,621)	(422,697)	(423,773)
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	3,099,362	3,418,397	3,792,765	2,074,049	2,781,813	2,180,832
7.	Transmission of Electricity by Others	0	0	378	21	0	635,637
8.	Transmission Revenues from Capacity Sales	(229,135)	(166,367)	(98,580)	(48,815)	(53,081)	33,367
9.	Total (Lines 1 through 8)	$ 51,600,067	$ 52,709,085	$ 52,581,634	$ 48,845,442	$ 50,413,779	$ 43,016,725
10.	Jurisdictional Separation Factor (a)	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%
11a.	Jurisdictional Capacity Charges	50,584,087	51,671,270	51,546,328	47,883,699	49,421,157	42,169,747
11b.	Nuclear Cost Recovery Costs	5,376,780	2,810,247	3,697,663	4,470,512	5,019,959	4,145,679
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	0	0	0	0
13.	Jurisdictional Capacity Charges Authorized	$ 51,215,401	$ 49,736,051	$ 55,243,991	$ 52,354,211	$ 54,441,116	$ 46,315,426
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 53,556,600	$ 44,803,546	$ 43,326,374	$ 40,527,864	$ 48,188,481	$ 56,628,272
15a.	Prior Period True-up Provision	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 47,633,513	$ 38,880,459	$ 37,403,287	$ 34,604,777	$ 42,265,394	$ 50,705,185
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(3,581,888)	(10,855,592)	(17,840,704)	(17,749,434)	(12,175,722)	4,389,759
18.	Interest Provision for Month	(8,171)	(8,594)	(10,282)	(12,947)	(18,926)	(22,332)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(71,077,044)	(68,744,016)	(73,685,116)	(85,613,014)	(97,452,309)	(103,723,869)
20.	Deferred True-up - Over/(Under) Recovery	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (47,852,518)	$ (52,793,618)	$ (64,721,516)	$ (76,560,811)	$ (82,832,371)	$ (72,541,857)

Notes:

(a) Jurisdictional separation factor approved by the FPSC in Order No. PSC-10-0153-FOF-EI, DOCKET NO. 080677-EI.

(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony, Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

Note that effective March 2010 this adjustment is no longer required as per Order No PSC-10-0153-FOF-EI, Docket No 080677-EI.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

LINE NO.		(7) ESTIMATED JUL 2010	(8) ESTIMATED AUG 2010	(9) ESTIMATED SEP 2010	(10) ESTIMATED OCT 2010	(11) ESTIMATED NOV 2010	(12) ESTIMATED DEC 2010	(13) TOTAL	LINE NO.
1.	Payments to Non-cogenerators (UPS & SJRPP)	$7,028,944	$7,028,944	$7,028,944	$7,028,944	$7,028,944	$7,028,944	$159,004,713	1.
2.	Short-Term Capacity Purchases CCR	8,922,124	8,922,124	8,922,124	7,980,964	7,980,964	8,308,324	61,684,562	2.
3.	QF Capacity Charges	24,381,882	24,381,882	24,381,882	24,381,882	24,381,882	24,381,882	302,408,414	3.
4.	SJRPP Suspension Accrual	134,495	134,495	134,495	134,495	134,495	134,495	1,613,942	4.
5.	Return on SJRPP Suspension Liability	(424,850)	(425,926)	(427,002)	(428,078)	(429,154)	(430,231)	(5,222,233)	5.
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	4,338,150	4,999,285	5,948,155	5,085,988	7,005,556	8,138,897	52,863,248	6.
7.	Transmission of Electricity by Others	1,013,532	1,091,942	1,031,033	1,039,719	1,664,984	1,619,901	8,097,146	7.
8.	Transmission Revenues from Capacity Sales	(91,663)	(132,593)	(43,013)	(88,095)	(184,671)	(390,068)	(1,492,712)	8.
9.	Total (Lines 1 through 8)	$ 45,302,615	$ 46,000,153	$ 46,976,618	$ 45,135,818	$ 47,582,999	$ 48,792,144	$ 578,957,079	9.
10.	Jurisdictional Separation Factor (a)	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	N/A	10.
11a.	Jurisdictional Capacity Charges	44,410,629	45,094,433	46,051,672	44,247,117	46,646,113	47,831,452	567,557,704	11a.
11b.	Nuclear Cost Recovery Costs	6,739,325	4,870,322	4,783,182	7,748,437	6,168,419	6,845,841	62,676,366	11b.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	0	0	0	0	0	0	(9,490,932)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 51,149,954	$ 49,964,755	$ 50,834,854	$ 51,995,553	$ 52,814,532	$ 54,677,293	$ 620,743,138	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 55,977,063	$ 55,607,966	$ 58,306,298	$ 50,010,957	$ 46,249,812	$ 44,418,370	$ 597,601,604	14.
15a.	Prior Period True-up Provision	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(5,923,087)	(71,077,044)	15a.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 50,053,976	$ 49,684,879	$ 52,383,211	$ 44,087,870	$ 40,326,725	$ 38,495,283	$ 526,524,560	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(1,095,978)	(279,876)	1,548,357	(7,907,683)	(12,487,807)	(16,182,010)	(94,218,578)	17.
18.	Interest Provision for Month	(20,456)	(18,935)	(17,028)	(16,233)	(17,484)	(19,943)	(191,332)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(93,433,355)	(88,626,703)	(83,002,427)	(75,548,011)	(77,548,840)	(84,131,045)	(71,077,044)	19.
20.	Deferred True-up - Over/(Under) Recovery	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20,891,498	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087	5,923,087	71,077,044	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (67,735,205)	$ (62,110,929)	$ (54,656,513)	$ (56,657,342)	$ (63,239,547)	$ (73,518,412)	$ (73,518,412)	22.

Notes:

(a) Jurisdictional separation factor approved by the FPSC in Order No. PSC-10-0153-FOF-EI, DOCKET NO. 080677-EI.

(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony, Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

Note that effective March 2010 this adjustment is no longer required as per Order No PSC-10-0153-FOF-EI, Docket No 080677-EI.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2010

Line No.		(1) ESTIMATED / ACTUAL (a)	(2) ORIGINAL PROJECTION	(3) VARIANCE AMOUNT	(4) VARIANCE %
1	Payments to Non-cogenerators (UPS & SJRPP)	$ 159,004,713	$ 157,009,305	$ 1,995,408	1.3 %
2	Short Term Capacity Payments	61,684,562	8,184,000	53,500,562	653.7 %
3	Payments to Cogenerators (QF's)	302,408,414	299,568,081	2,840,333	0.9 %
4	SJRPP Suspension Accrual	1,613,942	2,156,916	(542,975)	(25.2) %
5	Return Requirements on SJRPP Suspension Liability	(5,222,233)	(5,914,897)	692,664	(11.7) %
6	Incremental Plant Security Costs-Order No. PSC-02-1761	52,863,248	45,592,794	7,270,454	15.9 %
7	Transmission of Electricity by Others	8,097,146	-	8,097,146	N/A
8	Transmission Revenues from Capacity Sales	(1,492,712)	(2,488,823)	996,111	(40.0) %
9	Total (Lines 1 through 8)	$ 578,957,079	$ 504,107,376	$ 74,849,703	14.8 %
10	Jurisdictional Separation Factor (a)	98.03105%	99.09578%	1.06473%	1.1 %
11a	Jurisdictional Capacity Charges	$ 567,557,704	$ 499,549,136	$ 68,008,568	13.6 %
11b	Nuclear Cost Recovery Costs	$ 62,676,366	$ 62,676,366	-	0.0 %
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (9,490,932)	(56,945,592)	47,454,660	(83.3) %
13	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 620,743,138	$ 505,279,910	$ 115,463,228	22.9 %
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 597,601,604	$ 576,356,954	$ 21,244,650	3.7 %
15a	Prior Period True-up Provision	$ (70,908,235)	(70,908,235)	-	N/A
15b	Turkey Point Unit 5 GBRA Refund	$ (168,809)	(168,809)	-	N/A
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 526,524,560	$ 505,279,910	$ 21,244,650	4.2 %
17	True-up Provision for Period - Over/(Under) Recovery (Line 16 - Line 13)	$ (94,218,578)	$ -	$ (94,218,578)	N/A
18	Interest Provision for Period	(191,332)	-	$ (191,332)	N/A
19a	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	(70,908,235)	(70,908,235)	-	N/A
19b	Deferred True-up - Turkey Point 5 GBRA Refund	(168,809)	(168,809)	-	N/A
20	Deferred True-up - Over/(Under) Recovery	20,891,498	-	$ 20,891,498	N/A
21a	Turkey Point Unit 5 GBRA Refund	168,809	168,809	-	N/A
21b	Prior Period True-up Provision - Collected/(Refunded) this Period	70,908,235	70,908,235	-	N/A
22	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (73,518,412)	$ -	$ (73,518,412)	N/A

Notes: (a) Jurisdictional separation factor approved by the FPSC in Order No. PSC-10-0153-FOF-EI, Docket No. 080677-EI.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.
Note that effective March 2010 this adjustment is no longer required as per Order No PSC-10-0153-FOF-EI, Docket No 080677-EI.

APPENDIX III

FUEL COST RECOVERY

2011 RISK MANAGEMENT PLAN

GJY-2
DOCKET NO. 100001-EI
FPL WITNESS: G. J. YUPP
August 2, 2010

APPENDIX III

2011 RISK MANAGEMENT PLAN

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Florida Power and Light Company (FPL)
2011 Risk Management Plan

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

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

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

b) Hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the hedges were placed. FPL does not predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.

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

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

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

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

Fuel Procurement Risks (TFB-4, Item 3)

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

Market Risk

The risk of changes in economic fair value due to fluctuations in market prices, volatility, correlation, and interest rates will have a direct impact on any open or unhedged energy positions. The utility determines acceptable levels of risk for fuel procurement by performing various analyses that include forecasted/expected levels of activity, forecasted price levels and price changes, price volatility, and Value-at-Risk (VaR) calculations. The analyses are then presented to the Exposure Management Committee (EMC) for review and approval. The EMC is comprised of executive and senior management and has responsibility for developing and approving the company's risk strategies and objectives, including the overall hedging strategy. Approval is given to remain within specified VaR limits.

Credit Risk

Credit risk management includes appropriate creditworthiness review and monitoring processes, the request for collateral if deemed necessary, and the inclusion of contractual risk mitigation terms and conditions whenever possible. Such credit risk mitigations include collateral threshold amounts, cross default amounts, payment netting, and set-off agreements.

Liquidity Risk

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

Short-Term Funding Liquidity: Changes in underlying market parameters may impact movements of cash in relation to business activities. Positions that are balanced for fair value purposes, but unbalanced for cash flow purposes, may give rise to large swings in cash balances.

Operational Risk

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

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

FPL provides its fuel procurement activities with independent oversight.

The President of FPL is responsible for authorizing the overall hedging strategy. Changes in strategies and any deviations from the program are approved by the President of FPL prior to execution. In the absence of the President of FPL, the Chief Operating Officer (COO) or the Chief Financial Officer (CFO) of NextEra Energy, Inc. (NextEra Energy) may also authorize any changes in strategies and deviations from the program. Program activity is included in the Monthly Operations Performance Review (MOPR) chaired by the Chief Executive Officer (CEO) of NextEra Energy. In addition, the EMC meets monthly to review performance and discuss current procurement/hedging activities and monitors daily results of procurement activity.

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

Policy and Procedures

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

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

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

The Procedures provide guidance that will promote efficient and accurate processing of transactions, effective preparation and distribution of information relating to trading and marketing activities, and efficient monitoring of the portfolio of risks, all within a well-controlled environment. The Procedures define VaR and duration limits for all forward activity, by portfolio. In addition, individual procurement strategies must be documented and approved by front and middle office management prior to deal execution.

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

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

Deal Execution Details

FPL traders receive daily credit reports and credit watch lists from the Risk Management department to ensure that FPL does not enter into a trade with an unauthorized counterparty. FPL traders then select counterparties from this list to transact with as the hedging program is executed. FPL uses a market comparison approach to execute financial hedges. For natural gas, real-time prices can be observed by FPL through electronic tools, such as ICE (InterContinental Exchange), FutureSource, or over-the-counter brokers. Residual fuel oil swaps are not an exchange traded commodity and hence competing prices from counterparties, over-the-counter broker quotes, along with observed trends in crude oil prices, and estimated price differentials to crude oil prices, are used to determine the market value.

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

2011 Hedging Strategy (TFB-4, Items 2 and 8)

FPL plans to hedge a portion of its projected 2012 residual fuel oil and natural gas requirements during 2011. Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions), FPL will implement its hedging program within the following parameters:

Natural Gas

1) FPL will hedge approximately [redacted] of its projected 2012 natural gas requirements within the Hedging Window during 2011. This hedge percentage is consistent with 2011 hedge levels and is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements.
2) FPL will utilize [redacted] to hedge its projected natural gas requirements.
3) FPL will execute its natural gas hedges for 2012 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2012 natural gas requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

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

Heavy Fuel Oil

1) FPL will hedge approximately [redacted] of its projected [redacted] through [redacted] heavy fuel oil requirements. This hedge percentage is consistent with 2011 hedge levels and is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each of these individual month's projected heavy fuel oil requirements.
2) FPL will utilize [redacted] to hedge its projected heavy fuel oil requirements.
3) FPL will execute its heavy oil hedges for 2012 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected [redacted] heavy fuel oil requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

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

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

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

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

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

Daily Management Report

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

Credit Exposure Reporting

For each business day a formal report is produced for distribution to business unit and desk heads and members of the EMC. This report details:

- Credit exposure against available limits, highlighting instances in which exposure exceeds available limits; and
- Current credit liabilities.

Exposure Management Committee Update

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

- Summary and explanation of significant changes in market risk and fair value, including VaR back-testing results;
- Summary and explanation of significant changes in credit risk;
- Exception to Risk Management Policy; and
- Minutes of previous EMC update for approval.

Hedge Program Limitations (TFB-4, Item 15)

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

Potential Impact of Financial Reforms

The Frank-Dodd Wall Street Reform and Consumer Protection Act (the Act) was passed by the U.S. House of Representatives on June 30, 2010, the U.S. Senate on July 15, 2010 and signed into law by the President on July 21, 2010. The onus is now on the U.S. Securities and Exchange Commission (SEC) and the Commodity Futures Trading Commission (CFTC) to prepare regulatory policies in accordance with the provisions of the Act. FPL anticipates that some provisions in this Act could have an impact on the management of its hedge program. FPL has to await the regulators' interpretation of the Act to determine the effect on its hedge program.

One provision in the Act requires financial institutions to centrally clear all derivative transactions, while non-financial companies are exempt from this requirement. While FPL would be classified as a non-financial company, a majority of the counterparties that FPL utilizes to execute hedges would be classified as financial companies. It is still unclear how this will be achieved from an operational perspective. The SEC and CFTC will be working on these details. A majority of FPL's counterparties will see higher costs associated with derivatives' trading and may attempt to pass these costs on to end-users like FPL.

Another provision in the Act requires certain institutions to be identified as Major Swap Participants (MSP). This designation is reserved for entities that have a substantial net position in swaps and whose outstanding swaps create substantial counterparty exposure that can affect the stability of the U.S. financial system. While FPL itself is unlikely to be classified as an MSP, it is very possible that some of FPL's counterparties could receive this classification, subjecting them to higher regulation, capital requirements and business standards. This could potentially impact derivative trading operations for some of FPL's counterparties which could ultimately affect FPL.

Another possible outcome of the Act is the imposition of higher margins on non-cleared, over-the-counter (OTC) swaps and higher margin requirements from clearinghouses. However, regulators might allow non-financial companies more flexibility to utilize non-cash collateral. This area of legislation is still unclear until the regulators provide some directives to the market on their interpretation.

Finally, all entities will be subject to "real-time" reporting of swap volumes and prices, irrespective of whether the trade is cleared or OTC. This will certainly increase price transparency and should be beneficial in determining fair market pricing.

Energy Marketing & Trading

A division of Florida Power & Light Company.

Trading and Risk Management

Procedures Manual

Revision: June 2010

Approved By: ________________

(If the original signature is needed, please contact Risk Management at 304-6028)

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

TRADING AND RISK MANAGEMENT PROCEDURES MANUAL

APPROVED BY THE EMC ON:

December 17, 2009

Updated on July 14, 2010

(See EMC Meeting Minutes dated December 17, 2009. Please contact Risk Management at 304-6028)

NextEra Energy, Inc.
Energy Trading and Risk Management Policy

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

ENERGY TRADING AND RISK MANAGEMENT POLICY

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

PLANNED POSITION STRATEGY